INFORMATION SHEET

PRESIDING: Chair Mitchell, Commissioners Brown-Bland, Gray, Clodfelter, Duffley, Hughes
PLACE: Dobbs Building, Raleigh, North Carolina
DATE: December 18, 2019
TIME: 1:00 p.m. to 4:59 p.m.
DOCKET NO.: EMP-105, Sub 0
COMPANY: Friesian Holdings, LLC
DESCRIPTION: Application of Friesian Holdings, LLC, for a Certificate of Public Convenience and Necessity to Construct a 70-MW Solar Facility in Scotland County, North Carolina
VOLUME: 3

OFFICIAL COPY

APPEARANCES
(See attached.)

EXHIBITS
(See attached.)

COPIES ORDERED: Email: Levitas, Smith, Snowden, Dodge, Kemerait, Jirak
REPORTED BY: Linda Garrett
TRANSCRIBED BY: Linda Garrett
DATE TRANSCRIBED: January 7, 2019

TRANSCRIPT PAGES: 186
PREFILED PAGES: 37
TOTAL PAGES: 223

FILED

JAN 10 2020

Clerk's Office
N.C. Utilities Commission

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A P P E A R A N C E S:

FOR FRIESIAN HOLDINGS, LLC:

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Fox Rothschild, LLP
434 Fayetteville Street
Suite 2800
Raleigh, North Carolina 27601

Steven J. Levitas, Esq.
Kilpatrick Townsend & Stockton, LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR DUKE ENERGY PROGRESS:

Jack E. Jirak, Esq.
Associate General Counsel
Duke Energy Corporation
P.O. Box 1551/NCH 20
Raleigh, North Carolina 27602

A P P E A R A N C E S (Cont'd.):

FOR NORTH CAROLINA SUSTAINABLE
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Benjamin Smith, Esq.
North Carolina Sustainable Energy Association
4800 Six Forks Road
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Raleigh, North Carolina 27609

FOR NORTH CAROLINA CLEAN
ENERGY ALLIANCE:
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Raleigh, North Carolina 27609

FOR THE USING AND CONSUMING PUBLIC:
Tim R. Dodge, Esq.
Layla Cummings, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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EXAMINATIONS

TABLE OF CONTENTS

EXAMINATIONS (Cont'd.)

E X H I B I T S

EXHIBITS (Cont'd.)

IDENTIFIED/ADMITTED

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12/18/2019 DOCKET NO.: EMP-105, Sub 0

ATTORNEY NAME and TITLE: Karen Kemerait

FIRM NAME: ____________________

ADDRESS: ____________________

CITY: __________ STATE: __________ ZIP CODE: __________

APPEARING FOR: Applicant Friesian

APPLICANT: ✓ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

PLEASE NOTE: Non-confidential transcripts may be accessed by visiting the Commission's website at https://ncuc.net. Hover over the Dockets tab, select Docket Search from the drop-down menu, and enter the docket number.

Electronic transcripts are available at a charge of $5.00 per transcript

To order an electronic transcript, please provide an email address and sign below:

Email: ____________________

To order an electronic **confidential transcript**, please check the box and sign below:

☒ Yes, **I have signed the Confidentiality Agreement.**

SIGNATURE: Karen

(**Signature required** for distribution of ALL transcripts)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12/18/19 DOCKET NO.: EMP-105 sub 0

ATTORNEY NAME and TITLE: Steven Levitas

FIRM NAME: Kilpatrick Townsend

ADDRESS: 4208 Six Forks Road Suite 1400

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARING FOR: Friesian Holdings LLC

APPLICANT: ✓ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

PLEASE NOTE: Non-confidential transcripts may be accessed by visiting the Commission's website at https://ncuc.net. Hover over the Dockets tab, select Docket Search from the drop-down menu, and enter the docket number.

Electronic transcripts are available at a charge of $5.00 per transcript

To order an electronic transcript, please provide an email address and sign below:

Email: slevitas@kilpatricktownsend.com

To order an electronic **confidential transcript**, please check the box and sign below:

☑ Yes, **I have signed the Confidentiality Agreement.**

SIGNATURE: [signature]

(**Signature required** for distribution of <u>ALL</u> transcripts)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12-18-19 DOCKET NO.: EMP-105, Sub 0

ATTORNEY NAME and TITLE: Jack Jirak

FIRM NAME: Duke Energy

ADDRESS: ______

CITY: ______ STATE: ______ ZIP CODE: ______

APPEARING FOR: Duke

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

PLEASE NOTE: Non-confidential transcripts may be accessed by visiting the Commission's website at https://ncuc.net. Hover over the Dockets tab, select Docket Search from the drop-down menu, and enter the docket number.

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SIGNATURE: ______

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: Dec. 18, 2019 DOCKET NO.: EMP-105 Sub 0

ATTORNEY NAME and TITLE: Peter Ledford, General Counsel

FIRM NAME: NC Sustainable Energy Association

ADDRESS: 4800 Six Forks Road, Suite 300

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARING FOR: NC Sustainable Energy Association

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

PLEASE NOTE: Non-confidential transcripts may be accessed by visiting the Commission's website at https://ncuc.net. Hover over the Dockets tab, select Docket Search from the drop-down menu, and enter the docket number.

Electronic transcripts are available at a charge of $5.00 per transcript

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Email: ______________________________

To order an electronic **confidential transcript**, please check the box and sign below:

☐ Yes, **I have signed the Confidentiality Agreement.**

SIGNATURE: ______________________________

(**Signature required** for distribution of ALL transcripts)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12-18-2017 DOCKET NO.: EMP 105, S-50

ATTORNEY NAME and TITLE: Ben Smith Regulatory Counsel

FIRM NAME: N/A

ADDRESS: 4800 Six Forks Rd, Suite 300

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARING FOR: NCSEA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: ✓

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

PLEASE NOTE: Non-confidential transcripts may be accessed by visiting the Commission's website at https://ncuc.net. Hover over the Dockets tab, select Docket Search from the drop-down menu, and enter the docket number.

Electronic transcripts are available at a charge of $5.00 per transcript

To order an electronic transcript, please provide an email address and sign below:

Email: ben@energync.org

To order an electronic **confidential transcript**, please check the box and sign below:

☑ Yes, **I have signed the Confidentiality Agreement.**

SIGNATURE: ______________________

(**Signature required** for distribution of <u>ALL</u> transcripts)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 12/18/19 DOCKET NO.: EMP 105 Sub 0

ATTORNEY NAME and TITLE: Ben Snowden, counsel

FIRM NAME: Kilpatrick Townsend Stockton

ADDRESS: 4208 Six Forks Rd. Suite 1400

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARING FOR: NCCEBA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: ✓

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

PLEASE NOTE: Non-confidential transcripts may be accessed by visiting the Commission's website at https://ncuc.net. Hover over the Dockets tab, select Docket Search from the drop-down menu, and enter the docket number.

Electronic transcripts are available at a charge of $5.00 per transcript

To order an electronic transcript, please provide an email address and sign below:

Email: bsnowden@kilpatricktownsend.com

To order an electronic **confidential transcript**, please check the box and sign below:

☐ Yes, **I have signed the Confidentiality Agreement.**

SIGNATURE: Ben L. Snowden

(**Signature required** for distribution of <u>ALL</u> transcripts)

NORTH CAROLINA UTILITIES COMMISSION
PUBLIC STAFF - APPEARANCE SLIP

DATE 12-18-19 DOCKET # : EMP-105, Sub 0

PUBLIC STAFF MEMBER Tim Dodge / Layla Cummings

ORDER FOR TRANSCRIPT OF TESTIMONY TO BE **EMAILED** TO THE PUBLIC STAFF - PLEASE INDICATE YOUR DIVISION AS WELL AS YOUR EMAIL ADDRESS BELOW:

ACCOUNTING
WATER
COMMUNICATIONS
ELECTRIC
GAS
TRANSPORTATION
ECONOMICS
LEGAL tim.dodge@psncuc.nc.gov
CONSUMER SERVICES

PLEASE NOTE: Electronic Copies of the regular transcript can be obtained from the NCUC web site at HTTP://NCUC.commerce.state.nc.us/docksrch.html under the respective docket number.

1 Number of copies of Confidential portion of regular transcript (assuming a confidentiality agreement has been signed). Confidential pages will still be received in paper copies.

***PLEASE INDICATE BELOW WHO HAS SIG NED A CONFIDENTIALITY AGREEMENT. IF YOU DO NOT SIGN, YOU WILL NOT RECEIVE THE CONFIDENTIAL PORTIONS!!!!

Tim Dodge & Layla Cummings

Signature of Public Staff Member

Bidnar I/A

EMP-105, SUB 0

EXHIBIT 1

SOSID: 1436581
Date Filed: 3/30/2015 3:24:00 PM
Elaine F. Marshall
North Carolina Secretary of State

C2015 082 02832

OFFICIAL COPY

May 15 2019

State of North Carolina
Department of the Secretary of State
LIMITED LIABILITY COMPANY
ARTICLES OF ORGANIZATION

Pursuant to Section 57D-2-20 of the General Statutes of North Carolina, the undersigned does hereby submit these Articles of Organization for the purpose of forming a limited liability company.

1. The name of the limited liability company is: **Friesian Holdings LLC**

2. The name and address of each person executing these articles is as follows:

Name:	**Paula A. Kohut, organizer**
Number and Street:	**1422 Country Club Road**
City, State, Zip Code:	**Wilmington, NC 28403**

3. The name of the initial registered agent is: **Brian C. Bednar**

4. The street address and county of the initial registered agent is of the limited liability company is:

Number and Street:	**1125 E. Morehead Street, Suite 202**
City, State, Zip Code:	**Charlotte, NC 28204**
County:	**Mecklenburg**

5. The street address and telephone number of the principal office of the limited liability company is:

Number and Street:	**1125 E. Morehead St., Suite 202**
City, State, Zip Code:	**Charlotte, NC 28204**
County:	**Mecklenburg**
Telephone Number:	**(704) 665-5978**

6. The limited liability company does not elect to include any other provisions.

7. The business e-mail address for communication from the Secretary of State's Office is: *Privacy Redaction*

8. These articles will be effective upon filing.

This the 23rd day of March, 2015.

Paula A. Kohut, Organizer

4845-8790-6594, v. 1

EMP-105, SUB 0

EXHIBIT 4

I/A

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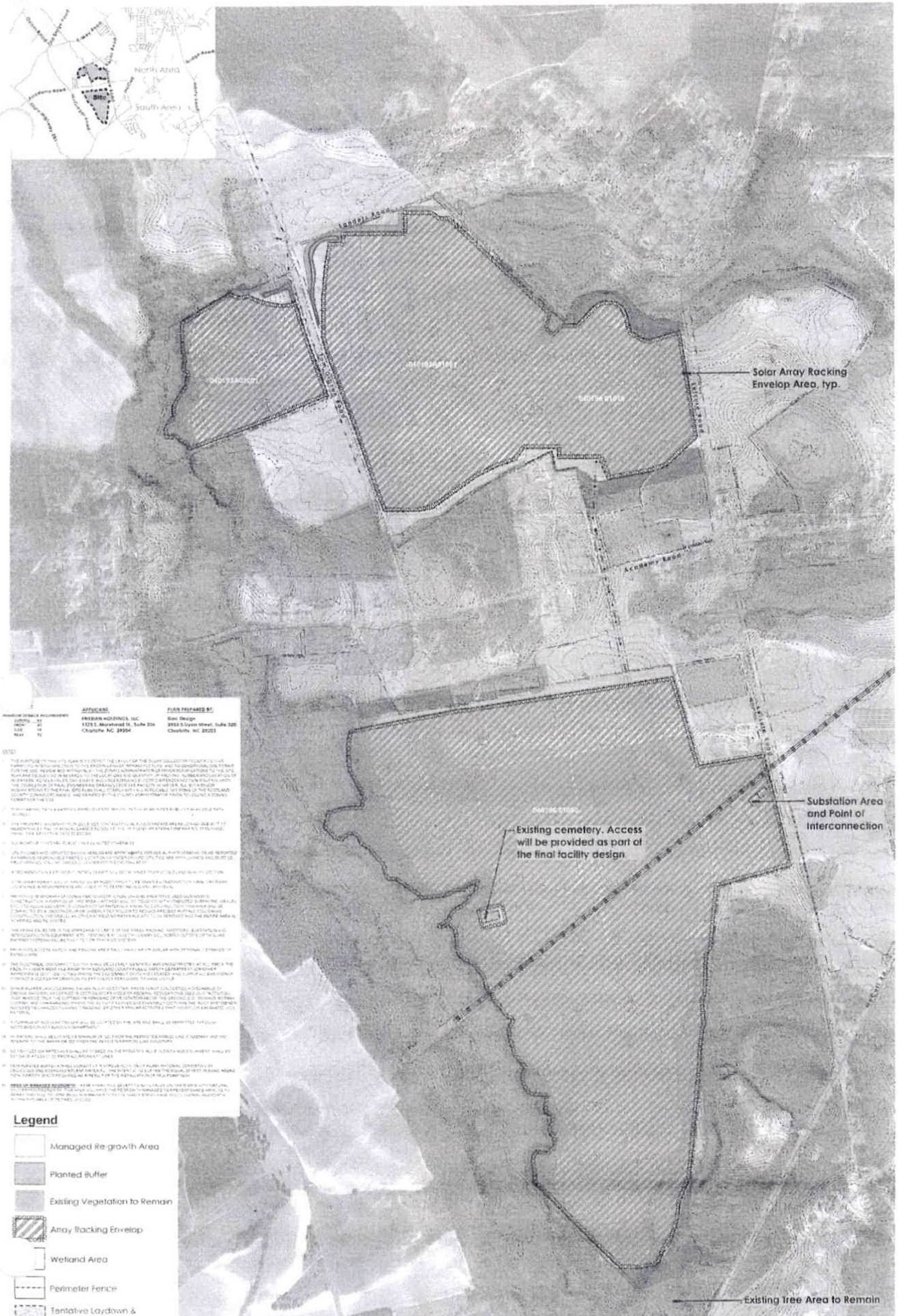
May 15 2019



PIN	OWNER	ZONING	PARCEL ACREAGE	LEASE (AC.)
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
		TOTAL	[illegible]	[illegible]

Friesian Solar

SUNSTUDIO

BIRDSEYE

Overall Plan

05.15.19

EMP-105, SUB 0

EXHIBIT 5

Bednar

I/A

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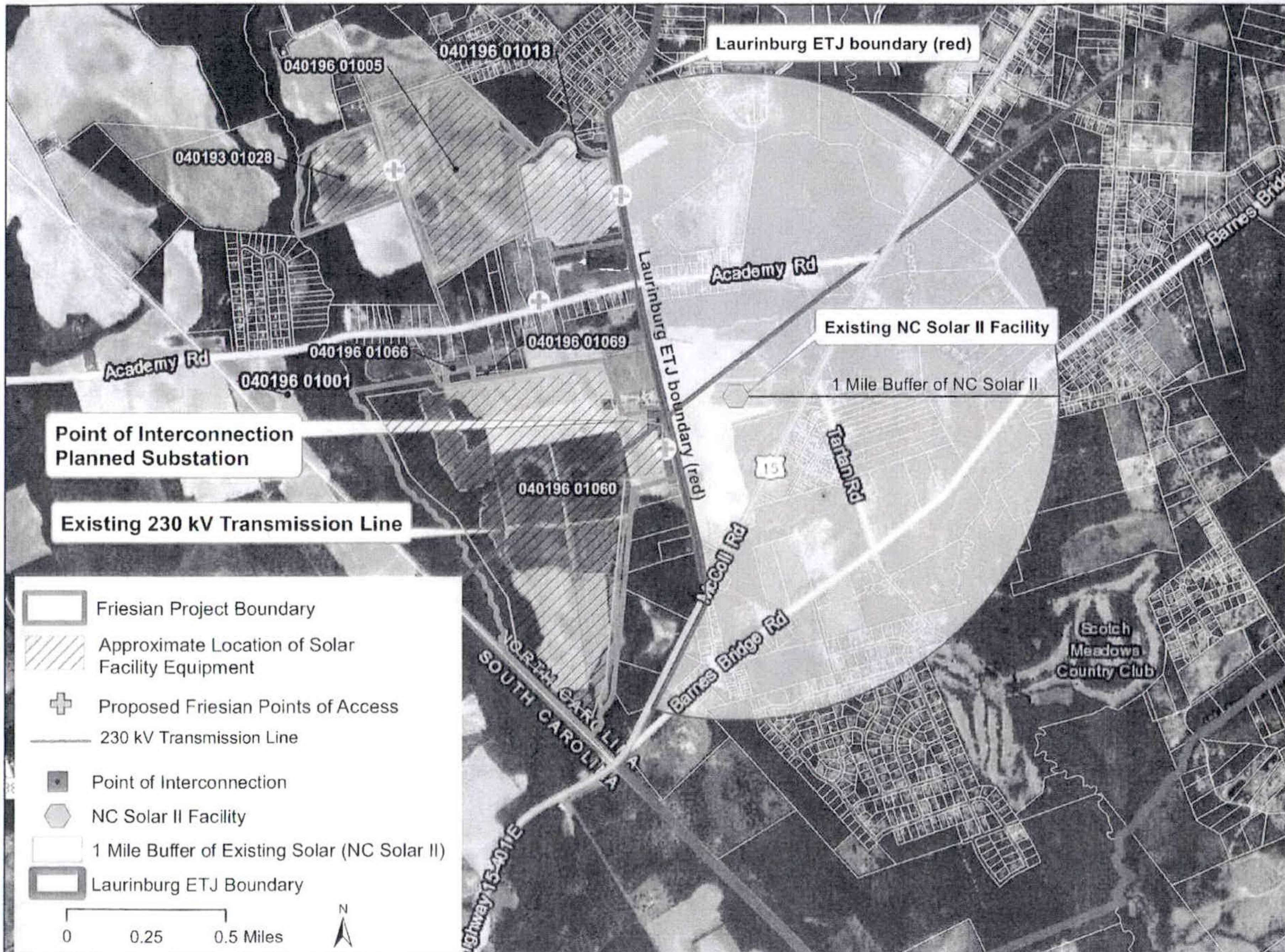
May 15 2019

Proposed Friesian Solar Development, Scotland County, NC



Bednar

EMP-105, SUB 0

EXHIBIT 6 (A)

I/A

OFFICIAL COPY

May 15 2019

County of Scotland

507 West Covington Street
Laurinburg, North Carolina 28352
Telephone: (910) 277-2406
Fax: (910) 277-2411
www.scotlandcounty.org

Kevin Patterson
County Manager

Travis Allen
Clerk to the Board

Board of Commissioners
Whit Gibson, Chair
Carol McCall, Vice Chair
John T. Alford
Bob Davis
Betty Blue Gholston
Guy McCook
Clarence McPhatter II

June 5, 2018

Mr. Brian C. Bednar
President
Birdseye Renewable Energy
1125 E. Morehead Street, Suite 202
Charlotte, NC 28204

Dear Mr. Bednar,

The Scotland County Board of Commissioners by unanimous vote at its June 4, 2018 regular meeting approved the conditional use permit for Birdseye Renewable Energy to construct a 604 acre solar farm to be located on three separate parcels identified as Scotland County Parcels 04019601060, 04019601018, and 040193A01001.

Sincerely,

Travis Allen
Clerk to the Board

AFFP
NOTICE OF PUBLIC HEARING

Affidavit of Publication

STATE OF NORTH CAROLINA } SS
COUNTY OF SCOTLAND }

Althea Simpson, being duly sworn, says:

That she is General Manager/Advertising Manager of the The Laurinburg Exchange, a daily newspaper of general circulation, printed and published in Laurinburg, Scotland County, North Carolina; that the publication, a copy of which is attached hereto, was published in the said

May 25, 2018, June 01, 2018

NOTICE OF
PUBLIC HEARING

Notice is hereby given that a Public Hearing will be held by the Scotland County Board of Commissioners at 7:00 PM (or as soon thereafter as possible) on Monday, June 4, 2018 in the A B Gibson Center Board Room, 322 S. Main St, Laurinburg, NC, to consider the following request:
Conditional Use Application Number 483-18 – Friesian Holdings, LLC (Birdseye Renewable Energy) – Request for a conditional use permit to construct a solar energy farm to produce clean renewable energy. The properties are located on McColl Road and Leisure Road, Laurinburg, North Carolina. Properties also known as Tax Map #196 Block 01 Parcel 060; Tax Map # 196 Block 01 Parcel 018 owned by William Bethea. Also property of Phillip and Ellen Futrell known as Tax Map # 193A Block 01 Parcel 001.

Persons interested are invited to attend this Public Hearing and express their opinions regarding the above request. Scotland County Government makes every effort to comply with the Americans with Disabilities Act. If you are handicapped individual and/or need an interpreter, please notify us at 910-277-3191 at least 72 hours before the hearing.

Laurinburg Exchange
May 25th, 2018 and June 1st, 2018

That said newspaper was regularly issued and circulated on those dates.
SIGNED:

Althea Simpson

General Manager/Advertising Manager

Subscribed to and sworn to me this 1st day of June 2018.

Amy Johnson-McNeill

Amy Johnson-McNeill, Notary Public, Scotland County, North Carolina
My commission expires: July 29, 2019

Amy Johnson-McNeill
Notary Public
Scotland County, North Carolina
My Commission Expires July 29, 2019

20082139 00931102 910-277-2411

Travis Allen
425-Scotland County
P.O. Box 489
Laurinburg, NC 28353-0489

Bearer
EMP-105, SUB 0

EXHIBIT 6 (B)

I/A

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May 15 2019

PILOT ENVIRONMENTAL, INC

May 30, 2018

Mr. Luke Rogers
Friesian Holdings Solar, LLC
1125 East Morehead Street, Suite 202
Charlotte, North Carolina 28204

Reference: Wetland Delineation
Friesian Holdings Solar Farm
Approximate 688 Acre Tract
Leisure Road
Laurinburg, Scotland County, North Carolina
Pilot Project 3536

Dear Mr. Rogers:

Pilot Environmental, Inc. (Pilot) is pleased to submit this report of the wetland delineation for the approximate 688 acre tract located west of Leisure Road in Laurinburg, Scotland County, North Carolina.

Background

Wetlands are defined by the United States Army Corps of Engineers (USACE) and the United States Environmental Protection Agency (EPA) as "those areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and under normal circumstances, do support a prevalence of vegetation typically adapted for life in saturated soil conditions." In order for an area to be classified as wetland, hydrophytic vegetation, hydric soils, and wetland hydrology indicators must be present.

Section 404 of the Clean Water Act regulates the discharge of dredge and fill materials into waters of the United States (lakes, rivers, ponds, streams, etc.), including wetlands. Waters of the United States include the territorial seas, navigable coastal and inland lakes, rivers and streams, intermittent streams, and wetlands. The EPA and the USACE jointly administer the Section 404 program. Section 401 of the Clean Water Act grants each state the authority to approve, condition, or deny any Federal permits that could result in a discharge to State waters.

Jurisdictional features include wetlands, open waters, ponds, lakes and perennial/intermittent streams. Jurisdictional features are regulated by the USACE and North Carolina Department of Environmental Quality-Division of Water Resources (NCDEQ-DWR). Permits are required prior to impacting any jurisdictional features. The type of permit required is specific to the type, location and amount of impacts. Stormwater management plans and/or mitigation for proposed impacts could be a requirement of the permit approval process.

The findings and conclusions found in this report are our opinions based on field conditions encountered at the time of the site visit. Changes including, but not limited to, regulations, weather, timber/vegetation removal and usage/development of the site or nearby properties can alter the findings and opinions presented in this report. We recommend that this report only be used for preliminary planning purposes. Agency verifications, followed by a survey of jurisdictional features are required to determine the exact extent and locations of jurisdictional features and are valid for a period of up to five years following issuance of a USACE Jurisdictional Determination (JD) and/or NCDEQ-DWR Site Determination Letter.

Global Positioning System (GPS) location of jurisdictional features has been conducted by Pilot personnel in the field utilizing a Trimble handheld GPS unit capable of sub-meter accuracy. Field GPS data has been post-processed by Pilot personnel and digitally provided to the client for assistance with preliminary planning. Pilot expresses no warranties or liabilities to accuracy of GPS locations and/or provided GPS data.

Scope of Services

Pilot was contracted to perform a wetland delineation for the approximate 688 acre tract located west of Leisure Road in Laurinburg, Scotland County, North Carolina. The site includes five parcels identified by the Scotland County Geographical Information System (GIS) as Parcel Numbers 04019601060, 04019601059, 04019604008, 04019601018 and 040193A01001. The site is being evaluated for proposed development with a solar farm. The scope of services included a delineation of jurisdictional features (streams, wetlands and other surface waters) located on the site. The site boundaries were not marked at the time of our field delineation. Pilot was provided the site boundary in a Google Earth digital file.

Literature Review

We reviewed the U.S. Geological Survey (USGS) Topographic Map, the U.S. Department of Agriculture (USDA) Soil Survey of Scotland County, the U.S. Fish and Wildlife Service (USFWS) National Wetland Inventory (NWI) Map and the Federal Emergency Management Agency (FEMA) Flood Insurance Rate Map (FIRM).

- The USGS Topographic Map (Drawing 1) identifies Bear Creek and associated wetlands along the western site boundary. An unnamed tributary to Bear Creek is depicted along the southeastern site boundary. An unnamed tributary to Gum Swamp is depicted near the northeastern site boundary. Several Carolina Bay depressions are depicted across the site. Additional drainage swales that could contain surface waters or wetlands are depicted on the site.

- The USDA Web Soil Survey of Scotland County (Drawing 2) depicts the following soil mapping units on the site:

Map unit symbol	Map unit name	Rating (% Hydric by Component)	Acres	Percent of Site
AeC	Ailey loamy sand, 8 to 15 percent slopes	3	10.9	1.6%
AuB	Autryville sand, 0 to 6 percent slopes	0	37.6	5.4%
BaA	Bibb soils, 0 to 2 percent slopes, frequently flooded	90	2.9	0.4%
BlC	Blanton sand, 8 to 15 percent slopes	0	17.8	2.6%
CoA	Coxville loam, 0 to 2 percent slopes	95	2.6	0.4%
DbA	Dunbar fine sandy loam, 0 to 2 percent slopes	4	25.5	3.7%
DpA	Duplin sandy loam, 0 to 2 percent slopes	5	23.2	3.4%
GoA	Goldsboro loamy sand, 0 to 2 percent slope	0	18.7	2.7%
GrC	Gritney sandy loam, 6 to 10 percent slopes	3	0.4	0.1%
JmA	Johnston soils, 0 to 2 percent slopes, frequently flooded	100	83.2	12.0%
LyA	Lynchburg sandy loam, 0 to 2 percent slopes	8	2.6	0.4%
McA	McColl loam, 0 to 1 percent slopes, ponded	90	9.5	1.4%
NcA	Noboco loamy sand, 0 to 2 percent slopes	0	132.7	19.2%
NcB	Noboco loamy sand, 2 to 6 percent slopes	0	16.6	2.4%
NoA	Norfolk loamy sand, 0 to 2 percent slopes	0	92.4	13.4%
NoB	Norfolk loamy sand, 2 to 6 percent slopes	0	41.0	5.9%
PuA	Plummer and Osier soils, 0 to 2 percent slopes	70	0.5	0.1%
WaB	Wagram loamy sand, 0 to 6 percent slopes	5	168.8	24.4%
Subtotals for Soil Survey Area			**686.8**	**99.5%**

Pilot also reviewed the last published USDA Soil Survey of Scotland County (Drawing 2A). Bear Creek is identified on the western portion of the site. Surface waters or wetlands are not depicted on the site.

- The USFWS NWI Map (Drawing 3) identifies freshwater ponds and forested/shrub and emergent wetlands around the perimeter of the site. A linear riverine feature is depicted on the southeastern portion of the site.

- The FEMA FIRM (Drawing 4) indicates that the majority of the site is located within Zone X, an area outside the 100-year floodplain. A small area on the southern portion of the site is identified as being located within the 100-year floodplain.

Field Delineation

Pilot personnel conducted the field delineation on March 20, 2018. The site contains wooded land and fields. Structures are not located on the site. Neither ponds nor streams are located on the site.

Wetlands are located within several areas around the perimeter of the site. The wetlands are separated from uplands by distinct breaks in topography, soils and/or vegetation. USACE Wetland Determination Data Forms, documenting our findings, are included as attachments. The wetlands were flagged in the field with red and white striped surveyor flagging and located with a handheld Trimble GPS unit.

Watershed Classification/Buffer Requirements

According to the NCDEQ-DWR, the site is located in the Lumber River Basin. The site drains to Bear Creek (Class C; Swamp waters) and Gum Swamp (Class B; Swamp waters). In accordance with 15A NCAC 02B .0200, state riparian buffer regulations are not applicable to surface waters located on or adjacent to the site.

Pilot reviewed the Scotland County Zoning Ordinance and contacted the Scotland County Planning Department to inquire about surface water and/or wetland buffer regulations. According to Ms. Joy Nolan, Zoning Official with the Scotland County Zoning Department, Scotland County buffer regulations are generally consistent with the state. Consultation with Scotland County is recommended to determine development specific buffer requirements.

According to the NCDEQ-DWR Interactive Stormwater Map, the site is located in an area identified as "No Program - Verify Locally." Consultation with Scotland County is recommended to determine site and development specific setbacks from surface waters for compliance with state and local stormwater requirements.

Agency Verification

The delineation was verified in the field by Ms. Rachel Capito, Regulatory Specialist with the USACE, on May 23, 2018. Ms. Capito concurred with the delineation as depicted on the attached Drawing 5. Drawing 5 shows the results of the delineation as verified by the USACE and is intended for preliminary planning purposes. We understand that jurisdictional features will be surveyed to determine their exact extents and locations. A preliminary Jurisdictional Determination (PJD) has been requested and will be provided upon receipt from the USACE.

Closing

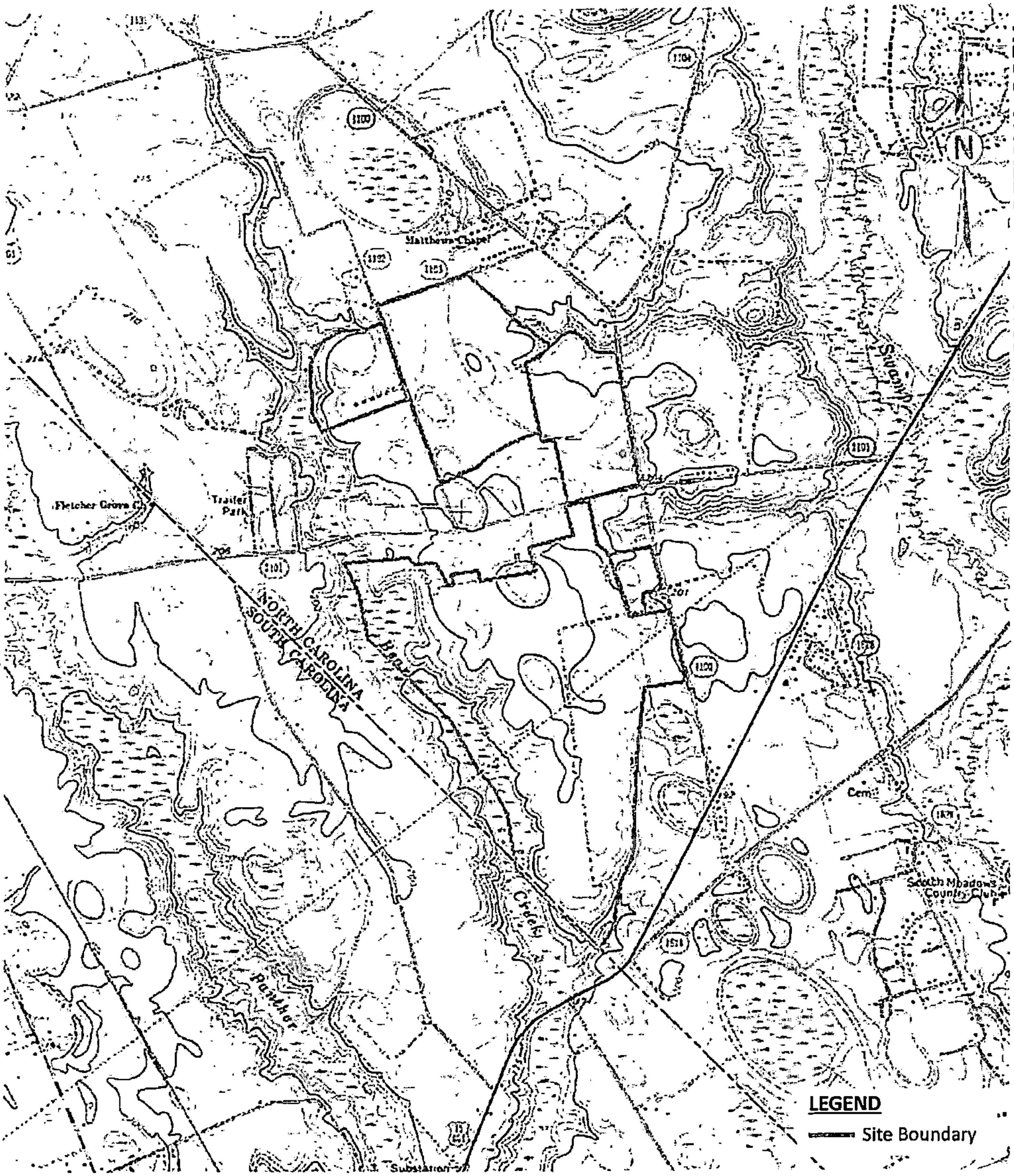
We appreciate the opportunity to provide our services to you. Please contact us at (336) 310-4527 if you have questions or require additional information.

Sincerely,

David S. Brame, PWS
Project Manager

Michael T. Brame, PWS
Principal

Attachments: Drawing 1 – USGS Topographic Map
Drawing 2 – Web Soil Map
Drawing 2A – Published Soil Map
Drawing 3 – NWI Map
Drawing 4 – FEMA FIRM
Drawing 5 – Wetland Map
Wetland Determination Data Forms



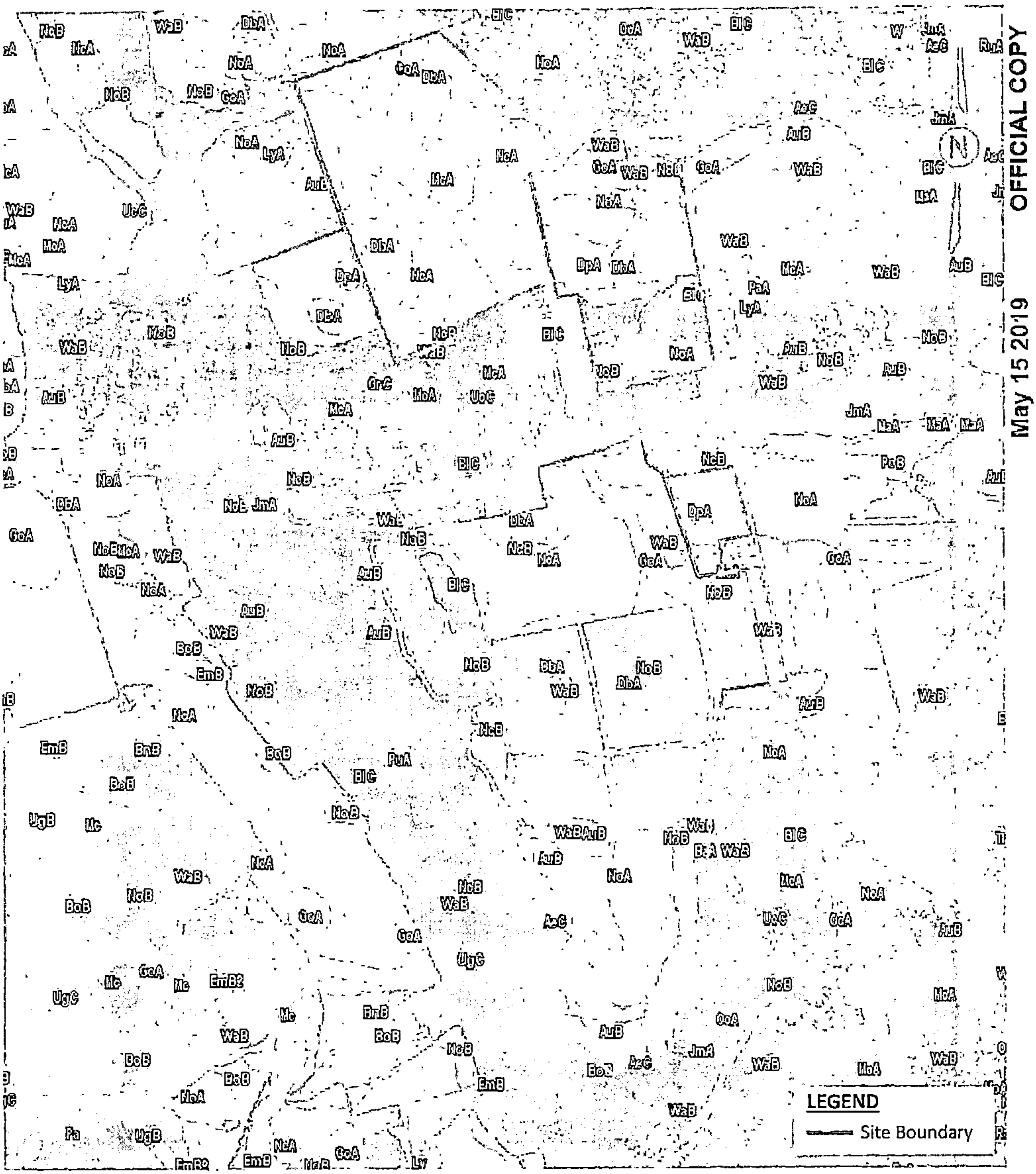
OFFICIAL COPY

May 15 2019

Drawing 1
USGS Topographic Map
McColl, SC Quadrangle
Scale: 1" = 2,000'

PILOT
PILOT ENVIRONMENTAL, INC

USGS Topographic Map
Friesian Holdings
Approximate 688 Acre Tract
Laurinburg, Scotland County, NC
Pilot Project 3536

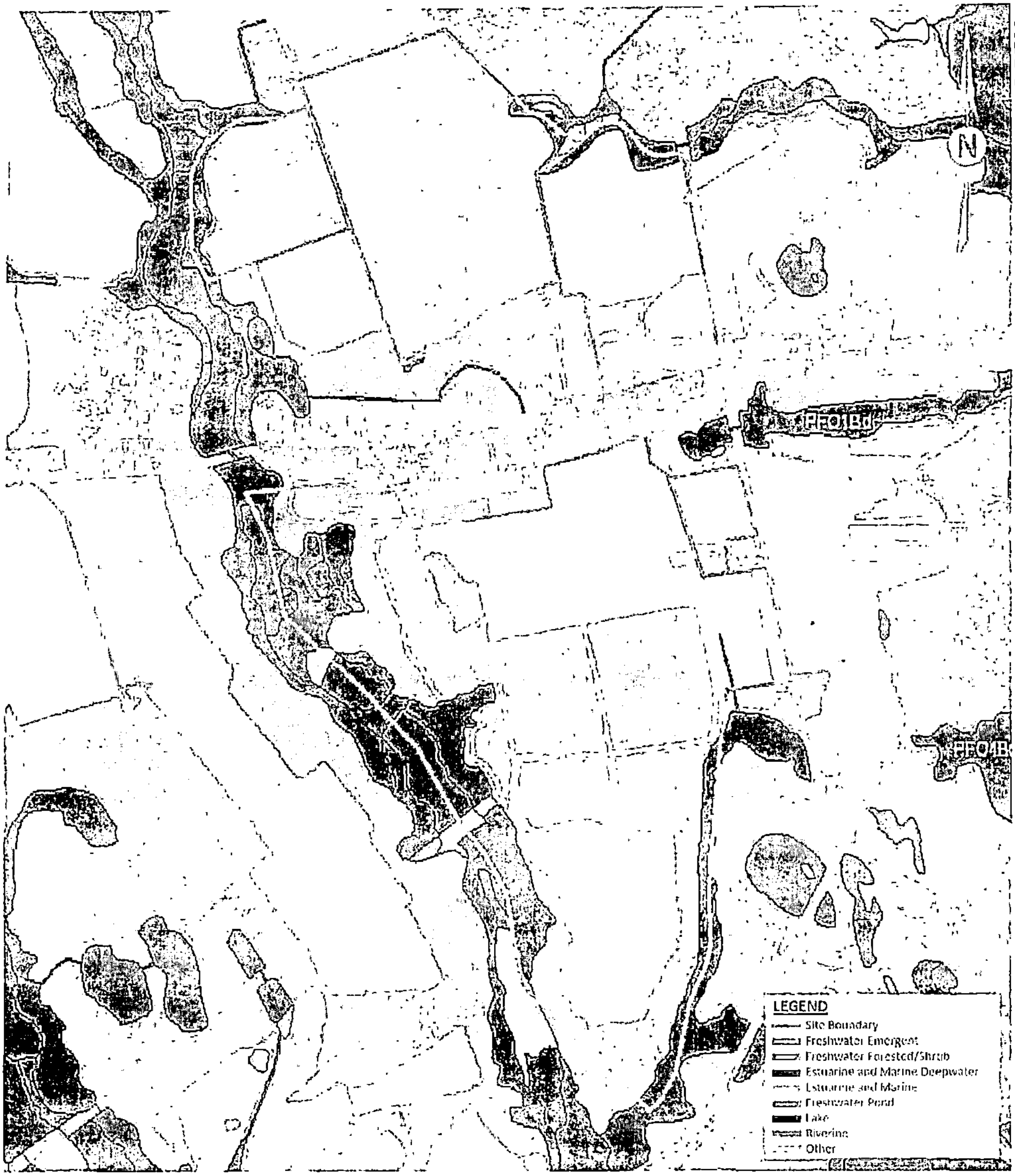


Drawing 2
USDA Web Soil Survey
of Scotland County NC
Scale: 1" = 1,250'

Web Soil Map
Friesian Holdings
Approximate 688 Acre Tract
Laurinburg, Scotland County, NC
Pilot Project 3536

Drawing 2A
USDA Soil Survey
of Scotland County, NC
Published 2006, Sheet 27
Scale: 1″ = 1,250′

Published Soil Map
Friesian Holdings
Approximate 688 Acre Tract
Laurinburg, Scotland County, NC
Pilot Project 3536



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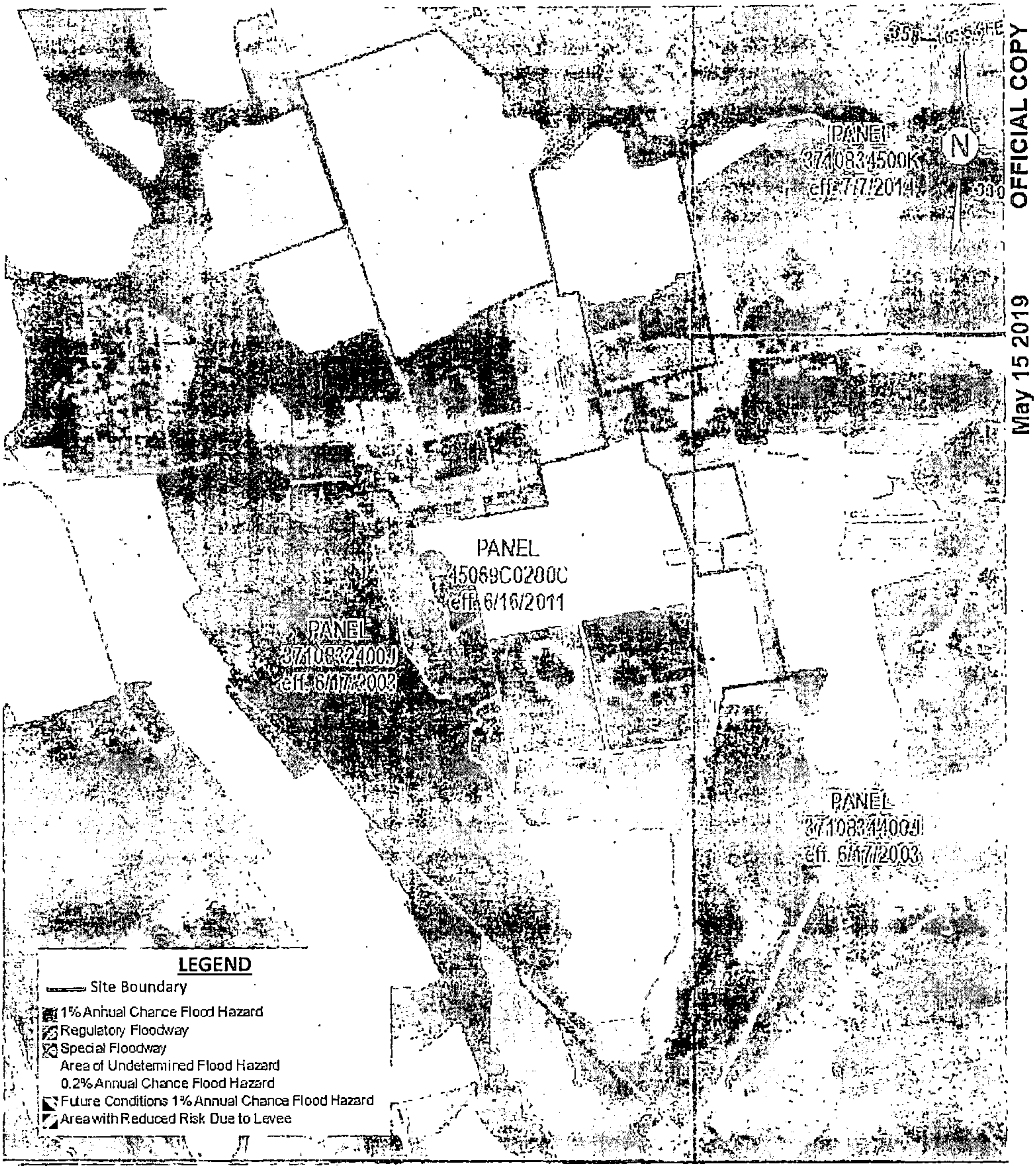
May 15 2019

Drawing 3
USFWS NWI
Wetlands Mapper
Scale: 1" = 1,250'

PILOT
PILOT ENVIRONMENTAL, INC

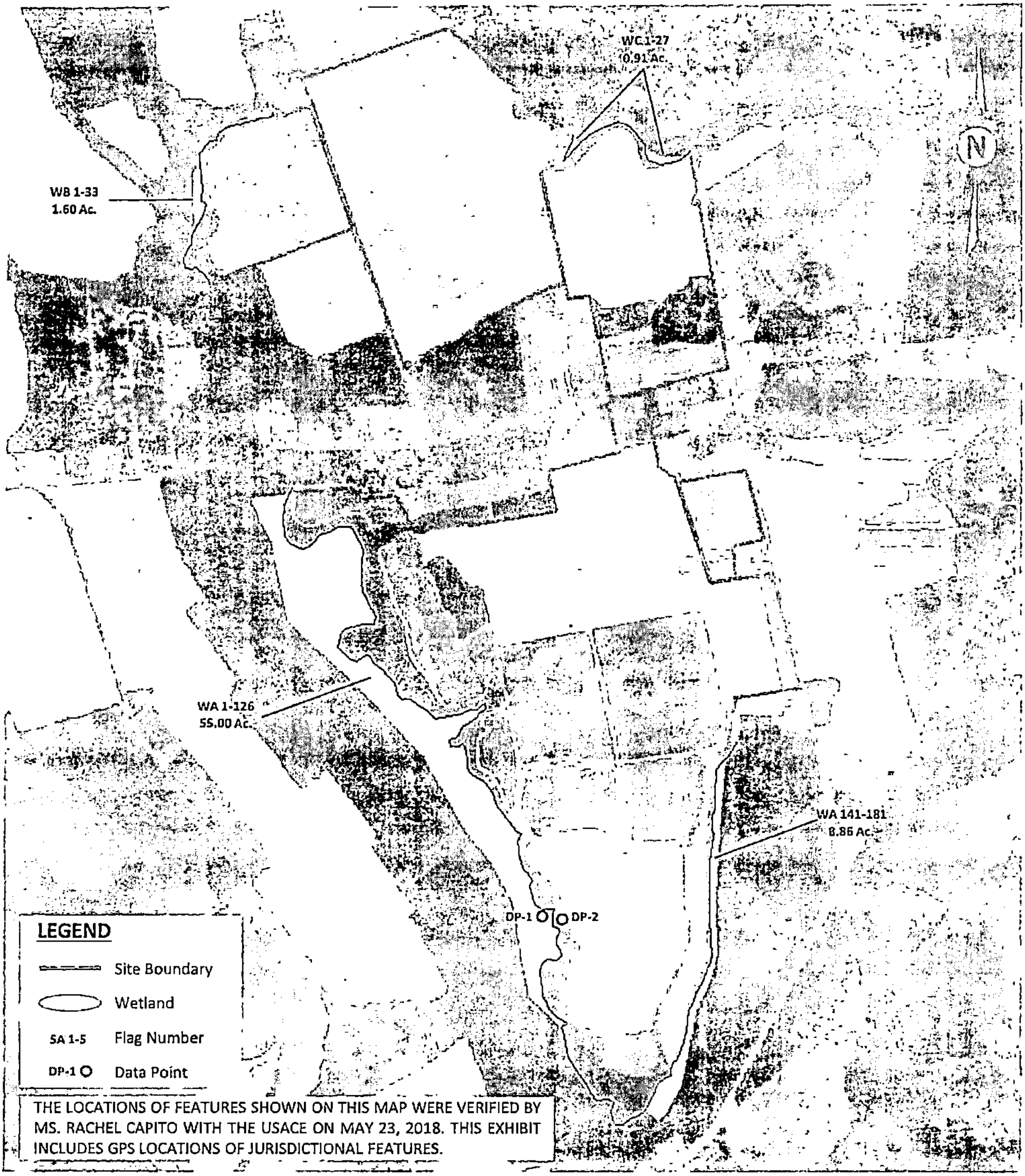
NWI Map
Friesian Holdings
Approximate 688 Acre Tract
Laurinburg, Scotland County, NC
Pilot Project 3536



Drawing 4
National Flood Hazard Layer
from FEMA Web Map Service
Scale: 1" = 1,250'

PILOT
PILOT ENVIRONMENTAL, INC

FEMA FIRM
Friesian Holdings
Approximate 688 Acre Tract
Laurinburg, Scotland County, NC
Pilot Project 3536



OFFICIAL COPY

May 15 2019

Drawing 5
Aerial Imagery from ESRI
and Pilot GPS Data
Scale: 1" = 1,250'
Date: 3.22.18
Revised: 5.29.18

PILOT
PILOT ENVIRONMENTAL, INC

Wetland Map
Friesian Holdings
Approximate 688 Acre Tract
Laurinburg, Scotland County, NC
Pilot Project 3536

WETLAND DETERMINATION DATA FORM – Atlantic and Gulf Coastal Plain Region

Project/Site: Friesian Holdings City/County: McColl/Scotland & Marlboro Sampling Date: 03.20.2018

Applicant/Owner: Birdseye Renewables State: NC Sampling Point: DP-1

Investigator(s): Brame Section, Township, Range: NA

Landform (hillslope, terrace, etc.) Floodplain Local relief (concave, convex, none): Flat Slope (%): 1

Subregion (LRR or MLRA): T Lat: 34.694708 Long: -79.537743 Datum: WGS 84

Soil Map Unit Name: Johnston soils (JmA) NWI Classification: None

Are climatic / hydrologic conditions on the site typical for this time of year? Yes X No ___ (If no, explain in Remarks.)

Are Vegetation ___, Soil ___, or Hydrology ___ significantly disturbed? Are "Normal Circumstances" present? Yes X No ___

Are Vegetation ___, Soil ___, or Hydrology ___ naturally problematic? (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes X No ___	Is the Sampled Area within a Wetland? Yes X No ___
Hydric Soil Present?	Yes X No ___	
Wetland Hydrology Present?	Yes X No ___	

Remarks:
This data point is representative of all the wetlands on the site.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one is required; check all that apply)

- ___ Surface Water (A1)
- X High Water Table (A2)
- X Saturation (A3)
- ___ Water Marks (B1)
- ___ Sediment Deposits (B2)
- ___ Drift Deposits (B3)
- ___ Algal Mat or Crust (B4)
- ___ Iron Deposits (B5)
- ___ Inundation Visible on Aerial Imagery (B7)
- X Water-Stained Leaves (B9)
- ___ Aquatic Fauna (B13)
- ___ Marl Deposits (B15) **(LRR U)**
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres on Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ___ Surface Soil Cracks (B6)
- ___ Sparsely Vegetated Concave Surface (B8)
- ___ Drainage Patterns (B10)
- ___ Moss Trim Lines (B16)
- ___ Dry-Season Water Table (C2)
- X Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- X Geomorphic Position (D2)
- ___ Shallow Aquitard (D3)
- X FAC-Neutral Test (D5)
- X Sphagnum moss (D8) **(LRR T, U)**

Field Observations:

Surface Water Present?	Yes ___	No X	Depth (inches):	
Water Table Present?	Yes X	No ___	Depth (inches):	10
Saturation Present? (includes capillary fringe)	Yes X	No ___	Depth (inches):	1

Wetland Hydrology Present? Yes X No ___

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

VEGETATION (Five Strata) - Use scientific names of plants. Sampling Point DP-1

Tree Stratum (Plot size: 30)

	Absolute % Cover	Dominant Species?	Indicator Status
1. Liquidambar styraciflua	40	Y	FAC
2. Acer rubrum	10	Y	FAC
3. Nyssa biflora	10	Y	OBL
4.			
5.			
6.			
	40	= Total Cover	

50 % of total cover: 20 20 % of total cover: 8

Sapling Stratum (Plot size: 30)

	Absolute % Cover	Dominant Species?	Indicator Status
1. Lyonia lucida	10	Y	FACW
2. Persea borbonia	5	Y	FACW
3.			
4.			
5.			
6.			
	15	= Total Cover	

50 % of total cover: 7.5 20 % of total cover: 3

Shrub Stratum (Plot size: 30)

	Absolute % Cover	Dominant Species?	Indicator Status
1. Ligustrum sinense	10	Y	FAC
2.			
3.			
4.			
5.			
6.			
	10	= Total Cover	

50 % of total cover: 5 20 % of total cover: 2

Herb Stratum (Plot size: 30)

	Absolute % Cover	Dominant Species?	Indicator Status
1. Arundinaria gigantea	10	Y	FAC
2. Woodwardia areolata	5	Y	OBL
3. Rosa palustris	5	Y	OBL
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	20	= Total Cover	

50 % of total cover: 10 20 % of total cover: 4

Woody Vine Stratum (Plot size: 30)

	Absolute % Cover	Dominant Species?	Indicator Status
1. Smilax glauca	5	Y	FAC
2. Smilax rotundifolia	5	Y	FAC
3.			
4.			
5.			
	10	= Total Cover	

50 % of total cover: 5 20 % of total cover: 2

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 11 (A)

Total Number of Dominant Species Across All Strata: 11 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 100 (A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:	
OBL species		x 1 =	
FACW species		X 2 =	
FAC species		X 3 =	
FACU species		X 4 =	
UPL species		X 5 =	
Column Totals:		(A)	(B)

Prevalence Index = B/A =

Hydrophytic Vegetation Indicators:

___ 1 – Rapid Test for Hydrophytic Vegetation

X 2 – Dominance Test is > 50%

___ 3 – Prevalence Test is ≤ 3.0[1]

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Definitions of Vegetation Strata:

Tree – Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling – Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub – Woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb – All herbaceous (non-woody) plants, including herbaceous vines, regardless of size. Includes woody plants, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vine – All woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes X No ___

Remarks: (Include photo numbers here or on a separate sheet.)

SOIL

Sampling Point: DP-1

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox Features %	Type[1]	Loc[2]	Texture	Remarks
0-3	10YR 3/2	100					Loam	
3-18	2.5Y 4/1	95	10YR 4/6	5	C	M	Loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators:

- __ Histosol (A1)
- __ Histic Epipedon (A2)
- __ Black Histic (A3)
- __ Hydrogen Sulfide (A4)
- __ Stratified Layers (A5)
- __ Organic Bodies (A6) **(LRR P, T, U)**
- __ 5 cm Mucky Mineral (A7) **(LRR P, T, U)**
- __ Muck Presence (A8) **(LRR U)**
- __ 1 cm Muck (A9) **(LRR P, T)**
- __ Depleted Below Dark Surface (A11)
- __ Thick Dark Surface (A12)
- __ Coast Prairie Redox (A16) **(MLRA 150A)**
- __ Sandy Mucky Mineral (S1) **(LRR O, S)**
- __ Sandy Gleyed Matrix (S4)
- __ Sandy Redox (S5)
- __ Stripped Matrix (S6)
- __ Dark Surface (S7) **(LRR P, S, T, U)**
- __ Polyvalue Below Surface (S8) **(LRR S, T, U)**
- __ Thin Dark Suface (S9) **(LRR S, T, U)**
- __ Loamy Gleyed Matrix (F1) **(LRR O)**
- __ Loamy Gleyed Matrix (F2)
- X Depleted Matrix (F3)
- __ Redox Dark Surface (F6)
- __ Depleted Dark Surface (F7)
- __ Redox Depressions (F8)
- __ Marl (F10) **(LRR U)**
- __ Depleted Ochric (F11) **(MLRA 151)**
- __ Iron Manganese Masses (F12) **(LRR O, P, T)**
- __ Umbric Surface (F13) **(LRR P, T, U)**
- __ Delta Ochric (F17) **(MLRA 151)**
- __ Reduced Vertic (F18) **(MLRA 150A, 150B)**
- __ Piedmont Floodplain Soils (F19) **(MLRA 149A)**
- __ Anomalous Bright Loamy Soils (F20) **(MLRA 149A, 153C, 153D)**

Indicators for Problematic Hydric Soils[3]:

- __ 1 cm Muck (A9) **(LRR O)**
- __ 2 cm Muck (A10) **(LRR S)**
- __ Reduced Vertic (F18) **(outside MLRA 150A,B)**
- __ Piedmont Floodplain Soils (F19) **(LRR P, S, T)**
- __ Anomalous Bright Loamy Soils (F20) **(MLRA 153B)**
- __ Red Parent Material (TF2)
- __ Very Shallow Dark Surface (TF12)
- __ Other (Explain in Remarks)

[3]Indicators of Hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):

Type: ____

Depth (inches): ____

Hydric Soil Present? Yes X No ____

Remarks:

WETLAND DETERMINATION DATA FORM – Atlantic and Gulf Coastal Plain Region

Project/Site: Friesian Holdings City/County: McColl/Scotland & Marlboro Sampling Date: 03.20.2018

Applicant/Owner: Birdseye Renewables State: NC Sampling Point: DP-2

Investigator(s): Brame Section, Township, Range: NA

Landform (hillslope, terrace, etc.) Side Slope Local relief (concave, convex, none): Gentle Slope Slope (%): 2-3

Subregion (LRR or MLRA): T Lat: 34.694679 Long: -79.537117 Datum: WGS 84

Soil Map Unit Name: Ailey loamy sand (AeC) NWI Classification: None

Are climatic / hydrologic conditions on the site typical for this time of year? Yes X No ___ (If no, explain in Remarks.)

Are Vegetation ___, Soil ___, or Hydrology ___ significantly disturbed? Are "Normal Circumstances" present? Yes X No ___

Are Vegetation ___, Soil ___, or Hydrology ___ naturally problematic? (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes X No ___	Is the Sampled Area within a Wetland? Yes ___ No X
Hydric Soil Present?	Yes ___ No X	
Wetland Hydrology Present?	Yes ___ No X	

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one is required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1)
- ___ Sediment Deposits (B2)
- ___ Drift Deposits (B3)
- ___ Algal Mat or Crust (B4)
- ___ Iron Deposits (B5)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Aquatic Fauna (B13)
- ___ Marl Deposits (B15) **(LRR U)**
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres on Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (minimum of two required)

- ___ Surface Soil Cracks (B6)
- ___ Sparsely Vegetated Concave Surface (B8)
- ___ Drainage Patterns (B10)
- ___ Moss Trim Lines (B16)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Geomorphic Position (D2)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)
- ___ Sphagnum moss (D8) **(LRR T, U)**

Field Observations:

Surface Water Present?	Yes ___	No X	Depth (inches): ___
Water Table Present?	Yes ___	No X	Depth (inches): ___
Saturation Present? (includes capillary fringe)	Yes ___	No X	Depth (inches): ___

Wetland Hydrology Present? Yes ___ No X

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

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May 15 2019

VEGETATION (Five Strata) - Use scientific names of plants.

Sampling Point DP-2

Tree Stratum (Plot size: 30)	Absolute % Cover	Dominant Species?	Indicator Status
1. Liquidambar styraciflua	20	Y	FAC
2. Liriodendron tulipifera	20	Y	FACU
3. Pinus taeda	20	Y	FAC
4.			
5.			
6.			
	60	= Total Cover	
50 % of total cover: 30	20 % of total cover: 12		

Sapling Stratum (Plot size: 30)	Absolute % Cover	Dominant Species?	Indicator Status
1. Juniperus virginiana	5	Y	FACU
2.			
3.			
4.			
5.			
6.			
	5	= Total Cover	
50 % of total cover: 2.5	20 % of total cover: 1		

Shrub Stratum (Plot size: 30)	Absolute % Cover	Dominant Species?	Indicator Status
1. Ligustrum sinense	10	Y	FAC
2.			
3.			
4.			
5.			
6.			
	10	= Total Cover	
50 % of total cover: 5	20 % of total cover: 2		

Herb Stratum (Plot size: 30)	Absolute % Cover	Dominant Species?	Indicator Status
1. Allium canadense	5	Y	FACU
2. Microstegium nepal	10	Y	FAC
3. Smilax rotundifolia	5	Y	FAC
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	20	= Total Cover	
50 % of total cover: 10	20 % of total cover: 4		

Woody Vine Stratum (Plot size: 30)	Absolute % Cover	Dominant Species?	Indicator Status
1. Vitis rotundifolia	5	Y	FAC
2.			
3.			
4.			
5.			
	10	= Total Cover	
50 % of total cover: 5	20 % of total cover: 2		

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 6 (A)

Total Number of Dominant Species Across All Strata: 9 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 66 (A/B)

Prevalence Index worksheet:

Total % Cover of:		Multiply by:	
OBL species		x 1 =	
FACW species		X 2 =	
FAC species		X 3 =	
FACU species		X 4 =	
UPL species		X 5 =	
Column Totals:		(A)	(B)

Prevalence Index = B/A =

Hydrophytic Vegetation Indicators:

___ 1 – Rapid Test for Hydrophytic Vegetation
X 2 – Dominance Test is > 50%
___ 3 – Prevalence Test is ≤ 3.0[1]
___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Definitions of Vegetation Strata:

Tree – Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and 3 in. (7.6 cm) or larger in diameter at breast height (DBH).

Sapling – Woody plants, excluding woody vines, approximately 20 ft (6 m) or more in height and less than 3 in. (7.6 cm) DBH.

Shrub – Woody plants, excluding woody vines, approximately 3 to 20 ft (1 to 6 m) in height.

Herb – All herbaceous (non-woody) plants, including herbaceous vines, regardless of size. Includes woody plants, except woody vines, less than approximately 3 ft (1 m) in height.

Woody vine – All woody vines, regardless of height.

Hydrophytic Vegetation Present? Yes X No ___

Remarks: (Include photo numbers here or on a separate sheet.)

SOIL

Sampling Point: DP-2

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth	Matrix		Redox Features					
(inches)	Color (moist)	%	Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-4	10YR 4/3	100					Loam	
4-18	2.5Y 4/4	100					Loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators:

__ Histosol (A1)
__ Histic Epipedon (A2)
__ Black Histic (A3)
__ Hydrogen Sulfide (A4)
__ Stratified Layers (A5)
__ Organic Bodies (A6) **(LRR P, T, U)**
__ 5 cm Mucky Mineral (A7) **(LRR P, T, U)**
__ Muck Presence (A8) **(LRR U)**
__ 1 cm Muck (A9) **(LRR P, T)**
__ Depleted Below Dark Surface (A11)
__ Thick Dark Surface (A12)
__ Coast Prairie Redox (A16) **(MLRA 150A)**
__ Sandy Mucky Mineral (S1) **(LRR O, S)**
__ Sandy Gleyed Matrix (S4)
__ Sandy Redox (S5)
__ Stripped Matrix (S6)
__ Dark Surface (S7) **(LRR P, S, T, U)**
__ Polyvalue Below Surface (S8) **(LRR S, T, U)**
__ Thin Dark Suface (S9) **(LRR S, T, U)**
__ Loamy Gleyed Matrix (F1) **(LRR O)**
__ Loamy Gleyed Matrix (F2)
__ Depleted Matrix (F3)
__ Redox Dark Surface (F6)
__ Depleted Dark Surface (F7)
__ Redox Depressions (F8)
__ Marl (F10) **(LRR U)**
__ Depleted Ochric (F11) **(MLRA 151)**
__ Iron Manganese Masses (F12) **(LRR O, P, T)**
__ Umbric Surface (F13) **(LRR P, T, U)**
__ Delta Ochric (F17) **(MLRA 151)**
__ Reduced Vertic (F18) **(MLRA 150A, 150B)**
__ Piedmont Floodplain Soils (F19) **(MLRA 149A)**
__ Anomalous Bright Loamy Soils (F20) **(MLRA 149A, 153C, 153D)**

Indicators for Problematic Hydric Soils[3]:

__ 1 cm Muck (A9) **(LRR O)**
__ 2 cm Muck (A10) **(LRR S)**
__ Reduced Vertic (F18) **(outside MLRA 150A,B)**
__ Piedmont Floodplain Soils (F19) **(LRR P, S, T)**
__ Anomalous Bright Loamy Soils (F20) **(MLRA 153B)**
__ Red Parent Material (TF2)
__ Very Shallow Dark Surface (TF12)
__ Other (Explain in Remarks)

[3]Indicators of Hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if observed):
Type: ____________
Depth (inches): ____________

Hydric Soil Present? Yes ______ No __X__

Remarks:

Bednarc

EMP-105, SUB 0

EXHIBIT 6 (C)

I/A

U.S. ARMY CORPS OF ENGINEERS
WILMINGTON DISTRICT

Action Id. **SAW-2018-01137** County: **Scotland** U.S.G.S. Quad: **NC-Laurinburg**

NOTIFICATION OF JURISDICTIONAL DETERMINATION

Applicant:	**William Bethea** **1056 Academy Road** **Laurinburg, NC, 28352**	Agent:	**Pilot Environmental** **David Brame** **PO Box 128** **Kernersville, NC 27285**
Applicant:	**Phillip Futrell** **PO Box 840** **Wagram, NC 28396**		
Size (acres) Nearest Waterway USGS HUC	**688** **Bear Creek** **03040204**	Nearest Town River Basin Coordinates	**Laurinburg** **Pee Dee** Latitude: **34.705193** Longitude: **-79.536815**

Location description: **Project area is made up of multiple tracts located north and south of Academy Road in Laurinburg, Scotland, North Carolina. Project area continues south into South Carolina. Western side of project area in bordered by Bear Swamp and is located west of McColl Road.**

Indicate Which of the Following Apply:

A. Preliminary Determination

☒ There appear to be **wetlands** on the above described project area/property, that may be subject to Section 404 of the Clean Water Act (CWA)(33 USC § 1344) and/or Section 10 of the Rivers and Harbors Act (RHA) (33 USC § 403). The **wetlands** have been delineated, and the delineation has been verified by the Corps to be sufficiently accurate and reliable. The approximate boundaries of these waters are shown on the enclosed delineation map dated **6/11/2018**. Therefore this preliminary jurisdiction determination may be used in the permit evaluation process, including determining compensatory mitigation. For purposes of computation of impacts, compensatory mitigation requirements, and other resource protection measures, a permit decision made on the basis of a preliminary JD will treat all waters and wetlands that would be affected in any way by the permitted activity on the site as if they are jurisdictional waters of the U.S. This preliminary determination is not an appealable action under the Regulatory Program Administrative Appeal Process (Reference 33 CFR Part 331). However, you may request an approved JD, which is an appealable action, by contacting the Corps district for further instruction.

☐ There appear to be **wetlands** on the above described project area/property, that may be subject to Section 404 of the Clean Water Act (CWA)(33 USC § 1344) and/or Section 10 of the Rivers and Harbors Act (RHA) (33 USC § 403). However, since the **wetlands** have not been properly delineated, this preliminary jurisdiction determination may not be used in the permit evaluation process. Without a verified wetland delineation, this preliminary determination is merely an effective presumption of CWA/RHA jurisdiction over all of the **wetlands** at the project area, which is not sufficiently accurate and reliable to support an enforceable permit decision. We recommend that you have the **wetlands** on your project area/property delineated. As the Corps may not be able to accomplish this wetland delineation in a timely manner, you may wish to obtain a consultant to conduct a delineation that can be verified by the Corps.

B. Approved Determination

☐ There are Navigable Waters of the United States within the above described project area/property subject to the permit requirements of Section 10 of the Rivers and Harbors Act (RHA) (33 USC § 403) and Section 404 of the Clean Water Act (CWA)(33 USC § 1344). Unless there is a change in law or our published regulations, this determination may be relied upon for a period not to exceed five years from the date of this notification.

☐ There are **wetlands** on the above described project area/property subject to the permit requirements of Section 404 of the Clean Water Act (CWA) (33 USC § 1344). Unless there is a change in the law or our published regulations, this determination may be relied upon for a period not to exceed five years from the date of this notification.
☐ We recommend you have the **wetlands** on your project area/property delineated. As the Corps may not be able to accomplish this wetland delineation in a timely manner, you may wish to obtain a consultant to conduct a delineation that can be verified by the Corps.

☐ The wetlands on your project area/property have been delineated and the delineation has been verified by the Corps. The approximate boundaries of these waters are shown on the enclosed delineation map dated MAP DATE. If you wish to have the delineation surveyed, the Corps can review and verify the survey upon completion. Once verified, this survey will provide an accurate depiction of all areas subject to CWA and/or RHA jurisdiction on your property which, provided there is no change in the law or our published regulations, may be relied upon for a period not to exceed five years.

☐ The wetlands have been delineated and surveyed and are accurately depicted on the plat signed by the Corps Regulatory Official identified below on SURVEY SIGNED DATE. Unless there is a change in the law or our published regulations, this determination may be relied upon for a period not to exceed five years from the date of this notification.

☐ There are no waters of the U.S., to include wetlands, present on the above described project area/property which are subject to the permit requirements of Section 404 of the Clean Water Act (33 USC 1344). Unless there is a change in the law or our published regulations, this determination may be relied upon for a period not to exceed five years from the date of this notification.

☐ The property is located in one of the 20 Coastal Counties subject to regulation under the Coastal Area Management Act (CAMA). You should contact the Division of Coastal Management in in **Wilmington, NC, at (910) 796-7215** to determine their requirements.

Placement of dredged or fill material within waters of the US, including wetlands, without a Department of the Army permit may constitute a violation of Section 301 of the Clean Water Act (33 USC § 1311). Placement of dredged or fill material, construction or placement of structures, or work within navigable waters of the United States without a Department of the Army permit may constitute a violation of Sections 9 and/or 10 of the Rivers and Harbors Act (33 USC § 401 and/or 403). If you have any questions regarding this determination and/or the Corps regulatory program, please contact **Rachel Capito at (910)-251-4487 or Rachel.A.Capito@usace.army.mil**

C. Basis For Determination: Basis For Determination: See the preliminary jurisdictional determination form dated 6/11/2018.

D. Remarks: None.

E. Attention USDA Program Participants

This delineation/determination has been conducted to identify the limits of Corps' Clean Water Act jurisdiction for the particular site identified in this request. The delineation/determination may not be valid for the wetland conservation provisions of the Food Security Act of 1985. If you or your tenant are USDA Program participants, or anticipate participation in USDA programs, you should request a certified wetland determination from the local office of the Natural Resources Conservation Service, prior to starting work.

F. Appeals Information (This information applies only to approved jurisdictional determinations as indicated in B. above)

This correspondence constitutes an approved jurisdictional determination for the above described site. If you object to this determination, you may request an administrative appeal under Corps regulations at 33 CFR Part 331. Enclosed you will find a Notification of Appeal Process (NAP) fact sheet and request for appeal (RFA) form. If you request to appeal this determination you must submit a completed RFA form to the following address:

US Army Corps of Engineers
South Atlantic Division
Attn: Jason Steele, Review Officer
60 Forsyth Street SW, Room 10M15
Atlanta, Georgia 30303-8801

In order for an RFA to be accepted by the Corps, the Corps must determine that it is complete, that it meets the criteria for appeal under 33 CFR part 331.5, and that it has been received by the Division Office within 60 days of the date of the NAP. Should you decide to submit an RFA form, it must be received at the above address by N/A.
It is not necessary to submit an RFA form to the Division Office if you do not object to the determination in this correspondence.

Corps Regulatory Official: CAPITO.RACHEL.ANN.1536276790 Digitally signed by CAPITO.RACHEL.ANN.1536276790 DN: c=US, o=U.S. Government, ou=DoD, ou=PKI, ou=USA, cn=CAPITO.RACHEL.ANN.1536276790 Date: 2018.06.11 10:21:00 -04'00'

Date of JD: 6/11/2018 Expiration Date of JD: N/A

NOTIFICATION OF ADMINISTRATIVE APPEAL OPTIONS AND PROCESS AND REQUEST FOR APPEAL

Applicant: William Bethea, Phillip Futrell	File Number: SAW-2018-01137	Date: 6/11/2018

Attached is:	See Section below
☐ INITIAL PROFFERED PERMIT (Standard Permit or Letter of permission)	A
☐ PROFFERED PERMIT (Standard Permit or Letter of permission)	B
☐ PERMIT DENIAL	C
☐ APPROVED JURISDICTIONAL DETERMINATION	D
☒ PRELIMINARY JURISDICTIONAL DETERMINATION	E

SECTION I - The following identifies your rights and options regarding an administrative appeal of the above decision. Additional information may be found at or http://www.usace.army.mil/Missions/CivilWorks/RegulatoryProgramandPermits.aspx or the Corps regulations at 33 CFR Part 331.

A: INITIAL PROFFERED PERMIT: You may accept or object to the permit.

- ACCEPT: If you received a Standard Permit, you may sign the permit document and return it to the district engineer for final authorization. If you received a Letter of Permission (LOP), you may accept the LOP and your work is authorized. Your signature on the Standard Permit or acceptance of the LOP means that you accept the permit in its entirety, and waive all rights to appeal the permit, including its terms and conditions, and approved jurisdictional determinations associated with the permit.
- OBJECT: If you object to the permit (Standard or LOP) because of certain terms and conditions therein, you may request that the permit be modified accordingly. You must complete Section II of this form and return the form to the district engineer. Your objections must be received by the district engineer within 60 days of the date of this notice, or you will forfeit your right to appeal the permit in the future. Upon receipt of your letter, the district engineer will evaluate your objections and may: (a) modify the permit to address all of your concerns, (b) modify the permit to address some of your objections, or (c) not modify the permit having determined that the permit should be issued as previously written. After evaluating your objections, the district engineer will send you a proffered permit for your reconsideration, as indicated in Section B below.

B: PROFFERED PERMIT: You may accept or appeal the permit

- ACCEPT: If you received a Standard Permit, you may sign the permit document and return it to the district engineer for final authorization. If you received a Letter of Permission (LOP), you may accept the LOP and your work is authorized. Your signature on the Standard Permit or acceptance of the LOP means that you accept the permit in its entirety, and waive all rights to appeal the permit, including its terms and conditions, and approved jurisdictional determinations associated with the permit.
- APPEAL: If you choose to decline the proffered permit (Standard or LOP) because of certain terms and conditions therein, you may appeal the declined permit under the Corps of Engineers Administrative Appeal Process by completing Section II of this form and sending the form to the division engineer. This form must be received by the division engineer within 60 days of the date of this notice.

C: PERMIT DENIAL: You may appeal the denial of a permit under the Corps of Engineers Administrative Appeal Process by completing Section II of this form and sending the form to the division engineer. This form must be received by the division engineer within 60 days of the date of this notice.

D: APPROVED JURISDICTIONAL DETERMINATION: You may accept or appeal the approved JD or provide new information.

- ACCEPT: You do not need to notify the Corps to accept an approved JD. Failure to notify the Corps within 60 days of the date of this notice, means that you accept the approved JD in its entirety, and waive all rights to appeal the approved JD.
- APPEAL: If you disagree with the approved JD, you may appeal the approved JD under the Corps of Engineers Administrative Appeal Process by completing Section II of this form and sending the form to the district engineer. This form must be received by the division engineer within 60 days of the date of this notice.

E: PRELIMINARY JURISDICTIONAL DETERMINATION: You do not need to respond to the Corps regarding the preliminary JD. The Preliminary JD is not appealable. If you wish, you may request an approved JD (which may be appealed), by contacting the Corps district for further instruction. Also you may provide new information for further consideration by the Corps to reevaluate the JD.

SECTION II - REQUEST FOR APPEAL or OBJECTIONS TO AN INITIAL PROFFERED PERMIT		
REASONS FOR APPEAL OR OBJECTIONS: (Describe your reasons for appealing the decision or your objections to an initial proffered permit in clear concise statements. You may attach additional information to this form to clarify where your reasons or objections are addressed in the administrative record.)		
ADDITIONAL INFORMATION: The appeal is limited to a review of the administrative record, the Corps memorandum for the record of the appeal conference or meeting, and any supplemental information that the review officer has determined is needed to clarify the administrative record. Neither the appellant nor the Corps may add new information or analyses to the record. However, you may provide additional information to clarify the location of information that is already in the administrative record.		
POINT OF CONTACT FOR QUESTIONS OR INFORMATION:		
If you have questions regarding this decision and/or the appeal process you may contact: **District Engineer, Wilmington Regulatory Division** **Attn: Rachel Capito** **Wilmington Regulatory Office** **U.S Army Corps of Engineers** **69 Darlington Avenue** **Wilmington, North Carolina 28403**	If you only have questions regarding the appeal process you may also contact: Mr. Jason Steele, Administrative Appeal Review Officer CESAD-PDO U.S. Army Corps of Engineers, South Atlantic Division 60 Forsyth Street, Room 10M15 Atlanta, Georgia 30303-8801 Phone: (404) 562-5137	
RIGHT OF ENTRY: Your signature below grants the right of entry to Corps of Engineers personnel, and any government consultants, to conduct investigations of the project site during the course of the appeal process. You will be provided a 15 day notice of any site investigation, and will have the opportunity to participate in all site investigations.		
Signature of appellant or agent.	Date:	Telephone number:

For appeals on Initial Proffered Permits send this form to:

District Engineer, Wilmington Regulatory Division, Attn: Rachel Capito , 69 Darlington Avenue, Wilmington, North Carolina 28403

For Permit denials, Proffered Permits and Approved Jurisdictional Determinations send this form to:

Division Engineer, Commander, U.S. Army Engineer Division, South Atlantic, Attn: Mr. Jason Steele, Administrative Appeal Officer, CESAD-PDO, 60 Forsyth Street, Room 10M15, Atlanta, Georgia 30303-8801
Phone: (404) 562-5137

PRELIMINARY JURISDICTIONAL DETERMINATION (PJD) FORM

BACKGROUND INFORMATION

A. REPORT COMPLETION DATE FOR PJD: June 11, 2018

B. NAME AND ADDRESS OF PERSON REQUESTING PJD: David Brame, Pilot Environmental, Inc.
Post Office Box 128, Kernersville, North Carolina 27285

C. DISTRICT OFFICE, FILE NAME, AND NUMBER: Wilmington, Friesian Holding, SAW 2018-

D. PROJECT LOCATION(S) AND BACKGROUND INFORMATION: The site is located west of Leisure Road, Laurinburg, Scotland County, NC. The site contains fields and wooded land. The site is proposed for development with a solar farm.

(USE THE TABLE BELOW TO DOCUMENT MULTIPLE AQUATIC RESOURCES AND/OR AQUATIC RESOURCES AT DIFFERENT SITES)

State: North Carolina County/parish/borough: Scotland City: Laurinburg

Center coordinates of site (lat/long in degree decimal format): Lat.: 34.703459° Long.: -79.536680°

Universal Transverse Mercator: WGS 84

Name of nearest waterbody: Bear Creek

E. REVIEW PERFORMED FOR SITE EVALUATION (CHECK ALL THAT APPLY):

☐ Office (Desk) Determination. Date:

☒ Field Determination. Date(s): 05/23/2018

TABLE OF AQUATIC RESOURCES IN REVIEW AREA WHICH "MAY BE" SUBJECT TO REGULATORY JURISDICTION.

Site Number	Latitude (decimal degrees)	Longitude (decimal degrees)	Estimated amount of aquatic resources in review area (acreage and linear feet, if applicable	Type of aquatic resources (i.e., wetland vs. non-wetland waters)	Geographic authority to which the aquatic resource "may be" subject (i.e., Section 404 or Section 10/404)
WA 1-126	34.698903°	-79.540870°	55 Ac.	Wetland - PFO	Section 404
WA 141-181	34.695868°	-79.531950°	8.86 Ac.	Wetland - PFO	Section 404
WB 1-33	34.715050°	-79.549549°	1.6 Ac.	Wetland - PFO	Section 404
WC 1-27	34.715563°	-79.534274°	0.91 Ac.	Wetland - PFO	Section 404

1) The Corps of Engineers believes that there may be jurisdictional aquatic resources in the review area, and the requestor of this PJD is hereby advised of his or her option to request and obtain an approved JD (AJD) for that review area based on an informed decision after having discussed the various types of JDs and their characteristics and circumstances when they may be appropriate.

2) In any circumstance where a permit applicant obtains an individual permit, or a Nationwide General Permit (NWP) or other general permit verification requiring "pre- construction notification" (PCN), or requests verification for a non-reporting NWP or other general permit, and the permit applicant has not requested an AJD for the activity, the permit applicant is hereby made aware that: (1) the permit applicant has elected to seek a permit authorization based on a PJD, which does not make an official determination of jurisdictional aquatic resources; (2) the applicant has the option to request an AJD before accepting the terms and conditions of the permit authorization, and that basing a permit authorization on an AJD could possibly result in less compensatory mitigation being required or different special conditions; (3) the applicant has the right to request an individual permit rather than accepting the terms and conditions of the NWP or other general permit authorization; (4) the applicant can accept a permit authorization and thereby agree to comply with all the terms and conditions of that permit, including whatever mitigation requirements the Corps has determined to be necessary; (5) undertaking any activity in reliance upon the subject permit authorization without requesting an AJD constitutes the applicant's acceptance of the use of the PJD; (6) accepting a permit authorization (e.g., signing a proffered individual permit) or undertaking any activity in reliance on any form of Corps permit authorization based on a PJD constitutes agreement that all aquatic resources in the review area affected in any way by that activity will be treated as jurisdictional, and waives any challenge to such jurisdiction in any administrative or judicial compliance or enforcement action, or in any administrative appeal or in any Federal court; and (7) whether the applicant elects to use either an AJD or a PJD, the JD will be processed as soon as practicable. Further, an AJD, a proffered individual permit (and all terms and conditions contained therein), or individual permit denial can be administratively appealed pursuant to 33 C.F.R. Part 331. If, during an administrative appeal, it becomes appropriate to make an official determination whether geographic jurisdiction exists over aquatic resources in the review area, or to provide an official delineation of jurisdictional aquatic resources in the review area, the Corps will provide an AJD to accomplish that result, as soon as is practicable. This PJD finds that there *"may be"* waters of the U.S. and/or that there *"may be"* navigable waters of the U.S. on the subject review area, and identifies all aquatic features in the review area that could be affected by the proposed activity, based on the following information:

SUPPORTING DATA. Data reviewed for PJD (check all that apply)

Checked items should be included in subject file. Appropriately reference sources below where indicated for all checked items:

☐ Maps, plans, plots or plat submitted by or on behalf of the PJD requestor:
Map:______________________

☒ Data sheets prepared/submitted by or on behalf of the PJD requestor.

☒ Office concurs with data sheets/delineation report.

☐ Office does not concur with data sheets/delineation report. Rationale:____________________

☐ Data sheets prepared by the Corps:__________________

☐ Corps navigable waters' study:____________________

☐ U.S. Geological Survey Hydrologic Atlas:________________

☐ USGS NHD data.

☐ USGS 8 and 12 digit HUC maps.

☒ U.S. Geological Survey map(s). Cite scale & quad name: Drawing 1

☒ Natural Resources Conservation Service Soil Survey. Citation: Drawings 2 & 2A

☒ National wetlands inventory map(s). Cite name: Drawing 3

☐ State/local wetland inventory map(s):______________________

☒ FEMA/FIRM maps: Drawing 4

☐ 100-year Floodplain Elevation is:______________ (National Geodetic Vertical Datum of 1929)

☒ Photographs: ☒ Aerial (Name & Date): Drawing 5

or ☐ Other (Name & Date):_____________

☐ Previous determination(s). File no. and date of response letter:______________________

☐ Other information (please specify):______________________

IMPORTANT NOTE: The information recorded on this form has not necessarily been verified by the Corps and should not be relied upon for later jurisdictional determinations.

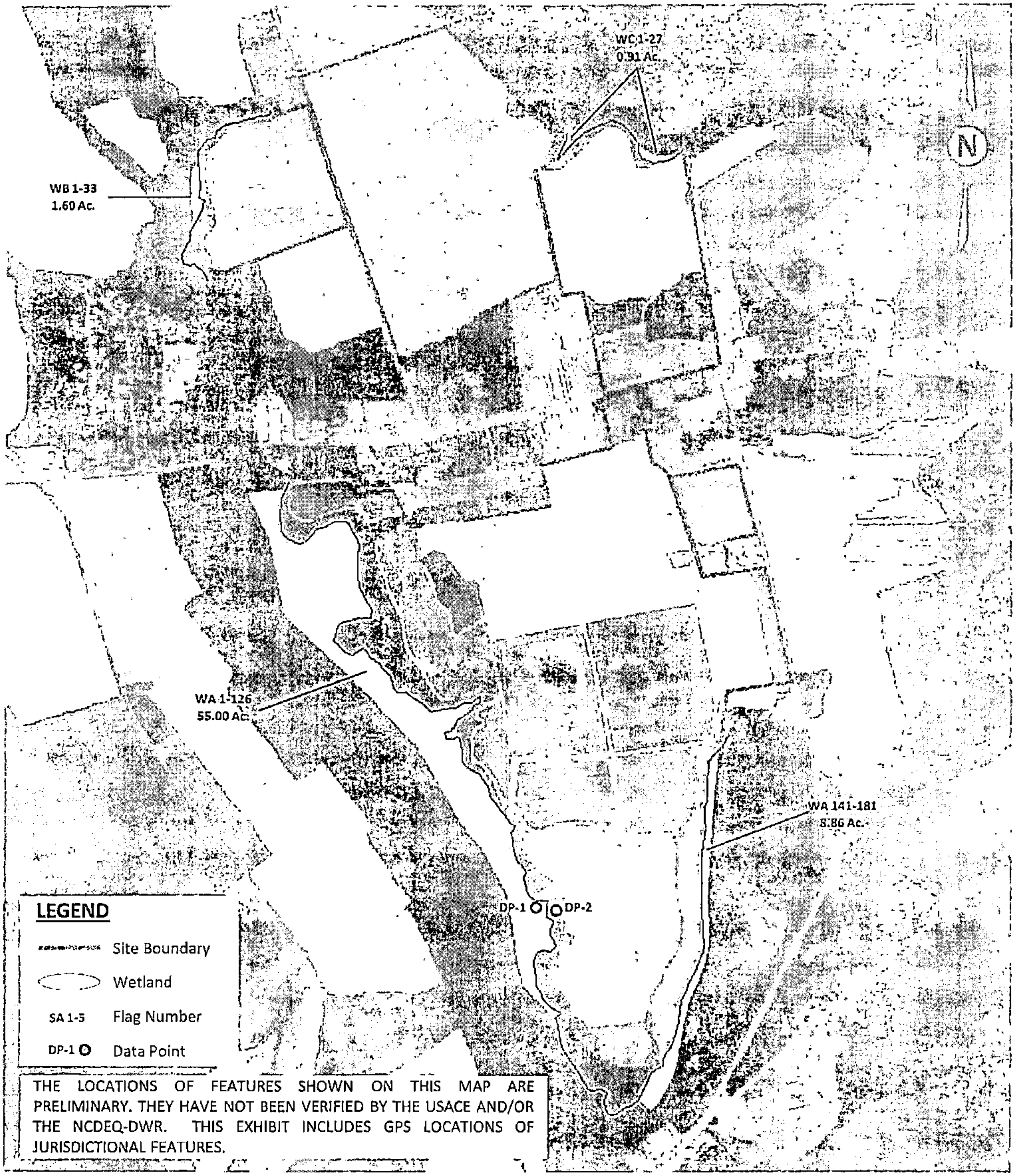
CAPITO.RACHEL.AN
N.1536276790
Digitally signed by CAPITO.RACHEL.ANN.1536276790
DN: c=US, o=U.S. Government, ou=DoD, ou=PKI, ou=USA, cn=CAPITO.RACHEL.ANN.1536276790
Date: 2018.06.11 10:21:54 -04'00'

Signature and date of Regulatory staff member completing PJD

June 8, 2018

Signature and date of person requesting PJD (REQUIRED, unless obtaining the signature is impracticable)[1]

[1] Districts may establish timeframes for requester to return signed PJD forms. If the requester does not respond within the established time frame, the district may presume concurrence and no additional follow up is necessary prior to finalizing an action.



Drawing 5
Aerial Imagery from ESRI
and Pilot GPS Data
Scale: 1" = 1,250'
Date: 3.22.18

PILOT ENVIRONMENTAL, INC

Wetland Map
Friesian Holdings
Approximate 688 Acre Tract
Laurinburg, Scotland County, NC
Pilot Project 3536

CAPITO.RACHEL.ANN.1536276
790

Bednar Supplemental Direct

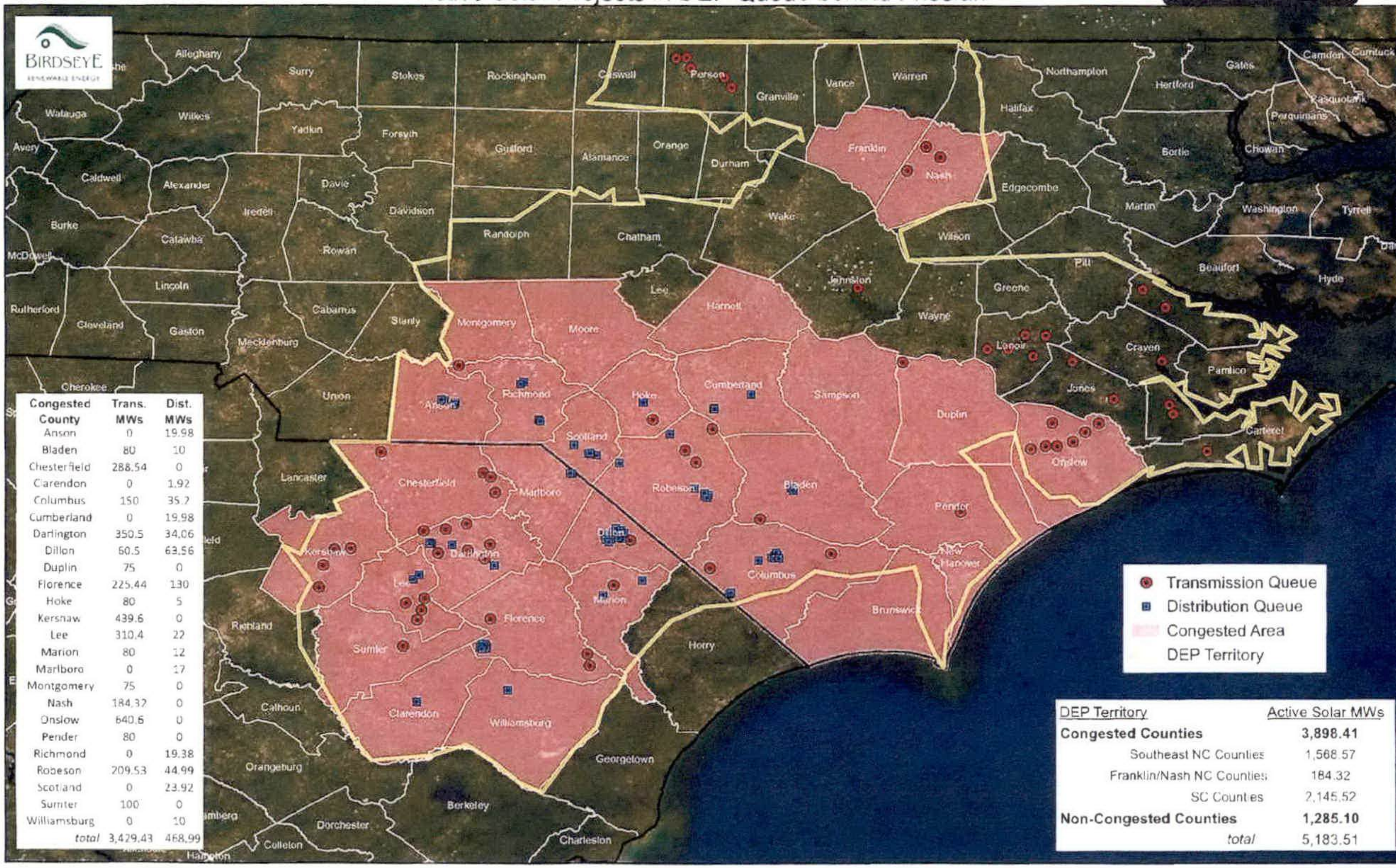
EXHIBIT

A

PENGAD 800-631-6989

I/A

Active Solar Projects in DEP Queue behind Friesian



Congested County	Trans. MWs	Dist. MWs
Anson	0	19.98
Bladen	80	10
Chesterfield	288.54	0
Clarendon	0	1.92
Columbus	150	35.2
Cumberland	0	19.98
Darlington	350.5	34.06
Dillon	60.5	63.56
Duplin	75	0
Florence	225.44	130
Hoke	80	5
Kershaw	439.6	0
Lee	310.4	22
Marion	80	12
Marlboro	0	17
Montgomery	75	0
Nash	184.32	0
Onslow	640.6	0
Pender	80	0
Richmond	0	19.38
Robeson	209.53	44.99
Scotland	0	23.92
Sumter	100	0
Williamsburg	0	10
total	3,429.43	468.99

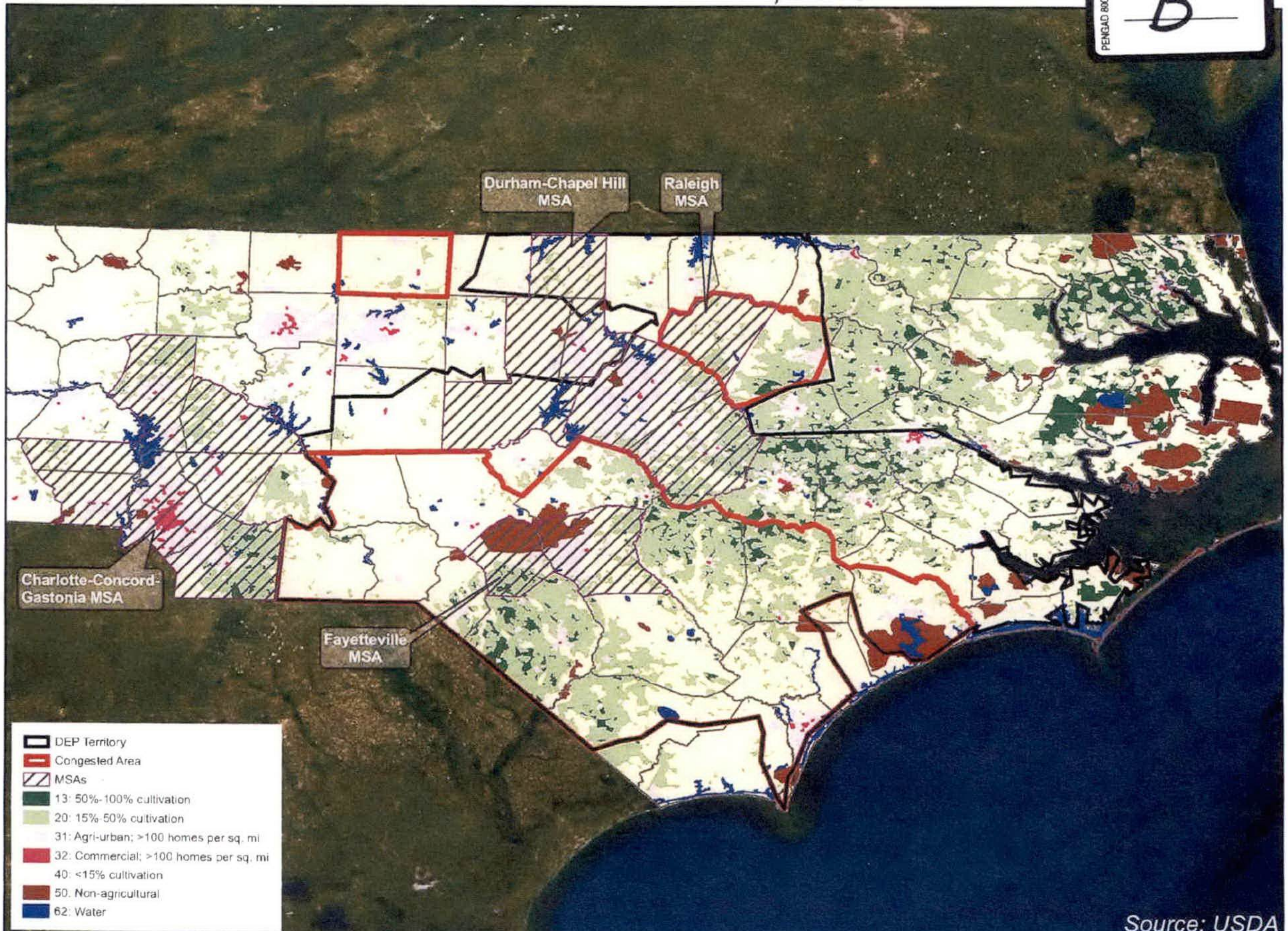
DEP Territory	Active Solar MWs
Congested Counties	**3,898.41**
Southeast NC Counties	1,568.57
Franklin/Nash NC Counties	184.32
SC Counties	2,145.52
Non-Congested Counties	**1,285.10**
total	5,183.51

Bednar Supplemental Direct

EXHIBIT B
PENGAD 800-631-6989

I/A

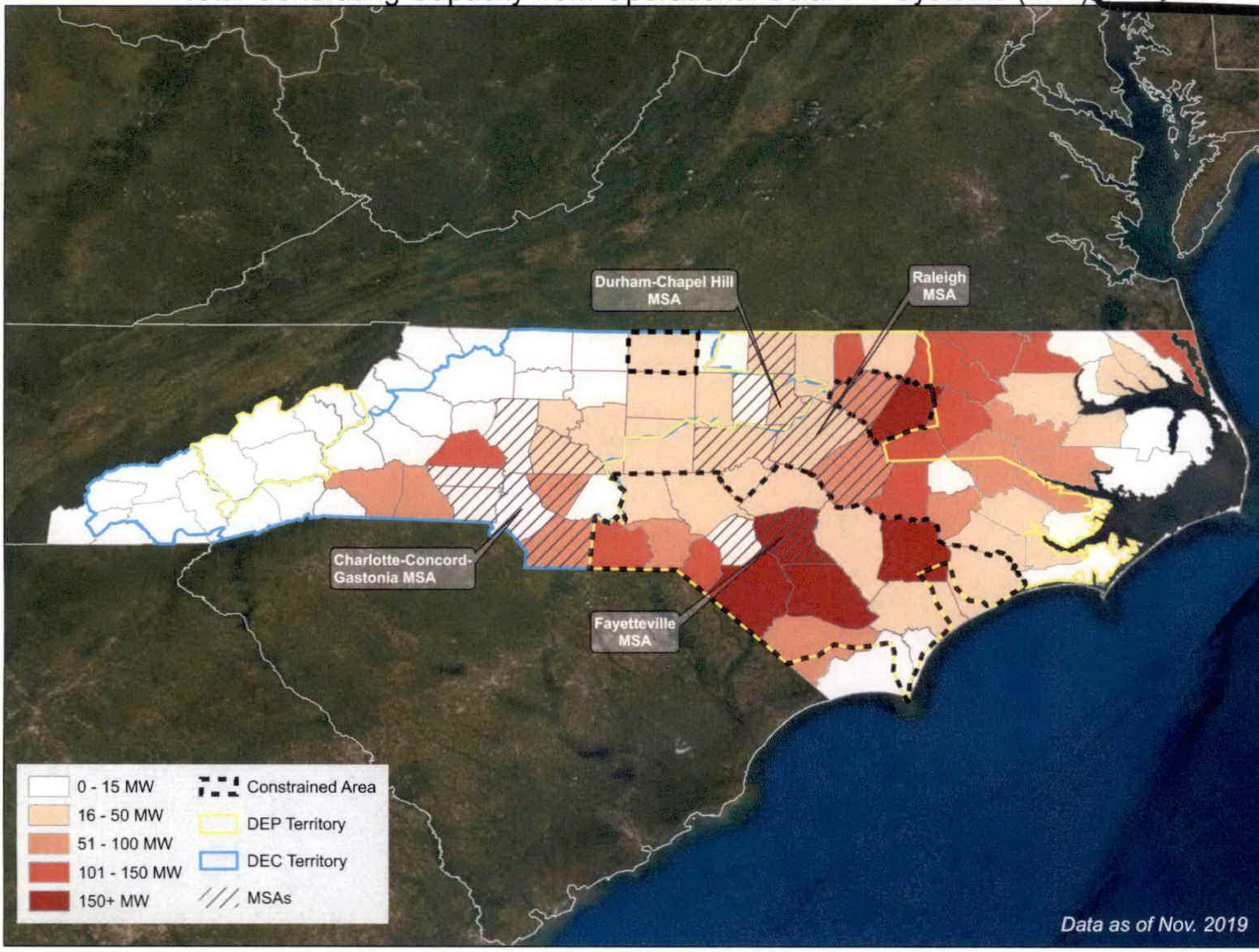
Land Use Stratification, 2015



I/A Bednar Rebuttal

EXHIBIT A

Total Generating Capacity from Operational Solar PV Systems (MW)



CHARLES M. ASKEY
6008 Alexa Road Charlotte, North Carolina 28277
(704) 840-7718 (Mobile) / charlieaskey@aol.com

Askey Supplemental Direct

EXHIBIT
PENGAD 800-631-6989
A
EMP-105, SubD

I/A

BUSINESS PROFILE

An accomplished and highly successful Professional Manager who is innovative, profit-oriented and performance-driven. Extensive experience in positions of increasing responsibility in transmission planning, resource and project management, developing strong implementation teams and delivering desired results. An action person with a proven record of success. Highly organized with an innate ability to get things done working with, and through, others at all levels in the organization. Strong multi-tasking and problem-solving skills. Adjusts to change easily by creating new and improved methods to reach goals and objectives. Intuitive and effective decision maker.

AREAS OF EXPERTISE

- Project Management
- Resource Management
- Transmission Planning
- Contract Administration
- Problem Solving
- Customer Service
- Team Development
- Relationship Building
- Strategic Planning
- Multi-Tasking
- Consulting
- Systems Operations
- Facility Siting
- Contract Negotiation
- Scheduling/Organizing

ACCOMPLISHMENTS

- Started the Power Engineering & System Planning Group at Timmons Group, Inc. Currently responsible for the staffing and participating in the design work on a 162.15 MW Wind Farm and four utility scale solar projects.
- Launched the System Planning business function at three companies. Perform steady-state assessments of the transmission system's ability to accept injections of power from generation projects. The purpose of these studies is to determine the maximum generator output that can be achieved under all studied conditions before system limitations are observed. These assessments are performed throughout the country and for various types of resources (wind, solar, gas, biomass, etc.). The determination of the Available Transfer Capability (ATC) is performed under a variety of load levels and system dispatch scenarios. Prepare generation interconnection documentation and advise clients regarding system studies. (Timmons Group, Pike/UCS & ERP)
- Managed the division of UC Synergetic (UCS) that specializes in providing system planning studies, siting, site engineering, environmental analysis, project permitting, and landscape services to the electric industry. In addition to performing system assessments and NERC planning studies, the team was responsible for conducting infrastructure facility siting studies by executing a comprehensive siting process. Execution included land use studies; visual impact; hydrology, wildlife and fisheries studies; cultural and historic resource investigations; rare, endangered species investigations; engineering evaluation and construction feasibility analyses of alternate sites/routes; and cost analysis of alternate sites/routes. (UCS/Pike).
- Responsible for business development of the system planning & siting function. Achieved financial & resource utilization goals and objectives. Prepared and submit responses to Request for Proposals. (UCS/Pike)
- Performed a variety of power flow studies and assessed the transmission and distribution substation reliability for two large transmission cooperatives' systems. Recommended capital projects and operating procedures addressing identified deficiencies. (Pike and EnerVision)
- Provided services for the negotiation and implementation of new power supply contracts for five electric distribution cooperatives in North Carolina. Coordinated the successful completion of transmission contracts, and managed implementation, scheduling, operations, billings and regulatory issues. (EnerVision)
- Prepared for and participated in the successful completion of planning compliance audits. (EnerVision)
- Monitored and analyzed market and regulatory activities at the national, regional and state level assessing their relevance. (FPLE)
- Advocated policies and positions influencing the outcome of market designs, regulations and governmental actions to further commercial interests. Worked closely with the Development and Origination Departments to assist with power supply contacts, transmission interconnections and market relations. (FPLE)
- Participated in external venues, including representing company in the FERC RTO Southeast Mediation Process, performing as Sector Representative on the SeTrans Stakeholder Advisory Committee, providing input to the state commissions of NC, VA, GA, SC and LA, and commenting on FERC Orders and NOPRs. (FPLE)
- Managed a team of 8 to 18 developing the requirements, process descriptions, application summaries and job descriptions for the Operations and Planning Organizations of the GridSouth Transco (start-up). (Duke)
- Requested, received and reviewed bid packages from vendors satisfying the requirements of Order 2000 and the GridSouth Filing. Selected the best solution providers and negotiated Letters of Intent for Energy Management System software and computer equipment. (Duke)

- Provided leadership on transmission issues related to the Operational Planning time horizon. (Duke)
- Managed the implementation of the VACAR-South Security Coordinator and participated on the SERC and NERC ATC Working Groups. (Duke)
- Performed power flow studies, special studies and assisted in the development and delivery of training materials to system coordinators. (Duke)
- Directed and supervised successfully all transmission related activities: corporate transmission strategy development including rate modifications, transmission expansion planning, project approval among and with the Georgia Integrated Transmission System (ITS) Participants, participation in regional reliability organizations, release of all capital transmission projects (over $50 million per year) including presentation to the Board, administration of the ITS Agreement and direct management of 12 full-time and 2 part-time positions. (Oglethorpe Power)

PROFESSIONAL EXPERIENCE

2017-Present	**Timmons Group, Inc.** Client Consultation Senior Project Manager		Charlotte, NC
2015-2016	**Energy Renewal Partners, LLC** Client Consultation Director, System Planning		Charlotte, NC
2012-2015	**UC Synergetic, LLC** (f/k/a Pike Energy Solutions) Client Consultation Director, System Planning & Siting		Fort Mill, SC
2009-2012	**Pike Energy Solutions, LLC** Client Consultation Director, System Planning		Charlotte, NC
2003-2009	**EnerVision, Inc.** Consulting to distribution / transmission cooperatives Principal Consultant		Atlanta, GA Charlotte, NC
2002-2003	**Independent Consultant** Consulting to distribution / transmission co-ops		Atlanta, GA Charlotte, NC
2001-02	**Florida Power & Light Energy** Merchant generation developer Director, Market Affairs – Southeast Region		Charlotte, NC
1996-01	**Duke Energy** Investor owned utility Team Lead, GridSouth Consulting Engineer	 2000-01 1996-00	Charlotte, NC
1985-96	**Oglethorpe Power Corporation** Generation/transmission cooperative Manager, Transmission Planning Senior Electrical System Planner Transmission Service Engineer System Planning Engineer	 1995-96 1992-95 1991-92 1985-91	Tucker, GA
	Dekalb Technical Institute Adjunct Instructor – Mathematics **Clemson University** Graduate Teaching/Research Assistant **Georgia Power Company** Research and Test Lab Engineer **Westinghouse Transformer Division** Core/Council Designing Engineer – Co-Op Student		

EDUCATION/PROFESSIONAL AFFILIATIONS

Clemson University Clemson, SC
Master of Science – Electrical Engineering
Major – Power System Analysis, Minor – Mathematics
Bachelor of Science – Electrical Engineering

Registered Professional Engineer in the State of Georgia

PUBLICATIONS

C.M. Askey, M.A. Wortman, "A Mathematical Formulation for the Reliability of Power System State Estimators", proceedings 17th Annual Southeastern Symposium on System Theory, March 1985.

Masters Thesis – "A Technique for Evaluating the Reliability of a Power System State Estimator", presented to and accepted by the Graduate School at Clemson University in May 1985.

Askey
Supplemental
Direct

EXHIBIT
B
Emp 105, Sub0
I/A

DEP Queue Analysis

Review of Transmission System Upgrades and Project Impact

Provided by

TIMMONS GROUP
YOUR VISION ACHIEVED THROUGH OURS.

For

BIRDSEYE
RENEWABLE ENERGY

November 26, 2019

Background

Birdseye Renewable Energy is in the process of developing four photovoltaic projects, including Friesian Holdings, LLC ("Friesian"), in Duke Energy Progress, LLC's ("DEP") North Carolina Territory. Friesian is in DEP's FERC Generation Interconnection Queue and has advanced through the study phases outlined in the Large Generation Interconnection Procedures (LGIP). The four projects are listed below:

Name	Queue #	County	MW	POI
Friesian	380	Scotland	70	Laurinburg – Bennettsville 230kV
Homer	381	Hoke	75	Blewett – Tillery 115 kV
Slender Branch	383	Bladen	80	Cumberland – Whiteville 230 kV
Fair Bluff	387	Columbus	75	Marion – Whiteville 230 kV

In response to Friesian's data request, DEP provided information that it has completed an assessment for interconnection requests received through September 30, 2017. There are 108 interconnection requests totaling 1,561 megawatts ("MW") that have been identified as interdependent on the network upgrades assigned to Friesian. In addition to the projects specifically identified to date by DEP as interdependent on the Friesian upgrades, DEP stated that there are likely many additional later-queued projects that are also technically interdependent on the Friesian upgrades. DEP also stated that the interconnection study is designed to assess whether upgrades are needed to accommodate a particular generating facility but are not intended to assess whether a particular upgrade will accommodate a particular set of future generating facilities. However, DEP believes that it is undoubtedly the case that the Friesian upgrades will alleviate the interdependency of at least 1,561 MW of additional solar resources and provide a path forward for such projects to interconnect in a safe and reliable manner. Attached hereto as Exhibit A is Duke's response Friesian's data request that contains a list of projects that are interdependent to Friesian's upgrades.

Furthermore, DEP has provided information that as a general matter, substantial network upgrades will be needed to accommodate the addition of a substantial amount of new grid resources (not limited to solar resources). The Friesian upgrades are the type of requisite network upgrades that will help to accommodate the interconnection of a substantial amount of additional renewable and other resources. In fact, in addition to solar resources, Duke Energy's 1235 Combined Cycle Plan in Cumberland County is interdependent on the Friesian upgrades.

In conjunction with the study of the Friesen Solar Project along with several other previously queued projects, DEP has identified multiple system upgrades to be constructed prior to allowing the Friesian Solar Project to interconnect to the system. These transmission line upgrades are listed in the table below:

Transmission Upgrades	Description	Distance (Miles)
Erwin –Fayetteville East 230 kV Line	Reconductor to 6-1590 MCM ACSR Conductor	~23
Fayetteville – Fayetteville Dupont 115 kV Line	Reconductor to 3-1590 MCM ACSR Conductor	~3.2
Cape Fear – West End 230 kV Line	Reconductor to 6-1590 MCM ACSR Conductor	~26
Sanford Deep River Tap – Sanford Horner Blvd. 230 kV Line	Reconductor to 6-1590 MCM ACSR Conductor	~4.4
Erwin - Fayetteville 115 kV Line	Reconductor to 3-1590 MCM ACSR Conductor	~8.7
Rockingham – West End 230 kV Line	Upgrade the line to full conductor rating.	~7.7

The Appendices for the draft Large Generator Interconnection Agreement ("LGIA") for Friesian (Q380) includes Friesian's cost responsibility for the upgrades and the need for security when executing the LGIA. The LGIA also contains an outline of the reimbursement schedule for the network upgrade costs after construction is complete and the project is placed in service.

Birdseye Renewable Energy has engaged Charles Askey (Timmons Group) to evaluate the potential benefit of the upgrade projects listed above to DEP's system independent of the addition of the Friesian facility. Specifically, Timmons Group is to perform the following tasks:

1. To the extent possible using a recent version of the 2023 Summer Peak SERC (Southeastern Electric Reliability Council) power flow model, replicate the system impact study performed by Duke Energy Progress on the Friesian Solar Project. The focus being the contingency loading on the most critical system limitations associated with the transmission upgrades in the table listed above;
2. Using study criteria that closely mimics the Duke Energy Progress System Impact Study, evaluate the impact of the Friesian Project by itself on the contingency loading on each of the transmission lines;
3. Using study criteria that closely mimics the Duke Energy Progress System Impact Study, evaluate the contingency loading on each of the transmission lines without the queued generation projects in the model;

Timmons Group scope of work is to document the results of the study and comment on the need for the transmission system upgrades as it relates not just to renewable energy development, but also the origination of any generation in the eastern portion of the Duke Energy Progress System.

Power Flow Model

While Timmons Group can perform studies on the Duke Energy Progress system using the FERC issued power flow models, we cannot duplicate the Duke Energy Progress results exactly primarily because the dispatch of the generation will vary to some extent. However, Timmons Group has attended generation interconnection system impact study review meetings with DEP and Developer Clients and is familiar with the study methodology. Timmons Group's goal with this study is to show the approximate contingency loading levels on the critical facilities and also the relative amounts of those loadings associated with each scenario.

Duke Energy Progress System Impact Study Methodology

As part of their Large Generation Interconnection Procedures ("LGIP"), DEP uses a "Stressed" system model to evaluate impacts to the system caused by Generation Interconnection Facilities. The stated reason for this is to ensure that the DEP-owned transmission system can deliver on firm transmission commitments under the direst of circumstances.

Timmons Group, through its FERC Critical Energy Infrastructure Information (CEII) clearance, has access to the power flow models and maps for the power systems in the mainland United States. The current set of cases has a Southeastern Electric Reliability Council (SERC) 2023 Summer Peak model that Timmons Group will use for the analysis. In evaluating DEP's System Impact Studies of the Friesian Project, Timmons Group was able to access and evaluate Duke Energy's models to perform the requisite generation interconnection studies. Based on those models of the system, the following changes are made to the FERC CEII model in order to perform the scope of work outlined in the background section of this report.

Power Flow Study Assumptions

The power flow model modifications are listed below:

- Loss of the Harris Nuclear Unit;
- Maximum Import of the Duke Energy Progress (DEP) Transmission Reserve Margin (TRM). This is the amount that is defined in their Transmission Planning Summary as 1830 MW. DEP has stated that the VACAR reserve sharing complement of the TRM is 1830 MW. The model was modified to import 1400 MW (1830 MW less DEP's approximate share of the reserve).
- The Duke Energy Progress (DEP) generation dispatch in the study "stressed" case differs significantly from the FERC CEII base case. The net effect of the changes in dispatch biases the system from south to north such that additional flows are seen on the Erwin – Fayetteville East 230 kV Line (EFE230). The dispatch changes include the following:
  - ➢ The Fayetteville area generation is turned on and dispatched full in the stressed model.
    - o Weatherspoon 128MW petroleum liquid generator;
    - o Butler-Warner 225MW combined cycle natural gas generator;
    - o The Fayetteville PWC generation is dispatched full in the DEP Case;
  - ➢ The Roxboro / Mayo plants, located in the northern portion of the state, are ramped down from the dispatch in the FERC base case.
  - ➢ The Goldsboro area plants are ramped down. These plants are located north of the constrained EFE230 line and the dispatch down causes more MW to flow from south to north.
  - ➢ The Lee Combined Cycle 910MW combined cycle natural gas generator is dispatched lower in the stressed case than the FERC case.
  - ➢ The Wayne County 863MW combustion turbine natural gas generator is dispatched in the FERC CEII case, but is dispatched at 0 MW in the stressed Case.
  - ➢ Sherwood A Smith (i.e., Richmond County Energy Complex) 1868MW combined cycle + combustion turbine is located west and south of the EFE230 constraint. The stressed case dispatch is the plants maximum output and is higher than in the FERC base case, aggravating the south to north flows.
  - ➢ The Hamlet (339MW) and Anson County (345MW) natural gas combustion turbine units are dispatched at full output.

Timmons Group cannot match the exact dispatch performed by Duke Energy Progress (DEP) because some of the dispatch is based on proprietary generation cost information. However, using the assumptions provided to Timmons Group during the system impact study review, Timmons Group can approach contingency loading levels on the critical limiting element consistent with DEP's System Impact Study.

The critical contingency that causes the System Operating Limit (SOL) violation varies between the limiting transmission elements. The original system impact study showed that Bay Tree Solar (Q377) was the project that caused the majority of the loading issues; however, changes to queued generation (i.e., projects dropping out of the queue) have resulted in Friesian (Q380) becoming the project with the upgrade cost responsibility in the Generation Interconnection Agreement.

Queued Projects Included in the analysis

After creating the 2023 Summer Peak "Stressed" Power Flow Model described above, queued generation was added to the model to simulate the Friesian Solar System Impact study. These projects are consistent with the projects included in the 2018 summer peak power flow model that DEP used to study the Friesian Solar Project during the Facility Study.

- Q331 – 20 MW
- Q353 – 67 MW
- Q356 – 49.3 MW
- Q358 – 48.9 MW
- Q366 – 67 MW
- Q370 – 55 MW
- Q372 – 34 MW
- Q374 – 100 MW
- Q375 – 50.4 MW
- Q376 – 53.8 MW
- Q377 – 75 MW
- Q378 – 50.4 MW
- Q380 – 70 MW (Friesian Solar)

Timmons Group made dispatch assumptions consistent with the "Stressed Case" philosophy while incorporating the additional 740.8 MW of queued generation into the model.

Analysis

The following scenarios were performed on the stressed case model and the results recorded:

- The Loss of the Wake – Cumberland 500 kV Line and separately the loss of the Cumberland – Richmond 500 kV Line with the queued generation listed above in the model including the Friesian Solar Project;
- The Loss of the Wake – Cumberland 500 kV Line and separately the loss of the Cumberland – Richmond 500 kV Line with the queued generation listed above in the model except the Friesian Solar Project;
- The Loss of the Wake – Cumberland 500 kV Line and separately the loss of the Cumberland – Richmond 500 kV Line with none of the queued generation listed above in the model; and

Table 1 below shows the pre-contingency and post contingency flows, rating and percentage loading on the five limiting elements listed in the background section of the report based on the most critical contingency studied.

Table 1 - Pre-contingency and Post Continency Loading on the Friesian Related System Operating Limits for the loss of the Most Critical Contingency

Scenario	Post Contingency Flow (MVA)	Rating (MVA)	Voltage Adjusted Post Contingency Loading (%)
Limitation: Erwin - Fayetteville East 230 kV (~23 Miles)			
Contingency: Wake - Cumberland 500 kV			
Queue included up through Q380	492	478	105.51%
Queue included except for Q380	484	478	103.74%
No Queue	449	478	95.69%
Limitation: West End - Cape Fear 230 kV (~26.6 Miles)			
Contingency: Richmond - Cumberland 500 kV			
Queue included up through Q380	529	542	100.47%
Queue included except for Q380	523	542	99.32%
No Queue	499	542	94.34%
Limitation: Rockingham - West End 230 kV (7.7 Miles)			
Contingency: Richmond - Cumberland 500 kV			
Queue included up through Q380	505	542	96.13%
Queue included except for Q380	500	542	94.87%
No Queue	477	542	90.12%
Limitation: Erwin - Fayettevlle 115 kV (~8.7 Miles)			
Contingency: Wake - Cumberland 500 kV			
Queue included up through Q380	114	119	97.99%
Queue included except for Q380	112	119	95.89%
No Queue	105	119	89.65%
Limitation: Fayetteville - Fayetteville Dupont 115 kV			
Contingency: Richmond - Cumberland 500 kV			
Queue included up through Q380	120	119	103.54%
Queue included except for Q380	119	119	102.41%
No Queue	114	119	97.31%

Evaluation of Results

As stated earlier, Timmons Group cannot match the loadings exactly that DEP determined in the study of the Friesian Solar Project based on the reasons stated above. However, we believe we have determined loadings that approach the level of those in the System Impact Study based on the Stressed Case approach used by DEP.

DEP's System Impact Study contains the following the following statement regarding power flow results:

> "Facilities that may require upgrade within the first three to five years following the in-service date are identified. Based on projected load growth on the DEP transmission system, facilities of concern are those with post-contingency loadings of 95% or greater of their thermal rating and low voltage of 92% and below, for the requested in-service year or the in-service year of a higher queued request. The identification of these facilities is crucial due to the construction lead times necessary for certain system upgrades. This process will ensure that appropriate focus is given to these problem areas to investigate whether construction of upgrade projects is achievable to accommodate the requested interconnection service."

As can be seen from the results, with the queue loaded up through Project Q380, all the limiting elements are loaded over either 95 percent or 100 percent of their contingency ratings. Obviously, these loading levels are why DEP flagged these as facility loadings that need to be address prior to granting transmission service to the Friesian Solar. However, it is noted the while the loadings are heavy, the loadings without the queue are within five to ten percent of the contingency loading levels without the queued generation listed.

Also note that DEP has two, 1235 MW queued gas projects (Q398 & Q399) which will add significantly to most, if not all these line loadings absent any other upgrades. This projected outcome is consistent with the findings of the Q398 System Impact Study Report that was published in December 2018 and Q399 System Impact Study Report that was published in April 2019. The first report recommends building a new 35 mile, 230 kV line between the Cumberland and Erwin Substations and a similar 230 kV line between the Cumberland and Clinton Substations. While DEP has determined that its first gas project (Q398) is not dependent upon Friesian's upgrades, DEP's second Combined Cycle Plant (Q399) is interdependent upon Friesian's upgrades.

Timmons Group Summary and Conclusion

Based on the Friesian Solar System Impact Study and the study results presented herein, the network upgrades included in the Friesian Interconnection Agreement are required to allow the Friesian Solar Project to connect and deliver power to the system without violating the DEP LGIP Study Methodology. Further, without the Friesian upgrades or additional transmission improvements, new generation resources (i.e., renewable energy, Duke Energy's Gas Project(s), among others) in this area of the system will not be able to achieve full interconnection based on the limitations listed herein.

The benefits that result from the transmission system upgrades will include enhanced load serving capabilities, reduced power system losses and improved flexibility to operate the transmission grid. Finally, Duke Energy's integrated resource plan indicates that additional generation is needed to support load growth and resource portfolio improvements. Whether that new generation comes from renewable energy or other generation resources in eastern North Carolina, it cannot occur without the Friesian network upgrades or other major improvements to DEP's transmission system.

Friesian Holdings, LLC
Data Request No. 2
of
Duke Energy Progress, LLC
Docket No. EMP-105, Sub 0
Date Sent: November 8, 2019
Requested Due Date: November 20, 2019

Sent to Duke Energy Progress, LLC in c/o: Jack Jirak
E-mail: Jack.Jirak@duke-energy.com

Contact for Friesian Holdings, LLC
Karen M. Kemerait
E-mail: kkemerait@foxrothschild.com

1. Please list all projects in Duke's queue that are interdependent upon Friesian (Q380), and the total amount of megawatts of those interdependent projects.

Based on the assessment completed by DEP for interconnection requests received through September 30, 2017, there are 108 interconnection requests totaling 1,561 MW that have been identified as being interdependent on the upgrades assigned to Friesian. See Attachment DR 2-1 for a list of such projects. In addition to the projects specifically identified to date by DEP as interdependent on the Friesian upgrades, there are likely many additional later-queued projects that are also technically interdependent on the Friesian upgrades. Note that all such interdependent projects may also require upgrades in addition to the Friesian upgrades.

As a general matter, the interconnection study process is designed to assess whether upgrades are needed to accommodate a particular generating facility but are not intended to assess whether a particular upgrade will accommodate a particular set of future potential generating facilities. However, it is undoubtedly the case that the Friesian upgrades will at least partially facilitate the interconnection of more than 1,000 MW of additional solar generation.

Attachment%20DR
%202-1.xlsx

2. Please provide the Generator Queue Power Flow Study Case models for the following:

The Study Case referenced in subsection (b) has already been provided to Birdseye's consultant, who has executed the necessary FERC confidentiality document. The Study case referenced in subsections (c) and (d) will also be provided to Birdseye's consultant. The Company is not clear what is being requested in subsection (a) but notes that the Birdseye consultant is able to adjust the inputs in the Study Cases provided.

a. Base Case model with no queue generation dispatch.

b. Study Case with all generation dispatch up to Friesian (Q380).

c. Study Case with all generation dispatch up to Fairbluff (Q387).

d. Any contingency files and/or an explanation of studied scenarios beyond single contingency scenarios.

3. For Q380, please describe the benefits that Q380 upgrades would have on reliability, resiliency, and interconnecting additional renewables (transmission and distribution interconnected) and load.

NERC Reliability Standard TPL-001-4 establishes requirements for planning the interconnected bulk electric system such that the network can be operated to supply real and reactive forecasted loads and projected firm transmission services. DEP already complies with all of these requirements, and the Friesian Upgrades will allow DEP to continue to comply with NERC Reliability Standard TPL-001-4 after the addition of the Q380 project. In addition, the Friesian upgrades will not only provide sufficient capacity to allow the Friesian project to interconnect, but will also provide sufficient capacity to allow many other projects to interconnect due the size the next available upgrade. From an operational perspective, the Friesian upgrades will alleviate interdependency for at least 1,561 MW of additional solar resources, providing a path forward for such projects to interconnect in a safe and reliable manner (though some such projects may require additional upgrades at the transmission or distribution level).

4. Given the progress that has been made on planning the Q380 upgrades based on work funded by deposits already made under the Q380 LGIA, please provide any updates on cost estimates for these upgrades.

There are no cost updates at this time.

5. In Section 3.1 of the System Impact Study of Q398, Duke Energy's 1235 MW Combined Cycle Plant in Cumberland County, NC (as available on DEP's OASIS site as "Q398_SIS_Rev_1.pdf"), option 1 is dependent on upgrades of prior-queued projects. Please provide information as to whether option 2 is dependent on upgrades of prior-queued projects, and if not, why option 2 is not dependent on upgrades of prior-queued projects.

As a general matter, the transmission planning process assumes that all earlier queued projects and their associated upgrades are constructed and therefore does not attempt to assess system impacts based on alternative potential scenarios in which particular planned upgrades are not constructed. However, the Company has determined that Q398 is not dependent on the Friesian upgrades, including when studied under Option 1 or Option 2. Q399 which is a second 1235 MW Combined Cycle Plant in Cumberland County is interdependent on the Friesian upgrades. Also, for the sake of clarity, Option 1 and Option 2 are addressed in Section 3.2 of the Q398 System Impact Study Report.

6. Please describe the benefits that Q398 upgrades would have on reliability, resiliency, and interconnecting additional renewable (transmission and distribution interconnected) and load.

See the Company's responses to DR 2-1 and 2-3.

7. In Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Questions in August 27, 2019 Order Docket No. E-100, Sub 157 on November 4, 2019, Duke states on page 31: "The scenarios presented do not fully account for the real-world challenges that would be faced in adding a significant number of new grid resources in a short amount of time. Issues not addressed, but required to implement this pace of system transformation, include physical and regulatory challenges affecting the time to construct new assets and their associated interconnection and system upgrade requirements." Please state whether the upgrades associated with the Friesian project address one of the physical challenges affecting the interconnection of new renewable energy resources, and if, so the specific challenges that would be addressed.

As a general matter, substantial network upgrades will be needed to accommodate the addition of a substantial amount of new grid resources. While the referenced Company analysis from Docket No. E-100, Sub 157 did not attempt to identify what specific network upgrades will be needed, the Friesian upgrades are representative of the types of network upgrades that may be needed in the future and the Friesian upgrades would, in fact, help to accommodate the interconnection of a substantial amount of additional renewable and other resources.

8. In the same filing described in question 7 above, Duke states: "The Companies are presenting two potential, illustrative scenarios that would move the Companies closer to achieving 70% CO2 reduction target by 2030, utilizing a 2005 baseline. These reductions are achieved by increasing the pace of coal plant retirements while significantly increasing the Companies' mix of renewables (including wind generation), battery storage, energy efficiency, and combustion turbine (CT) generation." Please state how many additional MWs of renewables are called for in each plan respectively.

As stated in DEC's and DEP's response to the Commission's Question 3(b) filed on November 4, 2019 in Docket No. E-100, Sub 157, the Companies have not developed a preferred plan for how they would comply with the greenhouse gas emission reduction goals of the North Carolina Clean Energy Plan. However, see Table 1 on page 32 of the November 4, 2019 filing for the list of resources that comprise the generation mix under the potential illustrative scenarios, including additional MWs of renewables.

As shown in the potential illustrative scenarios comparison listed on Table 1 on Pg. 32, the base case (51% CO_2 reduction) requires 3,000+ MW of additional solar resources over current amounts. The 60% CO_2 reduction by 2030 scenario projects an additional 669 MW increase in the amount of solar resources (as compared with the base case), while the 64% reduction scenario projects an additional 2,100 MW increase in the amount of solar resources (as compared with the base case).

9. The transmission study that Duke conducted in 2017 finds that CPRE will use up the remainder of grid capacity to interconnect solar resources. Due to this finding, please confirm that in order to connect additional solar resources after CPRE, grid upgrades will be required in both DEC and DEP territories.

Duke is not aware of the referenced study.

10. Please explain whether or not it is possible to achieve a 70% reduction in CO2 emissions by 2030 without the upgrades associated with Q380?

The Company's analysis of potential pathways to further substantial reductions in CO2 has not attempted to assess whether the Friesian upgrades are required for such a reduction. Nevertheless, as stated in the Company's response to DR 2-7, substantial network upgrades will be needed to accommodate substantial amounts of new grid resources. The Friesian upgrades are representative of the types of upgrades that will be needed. The Friesian upgrades will, in fact, accommodate the interconnection of a substantial amount of solar resources which will introduce incremental renewable generation to the system that will, all things being equal, contribute to a reduction in CO_2.

11. Please state the total cost of network upgrades that Duke intends to construct over the next ten years in DEP and DEC territories.

[To be provided]

Queue Number	Generation Size (MW)
CHKLIST-8140	5
CHKLIST-8480	4.999
CHKLIST-8581	7
CHKLIST-8586	4.998
CHKLIST-8624	4.999
CHKLIST-8626	4.999
CHKLIST-8773	6.2
CHKLIST-8977	10
CHKLIST-8987	5
CHKLIST-9061	5
CHKLIST-9196	3.92
CHKLIST-9244	6.9
CHKLIST-9806	8.1
CHKLIST-10113	10.56
CHKLIST-10361	4.998
CHKLIST-10520	8.9
CHKLIST-10493	4.998
CHKLIST-10534	5
CHKLIST-10544	2.2
CHKLIST-10585	4.384
SC2015-00007	2
NC2015-00009	1.999
NC2015-00014	5
SC2015-00005	2
SC2015-00009	2
SC2015-00011	2
SC2015-00012	2
SC2015-00051	2
SC2015-00027	2
SC2015-00047	10
SC2015-00048	8.8
SC2015-00052	10
SC2015-00056	10
SC2015-00069	10
SC2015-00118	10
SC2015-00119	10
SC2015-00120	10
SC2015-00123	10
SC2015-00124	10
SC2015-00126	10
SC2015-00127	10
SC2015-00150	8.16
NC2015-00031	4.998
SC2015-00067	6
SC2015-00136	1

SC2015-00151	6.12
NC2015-00043	4
SC2015-00167	2
SC2015-00168	10.88
NC2016-00010	5
SC2016-00037	2
NC2016-00028	4.998
NC2016-00041	5
SC2016-00075	10
SC2016-00076	10
SC2016-00083	10
CHKLIST-9361	9.996
NC2016-02778	5
NC2016-02789	1.998
NC2016-02796	5
NC2016-02798	5
SC2016-00919	20
NC2016-02809	5
NC2016-02810	4.996
NC2016-02811	5
Q381	75
Q383	80
NC2016-02849	5
Q385	100
NC2016-02869	5
NC2016-02870	5
NC2016-02885	4.992
NC2016-02893	5
NC2016-02897	4.992
NC2016-02902	4.992
Q387	75
NC2016-02917	4.992
NC2016-02928	4.992
NC2016-02935	5
SC2016-01038	2
NC2016-02954	5
SC2016-01042	1.92
Q404	71.5
Q405	60.5
sc2017-01087	1.98
sc2017-01088	1.98
Q406	60.5
Q407	80
SC2017-01122	2
SC2017-01123	2
SC2017-01124	2
Q412	20

Q413	20
NC2017-02998	1.98
Q419	100
Q425	50
Q426	74.5
SC2017-01134	1.98
SC2017-01137	1.98
SC2017-01138	1.98
SC2017-01139	1
SC2017-01140	1.98
Q431	60
Q432	75
SC2017-01144	1.98
SC2017-01146	1.98
SC2017-01150	1.98
Q436	63

EXHIBIT
RW-1

I/A

North Carolina's Clean Energy Future

An Alternative to Duke's Integrated Resource Plan

Prepared for the North Carolina Sustainable Energy Association

March 7, 2019

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CONTENTS

FIGURES

1. INTRODUCTION

The Integrated Resource Plans (IRP) filed in North Carolina by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) in September 2018 reflect business as usual for the two utilities. The plans, which run through 2033 and include the Duke service territory in both North and South Carolina, rely heavily on new natural gas capacity. Together, they add more than 9,000 megawatts (MW) of new combined cycle and combustion turbine capacity over the 15-year analysis period from 2019 to 2033 to both meet anticipated increases in electricity demand and to replace certain retiring coal units. Renewable additions are comprised of solar photovoltaic (PV) and battery storage resources but are added in minimum amounts sufficient to comply with North Carolina House Bill 589.

Synapse performed a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy Carolinas and Duke Energy Progress's (collectively Duke Energy) IRPs. The clean energy future analysis included resources such as solar, wind, energy efficiency, and battery storage. These resources were offered to the EnCompass electric sector model to provide both energy and capacity, and to meet future reliability requirements as coal resources in the Carolinas approach retirement. This report compares one such optimized Clean Energy scenario to a Duke IRP scenario. Synapse analyzed the benefits of this modeled clean energy future on the electric power system, emissions, public health, job creation, and electricity customer rates and bills.

Renewable resource options, in addition to those modeled by Duke Energy, are comparably cost-effective to new natural gas for North Carolina ratepayers and offer other benefits to the state.

In the Clean Energy scenario, the EnCompass model is allowed to select the most cost-effective future resource build. In contrast to the Duke IRP scenario, the model chooses to build out solar and storage resources to meet future capacity and energy needs with zero incremental natural gas-fired unit additions. Coal generation declines between the Duke IRP and Clean Energy scenarios, lowering the electric system production cost and reducing emissions of carbon dioxide (CO_2) while maintaining system reliability. Emissions reductions of additional air pollutants result in health benefits to North and South Carolina, avoiding hospital and emergency visits and lost work days. Total revenue requirements of the Clean Energy scenario are lower than in the Duke IRP scenario, and North Carolina consumers see lower electricity rates as a result. Under the Clean Energy scenario, North Carolina consumers also use less energy due to the increased energy savings associated with the High Energy Efficiency scenario from the Duke Energy IRPs. When coupled with the decrease in rates, residential consumers in the state see their average annual electricity expenditures decline by approximately 2.5 to 5.5 percent.

2. Scenario Analysis

Synapse used the EnCompass capacity expansion and production cost model, licensed by Anchor Power Solutions, to examine two different future energy scenarios in the Duke Energy service territories from 2018 to 2033:

Duke IRP: The Duke IRP scenario reflects the anticipated energy resource future as outlined in the most recent Duke Energy IRPs. Specifically, the Duke IRP scenario assumes:

- The slate of planned resource additions already contracted or under construction, and the "optimized" natural gas combined cycle and combustion turbine plants selected during the IRP process. Duke Energy Carolinas and Duke Energy Progress were modeled as operating in a single Duke Energy service territory, but this does not assume the "capacity sharing" modeled by Duke in its IRPs as part of its Joint Planning scenario. Rather, the resource additions assumed by each utility in its individual IRPs are included and modeled as part of this scenario.

- Cost and operational data as outlined in Duke's discovery responses to North Carolina Utilities Commission Staff and other intervenors. In the absence of available data, Synapse relied on the Horizons Energy National Database (the primary data source for the EnCompass model) or other industry-recognized sources.

- Retirement dates for certain existing coal generators that are consistent with the utility IRPs.

- Must-run designations for coal units in the service territory, which force coal units to run regardless of price and reflect historical regional generation patterns.

Clean Energy: The Clean Energy scenario reflects an optimized view of the Duke Energy service territory with relaxed assumptions around operation and up-to-date renewable costs:

- The utility reserve margin is set at 15 percent (versus 17 percent in the Duke IRP scenario). This lower reserve margin was selected to be consistent with North American Electric Reliability Corporation (NERC) standards. It also reflects the assumption that as older units with higher forced outage rates retire and are replaced with new capacity, the reliability of the system is improved.

- Must-run designations for coal units are removed.

- Projected load includes the increased electric demand associated with the recent electric vehicle goal established in North Carolina Governor Roy Cooper's Executive Order Number 80.

- Energy efficiency is provided as a supply-side resource based on the High Energy Efficiency scenario in Duke Energy's IRPs.

- Renewable costs are based on the *2018 NREL Annual Technology Baseline*[1] or Lazard's *Levelized Cost of Storage Analysis.*[2]

- The Clean Energy scenario incorporates all planned resource additions outlined in the Duke IRPs that are currently under construction or necessary to comply with North Carolina's renewable procurement regulations but excludes the "optimized" natural gas combined cycle and combustion turbine units that were selected by the System Optimizer model to meet reserve margin constraints in and after 2025.

- The model can choose to build generic utility-scale solar, storage, wind, and paired solar-plus-storage resources in any amount (e.g. no restrictions were placed on either total or incremental renewable capacity), in addition to traditional natural gas-fired generating resources.

More information on the modeling structure, including detail on topology, load, fuel prices, and other assumptions, can be found in Technical Appendix A.

[1] National Renewable Energy Laboratory (NREL). 2018. *2018 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. Available at: https://atb.nrel.gov/.

[2] Lazard. 2018. *Lazard's Levelized Cost of Storage Analysis: Version 4.0*. Available at: https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/.

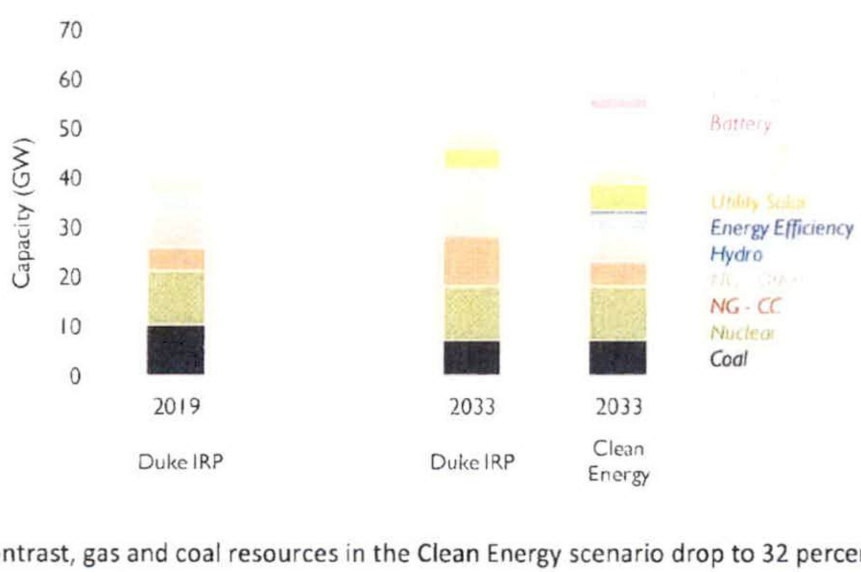
3. Results

3.1. Electric Sector Modeling

New generating capacity is constructed during the analysis period to meet the respective reserve margins in both the Duke IRP and Clean Energy scenarios; however, the type of capacity constructed differs between scenarios. The Duke IRP scenario relies heavily on generic natural gas-fired combined cycle and combustion turbine units, with renewable resources (solar PV and battery storage) added only in amounts sufficient for Duke Energy to comply with North Carolina House Bill 589. The Clean Energy scenario, on the other hand, relies on a slate of clean energy resources to meet its reserve margin requirement that includes energy efficiency, utility-scale storage and solar, and paired solar-plus-storage resources. EnCompass model results are presented here for the entirety of Duke Energy's service territory in both North and South Carolina.

Figure 1, below, shows the generating capacity in the Duke IRP and Clean Energy scenarios in 2033, as compared to Duke's actual capacity mix in 2019. As shown in Figure 1, approximately 55 percent (22 GW) of Duke's installed capacity in 2019 is fossil fuel-powered thermal (coal- or natural gas-fired), 27 percent (10.7 GW) of capacity is nuclear, and the remaining 18 percent (7 GW) comes from hydroelectric, renewable, and distributed energy resources. By 2033, the proportion of fossil-fired resources in the Duke IRP scenario is unchanged at 56 percent (27 GW), while clean energy resources have increased modestly to 23 percent (11 GW).

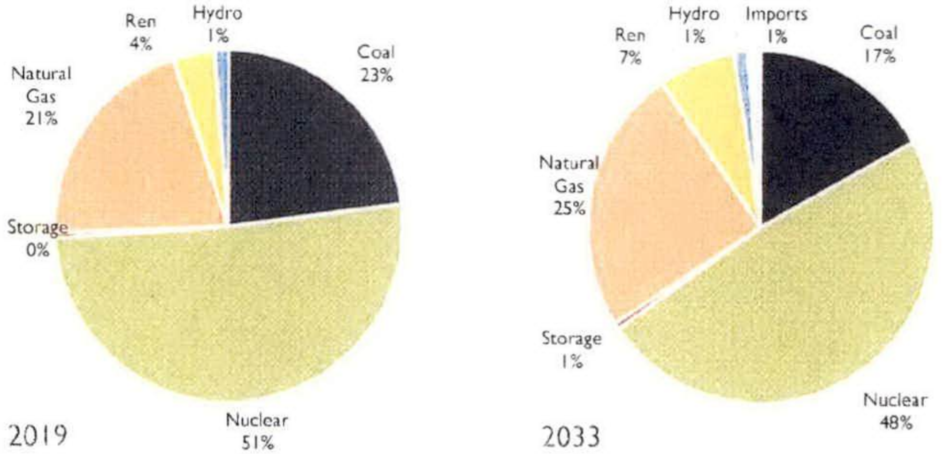
Figure 1. Duke Energy modeled nameplate capacity by scenario, 2019 and 2033



In contrast, gas and coal resources in the Clean Energy scenario drop to 32 percent (18 GW) of the capacity mix by 2033, and renewable energy resources comprise 49 percent (27 GW) of the utility mix. Nuclear capacity remains constant in both scenarios throughout the period. Notably, the EnCompass model makes the choice to retire the Allen coal plant at the end of 2019, accelerating the retirement from Duke Energy's anticipated dates of 2024 (for Units 1–3) and 2028 (for Units 4–5). While the coal capacity is the same at the end of the analysis period for both the Duke IRP and the Clean Energy scenarios, the latter retires a portion of this coal capacity earlier in the analysis period and thus has a lower volume of coal capacity during that time.

As shown in Figure 2 below, the fuel mix in Duke's service territory changes very little over time in the IRP scenario. Coal generation drops from 21 percent in 2019[3] to 17 percent in 2033, while natural gas generation increases over the study period from 19 percent to 25 percent. Renewable generation increases only slightly over the study period, from 4 percent in 2019 to 7 percent in 2033. Note that these percentages do not match those shown in Duke Energy's IRPs in Figure 12-F on pages 69 (Duke Energy Carolinas) and 71 (Duke Energy Progress). This is due to the different assumptions used by Duke Energy and Synapse around operational parameters of individual units and the regional market price of energy.

Figure 2. Modeled generation in the Duke IRP scenario, 2019 and 2033



In the Clean Energy Scenario, shown in Figure 3, renewable generation makes up 21 percent of the fuel mix in 2033 as compared to 7 percent in the Duke IRP scenario. Natural gas generation falls to 9 percent of total generation in 2033, as compared to 25 percent in the Duke IRP scenario in that same year. Imports make up a greater percentage of the generation in the Clean Energy scenario as the model takes advantage of lower out-of-system energy costs. Notably, coal generation is markedly lower in the Clean Energy scenario than in the Duke IRP scenario in 2019, and this immediate decrease can be attributed to the removal of the "must-run designations," which are present in the Duke IRP scenario and force units to run without consideration of their variable costs.[4] Duke's coal-fired power plants are some of the

[3] Note that approximately one-third of the coal generation shown in 2019 is exported to neighboring utility service territories rather than being used to meet Duke Energy's own load requirements.

[4] Must-run designations are set by Horizons Energy, the developers of the National Database used by the EnCompass model. They are based on Horizons' observations from EPA's Continuous Emissions Monitoring (CEMS) data as well as data from Energy Information Administration (EIA) Form 923. In setting the must-run designations, Horizons assumes that coal generators will retire a coal asset rather than running it under high stress (e.g. daily shut-down) situations for any period of time.

more expensive resources to operate in both scenarios. With the must-run designations applied, the Duke IRP scenario alternates between importing and exporting energy as it seeks to find a use for the costly must-run coal generation that has been forced into the electric grid. In contrast, coal generation falls at the beginning of the analysis period in the Clean Energy scenario when the must-run designations are removed.

Figure 3. Modeled generation in the Clean Energy scenario, 2019 and 2033

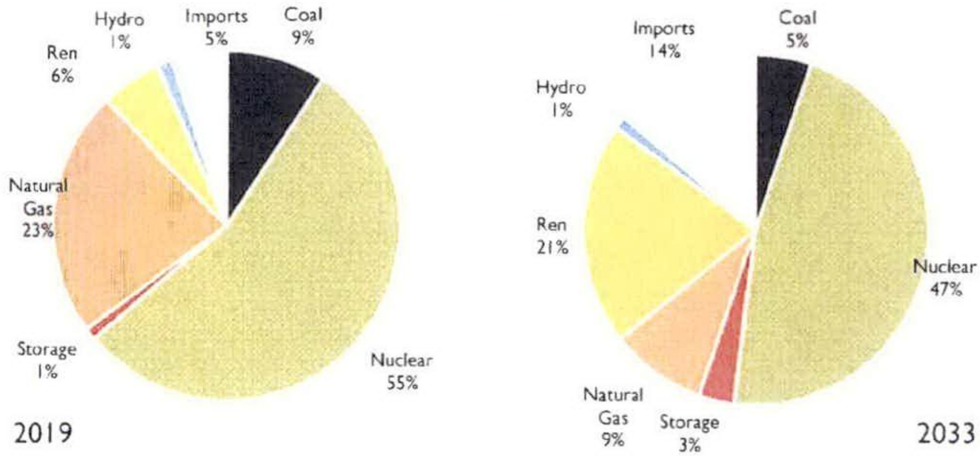
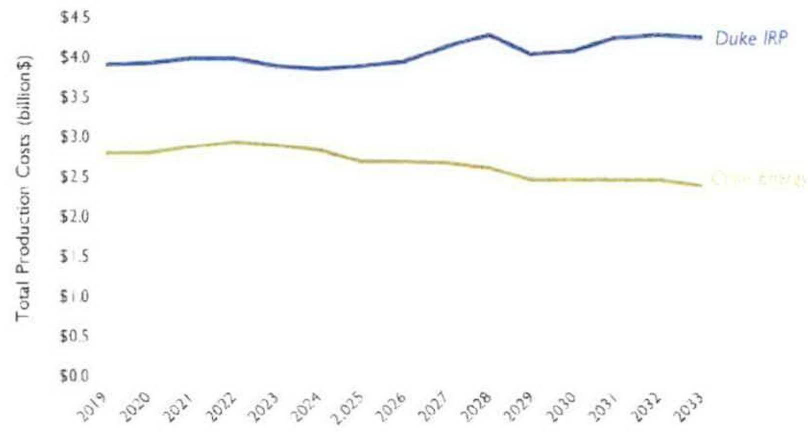


Figure 4 shows the total production cost associated with each scenario over the course of the analysis period. The Clean Energy scenario is considerably less expensive from an operational perspective than the Duke IRP scenario for two primary reasons. First, we note an immediate cost decline in the first year of the analysis period due to the removal of the must-run designations, as described above. Production costs immediately drop by 28 percent when uneconomic coal capacity is no longer forced to generate. In the absence of this coal-fired energy, EnCompass substitutes no- and low- variable cost energy from other sources.

Figure 4. Duke Energy total production cost by year by scenario



From a reliability perspective, Duke Energy meets its hourly demand requirements in all modeled days and hours during the analysis period. The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, even with the increased electric demand associated with the addition of new electric vehicles under Executive Order Number 80.

Figure 5 and Figure 6, below, show energy generation on January 3, 2028—a representative winter peak day—for the Duke IRP and Clean Energy scenarios. Both scenarios rely on nuclear generation and some level of energy imports to meet demand in peak hours and then export energy during the midday trough. The Duke Energy scenario dispatches must-run coal units throughout the day, and uses a mix of natural gas-fired, hydroelectric, and some solar generation to meet the hourly peaks. The modest amounts of battery storage capacity are charged in the early morning and midday hours. Conversely, the Clean Energy Scenario uses very little coal, less natural gas-fired generation, and relies on a greater mix of resources. Battery capacity is charged via solar generation during both an extended morning period and the midday trough, which allows batteries to discharge during evening hours to help meet the evening peak. Duke Energy's hourly load requirements are shown by the solid line. The area between the dashed line and the solid line in the two Figures represents the time in which battery resources are being charged, whether by solar resources within Duke's service territory or via imported energy. The area between the solid line and the dotted line represents energy exports.

Figure 5. Sample winter peak generation by fuel type, January 3, 2028, Duke IRP scenario

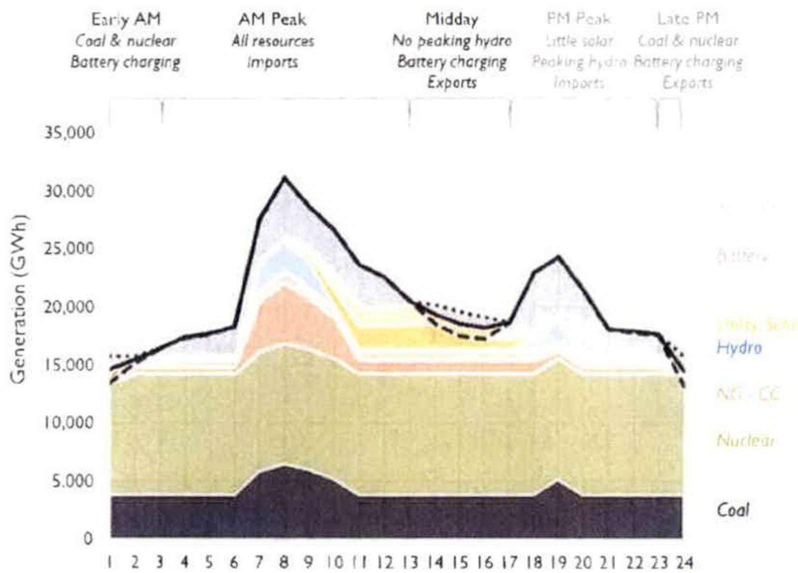
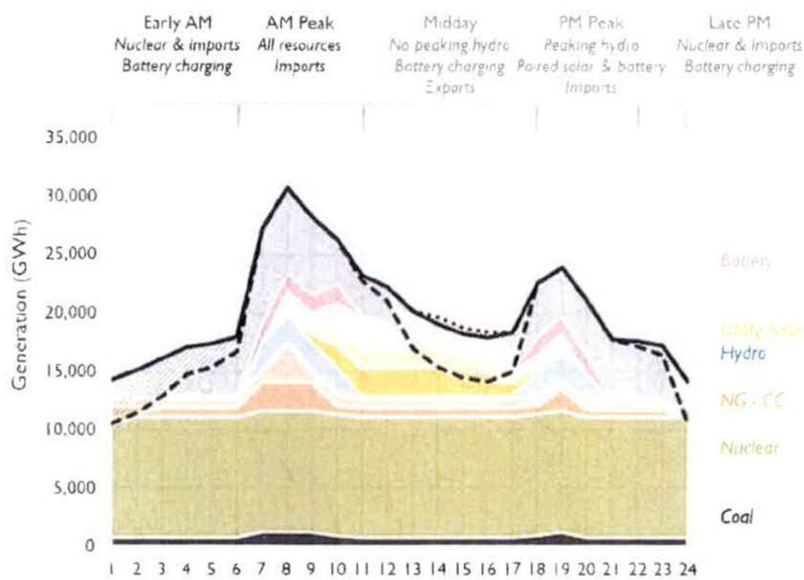
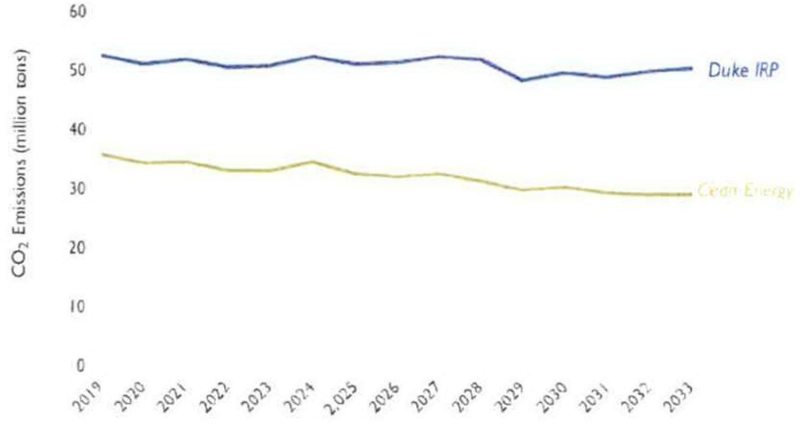


Figure 6. Sample winter peak generation by fuel type, January 3, 2028, Clean Energy scenario



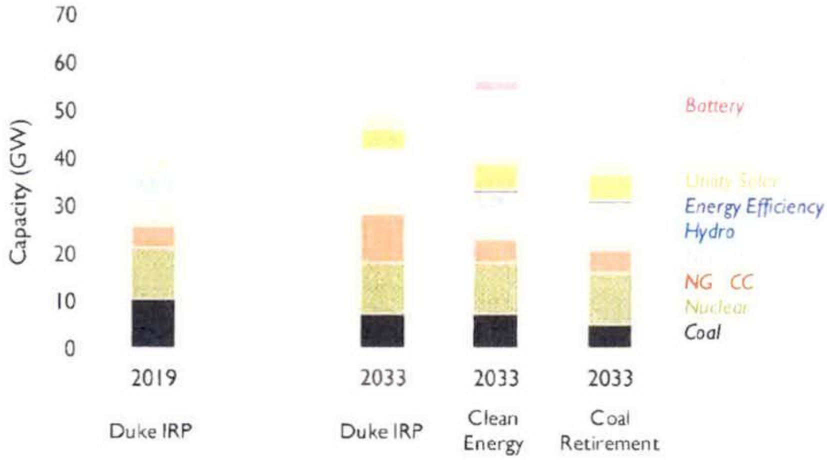
Finally, as expected based on the substantial difference in carbon-free capacity and generation between the two scenarios, the CO_2 emissions in the Clean Energy scenario are well below those in the Duke IRP scenario. The removal of the must-run coal designations immediately leads to a reduction in CO_2 emissions of almost 17 million tons in 2019. Though both scenarios see overall emissions decline, the gap between the two widens by the end of the period, when the Duke IRP scenario continues to emit almost 50 million tons of CO_2 while the Clean Energy scenario emits just under 30 million tons. Figure 7 depicts this widening gap, with both scenarios accounting for emissions associated with energy imports. Again, these volumes will differ from those reported by Duke Energy in Figure A-3 of each of its IRPs given the operational differences between generators that exist between the Company's modeled scenario and the Synapse Duke IRP scenario.

Figure 7. Duke Energy CO_2 emissions by year by scenario



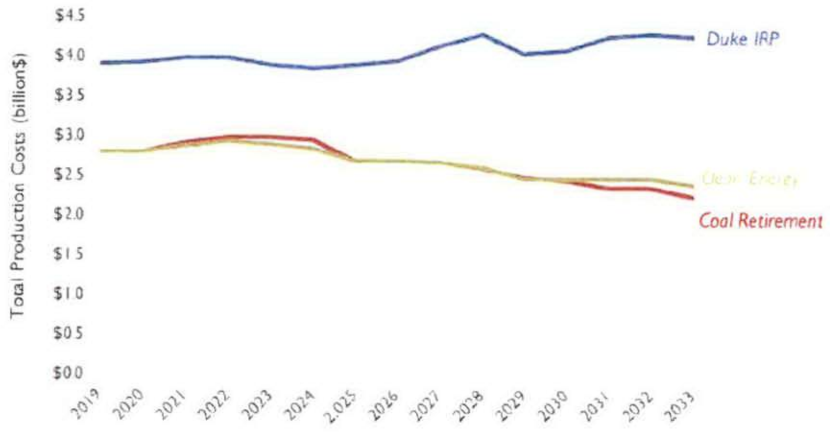
Synapse also examined an Accelerated Coal Retirement scenario in order to examine the ways in which advancing certain coal unit retirements changes system emissions and costs. This scenario accelerates Duke's retirement of the Roxboro Units 3 and 4 to December 2030 and the retirement of Marshall Units 1 and 2 to December 2032. As shown in Figure 8, the EnCompass model chooses to make up for the retired coal capacity through capacity purchases from surrounding states.

Figure 8. Duke Energy modeled nameplate capacity with Accelerated Coal Retirement, 2019 and 2033



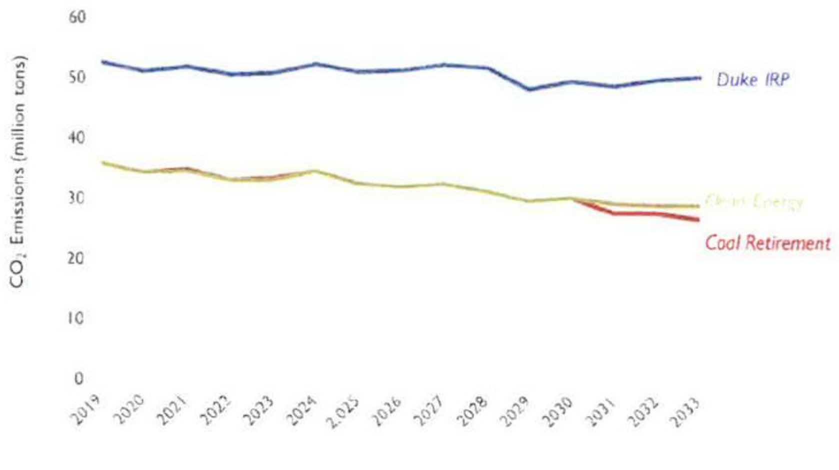
Production costs are extremely similar between the Clean Energy and Accelerated Coal Retirement scenarios, as shown in Figure 9. Costs drop slightly in the Accelerated Coal Retirement scenario in 2030 as the Roxboro 3 and 4 and Marshall 1 and 2 retirements move forward in time compared to the other scenarios. Energy imports increase slightly in the Accelerated Coal Retirement scenario as a replacement for the generation from these retiring units.

Figure 9. Duke Energy production cost by year by scenario



We see a comparable decrease in emissions after 2030 in the Accelerated Coal Retirement scenario, as shown in Figure 10.

Figure 10. Duke Energy CO_2 emissions by year by scenario



The following sections examine the impacts to human health, customer rates and bills, and state GDP and jobs of the Clean Energy scenario as compared to the Duke IRP scenario. Because the Clean Energy and Accelerated Coal Retirement scenarios were so similar, we limited our analysis to the differences between the Duke IRP and Clean Energy scenarios only.

3.2. Health Impacts

Synapse used the CO-Benefits Risk Assessment (COBRA) tool to assess the avoided health impacts in both North Carolina and South Carolina due solely to the change in emissions associated with our modeled Clean Energy scenario. Developed for the U.S. Environmental Protection Agency (EPA) State and Local Energy and Environment Program, COBRA utilizes a reduced form air quality model to measure the impacts of emission change on air quality and translates them into health and monetary effects. For this analysis, Synapse used modeled emissions (SO_2, NO_X, & $PM_{2.5}$) from the Duke IRP scenario as a baseline and compared them to modeled emissions from the Clean Energy scenario. The health and monetary benefits described below are those avoided by the Clean Energy scenario.

COBRA can estimate a number of detailed health impacts, including adult mortality, infant mortality, non-fatal heart attacks, respiratory hospital admissions, cardiovascular-related hospital admissions, acute bronchitis, upper respiratory symptoms, lower respiratory symptoms, asthma exacerbations, asthma emergency room visits, minor restricted activity days, and work loss days due to illness. A subset of those specific health impacts is shown in Table 1, with the numbers in the table representing the number of hospital visits and work loss days that could be avoided under the Clean Energy scenario.

Table 1. Avoided health impacts of the Clean Energy scenario

Year	Hospital Admits, Respiratory	Hospital Admits, Respiratory Direct	Hospital Admits, Asthma	Hospital Admits, Lung Disease	Hospital Admits, Cardio	Emergency Room Visits, Asthma	Work Loss Days
2020	6.0	4.3	0.5	1.2	7.1	10.8	2,398
2025	5.9	4.3	0.5	1.2	7.0	10.7	2,372
2030	4.9	3.5	0.4	1.0	5.8	8.9	1,966
2033	4.8	3.4	0.4	0.9	5.6	8.6	1,911

In 2020 the difference in Duke Energy's electric system dispatch in the Clean Energy scenario avoids approximately six respiratory-related hospital admits, seven cardiovascular-related hospital admits, and 11 asthma-related emergency room visits in North and South Carolina compared to the Duke IRP scenario. Notably, COBRA projects similar avoided health effects at the end of the modeling period (2033) compared to 2020. This is largely due to the removal of coal must-run designations in the Clean Energy scenario, which leads to an immediate decrease in emissions of air pollutants as coal generation drops. The Duke IRP scenario keeps uneconomic coal units online and, when not forced to generate, the Clean Energy scenario utilizes low-pollutant nuclear and renewable resources to generate in the place of coal. Thus, there is a sizeable difference in emissions between the two scenarios from the beginning of the period. The Duke IRP scenario slowly ramps down its reliance on coal-fired generation over the course of the analysis period, causing the gap in emissions avoided health impacts to narrow over time.

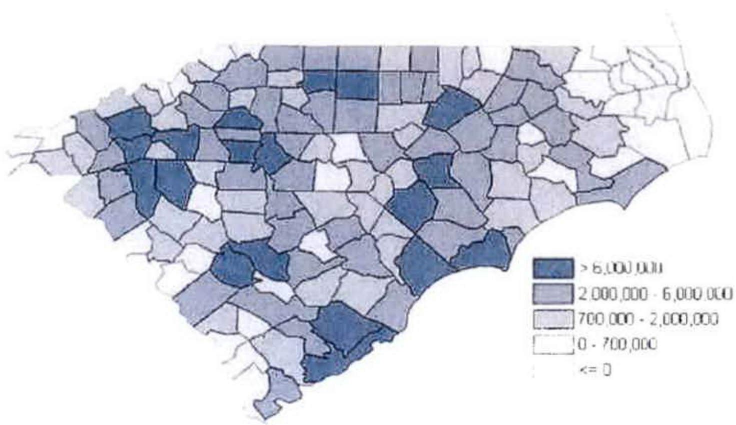
In addition to physical health effects and the costs of associated medical treatment, illnesses related to air pollution impose other costs on society, which include lost productivity and wages if a person misses work or school and restrictions on outdoor activity when air quality is poor. Table 2 shows low and high estimates of the monetized value of these total health benefits. These numbers place an economic value on all of the avoided health impacts modeled in COBRA, plus the value of minor restricted activity days and work loss days.

Table 2. Monetary benefits of all avoided health impacts under the Clean Energy scenario

Year	Total Health Benefits, Low	Total Health Benefits, High
2020	$196,778,415	$444,771,642
2025	$194,592,175	$439,830,666
2030	$161,291,821	$364,570,301
2033	$156,736,570	$354,274,856

The avoided health impacts and monetary benefits associated with the emissions reductions in the Clean Energy scenario vary by county, with the largest impacts seen in the most populous counties in North and South Carolina. Figure 11 shows the distribution of the monetized total health benefits across North and South Carolina in 2028. As one might intuit, greater benefits are realized in those counties with larger populations, where a larger number of people are affected by the local air quality.

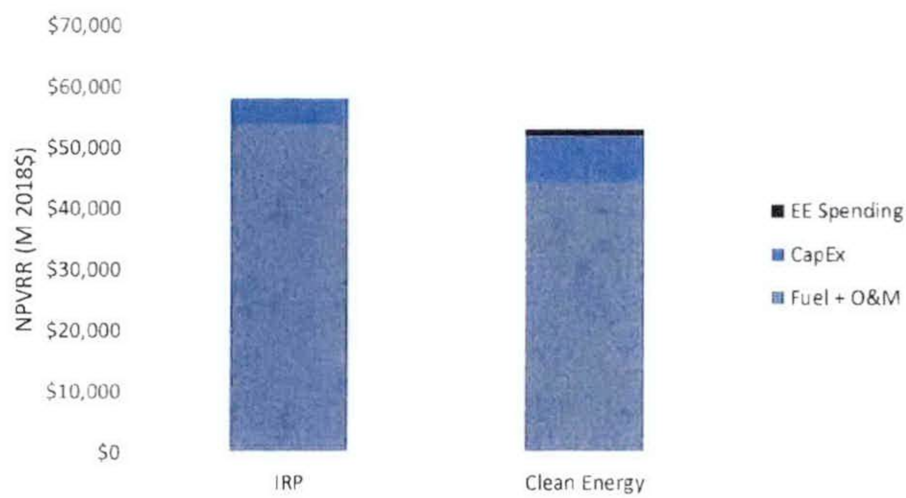
Figure 11. Total health-related monetary benefits ($ high estimate) of the Clean Energy scenario by county, 2028



3.3. Rate and Bill Impacts

Revenue requirements are lower under the Clean Energy scenario than in the IRP scenario, due primarily to the lower production cost associated with the operation of Duke's power plants. Capital expenditures in the IRP scenario are lower than in the Clean Energy scenario, as they represent only the cost of renewable procurement up to the levels specified by NC House Bill 589, along with North Carolina's portion of new, "optimized" combined-cycle and combustion turbine units added by Duke Energy post-2025. The Clean Energy scenario contains additional revenue requirements associated with capital spending on renewable resources over-and-above HB 589 levels and administration costs associated with incremental energy efficiency, but the fuel and operations and maintenance (O&M) savings from the operation of low- and no-variable cost resources lowers the total revenue requirement. These numbers do not include spending on transmission and distribution. Those revenue requirements are shown in Figure 12.

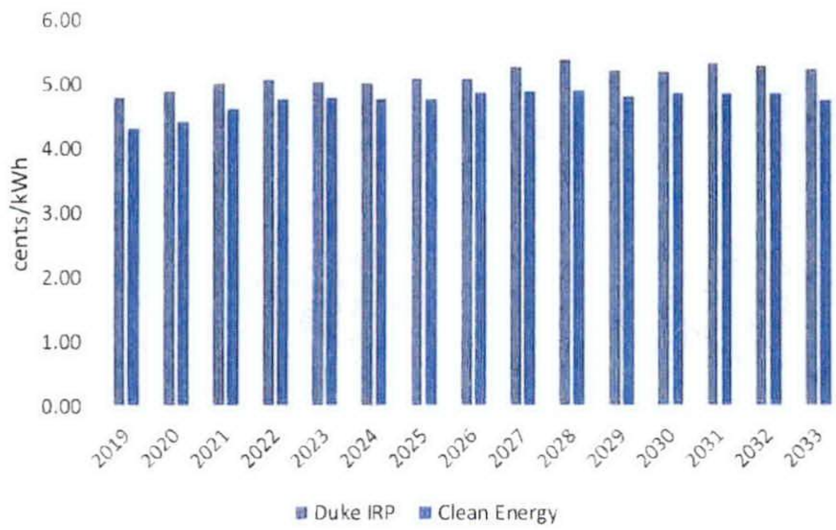
Figure 12. Revenue requirement of the Duke IRP and Clean Energy scenarios, North Carolina



Note that Duke Energy's capital cost assumptions were used for the resources in the IRP scenario. Synapse used capital costs for standalone solar and battery storage, wind, and paired solar and battery from NREL and Lazard. Duke's capital cost estimate for solar capacity from 2019 to 2033 is lower than the Synapse assumption, and the solar cost component of the capital spending revenue requirement is a conservative one.

Ratepayers in North Carolina save money under the Clean Energy scenario. Synapse calculated the estimated change in the rate components associated with capital spending and production costs. These values were taken from EnCompass and were allocated to North Carolina based on the percentage of Duke energy sales occurring in the state in 2017 according to EIA data. In the Clean Energy scenario, the increased spending on energy efficiency programs was added to this value. Total costs were then divided by Duke's energy sales to all customer classes to arrive at an average retail rate impact in each scenario that is associated with capital cost, production cost, and incremental energy efficiency spending.[5] We found that for any given year during the analysis period, ratepayers can expect to save anywhere from a minimum of .24 cents/kWh to a maximum of .48 cents/kWh, as shown in Figure 13, which translates to a savings of 4 to 9 percent over the study period.

Figure 13. Estimated average retail rate impact of the Duke IRP and Clean Energy scenarios



In order to estimate the total change in residential customers' electricity bills under the Clean Energy scenario, the average retail rate was multiplied by an assumed energy consumption by residential customers of 1,000 kWh per month, or 12,000 kWh per year. This was assumed to represent the component of residential rates associated with capital, fuel, variable O&M, and incremental energy efficiency spending (in the Clean Energy scenario). Costs associated with Transmission, Distribution, and Customer Charges were taken from slides 22 and 23 of the presentation entitled *North Carolina's Public Utility Infrastructure & Regulatory Climate* presented by the North Carolina Utilities Commission in October 2018.[6] A single weighted average of the sum of these costs for DEC and DEP was calculated based on the number of residential customers in each state, and was added to the capital/production cost component.

The lower production costs (fuel and variable O&M) in the Clean Energy scenario lead to immediate savings in customer electricity rates compared to the Duke IRP scenario. Under the Clean Energy scenario, North Carolina consumers also use less electricity under the Enhanced Energy Efficiency program. Lower electricity use,[7] coupled with the decrease in rates, causes residential consumers in the

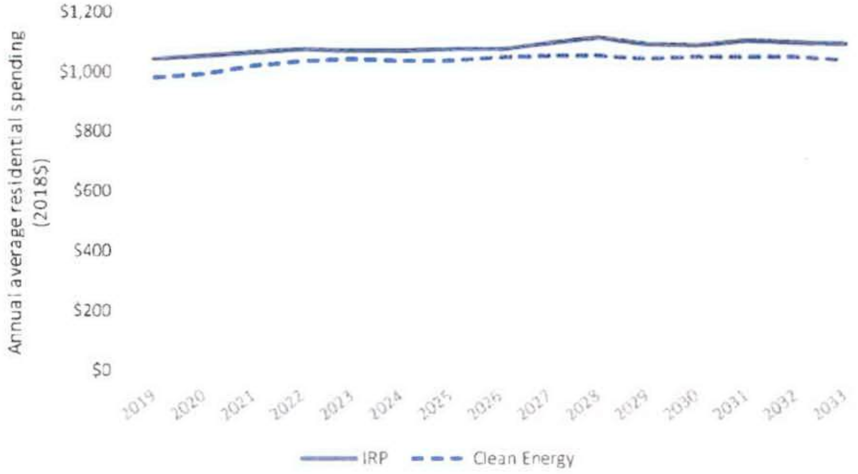
[5] For more information on the rate and bill impact calculation methodology, see Appendix A.

[6] This presentation is available at: https://www.ncuc.net/documents/overview.pdf

[7] Annual electricity use was calculated by dividing Duke Energy's forecasted energy sales by the forecasted customer count.

state see their average annual electricity costs decline by $27–$58 per year, or approximately 2.5 to 5.5 percent, depending on the year. This savings is shown in Figure 14.

Figure 14. Estimated residential bill impact of the Duke IRP and Clean Energy scenarios



3.4. Economic Impacts

Synapse used the IMPLAN model to evaluate the impacts of the Clean Energy scenario on employment, income, and Gross Domestic Product (GDP) in North Carolina. IMPLAN is an industry-standard model that can be used to evaluate the impacts of changes in direct spending patterns on a state's economy. For this analysis, North Carolina-specific spending impacts were determined by allocating Duke costs and spending based on North Carolina's proportion of system-wide energy sales. IMPLAN's framework enables us to assess not only impacts in directly affected industries, but also impacts on industries that serve as suppliers to directly impacted industries or that serve employees of directly and indirectly impacted industries. Synapse evaluated macroeconomic impacts resulting from changes in direct spending on the construction of each generation resource type, the operation of generation resources, and the installation of energy efficiency measures. We also assessed impacts associated with changes in disposable income among households and businesses facing lower (or higher) energy costs under the Clean Energy scenario.

Figure 15 displays the average annual North Carolina employment impacts of the Clean Energy scenario relative to the Duke IRP scenario in each of three five-year periods covering the IRP study timeframe. We find modest positive net positive employment impacts in each period, as positive impacts associated with re-spending of energy savings and increased spending on energy efficiency and renewable energy resources outweigh negative impacts associated with decreased spending on coal and natural gas power plants. Over the full IRP study period, our results indicate an average annual increase in North Carolina employment of approximately 3,000 full-time jobs.

Figure 15. Average annual employment impacts of Clean Energy scenario relative to Duke IRP scenario

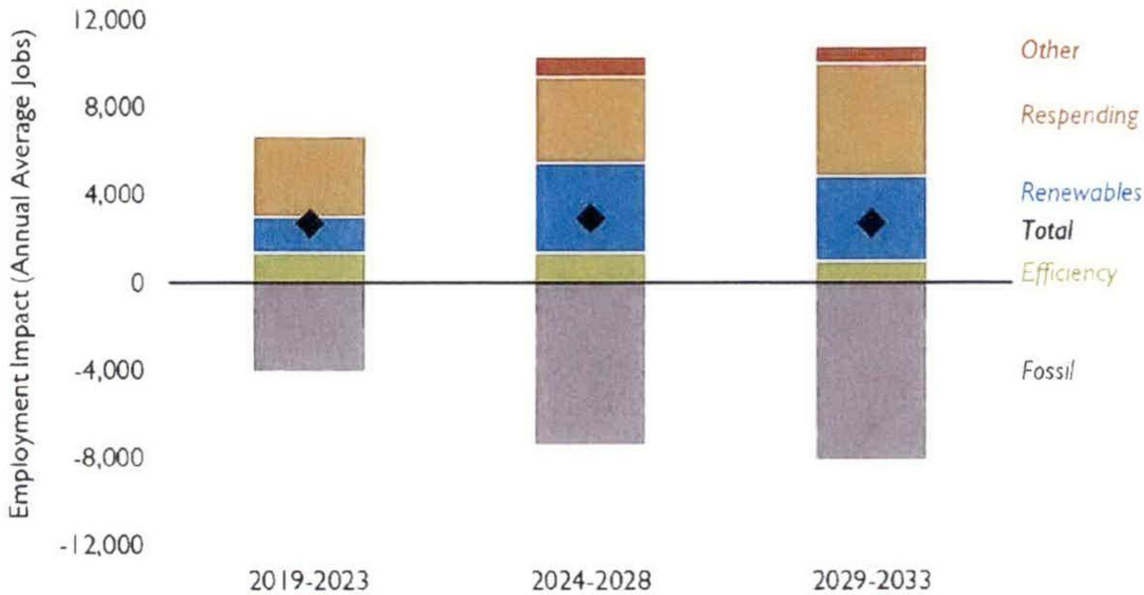


Figure 16 presents a similar picture regarding impacts on income of North Carolina residents. Our results indicate that the net increases in employment drive modest net increases in total income. Over the period from 2019 through 2023 we estimate net increases in average annual income of approximately $110 million.

Figure 16. Average annual income impacts of Clean Energy scenario relative to Duke IRP scenario

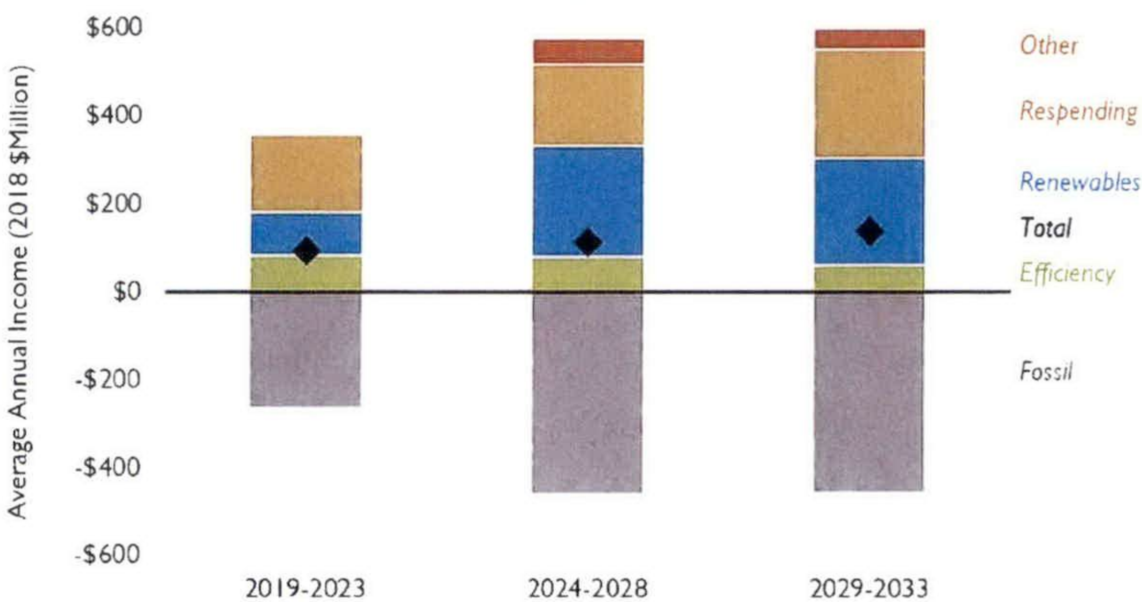
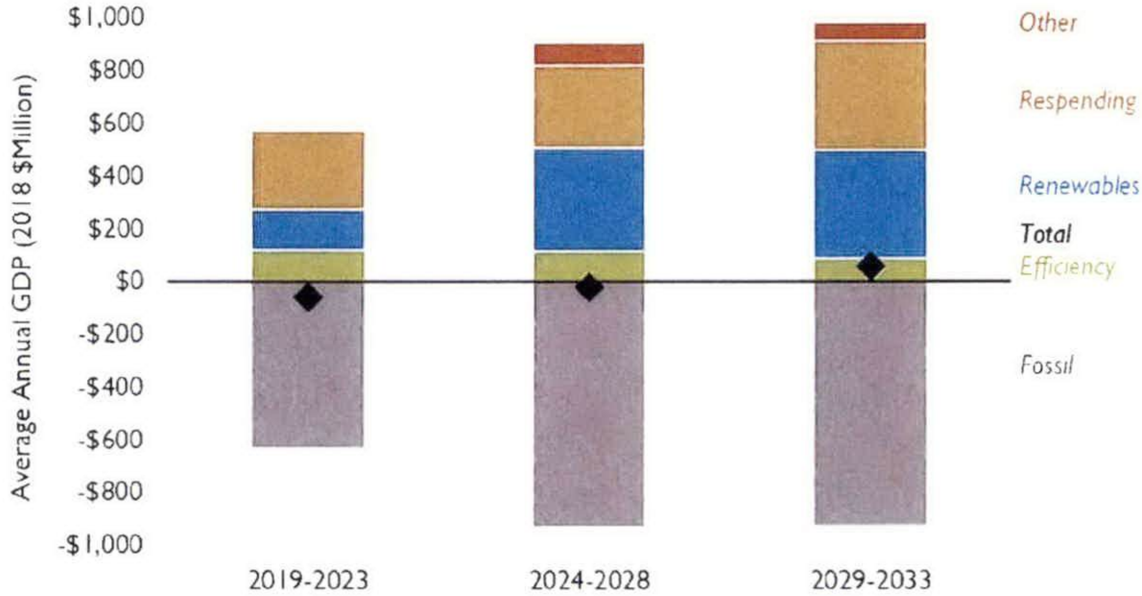


Figure 17 displays results for North Carolina state GDP. In this case, we find small net negative impacts, as GDP decreases associated with reduced spending on construction and operation of fossil fuel resources outweigh increases driven by greater spending on renewables, efficiency, and the wider economy. Over the period from 2019 through 2033 we find an average annual net GDP decrease of approximately $10 million. The discrepancy between this finding and our employment results reflects the fact that renewable resource and retail industries tend to be more labor-intensive than fossil fuel industries.

Figure 17. Average annual GDP impacts of Clean Energy scenario relative to Duke IRP



We note that all of these macroeconomic impacts are quite small in the context of North Carolina's economy. For example, our finding of an average annual employment increase of 3,000 amounts to less than 0.1 percent of the total number of jobs in North Carolina.[8] Similarly, an annual GDP impact of $10 million amounts to less than 0.01 percent of North Carolina's GDP.[9]

To summarize, Synapse performed a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy's IRPs. In contrast to Duke's preferred resource portfolio, we found that the EnCompass model chooses to build out solar and storage resources to meet future capacity and energy needs with zero incremental natural gas-fired unit additions when allowed to select the most cost-effective future resource build. Coal generation declines between the Duke IRP and Clean Energy scenarios, lowering the

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[8] Total employment in North Carolina is currently approximately 4.5 million. See https://www.bls.gov/news.release/laus.nr0.htm.

[9] 2017 North Carolina GDP was approximately $540 billion. See https://fred.stlouisfed.org/series/NCNGSP.

electric system production cost and reducing CO_2 emissions while maintaining system reliability. Our modeling shows that renewable resources are comparably cost-effective to new natural gas for North Carolina ratepayers and offer other benefits to consumers in the state, including a decrease in the number of hospital visits related to poor air quality, electricity rate and bill savings for consumers, and increased employment.

Appendix A. Technical Appendix

Synapse used EnCompass to model resource choice impacts in Duke's service territory in North and South Carolina. Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that provides an enterprise solution for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including:

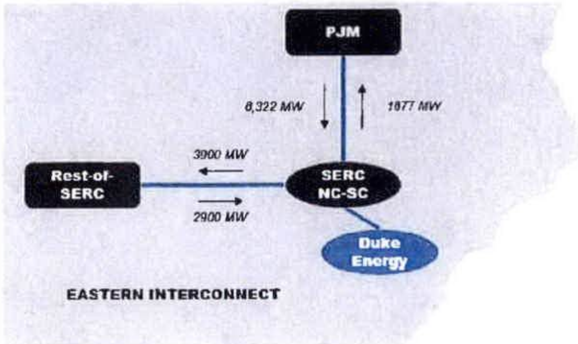
- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load shaping and shifting capabilities;
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis;
- Long-term integrated resource planning, including capital project optimization, economic generating unit retirements, and environmental compliance; and
- Market price forecasting for energy, ancillary services, capacity, and environmental programs.

Synapse used the EnCompass National Database created by Horizons Energy to model the Duke service territory. Horizons Energy has benchmarked dispatch and prices resulting from its comprehensive dataset to actual, historical data across all modeling zones. More information on EnCompass and the Horizons dataset is available at www.anchor-power.com.

Topology and Transmission

Synapse modeled two detailed areas with full unit-level operational granularity, the Duke Energy utility service territory, and the remaining SERC region comprised of North Carolina and South Carolina. Additionally, we modeled external contract regions representing the SERC and PJM balancing areas. We relied on transmission assumptions from the EnCompass National Database, displayed in Figure 18 below. Energy transfers between SERC NC-SC and the Rest-of-SERC and PJM regions are subject to a default 3.44 $/MWh tariff. Capacity transfers are unlimited within SERC regions. Energy from the PJM and Rest-of-SERC regions are priced at recent historical energy prices and escalated throughout the period.

Figure 18. Duke IRP modeling topology and energy transfer capabilities



Peak Load and Annual Energy

For the Duke Energy territory, Synapse relied on annual energy and peak load as defined in the 2018 Duke Energy Carolinas and Duke Energy Progress IRPs. Synapse used annual energy and peak projections from the NERC Long-term Reliability Assessment for the SERC-NC-SC region. We utilized hourly load shapes supplied by Horizons Energy in the EnCompass National Database for all modeled regions. Synapse also performed analysis in the proprietary Electric Vehicle Regional Emissions and Demand Impacts Tool (EV-REDI)[10] to model the load required to meet the electric vehicle (EV) target set in North Carolina Executive Order No. 80 (80,000 EVs by 2025, and an annual 5 percent increase through the end of the period). The additional EV load is included in the Clean Energy scenario.

Fuel Prices

For natural gas prices, Synapse relied on NYMEX futures for monthly Henry Hub gas prices through December 2019. For all years after 2019, Synapse used the annual average prices projected for Henry Hub in the AEO 2018 Reference case. We then applied trends in average monthly prices observed in the NYMEX futures to this longer-term natural gas price to develop long-term monthly trends. Delivery price adders for Zone 5 are sourced from the EnCompass National Database. Coal prices, from the Central Appalachia supply basin, and for the Carolinas delivery point are also sourced from the EnCompass National Database. Gas and coal price forecasts are shown in Figure 19 and Figure 20 below.

[10] More information on EV-REDI is available at: http://www.synapse-energy.com/tools/electric-vehicle-regional-emissions-and-demand-impacts-tool-ev-redi

Figure 19. Natural gas price forecast – Henry Hub and Zone 5 Delivery Point

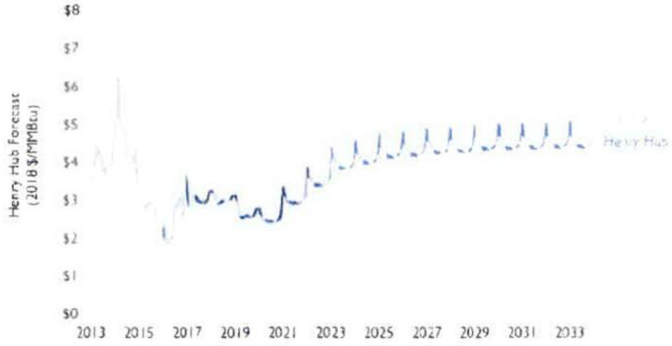
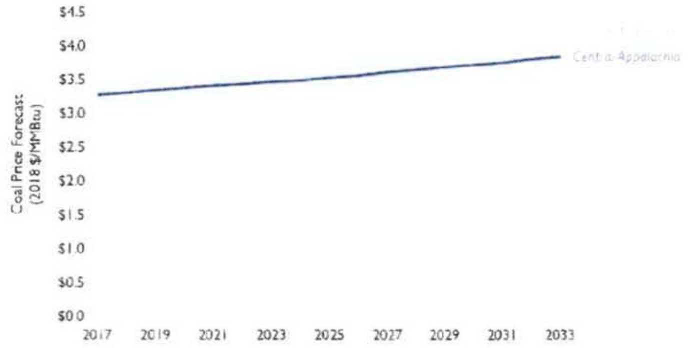


Figure 20. Coal price forecast – Central Appalachia Basin and Carolinas Delivery Point



Programs

Synapse modeled two major environmental programs: the North Carolina Renewable Energy & Energy Efficiency Portfolio Standard (REPS) and the carbon price forecast outlined in the 2018 Duke Energy IRPs. The REPS requires that 10 percent of electricity sales be met by renewable resources—stepping up to 12.5 percent in 2021—and up to 25 percent of the requirement can be met through energy efficiency technologies (40 percent after 2021). The carbon price outlined in the Duke IRPs begins at $5/ton (nominal) in 2025 and escalates at $3/ton annually.

Duke IRP Planned Resources

The Duke IRP scenario includes all planned additions, upgrades, and retirements described in the Duke IRPs, shown in Table 3 below, as well as generic combined cycle and combustion turbines added by the System Optimizer model in 2025 and beyond ("modeled additions").

Table 3. Duke IRP capacity (MW)

TYPE	PLANNED ADDITIONS	PLANNED RETIREMENTS	MODELED ADDITIONS
Coal		4,553	
CC	560	173	5,352
Hydro	260	1	
Nuclear	56		
CHP	81		
CT	402	843	3,220
Solar	673		
Storage	232		

Clean Energy Scenario Projects

For the Clean Energy scenario, Synapse allowed five generic project options in both North Carolina and South Carolina. They include onshore wind,[11] utility-scale battery, utility-scale solar, and a paired utility-scale battery and solar project. For these projects Synapse uses NREL's Advanced Technology Baseline projections and Lazard's Levelized Cost of Storage 2018 report to define cost and operational parameters.

Other Assumptions

Synapse made additional adjustments to our core modeling assumptions in consultation with the North Carolina Sustainable Energy Association. We list those assumptions below.

- In the Clean Energy scenario, the Duke territory has a required reserve margin of 15 percent, while the Duke IRP case uses the 17 percent reserve margin outlined in the Duke IRPs.
- Battery resources have a firm capacity credit of 75 percent throughout the analysis period, consistent with the recent study entitled *Energy Storage Options for North Carolina* and prepared by North Carolina State University.
- Coal must-run designations are applied in the Duke IRP scenario and are removed in the Clean Energy scenario.
- Energy efficiency is modeled as a supply-side resource in the Clean Energy scenario based on the Enhanced Energy Efficiency case described in the Duke IRPs. It is priced at the levels outlined in the *2016 Duke Energy North Carolina DSM Market Potential Study*.
- Carbon dioxide emissions associated with energy imports in each of the scenarios are calculated using a declining annual average emissions rate for generation in PJM. According to the region's emissions report *2013-2017 CO_2, SO_2 and NO_x Emissions*

[11] Offshore wind was not offered to the EnCompass model in Duke Energy's service territory. However, it was offered to the external NC-SC region and was not selected by the model.

Rates,[12] emissions of CO_2 have declined over the past five years. We applied this declining rate to the PJM System Average in 2017 to project future emissions rates. These rates were then multiplied by the volume of energy imports in each year, and calculated emissions were added to emissions from Duke's units to determine total annual CO_2 emissions from all sources.

COBRA Modeling Assumptions

The U.S. EPA's COBRA model contains baseline emissions estimates for the pollutants $PM_{2.5}$, SO_2, NO_x, NH_3, and VOCs for the year 2017. Users can adjust these estimates up or down, and the model utilizes a reduced form air quality model to estimate the effects of these emission changes on ambient particulate matter. It then calculates avoided health and monetary benefits associated with the emissions changes consistent with U.S. EPA practice. For more information visit https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool.

To estimate the health and economic impacts of NO_x and SO_2, Synapse utilized annual emissions outputs from the EnCompass model scenarios for the Duke service territory in North and South Carolina. Emission rates were based on the following specific assumptions:

- EnCompass approximates NO_x and SO_2 emissions using unit-specific emission rates, as defined in the Horizons Energy National Database.
- For this project, Synapse incorporated an average $PM_{2.5}$ emissions rate for all coal fuels in EnCompass of 0.027 lb/mmBtu. This emissions rate is in line with emission rates compiled by Argonne National Laboratory for *GREET Model Emission Factors for Coal- and Biomass-fired Boilers* and by EPA for the Avoided Emissions and generation Tool (AVERT).

Synapse assumed a 7 percent discount rate for all COBRA analyses. Additionally, the COBRA analysis relies on historical county-level emissions allocations and assumes no county-level shifting.

Rate and Bill Impacts

Synapse used spreadsheet analysis to estimate the impact of the Clean Energy scenario on estimated electric rates and bills in North Carolina. Customer electric rates in a given year are made up of a number of components, including, but not limited to: utility capital expenditures inclusive of accumulated depreciation and an approved rate of return; the cost to a utility of generating the electricity necessary to meet customer demand; utility spending on any energy efficiency programs; and the volume of sales to customers.

[12] Available at: https://www.pjm.com/-/media/library/reports-notices/special-reports/20180315-2017-emissions-report.ashx?la=en

We determined utility capital expenditures for the Duke IRP scenario using Duke Energy's anticipated future resource portfolio and capital cost trajectories for the resource technologies added to its capacity mix. In their IRPs, DEC and DEP do not differentiate between new thermal capacity added in North Carolina versus South Carolina, and thus capital expenditures on new natural gas-fired resources were allocated to states based on the proportion of customer sales. Renewable additions were assumed to be necessary to comply with North Carolina HB 589 and capital expenditures were allocated to North Carolina ratepayers. In the Clean Energy scenario, the capital expenditures associated with the volume of renewable additions necessary for HB 589 was again allocated to North Carolina, with any capital expenditures from renewable additions above these volumes being allocated between North and South Carolina based on forecasted energy sales.

Production costs (fuel and fixed and variable O&M) in the two modeled scenarios were allocated between DEC and DEP based on forecasted energy sales. The volume of energy sales expected to occur in North Carolina versus South Carolina was calculated using the historical ratio of 2017 sales found in the most recent EIA 861 data. The historical percentage of sales occurring in North and South Carolina in DEC and DEP service territories was applied to the anticipated energy sales contained in the utilities' IRPs.

Program administration costs for energy efficiency are from the *2016 Duke Energy North Carolina DSM Market Potential Study* and the *2016 Duke Energy South Carolina DSM Market Potential Study*, both done by Nexant Consulting.

Estimated average retail rates were calculated by summing anticipated capital expenditures, production costs, and incremental utility energy efficiency costs, and dividing by total sales in North Carolina. Though actual rates differ between different customer classes, for the sake of this analysis we assumed one standard electricity rate across customer classes, referred to in the text as the "average retail rate."

In order to estimate the total change in residential customers' electricity bills under the Clean Energy scenario, the average retail rate was multiplied by an assumed energy consumption by residential customers of 1,000 kWh per month, or 12,000 kWh per year. This was assumed to represent the component of residential rates associated with capital, fuel, variable O&M, and incremental energy efficiency spending (in the Clean Energy scenario). Costs associated with Transmission, Distribution, and Customer Charges were taken from slides 22 and 23 of the presentation entitled *North Carolina's Public Utility Infrastructure & Regulatory Climate* presented by the North Carolina Utilities Commission in October 2018. A single weighted average of the sum of these costs for DEC and DEP was calculated based on the number of residential customers in each state, assumed to grow at real rate of 2 percent per year, and was added to the capital/production cost component.

Modeling Economic Impacts

The differences in capacity, generation, emissions, and system costs between the Clean Energy and Duke IRP scenarios drive differences in employment, income, and state Gross Domestic Product (GDP). Synapse used the IMPLAN model to evaluate the impact of the Clean Energy scenario on each of these macroeconomic indicators in North Carolina.[13] IMPLAN is an industry-standard input-output model that relies upon historical economic relationships to evaluate the effects of changes in direct spending patterns on employment, income, and GDP within a given study area. For this analysis, Synapse assessed impacts resulting from changes in spending on the following economic activities:

- Construction of generating resources
- Installation of energy efficiency measures
- Operation and maintenance of generation resources
- Consumer and business re-spending of energy savings

Our analysis accounts for three types of impacts: direct, indirect, and induced.

Direct impacts

Direct impacts consist of changes in employment, income, and GDP within energy resource sectors immediately impacted by the change in resource plan between the Duke IRP and Clean Energy scenarios. For example, direct employment impacts may consist of additional jobs for contractors, construction workers, and plant operators working on the building or operation of a power plant.

Indirect impacts

Indirect impacts are changes in employment, income, and GDP within sectors that serve as suppliers to directly affected industries. Examples of such sectors include turbine manufacturers and manufacturers of energy-efficient appliances. Note that our analysis only accounts for impacts among suppliers located within North Carolina.

Induced impacts

Induced impacts result from residents spending more or less money in the local economy. For energy resources, these impacts result from: (1) changes in disposable income among employees in directly and indirectly impacted industries and (2) changes in energy expenditures by North Carolina electricity customers.

Direct inputs to our economic impact modeling consist primarily of vectors of changes in spending by and on various industries. These inputs are generally direct outputs from our EnCompass modeling. They include changes in spending on the construction and operation of each type of electricity resource (e.g., natural gas power plants, solar power plants, battery storage facilities). For each industry, Synapse

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[13] IMPLAN is a commercial model developed by IMPLAN Group PLC. Information on IMPLAN is available at: http://implan.com/.

allocated the total change in spending across the available IMPLAN industry categories based on data from the National Renewable Energy Laboratory's JEDI model[14] and supplemental Synapse research.

[14] Available at: https://www.nrel.gov/analysis/jedi/

Appendix B. Qualifications and Experience

About Synapse

Synapse Energy Economics is a research and consulting firm specializing in energy, economic, and environmental topics. Since its inception in 1996, Synapse has grown to become a leader in providing rigorous analysis of the electric power sector for public interest and governmental clients.

Synapse's staff of 30 includes experts in energy and environmental economics, resource planning, electricity dispatch and economic modeling, energy efficiency, renewable energy, transmission and distribution, rate design and cost allocation, risk management, benefit-cost analysis, environmental compliance, climate science, and both regulated and competitive electricity and natural gas markets. Several of our senior-level staff members have more than 30 years of experience in the economics, regulation, and deregulation of the electricity and natural gas sectors. They have held positions as regulators, economists, and utility commission and ISO staff.

Services provided by Synapse include economic and technical analyses, regulatory support, research and report writing, policy analysis and development, representation in stakeholder committees, facilitation, trainings, development of analytical tools, and expert witness services. Synapse is committed to the idea that robust, transparent analyses can help to inform better policy and planning decisions. Many of our clients seek out our experience and expertise to help them participate effectively in planning, regulatory, and litigated cases, and other forums for public involvement and decision-making.

Synapse's clients include public utility commissions throughout the United States and Canada, offices of consumer advocates, attorneys general, environmental organizations, foundations, governmental associations, public interest groups, and federal clients such as the U.S. Environmental Protection Agency and the Department of Justice. Our work for international clients has included projects for the United Nations Framework Convention on Climate Change, the Global Environment Facility, and the International Joint Commission, among others.

Relevant Experience

Modeling Gas-Fired Plant Alternatives in New Mexico

Client: Sierra Club | Project ongoing

On behalf of the Sierra Club, Synapse is performing modeling of the electric system in New Mexico using the EnCompass model in both capacity expansion and production cost modes. Synapse is comprehensively modeling zero-emission alternatives to a new utility-proposed gas-fired generation option intended to replace the retiring San Juan Generating Station units in New Mexico in 2023. The modeling accounts for the interconnectedness of the electric power grid in the Desert Southwest region, including detailed representation of generation units in Arizona and New Mexico (and portions of Texas and California), and aggregated treatment for resources in the rest of the West. Synapse has found that a combination of utility-scale and small-scale solar PV, utility-scale battery storage, and incremental wind resource procurements would provide Public Service of New Mexico with a less-expensive, and lower-emitting alternative than its proposed gas-fired generation, while meeting all reliability requirements.

Nova Scotia Power Generation Utilization and Optimization Study

Client: Nova Scotia Utility and Review Board | Project completed August 2018

Synapse was asked to conduct an Integrated Resource Planning-type analysis on the overall utilization and optimization of Nova Scotia Power's coal and thermal generating fleet. Synapse used the PLEXOS electric sector simulation model for both capacity expansion and production cost purposes to estimate the costs associated with various unit retirement pathways and resource replacement options.

Value of Solar Implications of South Carolina Electric & Gas Fuel Costs Rider 2018

Client: Southern Environmental Law Center | Project completed May 2018

Synapse provided analysis and expert testimony on behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy for South Carolina Electric & Gas' (SCE&G) 2018 annual update of solar PV avoided costs under PURPA. Witness Devi Glick submitted testimony (Docket no. 2018-2-E) regarding the appropriate calculation of benefit categories associated with the value of solar calculation for PURPA QF rates and for Act 236 compliance.

Avoided Energy Supply Costs in New England

Client: AESC Study Group | Project completed March 2018

Synapse and a team of subcontractors used EnCompass and other tools to develop projections of electricity and natural gas costs that would be avoided due to reductions in electricity and natural gas use resulting from improvements in energy efficiency. The 2018 report provides projections of avoided costs of electricity and natural gas by year from 2018 through 2035 with extrapolated values for another 15 years. In addition to projecting the costs of energy and capacity avoided directly by program participants, the report provides estimates of the Demand Reduction Induced Price Effect (DRIPE) of efficiency programs on wholesale market prices for electric energy, electric capacity, and natural gas. The report also provides a projection of avoided costs of fuel oil and other fuels, non-embedded environmental costs associated with emissions of CO_2, avoided costs of transmission and distribution, and the value of reliability. The 2018 AESC study was sponsored by a group representing all of the major electric and gas utilities in New England as well as efficiency program administrators, energy offices, regulators, and advocates. Synapse conducted prior AESC studies in 2007, 2009, 2011, and 2013.

Clean Energy for Los Angeles

Client: Food & Water Watch | Project completed March 2018

The Los Angeles City Council has mandated that the Los Angeles Department of Water and Power (LADWP), the largest municipally run utility in the United States, analyze powering 100 percent of demand with renewable energy. To date, LADWP's efforts have been insufficient, as the utility has only published an analysis of a slight increase over current renewable energy targets and is not planning to finalize its 100 percent renewable study until 2020 at the earliest.

Food & Water Watch engaged Synapse to analyze a potential pathway to 100 percent clean energy in Los Angeles by 2030 using the EnCompass model. The modeled scenarios in the *Clean Energy for Los Angeles* report include a substantial amount of storage capacity. The two 100 percent renewable scenarios build between 2 and 3 gigawatts of storage capacity which is dispatched liberally in order to shift generation from solar resources to meet demand in the region. Our analysis included hourly modeling that demonstrated exactly how storage could be charged and dispatched over the course of the day to meet the utility's needs.

In our study, we found that it is possible for LADWP to exclusively use renewable resources to power its system in every hour of the year. What's more, we found that under one of the clean energy pathways analyzed, the transition to 100 percent renewable energy in every hour of the year can occur at no net cost to the system. The resulting report, *Clean Energy for Los Angeles*, provides a roadmap for how to achieve 100 percent renewables by integrating and harnessing renewable energy more efficiently and investing in additional efficiency, storage, and demand response.

Although the report only focuses on a single city, the results are important and applicable to many other parts of the country. Los Angeles's four million residents make the city larger than 22 entire states, while the annual energy served by LADWP is greater than sales in 13 individual states, indicating that if this transition is possible in Los Angeles, it is feasible in other parts of the country as well.

An Analysis of the Massachusetts RPS
Client: E4theFuture | Project completed August 2017
Synapse Energy Economics joined with Sustainable Energy Advantage (SEA), as well as members from NECEC, Mass Energy Consumers Alliance, E4theFuture, and other organizations to analyze the current state of regional renewable portfolio standards in light of many of new policy actions that have been put into place over the last several years. These policy actions include new legislation requiring long-term contracting for renewables and other resources in Massachusetts, Connecticut, and Rhode Island, revised incentives for distributed generation resources, changes to RPS polices in other states in New England, proposed Massachusetts-specific CO_2 caps, and newly-revised forecasts for electricity sales that take the full impact of new energy efficiency measures into account. The Synapse team used the EnCompass model for this analysis.

Clean Power Plan Reports and Outreach for National Association of State Utility Consumer Advocates
Client: National Association of State Utility Consumer Advocates | Project completed August 2015
Synapse supported the National Association of State Utility Consumer Advocates and its members in addressing the EPA's proposed Clean Power Plan in a manner that is cost-effective and efficient from an electricity consumer perspective. Prior to the release of the rule, Synapse presented to NASUCA members key issues regarding the details of the proposed rule and the primary compliance options that may be available to states. Following the rule's release, Synapse prepared a report focusing on the details of the rule as proposed. Recognizing that stakeholders have a wide range of reactions to the EPA's Plan, the intent of the report is to be a common resource to help all of NASUCA's members think through a broad range of potential implications of various compliance approaches to their respective consumers—whatever their individual state's positions. Synapse presented on the findings

of *Implications of EPA's Proposed "Clean Power Plan"* at the 2014 NASUCA annual meeting in San Francisco, CA.

Synapse used its Clean Power Plan Planning Tool (CP3T) to perform multi-state analysis of the proposed rule to identify and explain a variety of challenges and opportunities related to multi-state compliance, including how states with dissimilar renewable technical potential, states with utilities that cross state boundaries, states with existing mechanisms for cooperation, etc., may approach regional compliance with the Clean Power Plan. Pat Knight, the lead developer of CP3T, provided a webinar for NASUCA members giving an overview of key issues surrounding the Clean Power Plan, as well as a walkthrough of CP3T's multi-state functionality. Synapse also prepared a report presenting the results of the analysis, presented at the NASUCA 2015 Mid-Year Meeting.

As a third element of Synapse's Clean Power Plan support to NASUCA members, Synapse prepared a report on best practices in planning for implementation of the Clean Power Plan. The report serves as a guide for consumer advocates to the logistics of developing a state implementation plan, with advice in areas such as stakeholder engagement, evaluating resource options, deciding on reasonable assumptions, identifying appropriate modeling tools, and selecting and implementing a plan.

Long-Term Procurement Plan Rulemaking

Client: California Office of Ratepayer Advocates | Project ongoing

Synapse is providing technical and expert witness services to the California Office of Ratepayer Advocates in connection with the Long-Term Procurement Plan proceeding affecting the three largest investor-owned utilities in California: Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric. As part of this project, Synapse conducted modeling of the California ISO (CAISO) area using PLEXOS to assess loads and emissions throughout California based on various California Public Utilities Commission scenarios. Synapse analyzed model inputs, assumptions, forecast projections, and outputs, and examined alternatives including renewable energy integration and retirement scenarios. Synapse's modeling enabled determination of areas within California that would be capacity constrained.

Best Practices in Electric Utility Integrated Resource Planning

Client: Regulatory Assistance Project | Project completed June 2013

Synapse prepared a report for the Regulatory Assistance Project examining best practices in electric utility integrated resource planning. Synapse researched and discussed specific integrated resource plan (IRP) statutes, regulations, and processes in Arizona, Colorado, and Oregon; examined "model" utility IRPs from Arizona Public Service, Public Service Company of Colorado, and PacifiCorp; and developed recommendations for prudent integrated resource planning. Our report provided recommendations for both the IRP process and the elements that are analyzed and included in the resource plan itself. These elements include load forecast, reserves and reliability, demand-side management, supply options, fuel prices, existing resources, and environmental costs and constraints, among others.

EXHIBIT RW-2 I/A

Synapse
Energy Economics, Inc.

Rachel Wilson, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139 I 617-453-7044
rwilson@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, April 2019 – present, *Senior Associate*, 2013 – 2019, *Associate*, 2010 – 2013, *Research Associate*, 2008 – 2010.

Provides consulting services and expert analysis on a wide range of issues relating to the electricity and natural gas sectors including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; electric system dispatch; and environmental compliance technologies, strategies, and costs. Uses optimization and electricity dispatch models, including Strategist, PLEXOS, EnCompass, PROMOD, and PROSYM/Market Analytics to conduct analyses of utility service territories and regional energy markets.

Analysis Group, Inc., Boston, MA.

Associate, 2007 – 2008, *Senior Analyst Intern*, 2006 – 2007.

Provided litigation support and performed data analysis on various topics in the electric sector, including tradeable emissions permitting, coal production and contractual royalties, and utility financing and rate structures. Contributed to policy research, reports, and presentations relating to domestic and international cap-and-trade systems and linkage of international tradeable permit systems. Managed analysts' work processes and evaluated work products.

Yale Center for Environmental Law and Policy, New Haven, CT. *Research Assistant*, 2005 – 2007.

Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts. Member of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

Marsh Risk and Insurance Services, Inc., Los Angeles, CA. *Risk Analyst*, Casualty Department, 2003 – 2005.

Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions. Supported the placement of $2 million in insurance premiums in the first year and $3 million in the second year. Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports. Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.

EDUCATION

Yale School of Forestry & Environmental Studies, New Haven, CT
Masters of Environmental Management, concentration in Law, Economics, and Policy with a focus on energy issues and markets, 2007

Claremont McKenna College, Claremont, California
Bachelor of Arts in Environment, Economics, Politics (EEP), 2003. *Cum laude* and EEP departmental honors.

School for International Training, Quito, Ecuador
Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador, Spring 2002.

ADDITIONAL SKILLS AND ACCOMPLISHMENTS

- Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, PROSYM/Market Analytics, EnCompass, and PLEXOS, some SAS and STATA.
- Competent in oral and written Spanish.
- Hold the Associate in Risk Management (ARM) professional designation.

PUBLICATIONS

Wilson, R., D. Bhandari. 2019. *The Least-Cost Resource Plan for Santee Cooper: A Path to Meet Santee Cooper's Customer Electricity Needs at the Lowest Cost and Risk*. Synapse Energy Economics for the Sierra Club, Southern Environmental Law Center, and Coastal Conservation League.

Wilson, R., N. Peluso, A. Allison. 2019. *North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan*. Synapse Energy Economics for the North Carolina Sustainable Energy Association.

Wilson, R., N. Peluso, A. Allison. 2019. *Modeling Clean Energy for South Carolina: An Alternative to Duke's Integrated Resource Plan*. Synapse Energy Economics for the South Carolina Solar Business Alliance.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation*. Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan*. Synapse Energy Economics for Centre for Environmental Rights.

Hall, J., R. Wilson, J. Kallay. 2018. *Effects of the Draft CAFE Standard Rule on Vehicle Safety*. Synapse Energy Economics on behalf of Consumers Union.

Whited, M., A. Allison, R. Wilson. 2018. *Driving Transportation Electrification Forward in New York: Considerations for Effective Transportation Electrification Rate Design*. Synapse Energy Economics on behalf of the Natural Resources Defense Council.

Wilson, R., S. Fields, P. Knight, E. McGee, W. Ong, N. Santen, T. Vitolo, E. A. Stanton. 2016. *Are the Atlantic Coast Pipeline and the Mountain Valley Pipeline Necessary? An examination of the need for additional pipeline capacity in Virginia and Carolinas*. Synapse Energy Economics for Southern Environmental Law Center and Appalachian Mountain Advocates.

Wilson, R., T. Comings, E. A. Stanton. 2015. *Analysis of the Tongue River Railroad Draft Environmental Impact Statement*. Synapse Energy Economics for Sierra Club and Earthjustice.

Wilson, R., M. Whited, S. Jackson, B. Biewald, E. A. Stanton. 2015. *Best Practices in Planning for Clean Power Plan Compliance*. Synapse Energy Economics for the National Association of State Utility Consumer Advocates.

Luckow, P., E. A. Stanton, S. Fields, B. Biewald, S. Jackson, J. Fisher, R. Wilson. 2015. *2015 Carbon Dioxide Price Forecast*. Synapse Energy Economics.

Stanton, E. A., P. Knight, J. Daniel, B. Fagan, D. Hurley, J. Kallay, E. Karaca, G. Keith, E. Malone, W. Ong, P. Peterson, L. Silvestrini, K. Takahashi, R. Wilson. 2015. *Massachusetts Low Gas Demand Analysis: Final Report*. Synapse Energy Economics for the Massachusetts Department of Energy Resources.

Fagan, B., R. Wilson, D. White, T. Woolf. 2014. *Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integrated Resource Plan: Key Planning Observations and Action Plan Elements*. Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Wilson, R., B. Biewald, D. White. 2014. *Review of BC Hydro's Alternatives Assessment Methodology*. Synapse Energy Economics for BC Hydro.

Wilson, R., B. Biewald. 2013. *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*. Synapse Energy Economics for Regulatory Assistance Project.

Fagan, R., P. Luckow, D. White, R. Wilson. 2013. *The Net Benefits of Increased Wind Power in PJM*. Synapse Energy Economics for Energy Future Coalition.

Hornby, R., R. Wilson. 2013. *Evaluation of Merger Application filed by APCo and WPCo*. Synapse Energy Economics for West Virginia Consumer Advocate Division.

Johnston, L., R. Wilson. 2012. *Strategies for Decarbonizing Electric Power Supply*. Synapse Energy Economics for Regulatory Assistance Project, Global Power Best Practice Series, Paper #6.

Wilson, R., P. Luckow, B. Biewald, F. Ackerman, E. Hausman. 2012. *2012 Carbon Dioxide Price Forecast*. Synapse Energy Economics.

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Johnston, L., E. Hausman., B. Biewald, R. Wilson, D. White. 2011. *2011 Carbon Dioxide Price Forecast*. Synapse Energy Economics.

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Peterson, P., V. Sabodash, R. Wilson, D. Hurley. 2010. *Public Policy Impacts on Transmission Planning*. Synapse Energy Economics for Earthjustice.

Fisher, J., J. Levy, Y. Nishioka, P. Kirshen, R. Wilson, M. Chang, J. Kallay, C. James. 2010. *Co-Benefits of Energy Efficiency and Renewable Energy in Utah: Air Quality, Health and Water Benefits.* Synapse Energy Economics, Harvard School of Public Health, Tufts University for State of Utah Energy Office.

Fisher, J., C. James, L. Johnston, D. Schlissel, R. Wilson. 2009. *Energy Future: A Green Alternative for Michigan*. Synapse Energy Economics for Natural Resources Defense Council (NRDC) and Energy Foundation.

Schlissel, D., R. Wilson, L. Johnston, D. White. 2009. *An Assessment of Santee Cooper's 2008 Resource Planning*. Synapse Energy Economics for Rockefeller Family Fund.

Schlissel, D., A. Smith, R. Wilson. 2008. *Coal-Fired Power Plant Construction Costs*. Synapse Energy Economics.

TESTIMONY

Mississippi Public Service Commission (Docket No. 2019-UA-116): Direct testimony of Rachel Wilson regarding Mississippi Power Company's petition to the Mississippi Public Service Commission for a Certification of Public Convenience and Necessity for ratepayer-funded investments required to meet Coal Combustion Residuals regulations at the Victor J. Daniel Electric Generating Facility. On behalf of the Sierra Club. October 16, 2019.

Georgia Public Service Commission (Docket No. 42310 & 42311): Direct testimony of Rachel Wilson regarding various components of Georgia Power's 2019 Integrated Resource Plan. On behalf of the Sierra Club. April 25, 2019.

Washington Utilities and Transportation Commission (Dockets UE-170485 & UG-170486): Response testimony regarding Avista Corporation's production cost modeling. On behalf of Public Counsel Unit of the Washington Attorney General's Office. October 27, 2017.

Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449): Cross-rebuttal testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. May 19, 2017.

Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449): Direct testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. April 25, 2017.

Virginia State Corporation Commission (Case No. PUE-2015-00075): Direct testimony evaluating the petition for a Certificate of Public Convenience and Necessity filed by Virginia Electric and Power Company to construct and operate the Greensville County Power Station and to increase electric rates to recover the cost of the project. On behalf of Environmental Respondents. November 5, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony evaluating the prudence of environmental retrofits at Kansas City Power & Light Company's La Cygne Generating Station. On behalf of Sierra Club. April 2, 2015 and June 5, 2015.

Oklahoma Corporation Commission (Cause No. PUD 201400229): Direct testimony evaluating the modeling of Oklahoma Gas & Electric supporting its request for approval and cost recovery of a Clean Air Act compliance plan and Mustang modernization, and presenting results of independent Gentrader modeling analysis. On behalf of Sierra Club. December 16, 2014.

Michigan Public Service Commission (Case No. U-17087): Direct testimony before the Commission discussing Strategist modeling relating to the application of Consumers Energy Company for the authority to increase its rates for the generation and distribution of electricity. On behalf of the Michigan Environmental Council and Natural Resources Defense Council. February 21, 2013.

Indiana Utility Regulatory Commission (Cause No. 44217): Direct testimony before the Commission discussing PROSYM/Market Analytics modeling relating to the application of Duke Energy Indiana for Certificates of Public Convenience and Necessity. On behalf of Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch. November 29, 2012.

Kentucky Public Service Commission (Case No. 2012-00063): Direct testimony before the Commission discussing upcoming environmental regulations and electric system modeling relating to the application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity and for approval of its 2012 environmental compliance plan. On behalf of Sierra Club. July 23, 2012.

Kentucky Public Service Commission (Case No. 2011-00401): Direct testimony before the Commission discussing STRATEGIST modeling relating to the application of Kentucky Power Company for a Certificate of Public Convenience and Necessity, and for approval of its 2011 environmental compliance plan and amended environmental cost recovery surcharge. On behalf of Sierra Club. March 12, 2012.

Kentucky Public Service Commission (Case No. 2011-00161 and Case No. 2011-00162): Direct testimony before the Commission discussing STRATEGIST modeling relating to the applications of Kentucky Utilities Company, and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity, and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

Minnesota Public Utilities Commission (OAH Docket No. 8-2500-22094-2 and MPUC Docket No. E-017/M-10-1082): Rebuttal testimony before the Commission describing STRATEGIST modeling performed in the docket considering Otter Tail Power's application for an Advanced Determination of Prudence for BART retrofits at its Big Stone plant. On behalf of Izaak Walton League of America, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy. September 7, 2011.

PRESENTATIONS

Wilson, R. 2017. "Integrated Resource Planning: Past, Present, and Future." Presentation for the Michigan State University Institute of Public Utilities Grid School. March 29, 2017.

Wilson, R. 2015. "Best Practices in Clean Power Plan Planning." NASEO/ACEEE Webinar. June 29, 2015.

Wilson, R. 2009. "The Energy-Water Nexus: Interactions, Challenges, and Policy Solutions." Presentation for the National Drinking Water Symposium. October 13, 2009.

Resume dated October 2019

Wilson Rebuttal

EXHIBIT
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EMP-105, Sub 0

I/A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-105, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of the Application of Friesian Holdings, LLC for a Certificate of Public Convenience and Necessity	**NCEMC'S INITIAL COMMENTS**

On May 15, 2019, Friesian Holdings, LLC ("Friesian") filed an application for a certificate of public convenience and necessity ("CPCN") for a 70-MW_{AC} solar photovoltaic facility in Scotland County, North Carolina ("Project"). Therein, Friesian indicated that it anticipated execution of a Project-related purchase power agreement ("Project PPA") between it and North Carolina Electric Membership Corporation ("NCEMC"). The Project PPA has now been executed.

NCEMC is a generation and transmission ("G&T") cooperative. To supply power to its member distribution cooperatives, NCEMC produces and sells power that it produces at NCEMC-owned electric generation resources; NCEMC also purchases and resells power, pursuant to wholesale contracts, from power providers such as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Dominion Energy North Carolina, and others like Friesian.

As a G&T cooperative, NCEMC continuously strives to supply power to its members that is affordable, reliable, and safe. Beginning a decade ago, NCEMC also began assisting its members with their compliance obligations under the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"). This assistance frequently took the form of purchasing renewable energy certificates from utility-scale solar facilities. More recently, NCEMC developed and began to pursue strategic business objectives under an initiative it christened "*A Brighter Energy Future*" ("BEF"), which entails supplying power that is not only affordable, reliable, and safe, but also increasingly low carbon (see attached BEF overview). Once constructed, the Project – specifically, the parties' execution of the Project PPA – will simultaneously advance NCEMC's pursuit of BEF and further its ability to achieve REPS compliance.

For the foregoing reasons, NCEMC supports issuance of a CPCN for the Project.

This the 18th day of July, 2019.

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

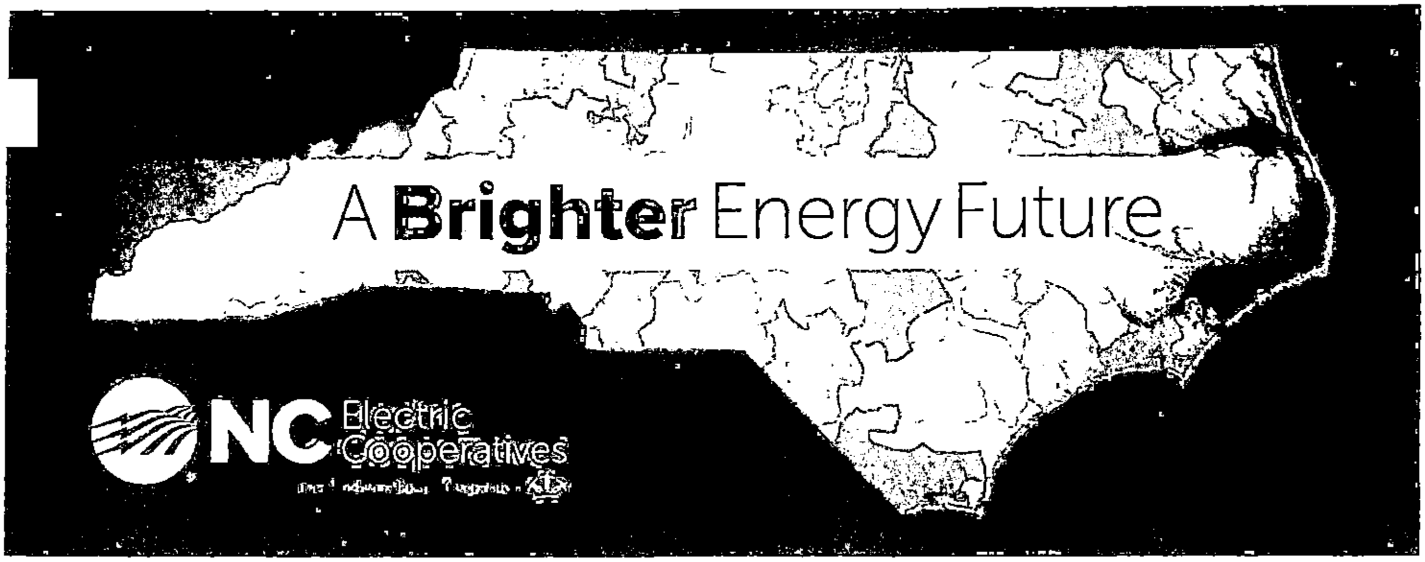
By: ______________________

Michael D. Youth
Government & Regulatory Affairs Counsel
Post Office Box 27306
Raleigh, North Carolina 27611
Telephone: (919) 875-3060
Email: michael.youth@ncemcs.com

CERTIFICATE OF SERVICE

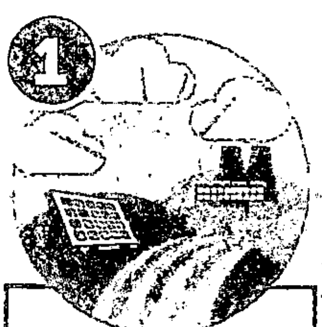
It is hereby certified that the foregoing document has been served upon all parties of record by electronic mail, or depositing the same in the United States mail, postage prepaid.

This the 18th day of July, 2019.



Driven by service and inspired by innovation, North Carolina's Electric Cooperatives are building a brighter energy future for 2.5 million North Carolinians. Working together, this group of 26 electric cooperatives is developing and delivering new energy solutions that put cooperative consumers and the vitality of our state first. The roots of these forward-focused energy solutions grow from three values North Carolina's Electric Cooperatives believe in:

1. Creating a low-carbon emissions environment through sustainability and continued investment in low- and zero-emissions resources.
2. Integrating technology to make distribution grids more resilient, robust and flexible for an energy future that includes consumers' participation through demand response programs and new energy resources distributed across the grid.
3. Improving efficiency of the overall energy sector by electrifying processes formerly powered by fossil fuels. Electric vehicles are a primary example of this conversion.

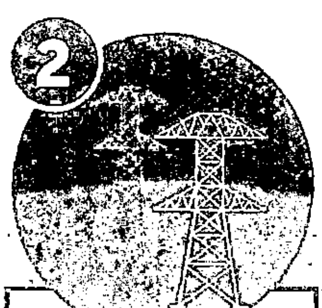


Low Carbon

Low Carbon Intensity

Industrial Process Conversion

Sustainability

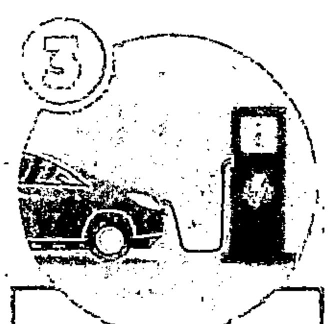


Grid Flexibility

Distributed Energy Resources

Microgrids

Distribution Operators



Beneficial Electrification

Electric Transportation

Agribusiness

Economic Development

704•644•7733

Docket No. EMP-105, Sub 0
Public Staff - Friesian Panel
Cross-Examination Exhibit No. 1

I/A

Investors

Birdseye Renewable Energy strives to deliver the lowest costs and best returns to its project investors. Birdseye is happy to accommodate investors' project investment needs through portfolios of projects or targeted single projects.

Successful Track Record

Birdseye has successfully delivered over 30 high-value renewable energy projects to its investors since 2009. Our investor clients have included the nation's largest regulated utilities, independent power producers, and private energy project investors. We have realized projects through both RFPs and bi-lateral agreements, with both PPA and turnkey arrangements.

Minimal Costs

Through experience and innovative approaches, we minimize direct development costs as well as site preparation costs. We collaborate with our engineers to secure reliable, low-cost interconnections.

Maximum Long-Term Revenue

Birdseye identifies the markets and counterparties that result in the highest value, lowest risk, and longest term off-take agreements.

CONNECT

1125 E Morehead St. Suite 202
Charlotte, NC 28204

704-644-7733
Contact Us »

Site by

Portfolio of Bi e Completed Projects

#	Facility Name	Location	Size (MWdc)	Acreage	Utility	Technology	Friesian Constrained Zone
1	Apple One Farm	Catawba County, NC	7	37	DEC	Solar PV - Polycrystalline	
2	Arndt Farm	Catawba County, NC	6.4	49	DEC	Solar PV - Polycrystalline	
3	Ayrshire Holdings	Cleveland County, NC	27.1	118	DEC	Solar PV - Thin Film	
4	Belwood Farm	Cleveland County, NC	5.3	40	DEC	Solar PV - Polycrystalline	
5	Blueberry One Farm	Wayne County, NC	6.8	32	DEP	Solar PV - Polycrystalline	
6	Clipperton Holdings	Sampson County, NC	7	40	DEP	Solar PV - Polycrystalline	x
7	Cocke County Schools	Cocke County, TN	0.69	n/a	Newport Utilities and TVA	Solar PV - Polycrystalline	
8	Daniel Farm	Davie County, NC	6.4	40	DEC	Solar PV - Polycrystalline	
9	Dixon Dairy Farm	Cleveland County, NC	5	29	DEC	Solar PV - Polycrystalline	
10	Hawkins County Schools	Hawkins County, TN	1.2	n/a	Holston Electric and TVA	Solar PV - Polycrystalline	
11	Hawkins Solar Two	Hawkins County, TN	1	6	Holston Electric and TVA	Solar PV - Polycrystalline	
12	Holstein Holdings	Scotland County, NC	25.7	125	DEP	Solar PV - Thin Film	x
13	Hutchinson Farms	Cleveland County, NC	6.8	32	DEC	Solar PV - Thin Film	
14	Jersey Holdings	Robeson County, NC	7	40	Lumbee River EMC & NCEMC	Solar PV - Polycrystalline	x
15	Kirkwall Holdings	Duplin County, NC	7	34	DEP	Solar PV - Polycrystalline	
16	Laurinburg Farm	Scotland County, NC	6.4	30	City of Laurinburg & NCEMPA	Solar PV - Thin Film	x
17	Leicester Farm	Buncombe County, NC	4.8	24	DEP	Solar PV - Polycrystalline	
18	Marshville Farm	Union County, NC	6	35	DEC	Solar PV - Polycrystalline	
19	McGoogan Farm	Robeson County, NC	6.5	39	DEP	Solar PV - Thin Film	x
20	Mocksville Farm	Davie County, NC	6.4	33	DEC	Solar PV - Polycrystalline	
21	Mocksville Solar Facility	Davie County, NC	19.9	99	DEC	Solar PV - Polycrystalline	
22	Monroe Solar Facility	Union County, NC	75.3	400	DEC	Solar PV - Thin Film	
23	Mount Olive I Solar Farm	Wayne County, NC	6.8	38	DEP	Solar PV - Thin Film	
24	Mount Olive II Solar Farm	Wayne County, NC	6.7	39	DEP	Solar PV - Polycrystalline	
25	NC Solar I Farm	Scotland County, NC	2.4	23	DEP	Solar PV - Polycrystalline	x
26	NC Solar II Farm	Scotland County, NC	2.4	13	DEP	Solar PV - Polycrystalline	x
27	Prestage Foods Solar Thermal	Robeson County, NC	0	6.5	On-site end user	Solar Thermal	x
28	Raeford Farm	Hoke County, NC	6.3	38	DEP	Solar PV - Polycrystalline	
29	Railroad I Farm	Robeson County, NC	6.4	33	DEP	Solar PV - Polycrystalline	x
30	Railroad II Farm	Robeson County, NC	6.8	52	DEP	Solar PV - Thin Film	x
31	Rock Farm	Richmond County, NC	6.7	39	DEP	Solar PV - Polycrystalline	x
32	Shannon Farm	Robeson County, NC	6.5	56	DEP	Solar PV - Polycrystalline	x
33	Sonne One Farm	Wayne County, NC	7	43	DEP	Solar PV - Polycrystalline	
34	Sonne Two Farm	Buncombe County, NC	7	44	DEC	Solar PV - Polycrystalline	
35	South Robeson Farm	Robeson County, NC	6.4	37	DEP	Solar PV - Polycrystalline	x
36	Tiburon Holdings	Davie County, NC	6.7	33	DEC	Solar PV - Polycrystalline	
37	Town of Warsaw Farm	Duplin County, NC	0.8	9	DEP	Solar PV - Polycrystalline	x
38	Waco Farm	Cleveland County, NC	6.5	42	DEC	Solar PV - Polycrystalline	
39	Warsaw Farm	Duplin County, NC	87.5	499	DEP	Solar PV - Thin Film	x
40	Watts Farm	Robeson County, NC	6.4	45	DEP	Solar PV - Polycrystalline	x
		Total	424.99				184.5 MW

Source: Birdseye Renewable Energy website. "Portfolio." Online at: https://birdseyeenergy.com/portfolio/

BIRDSEYE
RENEWABLE ENERGY

Docket No. EMP-105, Sub 0
Public Staff - Friesian Panel
Cross-Examination Exhibit No. 2
I/A

December 6, 2019

VIA ELECTRONIC FILING

Martha Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

RE: Docket No. SP-8210, Sub 0
Change in Contact Information for Fair Bluff Solar, LLC

Dear Ms. Jarvis,

Pursuant to R8-64(d)(d) and R8-66(h) of the North Carolina Utilities Commission "Commission") Rules and Regulations, Fair Bluff Solar, LLC ("Fair Bluff") submits this letter to notify the Commission of the change in the upstream ownership and change in contact information for Fair Bluff effective December 6, 2019. The updated information is as follows:

New Upstream Owner:	Friesian Portfolio Acquisition, LLC
Former Upstream Owner:	Sorghum Holdings, LLC
New Contact Information:	Fair Bluff Solar, LLC c/o Michael W. Cohen 880 Apollo St., Suite 333 El Segundo, CA 90245 (213) 444-7860

Please contact the undersigned if you require additional information or have any questions regarding this filing.

Very truly yours,

BCB

Brian C. Bednar
Manager, Fair Bluff Solar, LLC

Cc: Friesian Portfolio Acquisition, LLC

VERIFICATION

STATE OF North Carolina COUNTY OF Mecklenburg

Signature of Owner's Representative or Agent

Manager

Title of Representative or Agent

Brian C. Bednar

Typed or Printed Name of Representative or Agent

The above named person personally appeared before me this day and, being first duly sworn, says that the facts stated in the foregoing application and any exhibits, documents, and statements thereto attached are true as he or she believes.

WITNESS my hand and notarial seal, this 6th day of December, 2019.

My Commission Expires: March 23, 2024

Susan W Prentice

Signature of Notary Public

Susan W. Prentice

Name of Notary Public – Typed or Printed

Susan W. Prentice
NOTARY
PUBLIC
New Hanover County, N.C.

This original verification must be affixed to the original application, and a copy of this verification must be affixed to each of the copies that are also submitted to the Commission.

BIRDSEYE
RENEWABLE ENERGY

December 6, 2019

VIA ELECTRONIC FILING

Martha Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

RE: Docket No. SP-8056, Sub 0
Change in Contact Information for Homer Solar, LLC

Dear Ms. Jarvis,

Pursuant to R8-64(d)(d) and R8-66(h) of the North Carolina Utilities Commission "Commission") Rules and Regulations, Homer Solar, LLC ("Homer") submits this letter to notify the Commission of the change in the upstream ownership and change in contact information for Homer effective December 6, 2019. The updated information is as follows:

New Upstream Owner:	Friesian Portfolio Acquisition, LLC
Former Upstream Owner:	Sorghum Holdings, LLC
New Contact Information:	Homer Solar, LLC c/o Michael W. Cohen 880 Apollo St., Suite 333 El Segundo, CA 90245 (213) 444-7860

Please contact the undersigned if you require additional information or have any questions regarding this filing.

Very truly yours,

Brian C. Bednar
Manager, Homer Solar, LLC

Cc: Friesian Portfolio Acquisition, LLC

VERIFICATION

STATE OF North Carolina COUNTY OF Mecklenburg

BCB

Signature of Owner's Representative or Agent

Manager

Title of Representative or Agent

Brian C. Bednar

Typed or Printed Name of Representative or Agent

The above named person personally appeared before me this day and, being first duly sworn, says that the facts stated in the foregoing application and any exhibits, documents, and statements thereto attached are true as he or she believes.

WITNESS my hand and notarial seal, this 6th day of December, 2019.

My Commission Expires: March 23, 2024

Susan W Prentice

Signature of Notary Public

Susan W. Prentice

Name of Notary Public – Typed or Printed

Susan W. Prentice NOTARY PUBLIC New Hanover County, N.C.

This original verification must be affixed to the original application, and a copy of this verification must be affixed to each of the copies that are also submitted to the Commission.

OFFICIAL COPY

Dec 11 2019

Fox Rothschild LLP
ATTORNEYS AT LAW

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Raleigh, NC 27601
Tel (919) 755-8700 Fax (919) 755-8800
www.foxrothschild.com

KAREN M. KEMERAIT
Direct No: 919.755.8764
Email: kkemerait@foxrothschild.com

December 11, 2019

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street
Raleigh, NC 27603

RE: Motion for Extension of Waiver by Fair Bluff Solar, LLC and Homer Solar, LLC
NCUC Docket Nos. E-100, Sub 101, E-2, Sub 1159, and E-7, Sub 1156

Dear Ms. Campbell:

On behalf of Fair Bluff Solar, LLC and Homer Solar, LLC, we herewith submit the attached Motion for Extension of Waiver by Fair Bluff Solar, LLC and Homer Solar, LLC in the above-referenced dockets. The Commission had previously granted a waiver to these projects in its December 6, 2018 *Order Granting Limited Waiver*, and the current waiver will expire on December 31, 2019. We have confirmed with counsel for Duke Energy, the Public Staff, the North Carolina Sustainable Energy Association, and the North Carolina Clean Energy Business Alliance that they support the extension of the waiver. Since the current waiver will expire on December 31, 2019, *we respectfully request expedited consideration of this request.*

Should you have any questions about this request, please do not hesitate to contact me.

Sincerely,

/s/ Karen M. Kemerait

Karen M. Kemerait

CC: All Parties of Record
Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 101
DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION:

DOCKET NO. E-100, SUB 101 In the Matter of Petition for Approval of Generator Interconnection Standard DOCKET NO. E-2, SUB 1159 DOCKET NO. E-7, SUB 1156 In the Matter of Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program	MOTION FOR EXTENSION OF WAIVER BY FAIR BLUFF SOLAR, LLC AND HOMER SOLAR, LLC

MOTION FOR EXTENSION OF WAIVER

NOW COME Fair Bluff Solar, LLC ("Fair Bluff Solar") and Homer Solar, LLC ("Homer Solar"), pursuant to Commission Rule R1-7, and respectfully move the North Carolina Utilities Commission ("Commission") for an extension of the limited waiver that the Commission granted in its *Order Granting Limited Waiver* entered in these dockets on December 6, 2018 (the "December 6, 2018 Order"). Fair Bluff Solar and Homer Solar continue to be uniquely and adversely affected by Ordering Paragraph 2 of the Commission's *Order Approving Interim*

Modifications to North Carolina Interconnection Procedures for Tranche 1 of CPRE RFP issued on October 5, 2018 (the "October 5, 2018 Order") and Section 4.3.9 of the North Carolina Interconnection Procedures ("NCIP").

This purpose of this motion is to extend the waiver of payment of the Milestone Payments pursuant to Section 4.3.9 of the NCIP, and require instead that Fair Bluff Solar and Homer Solar provide the Milestone Payments within ten (10) business days following the earlier of (i) Friesian Solar, LLC ("Friesian") having made a contractual commitment to fund the Interdependent Upgrades that is irrevocable and not subject to any contingencies, (ii) Friesian having been removed from the queue, (iii) the execution of the Interconnection Agreements for Fair Bluff Solar and Homer Solar, or (iv) December 31, 2020.

In support of this Motion, Fair Bluff Solar and Homer Solar state the following:

1. The October 5, 2018 Order called for application of the Milestone Payment requirement to Interconnection Customers in the Facilities Study stage, stating in Ordering Paragraph 2:

> That Interconnection Customers affected by Section 4.3.9 that are currently in the facilities study stage of the NCIP shall have 30 business days from the date of this Order to submit a prepayment for Network Upgrades. For a given Interconnection Request, if no such payment is received, the Interconnection Request shall be removed from the interconnection queue.

2. Fair Bluff Solar and Homer Solar continue to be uniquely and negatively impacted by this aspect of the October 5, 2018 Order. Fair Bluff Solar and Homer Solar are transmission solar projects. Fair Bluff Solar signed a Facilities Study Agreement on February 27, 2018, and Homer Solar signed a Facilities Study Agreement on September 18, 2017.

3. Fair Bluff Solar and Homer Solar were identified in the System Impact Studies as being interdependent with Friesian, an earlier-queued FERC-jurisdictional Interconnection

Customer. Friesian has triggered substantial Network Upgrades at a cost in excess of $200 million. Friesian has submitted an application for a Certificate of Convenience and Public Necessity ("CPCN") in Docket No. EMP-105, Sub 0 that is pending before the Commission. The Commission has scheduled an evidentiary hearing for the application on December 18, 2019.

4. Fair Bluff Solar and Homer Solar both require substantial Network Upgrades ("the Interdependent Upgrades") that are also required by the earlier-queued Friesian project. As the earlier-queued project, Friesian is responsible for paying for the Network Upgrades. In addition to allowing Friesian to interconnect, those Network Upgrades will increase the capacity of the grid in that area of the state.

5. Fair Bluff Solar and Homer Solar also require other Network Upgrades ("the Independent Upgrades") that are independent of the Network Upgrades required for Friesian. The total estimated cost of the Independent Upgrades, which will be borne solely by Fair Bluff Solar and Homer Solar, is approximately $9.6 million.

6. The December 6, 2018 Order temporarily waived the requirement pursuant to Section 4.3.9 as to Fair Bluff Solar and Homer Solar and requires instead that Fair Bluff Solar and Homer Solar "provide Milestone Payments for the Independent Upgrades upon the earlier of: (i) Friesian Solar having made a contractual commitment to fund the Interdependent Upgrades that is irrevocable and not subject to any contingencies, (ii) Friesian Solar having been removed from the queue, or (iii) December 31, 2019.

7. The Friesian project -- which is subject to the FERC Large Generator Interconnection Procedures and is therefore not required to make a Milestone Payment -- has not yet made an irrevocable commitment to fund the Interdependent Upgrades and will not do so before December 31, 2019. If Friesian ultimately does not irrevocably commit to paying for its

Network Upgrades, and thus is forced out of the queue, Fair Bluff Solar and Homer Solar will become responsible for paying for the Interdependent Upgrades. That additional cost, which will be in excess of $200 million, would make Fair Bluff Solar and Homer Solar non-viable and cause them to exit the queue. In that event, Fair Bluff Solar and Homer Solar would be required to forfeit to Duke the $9.6 million Milestone Payments for Network Upgrades that would never be constructed.

8. Given the financial uncertainty that arises from this situation, if Fair Bluff Solar and Homer Solar were required to make the $9.6 Milestone Payment on December 31, 2019, they would be forced to withdraw from the queue, resulting in the loss of all investment and existing economic value in those projects. This would result in irreparable harm to the projects.

9. Fair Bluff Solar and Homer Solar therefore request that the Commission extend the waiver of payment of the Milestone Payments, and require instead that Fair Bluff Solar and Homer Solar provide the Milestone Payments within ten (10) business days following the earlier of (i) Friesian having made a contractual commitment to fund the Interdependent Upgrades that is irrevocable and not subject to any contingencies, (ii) Friesian having been removed from the queue, (iii) the execution of the Interconnection Agreements for Fair Bluff Solar and Homer Solar, or (iv) December 31, 2020.

10. Moreover, to the best of the knowledge of Fair Bluff Solar and Homer Solar, there are no projects in the interconnection queue with Network Upgrades dependent on Fair Bluff Solar's and Homer Solar's Independent Upgrades. There are later-queued projects that are dependent on Friesian's Network Upgrades. However, neither those projects nor Fair Bluff Solar and Homer Solar will have certainty as to their required Network Upgrades until Friesian definitively commits (or declines to commit) to its interdependent Network Upgrades. Extending

the deadline for Fair Bluff Solar's and Homer Solar's Milestone Payments would not alter this situation or cause harm to any party.

11. Counsel for Fair Bluff Solar and Homer Solar has conferred with Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, the North Carolina Clean Energy Business Alliance, the North Carolina Sustainable Energy Association, and the Public Staff, and each of these parties supports the further stay requested herein.

WHEREFORE, for the foregoing reasons, Fair Bluff Solar and Homer Solar respectfully request that the Commission extend the waiver of payment of the Milestone Payments pursuant to Section 4.3.9 of the NCIP, and require instead that Fair Bluff Solar and Homer Solar provide the Milestone Payments within ten (10) business days following the earlier of (i) Friesian having made a contractual commitment to fund the Interdependent Upgrades that is irrevocable and not subject to any contingencies, (ii) Friesian having been removed from the queue, (iii) the execution of the Interconnection Agreements for Fair Bluff Solar and Homer Solar, or (iv) December 31, 2020.

Respectfully submitted, this 11th day of December, 2019.

By: ______________________

Karen M. Kemerait
Fox Rothschild LLP
434 Fayetteville Street, Ste. 2800
Raleigh, NC 27601
Telephone: 919-755-8764
Email: kkemerait@foxrothschild.com
Attorneys for Petitioners Fair Bluff Solar, LLC and Homer Solar, LLC

CERTIFICATE OF SERVICE

It is hereby certified that the foregoing MOTION FOR EXTENSION OF WAIVER has been served this day upon each party of record in this proceeding or their attorney by electronic mail or by depositing a copy thereof in the United States mail, postage prepaid.

This the 11th day of December, 2019.

By: Karen Kemerait

Karen M. Kemerait
Fox Rothschild LLP
434 Fayetteville Street, Ste. 2800
Raleigh, NC 27601
Email:kkemerait@foxrothschild.com
Attorneys for Petitioners Fair Bluff Solar, LLC and Homer Solar, LLC

VERIFICATION

I. Ben Catt, having been duly sworn, deposes and says:

1. I am the Authorized Representative of Fair Bluff Solar, LLC and Homer Solar, LLC
2. I have read the foregoing Motion for Extension of Waiver and know its contents.
3. The matters stated in this instrument are true to the best of my knowledge.

Ben Catt

Sworn to and subscribed before me,

this 10th day of December, 2019.

Notary Public

My commission expires: Sept. 20, 2023

MONICA SUAREZ DEVIA NOTARY PUBLIC BUNCOMBE COUNTY, NC

104886332
Active\105774667.v1-12/6/19

Docket No. EMP-105, Sub 0
Public Staff - Friesian Panel
Cross-Examination Exhibit No. 3
I/A

DUKE ENERGY CAROLINAS, LLC
DUKE ENERGY PROGRESS, LLC

FINAL REPORT OF THE INDEPENDENT ADMINISTRATOR

RE:

DUKE ENERGY CAROLINAS (DEC)
Competitive Procurement of Renewable Energy Program (CPRE)
Request for Proposal (RFP) – 600 MW

DUKE ENERGY PROGRESS (DEP)
Competitive Procurement of Renewable Energy Program (CPRE)
Request for Proposals (RFP) – 80 MW

REQUEST FOR PROPOSALS FOR
THE COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY PROGRAM
TRANCHE 1

July 18, 2019

ACCION GROUP, LLC
244 North Main Street
Concord, New Hampshire 03301
Telephone: 603-229-1644
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www.acciongroup.com

244 North Main Street • Concord, NH 03301 • Phone: 603-229-1644 • Fax: 603-225-4923 • advisors@acciongroup.com

FINAL REPORT OF THE INDEPENDENT ADMINISTRATOR
RE: DUKE ENERGY CAROLINAS, LLC; DUKE ENERGY PROGRESS, LLC
REQUEST FOR PROPOSALS FOR
THE COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY PROGRAM
TRANCHE 1

July 18, 2019

I. EXECUTIVE SUMMARY

Accion Group, LLC ("Accion") serves as the Independent Administrator ("IA") of the Competitive Procurement of Renewable Energy ("CPRE") program and began the assignment in January 2018. The IA participated in all aspects of the program, from preparing the draft and final Request for Proposal ("RFP") documents through the final evaluation of all submitted Proposals. This is the IA's final report concerning Tranche 1 of the CPRE program. This report provides an overview of Tranche 1 with detailed explanation of the processes and procedures that were employed. The IA also provides recommendations for improvements in Tranche 2.

Figure 1 presents a summary of the Tranche 1 Results.

Figure 1

	DEC	DEP
MW Procured	465.50	85.72
Average price/MWh	$37.94	$38.30
Nominal Savings over 20 years	$228.00 Million	$33.17 Million

Currently, the CPRE Program Plan approved by the Commission projects the need for three tranches of CPRE solicitations to be completed within the time frame contemplated by HB 589. Tranche 1 was the "beta" for the program and initiated the processes and procedures of CPRE to comply with the Rules established by the North Carolina Utilities Commission ("NCUC") and refine the program for future Tranches. As such, the IA believes Tranche 1 was a success.

The CPRE program is designed to procure 2,600 MW [1] of new renewable resources over a 45-month period provided those purchases are below Duke Energy's respective forecasted avoided cost calculated over a twenty-year term either through the Power Purchase Agreement ("PPA" or "RPPA") or from resources to be owned by Duke. Tranche 1 sought 600 MW of qualifying renewable resources for Duke Energy Carolinas ("DEC") and 80 MW for Duke Energy Progress ("DEP"); collectively DEP and DEC are referred to as the "Duke Companies" or "Company" in this report. The Duke Companies and its affiliates are permitted to participate in the CPRE program with projects to be constructed or acquired by

[1] As specified in the currently effective CPRE Program Plan, the revised procurement target is now 1,460 - 1,960 MW due to the increase of the Transition MW.

244 North Main Street • Concord, NH 03301 • Phone: 603-229-1644 • Fax: 603-225-4923 • advisors@acciongroup.com

the Company to serve the goals of the CPRE program. Proposals from the Duke Companies were made by the DEP/DEC Proposal Team ("DEP/DEC Team"). [2]

The IA provided the web-based platform ("Website") for proposals submitted to DEC, DEP, and Asset Acquisition ("AA") proposals. The unregulated affiliate of the Duke Companies, Duke Energy Renewables ("DER"), participated in the same manner as other Market Participants ("MPs"). The IA Website maintained three separate and secure "Silos" for each of the three solicitations; all data related to these solicitations has been maintained by the IA on secure servers.

Proposals were received through October 9, 2018, when the Proposal submission period closed.[3] At that time, the ability for MPs to adjust their Proposal forms was terminated, including the ability to submit additional Proposals.

The IA received a robust number of Proposals and MWs in each Silo. Proposals included a balanced representation from North Carolina and South Carolina and ranged in size from seven to 80 MW AC of generating capacity in both DEC and DEP; 80 MW was the maximum size that could be submitted. The majority of Proposals would require transmission level service. There were also Proposals for projects that would interconnect to the Duke system at the distribution level. The Website functioned as desired in that it allowed a wide variance of Proposals to be submitted.

While MPs had the ability to provide renewable energy from certain technologies, [4] the IA received proposals for only solar photovoltaic ("PV") generation. Four of these projects proposed storage integration. The IA conducted the evaluation of Proposals as required for CPRE, that is with a preliminary evaluation of all Proposals in Step 1, followed by a Step 2 cost analysis study of the most competitive Proposals by the T&D Evaluation team, and a final step of the evaluation completed by the IA by imputing system impact costs to Proposals and conducting another iterative evaluation ranking of Proposals.

The Website remained the host of all CPRE activities through the Step 2 evaluation process and until each PPA was executed on July 8, 2019 and Performance Assurance security was provided. The IA retained all submissions by the MPs and all exchanges between the IA and MPs, as well as exchanges between individual MPs and members of the Duke Evaluation Team after the IA identified the Proposals selected for PPAs. Prior to the selection of finalists, the IA used the Message Board to communicate project-specific questions and comments with MPs, after consultation with the Duke Evaluation Team.

Before evaluating Proposals, the IA reviewed all Proposals submitted on the DEC and DEP Silos and completed a summary of each one. Each summary captured the core information provided with each Proposal and requested that the MP review and respond to the IA either confirming the accuracy of the information or identifying discrepancies. The Step 1 evaluation ranked Proposals into an initial

[2] Members of the DEP/DEC Team were subject to the Code of Conduct separation protocols, which isolated them from the Duke Evaluation Team.

[3] To avoid all inferences of bias, Proposals for projects to be originated by Duke and submitted by the DEP/DEC Team or DER were required to be submitted no later than October 8, 2018. Proposals by the DEP/DEC Team for projects selected for acquisition as part of CPRE were submitted on November 16, 2018.

[4] Tranche 1 accepted renewable energy resources as identified in G.S. 62-133.8(a)(8), with the exception of wind, swine, and poultry waste powered facilities.

Competitive Tier ("Competitive Tier"), Competitive Tier Reserve ("Competitive Tier Reserve" or "Reserve List"), and released Proposals.

On April 9, 2019, the IA completed the selection process, and final status notifications were sent to MPs for each Proposal. At that time, the IA created a separate message board for exchanges between the MPs of the Finalist Proposals ("Finalist MPs") and the appropriate Duke Personnel. Also, at that time, the same Duke Personnel were given access to the Proposal Books of the Finalist Proposals for review.

Subsequent to the notification of the parties representing winning proposals, two selected winning proposals chose to not proceed, one each in DEC and DEP. In DEC, there were no other active proposals remaining after Step 2, so the final results for Tranche 1 in DEC reflect the impact of this project withdrawing prior to signing the PPA. In DEP, the IA reached out to the MP with the next most competitive Proposal and substantially replaced the MWs of the withdrawn Proposal by the July 8, 2019 deadline. [5]

Attachment 1 sets forth the identity of the winning Proposals and those MPs that sponsored a winning Proposal but elected to withdraw.

The IA believes the CPRE Tranche 1 solicitation was conducted fairly and all MPs were given equal access to all information at the same time. The evaluation of Proposals was completed without bias towards or against any qualifying technology or participant. Further, the separation protocols that isolated Proposals from Duke Company personnel, including the Duke Evaluation Team, was strictly enforced. While the T&D Evaluation team had, out of necessity, the identity of projects as part of the Step 2 review, the IA is unaware of any instance where Duke personnel had access to project-identifying information from Proposals prior to the completion the CPRE Step 2 and the release of data to the Duke Evaluation Team. [6]

II. LESSONS LEARNED FROM TRANCHE 1

As the "beta test" of the CPRE Program, the IA is pleased with the accomplishments and success of Tranche 1. Below are observations and suggestions of the IA drawn from the Tranche 1 experience. The IA offers these suggestions as ways to improve the program for Tranche 2.

A. TRANSMISSION AND DISTRIBUTION EVALUATION PROCESS

The basis for these recommendations is discussed in the body of this report and summarized here:

1. There is a need for the Tranche 2 T&D system upgrade "base case" to better represent projects that will receive transmission and distribution services. The IA will work with the T&D Evaluation team to propose threshold standards for projects to be included in the base case. The Proposal will include a focus on upgrade cost and duration of necessary construction.

---

[5] The withdrawal in DEP occurred less than two weeks before the deadline for completing PPAs.

[6] There were three instances when MPs contacted members of the Duke Evaluation Team. Each time the Duke personnel declined to discuss the CPRE program and notified the IA.

2. Better locational guidance should reflect the commitment of transmission capacity to serve the successful CPRE Tranche 1 projects.

3. The Tranche 2 T&D system upgrade "base case" analysis should:

   - Exclude each project proposed and eliminated in Tranche 1 after it was established that upgrade costs would result in the project being well above avoided cost.

   - Only include the largest interconnection request when a project has multiple queue positions of differing sizes.

4. The IA should be included in all discussions with MPs until PPAs are signed in order to confirm the discussions are consistent with representations in Proposals concerning interconnection.

5. Duke Interconnection Account Managers should be included more on the T&D Evaluation team and actively engage in the Proposal analysis process, subject to following the appropriate communication protocols.

6. The IA should maintain a central ledger showing Proposal activity and current evaluation status. This is to be shared among all T&D Evaluation personnel and would be updated on a regular schedule.

7. Incorporate into the standard Proposal analysis document a more explicit discussion of risk and construction requirements needed to meet commercial operating dates.

8. Include reactive analysis as a standard part of the T&D system upgrade cost analysis process.

B. DOCUMENTS

Project documents were required as part of the due diligence review of project viability and state of completion. The goal of permitting so-called "shovel ready" projects to move forward could only be met by MPs confirming their projects were more than conceptual. A surprising number of Proposals were submitted with incomplete documents, including such basic items as proof of site control. During Tranche 2, the IA intends to continue to use the cure period to provide MPs the opportunity to meet their burden of proof with appropriate project documentation, rather than rejecting Proposals without the opportunity to correct misunderstandings and complete forms. While the cure period will continue to be limited to the Step 1 period, the response requirement for cures will be restricted.

The IA required identification of the transmission path from the project to the proposed Point of Interconnection ("POI"). A number of MPs failed to provide this information with their Proposals and were permitted to rectify the omissions during the cure period. The IA will use the pre-proposal period to impress upon MPs the need to identify each tract of land that would be crossed to reach the POI along with proof of site control of the path for the term of the PPA.

The Tranche 2 proposal form will include an acknowledgement that the MP is responsible for the accuracy of all documents. The IA is hopeful this will encourage MPs to be more attentive when submitting Proposals, so the IA need not require replacement documents, thus permitting the economic evaluation to occur more promptly.

Some MPs were unaware of which permits would be required for their project. The Tranche 2 Proposal form should include a form identifying the permits that could be required, and a "check off" identifying those applicable to the project.

Proof of Title Insurance was required as a tool to confirm site control. Few MPs provided the documentation. The IA is exploring additional ways to confirm sufficient site control of project sites and the transmission path.

Based on the experience in Tranche 1, the IA recommends the following requirements for documents to provide details on the generating facility design:

1. The Tranche 2 RFP and Proposal Form should include a requirement for MPs to provide the PV Syst input/output parameters and related calculations/work papers supporting the proposal's 8760 energy production profile. Had this been required in Tranche 1, some or all of the miscommunications between the IA team and certain MPs would have been avoided.
2. A required document entitled "Generating Facility Description" should describe or include: a) major structures related to the production of electricity; b) key equipment components (e.g., solar PV modules, inverters, transformers, energy storage devices if applicable); c) model numbers, nameplate capacities, spec sheets etc., as applicable; and d) transmission lines and electrical equipment leading to the POI with the existing electric grid. This facility description should be of sufficient accuracy and completeness that it can be inserted as an exhibit into a PPA to represent the exact facility that will be constructed and operated to meet the PPA terms and conditions.

C. PROPOSAL SECURITY

The need for Proposal security was confirmed in Tranche 1. At the same time, the process can be improved by the IA giving MPs more advanced notice of when Proposal security will be due, rather than the seven-day notice provided in Tranche 1. This was especially challenging for MPs during the iterative process of Step 2 with projects on the Competitive Tier Reserve who were subsequently moved to the Primary Competitive Tier after the initial completion of Step 1.

The IA proposes to provide a "two-step" approach whereby the IA will provide the MP with a preliminary notice that a project is under review and that a notice that Proposal security is required will be forwarded within one week.

D. UTILITY SELF-DEVELOPED PROPOSALS

As outlined in the IA's role in Section III, an important part of the IA's role is to ensure equitable treatment of all Proposals, including both third party Proposals and utility self-developed Proposals. Specifically, the NCUC established items (iv), (viii), and (ix) as the IA's responsibilities:

> (iv) Develop and publish the CPRE Program Methodology that shall ensure equitable review between an electric public utility's Self-developed Proposal(s) as addressed in subsection (f)(2)(iv) and proposals offered by third-party market participants.

(viii) Evaluate the electric public utility's Self-developed Proposals.

(ix) Provide an independent certification to the Commission in the CPRE Compliance Report that all electric public utility and third-party proposals were evaluated under the published CPRE Program methodology and that all proposals were treated equitably through the CPRE RFP Solicitation(s).

Based on the experience in Tranche 1, the IA recommends revising the Proposal security requirements for the DEP/DEC Team. Proposal security or some functional equivalent should be required in the case of both Duke self-developed projects and Asset Acquisition projects that the DEP/DEC team elects to sponsor. The IA will work with Duke to develop an appropriate structure for use in Tranche 2, which will be provided to the NCUC for consideration.

In Tranche 1, two winning Proposals withdrew after being selected as finalists after the close of Step 2. One Proposal was from a third-party MP and the other was from an Asset Acquisition Proposal sponsored by the DEP/DEC Team. The impact of the third-party MP withdrawing late in the process was mitigated by the existence of the non-refundable Proposal security. [7] The utility's Asset Acquisition winning Proposal that withdrew did not have Proposal security [8] and the related project developer was not obligated to provide comparable security in the event of withdrawal. In effect, the DEP/DEC Team and the developer had a free option to withdraw at any time, which the IA believes was an unanticipated result. [9] This issue arose during the final stages of the post-selection period, so fully developed recommendations for preventing this from reoccurring are being developed by the IA and Duke personnel and will be provided during the Tranche 2 formative stage. The recommendations will address ways to have both all Duke Proposals and developers of Asset Acquisition projects held to the same performance standards as MPs offering PPA Proposals. This issue is discussed in more detail later this report.

E. ASSET ACQUISITION

The IA is working with Duke to develop and clarify expectations for processing of Asset Acquisition proposals received from Market Participants to ensure a fair and transparent process and facilitate concurrent and post- review by the IA. This includes the communications through the website and other means with MPs, processing of proposals within Duke, and the process utilized by Duke to rank and select proposals for possible submission as Asset Acquisitions.

The Tranche 2 RFP should provide clear expectations/requirements for agreement between Duke and a Market Participant to in order for Duke to submit an Asset Acquisition proposal. For instance, a Letter of Intent covering principal terms and conditions should be required.

F. TRANSMISSION QUEUE ISSUES

After Proposals were received in Tranche 1, the IA and Duke T&D personnel worked to confirm the eligibility of each project. It soon became clear that the queue numbering system created an

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[7] As of the date of this report, the Proposal security payment had not been received.
[8] The RFP expressly waived the Proposal security requirement for utility self-developed Proposals.
[9] The reasoning behind the RFP waiver of Proposal security from the DEP/DEC team related to the fact that DEP/DEC would be unable to obtain a letter of credit in which DEP/DEC was both the beneficiary and applicant/obligor.

unnecessary challenge due to numerous different queue numbering methods. To illustrate this problem, the following are a list of possible queue numbers attached to a project: the queue number assigned by Duke Transmission, the queue number for projects registered with the Federal Energy Regulatory Commission ("FERC"), the queue numbering for North Carolina, the queue numbering used in South Carolina, and, in some instances, unique queue numbers assigned by Duke Account Managers.

To avoid future confusion, the IA will work with Duke to develop a unified project documentation system for Tranche 2 that will allow the IA to more efficiently assess and evaluate Proposals. This review will include developing a form to compare and confirm the projects associated with queue numbers as presented by MPs and assign one reference number to be used in the Step 2 process. For Tranche 2, the IA and the T&D team will reconcile in a sequential way all queue numbering, based on date of the MP requesting interconnection.

G. PROCESS RECOMMENDATIONS

The IA makes the following recommendations for Tranche 2, based on the Tranche 1 experience:

1. RFP Document

The IA recommends the following three general changes to the RFP:

a. Add definitions of the Step 1 ranking classifications; "Primary Competitive Tier," "Competitive Tier Reserve," and "Release List" in Section F on Proposal security (possibly in Section F on Proposal security).

b. Change the definition of the Proposal security calculation to match the term "Generating Capacity MW AC" supplied in the Proposal Forms.

c. Change some of the "non-economic criteria" in Appendix F to pass / fail when appropriate, such as Credit Worthiness to remove risk to Duke through the posting of Proposal security.

2. Proposal Form

The IA has the following recommendations to the Proposal Form:

a. Agree within Duke on a standard term to represent the output capacity for the term "Generating Capacity" to avoid confusion. Having all the terms such as Generating Capacity MW AC, Total DC Capacity [MW], Contract Capacity [MW], Installed Inverter Capacity [MW], and Max Design Capacity MW AC may be unnecessary.

b. If the term "Insta DC Rating [kWpDC]" is needed in future Proposal Forms, change the unit from kW to MW.

c. Remove "Decrement" from the calculated prices since the price that the bidder will be paid is not a decrement to the bidder.

d. Explicitly list the Proposal security calculation on the Proposal Form.

e. Investigate why multiple bidders had trouble selecting the correct drop-down box for Technology.

f. Investigate using a standard format for all queue numbers.

3. Evaluation Process

The IA offers the following recommendations to the Evaluation Process:

a. Update guidance for MPs regarding area of transmission congestion.

b. Duke T&D Account Managers should be included in T&D Evaluation team and included in the Proposal analysis process, and thereby will have access to the ranking knowledge earlier in the review process.

c. The IA should maintain a central ledger showing Step 2 activity and status of each proposal review. This would be shared among all T&D Evaluation team members and would be updated on a regular basis.

d. Create a better way of understanding construction timing; a standard approach to documenting the likely time constraints would be helpful. A table such as Figure 2 should be inserted in each standard cost analysis document.

Figure 2

COD Risk Due to Transmission?	Earliest Feasible COD
Moderate	To meet a COD of 1/7/2021, this Proposal would need to provide notice to proceed by 01/1/2020. A typical interconnection study process is approximately 1 year. Only after the study process can notice to proceed be issued. Additionally, this Proposal requires coordination with SCEG which could impact the feasibility of COD.

III. INDEPENDENT ADMINISTRATOR

A. ABOUT THE IA

With an average of more than thirty-five years of in-depth experience in electric, gas, water, and renewable utilities, Accion Group's diverse consortium of consultants provides insightful, candid, and practical advice to the utility industry and their associated government regulatory bodies. Headquartered in Concord, New Hampshire and consulting affiliates nationwide, Accion's specialties range from competitive procurement and utility management to construction monitoring and nuclear decommissioning.

Since its incorporation in 2001, Accion has been routinely involved in high-profile consulting engagements, thus securing a reputation as one of the premier firms providing independent review of utility procurement practices. Accion has served as Independent Administrator, Independent Evaluator, Independent Monitor, or Independent Observer to state commissions on competitive solicitations in major markets including California, Hawaii, Georgia, Colorado, Montana, Oregon, Florida, the Carolinas, and Arizona. Accion Group has also assisted utilities in the preparation for, and the conduct of, power supply solicitations in Maryland, Massachusetts, and Nevada. Having reviewed Proposals for generation by renewable sources (including wind, solar, bio-mass, wave action, storage, low-head hydroelectric, geothermal, and methane capture), distributed generation with storage, and the construction of as well as facilities using nuclear power, natural gas, and coal fuels, our consultants are well-versed in the subtleties of utility procurement practices. Accion Group's ultimate goal as IA is the same as the purchasing utility and state regulators: ensuring the solicitation obtains the best deal possible for ratepayers, given current market and regulatory conditions in terms of both price and non-price factors.

B. THE IA'S ROLE IN THE RFP

As IA, Accion conducted Tranche 1 on a website custom made for the purpose. The IA designed and implemented the evaluation of CPRE Tranche 1 Proposals in order to determine those Proposals which offered the greatest value to the ratepayers and recommend those Proposals for contracting with the Companies. The North Carolina Utilities Commission ("NCUC" or "Commission") required the IA perform the following tasks: [10]

(i) Monitor compliance with CPRE Program requirements.

(ii) Review and comment on draft CPRE Program filings, plans, and other documents.

(iii) Facilitate and monitor permissible communications between the electric public utilities' Evaluation Team and other participants in the CPRE RFP solicitations.

(iv) Develop and publish the CPRE Program Methodology that shall ensure equitable review between an electric public utility's DEP/DEC Proposal(s) as addressed in subsection (f)(2)(iv) and proposals offered by third-party market participants.

(v) Receive and transmit proposals.

(vi) Independently evaluate the proposals.

(vii) Monitor post-proposal negotiations between the electric public utilities' Evaluation Team(s) and participants who submitted winning proposals.

(viii) Evaluate the electric public utility's DEP/DEC Proposals.

(ix) Provide an independent certification to the Commission in the CPRE Compliance Report that all electric public utility and third-party proposals were evaluated under the published CPRE Program methodology and that all proposals were treated equitably through the CPRE RFP Solicitation(s).

This report addresses how Accion completed each task and the results of CPRE Tranche 1.

IV. WEBSITE

Accion Group provided the RFP Website ("Website") for CPRE Tranche 1 to operate as a secure platform for the solicitation process including bidding, evaluation, and contracting. Below is an overview of each major feature that was enabled for users within the Duke Tranche 1 CPRE program.

[10] NCUC Docket No. E-100, Sub 150; Rule R8-71(d)(5)

A. SCHEDULE

The "Schedule" page displayed the solicitation schedule. Registered users received an email if new events in the schedule were posted or if the schedule was updated.

B. ANNOUNCEMENTS

The "Announcements" page displayed public announcements regarding the solicitation. When posted, registered users received the announcements via email.

C. REGISTRATION

The IA utilized a login registration on the website for purposes of privacy and security. Interested parties were required to register on the website prior to filling out a Proposal form or gaining access to pages such as documents and Q&A.

D. USER PROFILE

Allowed users to update their contact information, and turn on or off email notifications when new documents, announcements, or scheduled events occurred.

E. TUTORIAL

The IA crafted tutorials in both written and video formats to guide individuals in the use of the website. When an individual registered on the website, an email was sent to them with the written tutorial attached. Both tutorials were posted on the "Tutorials" page on the website and could be accessed prior to registration.

F. DOCUMENTS

The "Documents" page displayed all public documents related to Tranche 1. When new documents were posted, registered users received a notification via email. The Documents page was made available after registration.

G. Q&A

The "Q&A" page was a forum for registered users to ask non-project specific questions. All questions were anonymous and could be viewed by all registered users. Each question was posted once the IA submitted a response. Users who asked questions received a notification via email when the IA responded to their question. Following the close of the Proposal submission period, the Q&A page was disabled for further questions, though the prior questions and answers remained viewable.

H. MESSAGES

Prior to the Proposal submission date, the "Message" page was used only for questions or comments which disclosed confidential project-specific information, and therefore could not be asked via the Q&A forum. This feature was available after registering as a Market Participant ("MP"). After the Proposal period closed, all communications with MPs who submitted Proposals was conducted via a "Finalist Messages" page. This page was used by Duke Evaluation Team members, the IA, and MPs. As with the pre-bid Message Board, these exchanges were preserved for future review.

I. PROPOSAL MANAGEMENT

The "Proposal Management" page acted as the homepage for all activities relating to an individual MP's Proposals. From this page, MPs could complete Proposals and redirect to a Proposal's bid form, designate contacts associated with each Proposal (who received emails when Proposal related activity occurred), upload required bid form documents, create, clone, or delete a Proposal, and redirect to the "Proposal Books" page, which contained all files and documented history relating to individual Proposals.

V. OVERVIEW OF TRANCHE 1 CPRE PROPOSAL PROCESS

The CPRE Tranche 1 solicitation was broken into three divisions: Duke Energy Carolinas, Duke Energy Progress, and Asset Acquisition. This division was reflected on the Website where each solicitation had its own site, or "Silo," within the Website. The separate Silos were used so that all data associated with the particular solicitation was self-contained, instead of being co-mingled with unrelated data. The data on each Silo was preserved for future review. The three Silos had identical structures and varied insofar as to accommodate minor differences in the solicitations. The Duke Energy RFP solicitation Website was released on April 6, 2018.

To register on a Silo, interested users were asked to read and agree to the terms and conditions put forth by the Independent Administrator, complete a "reCAPTCHA check," that is "I am not a robot," for website security, and complete the standard registration information, including a primary and secondary contact. Further, each individual had the option of registering as a Market Participant, or Non-Market Participant ("Non-MP"). Once registered, each individual received an automatic email notification acknowledging successful registration to the Silo along with a temporary username and password, which could be changed after login.

General information regarding the solicitation was made public upon the release of the Website. Certain features were made available to non-registrants, including the solicitation schedule, any announcements made thus far, public documents, viewership to Q&A, and website tutorials in both written and video formats. All other public information was available to registered users on the Silos; this included the Q&A forum, the Messages forum, and, following release of the Proposal form, the Proposal Management page. The Duke Companies Proposal Team required expanded Website access, and the IA selectively changed their registrant title to "DE Admin," which gave access to additional features on their respective Silo.

The Website was designed to be the medium for all CPRE related activities. As stated previously, embedded in the Website were three Silos, each representing a unique CPRE Tranche I process. Each Silo automatically saved all user activity tagged with the user information and a time and date stamp. Additionally, the IA strictly encouraged all participants to use the Website for all CPRE activities, thereby ensuring a complete record of the solicitation process.

Beginning on May 11, 2018, draft RPPA and RFP documents were available to registered users for the purpose of the commenting period. All registered users had access to these documents. Registered users were invited to provide comments on a special "Comments" page. Interested persons, and

Figure 3: Standard Proposal Book File System

especially MPs, were invited to review the draft documents and offer suggestions that would enable them to offer robust Proposals. In effect, interested parties were invited to help draft the RFP documents. The Comments page separated each RFP document into individual sections with the opportunity to provide explicit changes by "red-line" revisions, accompanied by a brief explanation of the intended result. While the approach has been very successful in other jurisdiction, the response in Tranche 1 provided few red-lined changes and the comments were along the line of "this section should be changed", without specific textural suggestions. The IA is hopeful there will be a more engaged response in Tranche 2.

On July 10, 2018, the Proposal form was released on the Website to all MPs. An announcement was made on each Silo, and an automatic email notification was sent informing the MPs of the release. When an MP created a Proposal, a corresponding Proposal Book folder was automatically generated within the MP's Proposal Books. A standard Proposal Book folder is shown in Figure 3, depicting subfolders containing uploads from the Proposal Form (Proposal Support Docs; Other Eligibility Documentation), Proposal submission and messaging history (Proposal History), and documents uploaded post submission period (Cure Documents).

The MPs were given nearly three months to complete the Proposal form on their respective Silo. During that time, the IA monitored the Website daily to ensure the functionality of the Website and to monitor and respond to all general and project specific questions. The IA achieved this by updating the schedule when appropriate, posting announcements, updating the FAQ's page, and responding to posts on the Q&A page and the Message Board in a timely manner.

VI. PRE-PROPOSAL SUBMISSION ACTIVITIES

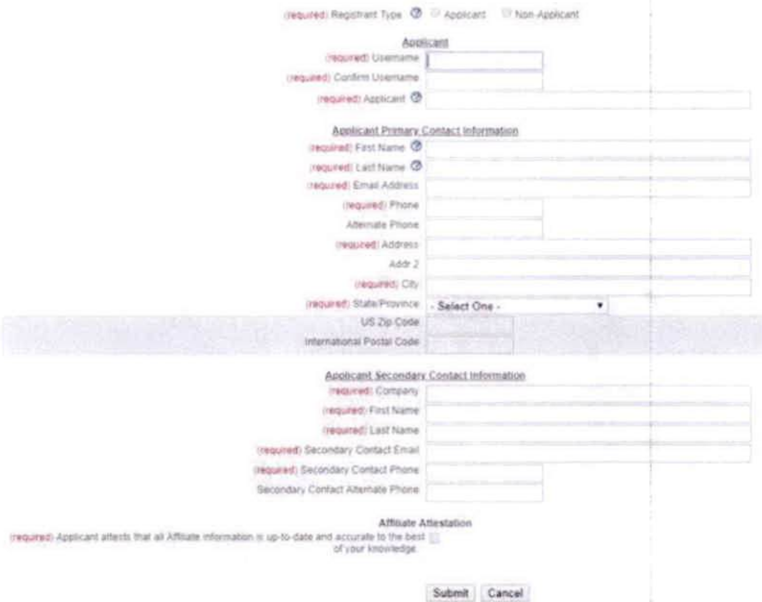
A. REGISTRATION

On April 6, 2018, Accion Group, opened registration on the Website. The Website contained three Silos: Duke Energy Carolinas, Duke Energy Progress, and Asset Acquisition. Once the Website was made public, interested parties had the ability to register on any Silo as Non-Market Participants or Market Participants. Registration on the Website remained open throughout the Tranche 1 CPRE process.

Registration was made straightforward and secure. The Registration page was accessed via the homepage of the Website through a tab on the menu bar titled "Register." Upon clicking the tab, users were introduced to the Terms and Conditions put forth by the IA, which they were then required to read and agree with to proceed. Users were then directed to a security page where the Website utilized *reCAPTCHA* technology to authenticate registrants.

Users were then transferred to the Registration Page, pictured in Figure 4. Registration was a crucial first step in the online solicitation for documentation purposes. Once registered, all user activity on the Website was automatically saved with an individual's identifying data. This provided a complete history of all CPRE related activities which could be tied to individual users.

Figure 4: Registration Page on the Website



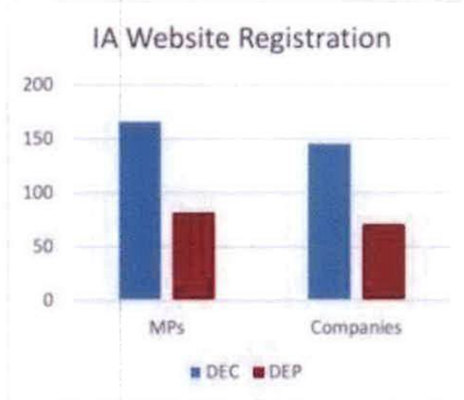
As highlighted on the top of the Registration Page, users were required to Register as either an Applicant or Non-Applicant, which is synonymous with Market Participant and Non-Market Participant. Non-MPs had restricted use on the Website compared to MPs. This allowed Non-MPs to have necessary access to understand the progression and process of the CPRE program without participating as a Market Participant. Likewise, MPs had all necessary tools to fully participate in Tranche 1 on the Website. Figure 5 identifies Website access granted to Non-MPs and MPs.

Figure 5: Access to the Website for Non-MP's and MPs. Check marks signify access.

	Non-MPs	MPs
Schedule	✓	✓
Announcements	✓	✓
Documents	✓	✓
Viewership to Q&A	✓	✓
Q&A		✓
User Profile	✓	✓
Tutorial	✓	✓
FAQ	✓	✓
Proposal Management		✓

Registration was available throughout the Tranche 1 process; however, Figure 6 represents the number of users registered to the Website as of the Proposal Submission deadline on October 9, 2018. Within the DEC Silo, 167 MPs registered from 147 different companies. Within the DEP Silo, 82 MPs registered from 72 different companies. A list of states and territories represented on the Website is shown in Figure 7.

Figure 6



The IA is satisfied with the dissemination of information about this RFP. Throughout the submission process, the Website received 364 MP and Non-MP registrants from thirty-four (34) jurisdictions, including the District of Columbia, and two Canadian provinces. These figures confirm that there was significant engagement from a wide range of companies.

Figure 7: Registration statistics on the Website from April 6, 2018 to October 9, 2018

State / Territory	Registered Users
Alabama	5
Arizona	5
California	44
Colorado	6
Connecticut	2
District of Columbia	6
Florida	30
Georgia	21
Hawaii	1
Idaho	2
Illinois	13
Indiana	3
Maryland	6
Massachusetts	1
Minnesota	3
Mississippi	1
Missouri	2
Nevada	1
New Hampshire	3
New Jersey	5
New Mexico	1
New York	10
North Carolina	128
Ohio	2
Ontario CA	5
Oregon	1
Pennsylvania	3
Quebec CA	1
South Carolina	18
Tennessee	4
Texas	19
Vermont	1
Virginia	7
Washington	4
Total:	364

B. IA GUIDANCE AND COMMUNICATION

1. Tutorial and Documents Pages

The IA maintained daily oversight of the Website and provided all means of Website and CPRE guidance. Within the Tutorial page, registrants could access a seven-page written tutorial overviewing the Website navigation, its features, and how to properly complete a Proposal form, as well as a six-minute video walkthrough highlighting the same. The IA also utilized the Documents page to post helpful information regarding the CPRE process, including the RFP and RPPA, Grid Locational Guidance, and Late Stage information. Before the Proposal submission deadline on October 9, 2018, the IA uploaded more than 60 documents.

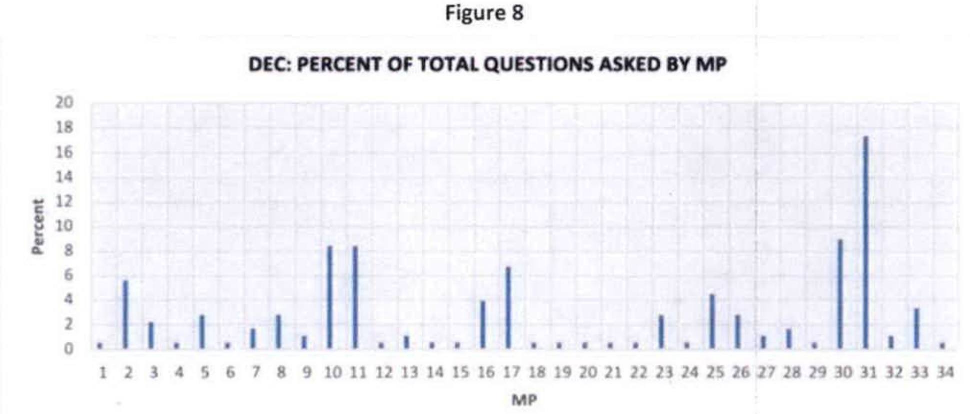
2. Q&A and Messages

For any questions or concerns, MPs contacted the IA via the Q&A or Messages pages. The IA created these pages to ensure that reasonable and efficient communications could be completed and documented on the Website. If the IA received phone calls or emails from MPs, the inquirer was immediately directed to continue the correspondence via the Website.

The Q&A page and the Message Board were created for distinct purposes. The Q&A page was open from the release of the Website on April 6, 2018, and closed at the end of the Submission period, on October 9, 2018. Questions on the Q&A page were non-project specific, and could therefore be useful to many Tranche 1 participants. Questions were visible to all users after the IA submitted their response. For all other questions during this time, MPs were directed to the Message Board. The intended uses of the Q&A page and Message Board were explicitly stated in both the written and video tutorials, and were displayed on their respective pages. After October 9, 2018, the Q&A page was disabled and all communication between the IA and MPs occurred on the Message Board. All posts on the Q&A page remained visible to registered users for the entirety of the Tranche 1 process.

On the DEC Silo, 34 MPs asked a total of 172 questions on the Q&A page between April 6, 2018 and October 9, 2018. 14 MPs asked one question, and one MP asked 31 questions. In DEP during the same period, seven MPs asked a total of 22 questions on the Q&A page. Figures 8 and 9 below show the percent of total Q&A posts shown by individual MPs on the DEC and DEP Silos.

Figure 8



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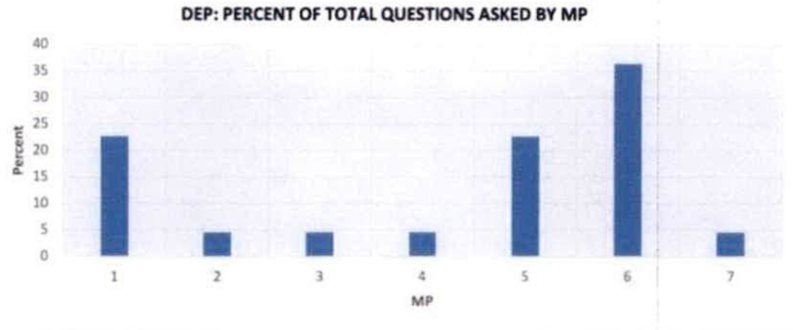
244 North Main Street • Concord, NH 03301 • Phone: 603-229-1644 • Fax: 603-225-4923 • advisors@acciongroup.com

Figure 9



C. BIDDER WEBINARS/CONFERENCES

A Pre-Bid Conference ("Webinar" or "Conference") was held on May 17, 2018 for which participants were invited to register and participate in the Webinar by going to the RFP Website, logging onto the first Silo (DEC) and selecting the "Pre-Bid Webinar" tab on the menu bar.

The following announcement was posted on the RFP Website on May 8, 2019 announcing the Pre-Bid Conference:

From: decpre@acciongroup.com
To: [Website Registrant]

Subject: Duke Energy Carolinas - Announcement Posting
Please do not reply to this auto-generated email.

An announcement has been posted on the Duke Energy Carolinas website. Information about the announcement follows:

Reference #: 3
Date Posted: 5/8/2018 1:37:33 PM

Announcement:

The Independent Administrator and Duke will present the CPRE RFP webinar for interested persons on Thursday, May 17, 2018, beginning at 8:30 am (Eastern). To register for the webinar, visit the RFP website https://decprerfp2018.accionpower.com, and log onto the first silo – Duke Energy Carolinas CPRE RFP – 600 MW and select the "Bidder Webinar" on the menu bar.

If you would no longer like to receive these announcement notifications, click the link below.

Unsubscribe
https://decprerfp2018.accionpower.com

Figure 10

States Represented	Attendees
Arizona	1
California	10
Colorado	2
District of Columbia	1
Florida	9
Georgia	2
Illinois	5
Indiana	1
Minnesota	2
Nevada	1
New Jersey	1
New York	1
North Carolina	44
Ohio	1
South Carolina	5
Tennessee	7
Texas	5
Virginia	2
Washington	1
Total	**101**

Upon successful registration on the RFP Website for the Webinar, registrants received confirmation of their registration and notification that Webinar call-in details would be emailed to everyone who registered within 24 hours before the Webinar.

One hundred twenty-five (125) individuals registered to attend the Pre-bid Webinar representing 60 Companies from 19 states.

A detailed breakdown showing states represented is displayed in Figure 10.

Of the total registrants, 21 were from Duke Energy, four were from the IA Team and one Staff member registered. One hundred one (101) individuals of the 125 registrants actually signed in to participate in the Webinar. Figure 11 shows the breakdown of individuals who registered to attend the Pre-Bid Webinar.

While registrants were encouraged to pre-register for the Webinar, and reminders were sent to encourage registration, no individual was ultimately denied access to participate in the Webinar. The Webinar Access information was also posted on the Announcement page prior to the start time to accommodate those who had not registered but wished to participate. Twenty (20) individuals registered after the Webinar had commenced.

Figure 11

The presentation slides created for the Webinar were posted on the RFP Website prior to the Webinar on May 16, 2017, for the benefit of all registrants and potential MPs, and additionally a recording of the entire program was posted on the Website following its completion, in order to provide all information for those unable to participate in the Webinar.

During the Webinar Duke and the IA provided background of the solicitation and an overview of the RFP process. The Webinar provided the participants with information on the following topics:

- Registration on the RFP Website
- Overview and Background
- HB 589 "Competitive Energy Solutions Law" for North Carolina
- CPRE Overview
- Information about the IA and the IA's role
- Communications protocols

- Standards of Conduct/Expectation of MPs
- Tranche 1 Capacity and Schedule
- Proposal Requirements/Types accepted
- Evaluation Process
- Interconnection
- Pro Forma and Storage
- Asset Acquisition Proposals
- RFP Website and Video Tutorials

Finally, the participants were given an opportunity to ask questions. The Webinar produced thirty-nine (39) questions, which were answered by Duke Personnel or the IA. All responses from Duke were reviewed by the IA. The questions and written responses were posted on the CPRE Tranche 1 RFP Website on May 30, 2018. Participants were advised that the written responses should be used when preparing Proposals, as the oral response at the Pre-Bid Webinar may have been incomplete.

VII. PROPOSAL SUBMISSION

A. SUBMISSION PROCESS

On July 10, 2018, the Proposal Management page, which served as the homepage for all Proposals, was released to registered MPs. Upon its release, an announcement was made on the Website, and was also sent via email to all registered participants. [11]

The Proposal Management page allowed MPs to manage their Proposals from start to finish. Features of this page included the ability, to start, edit, clone, submit, or delete Proposals. They could also manage uploaded documents, change notification settings, and generally monitor the status of their Proposals. These features were explained in detail in both the written and video tutorials.

The Proposal submission deadline was on October 9, 2018, giving MPs nearly three months from the release of the Proposal form to submit a Proposal. The IA estimated that it took a minimum of one to three hours to complete the Proposal form if all document uploads were previously assembled. The IA therefore stressed to MPs the importance of starting Proposals well in advance of the submission deadline. Announcements were posted on August 6, 2018, and September 28, 2018 notifying MPs of this guidance.

[11] Users received email notifications of announcements automatically, however this setting could be turned off in their User Profile. Users who turned off email notifications did not receive notification of the release of the Proposal Management page.

Figure 12: Announcement from the IA reminding MPs to allow at least 3 hours to complete Proposal form

9/28/2018 9:11:23 AM	As a reminder, the DUKE CPRE proposals are due on Tuesday, October 9, 2018, at noon EPT. The Market Participants ("MPs") **should allow at least 3 hours** to complete the proposal form, ***after*** assembly of required documents for upload as well as all required information. A copy of the proposal form is provided on the document page as a worksheet to assist in assembling proposal information. MPs are reminded that all proposal must be priced below avoided cost. The MP is to enter one value on the proposal form and the website will automatically calculate and present the price for each period. MPs are encouraged to complete and submit their proposal form on time if they intend to participate in the Duke CPRE RFP process because late proposals will not be accepted. Please CLICK on the submit button once you complete the proposal form. (Ref.# 18)

The electronic submission process provided MPs with several features which aimed to streamline the bidding process. First, all uploaded documents were automatically saved and organized into a Proposal folder system. Second, if an MP submitted an incomplete Proposal, a PDF version of the Proposal form appeared as currently completed with all incomplete fields highlighted in red. Finally, MPs could clone a Proposal at any time. Cloned Proposals created a new Proposal with identical information from the original; this feature allowed MPs who wished to submit similar, but not identical Proposals an the ability to duplicate relevant data with a single click.

B. PROPOSAL SUBMISSION REQUIREMENTS

1. Avoided Cost Thresholds

The CPRE program solicited resources that were priced below administratively-established avoided costs. The RFP provided avoided cost rates for three pricing periods: Summer, Non-Summer, and Off Peak, to which all Proposals must have bid at or below. The following are the charts of pricing periods taken from the RFP.

Figure 13

Transmission Connected Projects				
Avoided costs ($/MWh)	DEC		DEP	
	Summer	Non-Summer	Summer	Non-Summer
Capacity + Energy On Peak	$58.00	$74.90	$57.40	$78.20
Energy Off Peak	$36.40		$35.70	

Figure 14

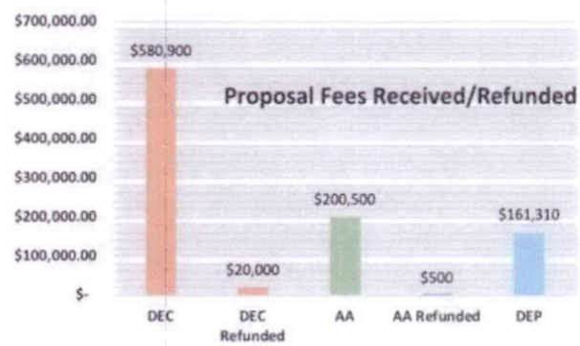
Distribution Connected Projects				
Avoided costs ($/MWh)	DEC		DEP	
	Summer	Non-Summer	Summer	Non-Summer
Capacity + Energy On Peak	$59.40	$76.70	$58.50	$79.70
Energy Off Peak	$37.20		$36.20	

2. Proposals Fees

Each MP in this RFP was required to pay a non-refundable "Proposal Fee" with each Proposal submitted based on the facility's nameplate capacity. For PPA Proposals, a minimum fee of five hundred dollars ($500) per MW with a maximum of ten thousand dollars ($10,000) was due at the time each Proposal was submitted. For Asset Acquisition Proposals, a non-refundable minimum Proposal Fee of ten thousand dollars ($10,000) was due for BOT and Joint Venture Proposals.

Proposal Fees were automatically calculated using the nameplate capacity entered on each Proposal Form, and instructions for electronic payment were provided both on the Proposal Form, and additionally on the RFP Website documents page. Failure to submit the Proposal Fee resulted in automatic disqualification of the Proposal from further consideration.

Figure 15



The IA received and reconciled all Proposal Fees with corresponding Proposals and confirmed that all fees were paid and received no later than 12:00 PM EDT (Noon) on the Proposal due date, as directed by the RFP Documents. The total amount of Proposal Fees received was $922,710. Figure 15 shows the breakdown of fees received for DEC, DEP and AA Proposals submitted, including all refunded Proposal Fees. During the reconciliation process, the IA reached out via the Message Board to one DEC MP who failed to complete and submit two Proposals but paid both Proposal Fees, and one AA MP who overpaid their Proposal fee. Upon confirmation from both MPs the IA refunded the $20,000 Proposal Fees for the unsubmitted Proposals and the $500 overpayment.

Fees were not refunded in the case of any modification of the RFP schedule, rejection of any Proposal, or failure by a winning MP to execute a PPA.

C. PROPOSAL SUBMISSION STATISTICS

1. Submission

Most MPs submitted more than a single Proposal. In DEC, 10 of the 18 bidding MPs submitted more than one Proposal. In DEP, three MPs submitted only one Proposal while seven of 10 bidding MPs submitted more than one Proposal. Eight MPs submitted only one Proposal in DEC, while one MP submitted 15. The average number of Proposals submitted by an MP was three in DEC and two in DEP.

Figure 16

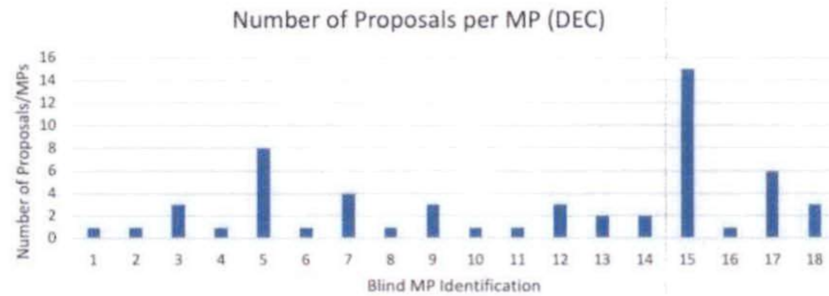
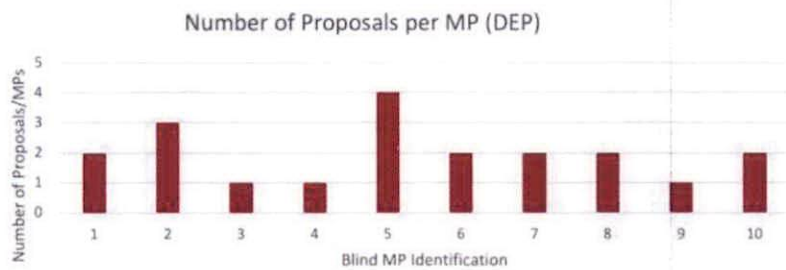
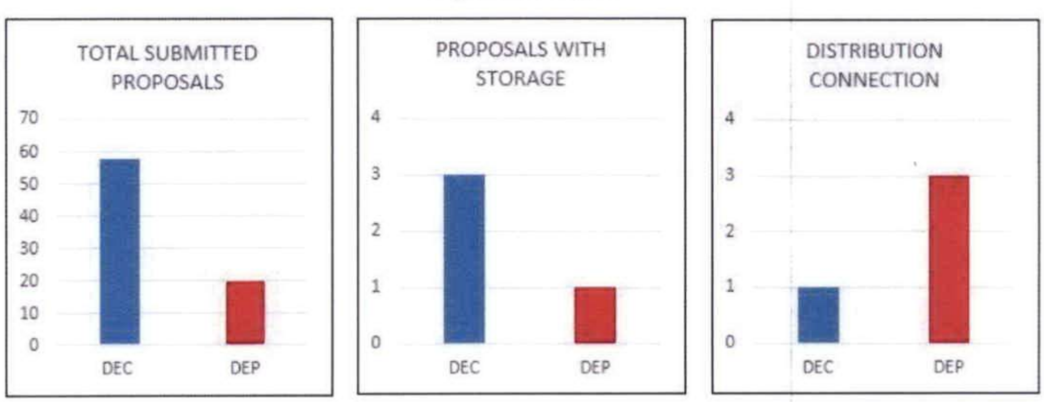


Figure 17



Both DEC and DEP had a robust number of Proposal submissions; DEC received 58 Proposals and DEP received 20. All Proposals were for solar photovoltaic generation. Three Proposals were submitted with energy storage systems integrated with PV systems in DEC, while one Proposal did the same in DEP. One Proposal would interconnect to the distribution system in DEC, and three would do the same in DEP; the remaining Proposals on each Silo required transmission system interconnection.

Figures 18, 19, 20

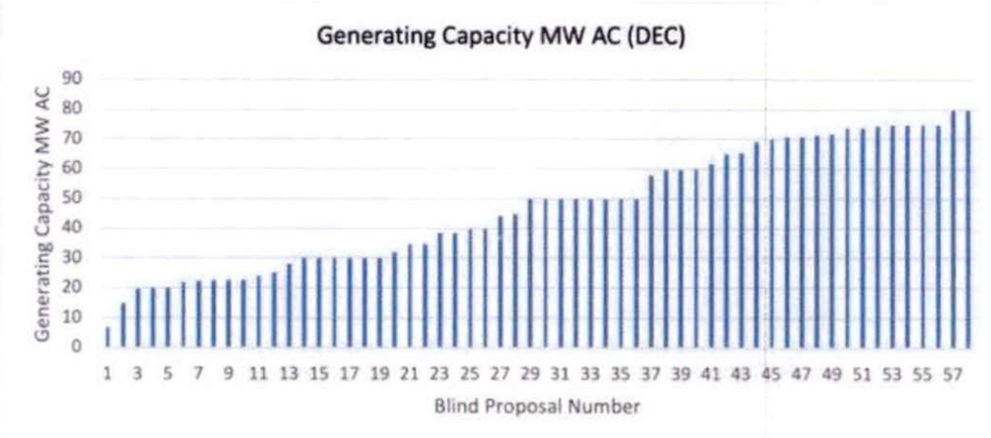


2. Generating Capacity

Duke Energies Carolina (DEC)

DEC received more than four times the targeted 600 MW for CPRE Tranche 1. Proposals were submitted with between seven and 80 MW of generating capacity, and totaled 2732.72 MW. The average Proposal was submitted with 47.16 MW of generating capacity.

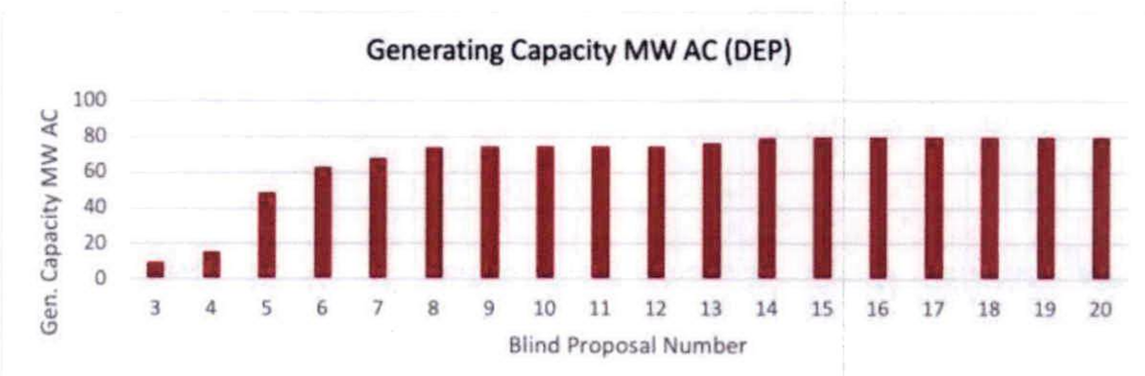
Figure 21



Duke Energies Progress (DEP)

DEP received more than 15 times the targeted 80 MW for CPRE Tranche 1. Proposals were submitted between 7.02 and 80 MW of generating capacity, and totaled 1,231.15 MW. The average Proposal was submitted with 61.55 MW of generating capacity.

Figure 22



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3. Transmission and Distribution

A goal of CPRE was to have "shovel ready" projects move forward by using available transmission and distribution resources. [12] MPs were required to identify the Point of Interconnection (POI) to which their project would connect, as well as whether the MP desired distribution level or transmission level service. All projects 20 MW and larger were required to have interconnection at transmission level. Projects sized smaller than 10 MW were required to have connection at distribution level. Projects sized 10 MW to 19 MW could interconnect at transmission level, but to maximize use of existing capacity for were assigned to the distribution system. A significantly higher number of MPs proposed to interconnect at the transmission level than to the distribution. In DEC, 57 Proposals sought transmission interconnection while only one sought distribution interconnection. In DEP, 17 Proposals sought transmission interconnection while only three sought distribution interconnections.

Figure 23

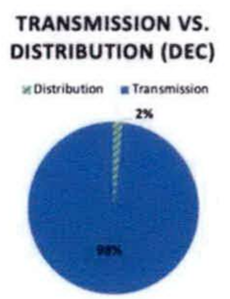
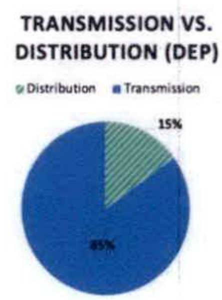


Figure 24



4. Submission by State

Pursuant to the CPRE requirements, all proposed facilities for DEC and DEP were required to be located in the respective DEC or DEP service territories. There were a total of 33 DEC Proposals totaling 1415.91 MWs and a total of 9 DEP Proposals totaling 617.3 MWs in North Carolina. In South Carolina, there were a total of 25 Proposals totaling 1316.81 MWs in DEC, and a total of 11 Proposals totaling 613.89 MWs in DEP. The IA believes Tranche 1 received a balanced load of Proposals between North Carolina and South Carolina.

Figure 25

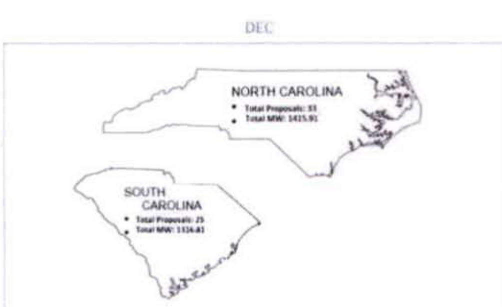


Figure 26

[12] In furtherance of this goal, in Tranche 1 projects that had completed interconnection studies and committed to pay the cost of interconnection were recognized as "Late Stage" Proposals and were excluded from the cluster study process. Thus, the Late Stage projects were recognized as being "shovel ready" and given priority during the Step 2 evaluation process.

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VIII. EVALUATION MODEL

A. OVERVIEW

Each Proposal was evaluated using the MP's pricing information (with three price tiers of decrement), the facility's MW AC generating capacity, and the MP's hourly production profile over 20 years ("Loadshape") information. For proposals that included storage, the facility storage parameters (nominal output, storage duration, and charging rate), and production profiles with and without storage were included in the evaluation.

The IA created a custom evaluation model based on prior experience and the needs of the CPRE program ("Evaluation Model") which utilized the bid input parameters to calculate each Proposal's benefit ("Net Benefit") to the Company system over the twenty-year PPA term. A Proposal's Net Benefit is the sum of the facility's net energy benefit and the facility's capacity benefit, less the costs of system upgrades required to interconnect the facility.

Net Benefit ($/MWh) = Net Energy Benefit ($/MWh) + Capacity benefit ($/MWh) - T&D ($/MWh)

In Step 1, the proposals were ranked based on the net energy and capacity benefits, excluding T&D system upgrade costs. In the Step 2 process, the T&D system upgrade costs for projects were calculated in an iterative process starting with the most attractive proposals and then imputed to the Proposal in the final ranking of Proposals.

B. REQUIRED INPUT DATA

1. Loadshape 8760

For each Proposal, the MP was required to supply a 20-year 8760 Loadshape that best represented the long-term output of the facility. The 8760 Loadshape was subject to review by the Independent Administrator to ascertain that the data within the Loadshape does not exceed the capability of the proposed facility.

A Proposal that included storage was required to submit a pre-storage Loadshape as well as the post-storage Loadshape. The pre-storage Loadshape represented the facility generation with the storage capability turned off. The post storage Loadshape represented the MP's best effort to utilize the facility with its storage capability to maximize facility value (but remain within the practical limits of the energy storage capability). The pre-storage Loadshape was compared to the post-storage Loadshape to evaluate whether the MP exceeded the limits of his Proposal's storage capability in submitting the post-storage Loadshape. The evaluation of a Proposal that included storage was based upon the post-storage 8760 20-year Loadshape data.

A Proposal that did not include storage was required to submit the single 20-year 8760 Loadshape which was used in the evaluation of the facility.

2. Facility Pricing

The CPRE program required that each Proposal was priced as a decrement (i.e., below) the levelized 20-year avoided cost identified in the RFP. This decrement was a single $/MWh amount that applied to each avoided cost pricing period. Once a single decrement amount was entered, the Website automatically converted the decrement into a price that would be below avoided costs for each of Duke's avoided cost price periods. The Proposal form prevented the entry of pricing above Duke's avoided costs. The Website Proposal form presented the calculated prices for each pricing period so the MP could confirm the pricing Proposal was as desired. As noted above, after the Proposal submission period closed, the IA provided each MP with a summary of their respective Proposal(s) and received a confirmation from each MP that the pricing was as intended.

The Avoided Cost rate was a three-tier rate which covers:

a. Summer Peak – the non-weekend and non-holiday hours between 1:00 PM and 9:00 PM during the months of June through September.

b. Non-Summer Peak – the non-weekend and non-holiday hours between 6:00 AM and 1:00 PM during the months of October through May.

c. Off-Peak – all weekend and holiday hours as well as weekday/non-holiday hours that fell outside of the 8 hour "Summer Peak" band during the months June through September and those weekday/non-holiday hours that fell outside of the 7 hour "Non-Summer Peak" band during the months October through May.

MP pricing was submitted as a decrement to the appropriate forecasted Avoided Cost rate which differed for transmission/distribution connection as well as balancing area (DEC or DEP). The minimum acceptable decrement was zero, which replicated the forecasted Avoided Cost rate.

There was a range of price decrements submitted. The median price decrement for Proposals submitted in both DEC and DEP was 6.73 $/MWh.

3. Other Required Inputs

a. In addition, evaluation of each facility included the following data:

b. Inverter Capability

c. Interconnection (Distribution or transmission) Voltage

d. Storage Capability (if applicable) in MW nominal output

e. Storage Capacity (if applicable) in Hours duration at the nominal output

f. Maximum Storage charging rate in MW (if applicable)

The inverter capability represented the maximum output from a project as submitted on each 8760. The interconnection voltage was included in the modeling to determine the energy that could flow from the facility.

C. EVALUATION MODEL PROCESSING

The first iteration of the evaluation model calculated for each proposal the capacity benefit, the energy benefit, and the Proposal cost on a year-by-year basis by using the MP's pricing information for the three price tiers, the inverter capability, the basic storage parameters (nominal output, storage duration, and charging rate) if storage is included, and the MP's Loadshape information. During the second iteration of the evaluation model, the after-curtailment, and, if appropriate, the after-storage benefit was calculated. Finally, the Proposal was evaluated on its twenty-year net present value of benefit per MWh which was used by the IA for ranking Proposals.

The evaluation model processing routine included these key elements:

1. **Pricing: Assign Periods and Generate 20 year $/MWh**

Each hour within the single 8760-hour year was assigned to one of the three pricing tiers (see "Facility Pricing" above) and an energy price was also assigned. This was repeated for all years until each hour of the twenty years of Loadshape data was assigned an energy price. Adjustments were made as required for holidays and weekends, daylight savings time shift, and leap year calendar effects.

2. **Capacity Benefit Calculation**

The facility's capacity benefit is the cost savings associated with the proposed facility's ability to defer future generating capacity on the Duke system. Each year of the production profile (8760) input data was compared against a Loss of Load Expectation ("LOLE") matrix that measured a facility's ability to generate electricity during periods of critical need for the grid. The facility's resulting capacity benefit was estimated by comparison to the Duke system (DEC or DEP) avoided cost. The benefit was estimated by using the system's avoided capacity cost (on a $/MW basis projected from the future cost of utility constructed supply side peaking generation) and allocated to that facility.

3. **Net Energy Benefit Calculation (Energy Benefit less Proposal Cost)**

The Net Energy Benefit was calculated as energy savings to Duke Energy resulting from the operation of the proposed facility. The energy savings for a facility was the difference between the Duke Energy marginal energy cost and the proposed facility's energy cost (as established by the MP's submitted pricing). This analysis was run on an 8760 hour per year basis for twenty years. In any hour that the facility generates energy, the energy savings for each hour would be the facility output multiplied by the difference between the Duke marginal energy price and the facility energy price. This was conducted in an iterative process to incorporate the impacts of curtailment and storage (if included).

IX. EVALUATION

A. OVERVIEW OF EVALUATION PROCESS

The IA strictly followed the evaluation protocol set forth in the Tranche 1 RFP and in NCUC Rule R8-71(f)(3). Further, all appropriate evaluation process information was communicated to MPs in a timely manner. The IA composed a flow chart depicting the entire process, which was then discussed with the Companies and shared on the Website for the MPs on September 19, 2018. Further, the Announcements, Messages, and Schedule pages were monitored daily to reflect the current Tranche 1 plan, or to remind MPs of an upcoming evaluation deadline.

The major components of the evaluation process are described in depth below. The process was designed to evaluate each Proposal individually while maximizing efficiency and fairness. The IA believes this process succeeded in this goal, and all refinement suggestions for Tranche 2 remain minor.

B. PRICE SCORING SHEETS

In accordance with the Appendix F of the RFP, the Price Scoring Sheet ("Scoring Sheet") was used to when reviewing each Proposal. The Scoring Sheets allocated weighted scores to each evaluation category, and category scores were summed to reach a Proposal's overall evaluation score. This method confirmed that each Proposal was evaluated using the same criteria. An example of a Scoring Sheet is attached as Appendix A.

C. EVALUATION TEAMS

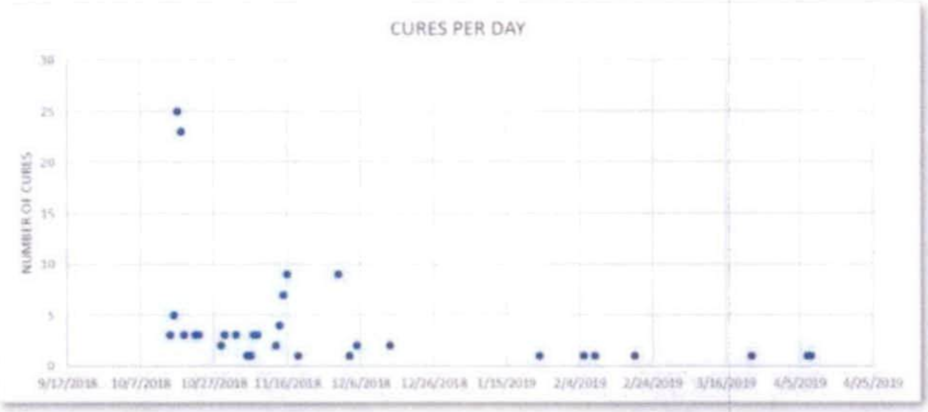
The IA created five subject matter evaluation teams: Modeling ("Modeling"), Financial ("Financial"), Legal ("Legal"), Transmission & Distribution ("T&D"), and Engineering/Project Sufficiency ("PST"). Each team contained subject matter experts and focused their work on their respective portions of the Proposal evaluation. Each of the teams used their designated sections of the Scoring Sheet as the basis of their evaluation. The Modeling Team designed and created the Evaluation Model and worked to determine the "Price Score" defined on the Scoring Sheet. The Financial Team determined the "Credit Worthiness" score for each Proposal by evaluating the MP's financial assurances and credit requirements. The Legal Team focused on three areas: determining that the MP could complete permitting to meet COD, determining that the Proposal had project site control for full term, and determining that the Proposal had site control to the POI for full term. The PST determined scores for four categories: experience of the project team, equipment to be used, required control equipment, and quality of project design. Finally, the T&D Team worked to assist the Modeling Team in determining the Price Score of each Proposal by conducting the T&D analysis of system upgrade costs as described below in Section XI.

D. CURE PROCESS

After Proposals were submitted, it was necessary to fix any inaccuracies made by MPs, and to gather any further materials requested by the IA's evaluation team. This process ("Cure Process"), cures occurred at the beginning stages of Step 1. In a few instances, the IA sought information from MPs when Proposals were moved from the reserve list and to the competitive tier, after the start of Step 2. The number of cures per day is shown in Figure 27. Together there were 125 cures in DEC and DEP throughout the evaluation process, with an average of 1.5 cures per Proposal. [13] The Cure Process confirmed the data inputted on the Proposal Forms to be correct and ready for evaluation. It is worth noting that the initial identification of deficiencies with Proposals, immediately after their receipt, obviated the need to delay evaluation later during the iterative process of elevating Proposals from the Reserve List to the Competitive Tier.

[13] Includes all cures/clarifications directly related to the characteristics of the proposal. This does not include cures for other aspects of the evaluation process, such as Proposal security Forms.

Figure 27: Number of cures per day over the evaluation process



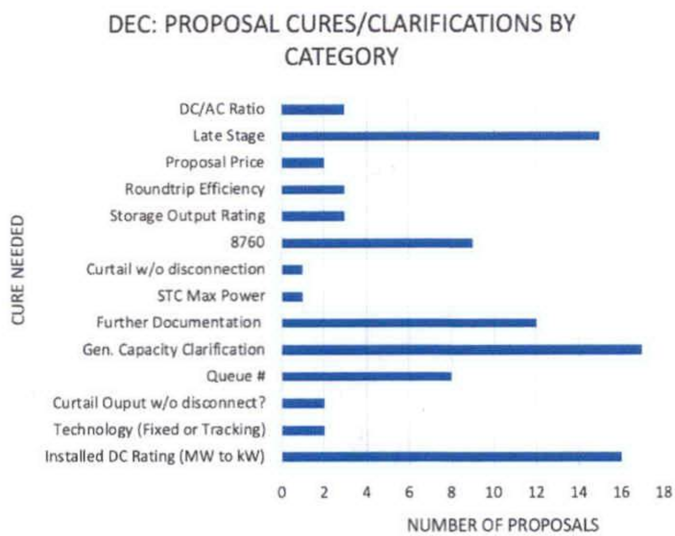
The Cure Process immediately followed Proposal submission on October 9, 2018, with each Evaluation team performing an overview analysis of the data pertaining to their expertise. If any questions were raised or clarifications required, an MP was notified via the Message Board and was given an appropriate amount of time to respond. In total, 48 of the original 58 DEC Proposals and 14 of the original 20 DEP Proposals submitted cures at some point during evaluation.

Most of the cures were identified and accomplished using the Confirm Bid Data Memorandum ("Confirm Bid Data Memo", or "Memo") created by the IA. On October 16, 2018, the IA sent a Memo to the MP of each Proposal with the following information:

- Technology
- Generating Capacity MW AC
- Installed DC Rating [kWpDC]
- Is Storage Included?
- Storage Size (MW)
- Storage Output Rating (MW)
- Price Decrement
- Summer Decrement
- Non-Summer Decrement
- Off-Peak Decrement
- Forecasted COD
- Curtail Output Without Disconnecting?
- Offering to Reduce MW size for Same MWh?
- MW Reduction Amount up to 10%
- Late Stage Proposal?

These Memos resulted in MPs identifying 31 DEC Proposals and 13 DEP Proposals that required cures. MPs were required to respond to the Memo with either confirmation of correct data or identification of inaccurate data. If an MP did not respond, the IA interpreted all data to be correct and evaluated as such. Following the Memo correspondence, alterations of data in these categories was prohibited.

Figure 28



1. **DEC**

In total, 102 cures/clarifications were made in DEC. 94 of the 102 cures were made during the Step 1 evaluation. The most requested cure by the Evaluation Team was the Generating Capacity of the facility. This is likely linked to confusion on the Proposal Form regarding the difference between inverter capacity and generating capacity as it applies to overall generation, and will be clarified for Tranche 2. Further, many Proposals used "MW" units when the Proposal Form indicated "kW." All cure categories and frequencies are depicted in Figure 28.

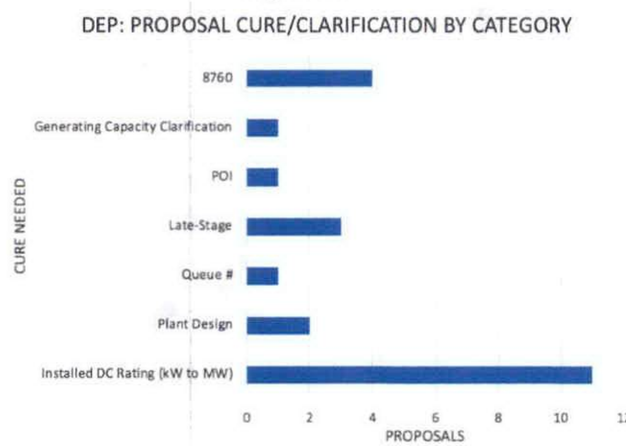
Most Proposals were submitted with no need for major adjustments. 62% of Proposals required no cures (10) or had only one cure (26). Three Proposals, all from the same MP, required eight cures.

2. **DEP**

In DEP, 23 cures were made. The Step 1 evaluation accounted for 22 of these cures. The most requested cure by the evaluation team was to change the units of the Installed DC Rating from MW to kW as requested on the Proposal Form. All cure categories and frequencies are depicted in Figure 29.

Most DEP Proposals were submitted with no need for major adjustments. 57% of Proposals required no cures (6) or had only one cure (7). Two Proposals required three cures.

Figure 29



X. STEP 1 EVALUATION PROCESS

A. OUTLINE OF PROCESS

The goal of the Step 1 evaluation was to categorize Proposals into three Tiers: The Primary Competitive Tier, the Competitive Tier Reserve, and the release list, ranked in order from most attractive to least attractive for ratepayers prior to the Step 2 T&D evaluation. The Tiers were constructed based upon two metrics: The Net Benefit ($/MWh) of each Proposal calculated by the Evaluation Model, and the cumulative generating capacity MW AC.

The Tier structure was created by the IA for the benefit of the MPs. In the Step 1 evaluation, Proposals were sorted based on the overall benefit to ratepayers prior to the Step 2 T&D evaluation of system upgrade costs. This allowed only Proposals with the highest likelihood of being selected as a winner being included in the Primary Competitive Tier and therefore required to post Proposal security. The Competitive Tier Reserve included Proposals with a lower likelihood of being selected for a PPA. A Proposal on the Reserve Tier remained in the CPRE program, but was not required to provide Proposal security until notified that the Proposal was eligible for evaluation in Step 2. Proposals in the Competitive Tier Reserve were moved into the Primary Competitive Tier when other Proposals dropped out due to declining to provide Proposal security, or were found to be above Avoided Cost during the iterative Step 2 evaluation, necessitating adding additional MWs to the Step 2 evaluation in order to meet the Tranche 1 goals.

The composition of each Tier at the end of Step 1 ("Initial Tier Ranking") was completed on December 6, 2018. On that date, a memo was uploaded to each Proposal's Cure Folder with the Proposal's initial status. Further, the IA published the "CPRE Tranche 1 Initial Status Report" for public viewership on the IA Website on December 7, 2018.

The final phase of the Step 1 evaluation required all Primary Competitive Tier Proposals to provide Proposal security. If an MP declined, their Proposal was released from CPRE. This allowed the IA to filter out uncommitted Proposals outright before having to undertake a time-consuming T&D evaluation in Step 2. Once an MP provided an acceptable form of Proposal security, the IA notified the T&D Team to begin evaluation of the Proposal, thus beginning the Step 2 evaluation of the Proposal.

B. INITIAL TIER RANKING

1. Primary Competitive Tier

The Primary Competitive Tier was composed of Proposals with the highest Net Benefit ($/MWh) as determined by the Evaluation Model before considering T&D system upgrade costs. The IA's goal was for the Primary Competitive Tier to contain two times the MW goal in each Silo, thus allowing for the elimination of some Proposals while still meeting the intended MW goal. This also allowed the IA to continue evaluation of Proposals beyond the original goals without a delay as new Proposals were asked to post security. Each Proposal received a memo regarding its Initial Tier Ranking status at the end of Step 1. In line with the RFP standards, MPs were given seven business days following notification of Primary Competitive Tier status to provide Proposal security in the amount of $20/kW.

CPRE is a multi-year procurement program, with the goals of Tranche 1 designed to begin the competitive procurement process. Tranche 1 had a goal of 600 MW for DEC and 80 MW for DEP. The DEC Initial Primary Competitive Tier contained 24 Proposals totaling 1270.22 MW. All Proposals selected for the Competitive Tier were bid in with a price decrement at least 8.9 below avoided cost, and with an average price decrement 12.36 below avoided cost. Following the Evaluation Model calculation, the estimated Net Benefit of Proposals was at least $6.48/MWh, and averaged $9.94/MWh. All Proposals selected were highly competitive and provided significant value to ratepayers.

The DEP Initial Primary Competitive Tier contained eight Proposals totaling 469.52 MW. The MW goal for DEP was 80 MW, thus the 469.52 MWs selected far exceeded the two-times MW goal. As stated above, this target goal was created to ensure that enough MPs would supply Proposal security and maintain their initial value to begin the Step 2 T&D evaluation. Because the DEP MW goal was smaller than that of DEC (80 MW vs. 600 MW), individual Proposals in DEP represented a larger fraction of the MW targeted goal than those in DEC. In fact, several Proposals in DEP were bid with a generating capacity equal to the MW goal. For this reason, the IA chose to include Proposals representing a greater MW total than in DEC in the Initial Tier Ranking for DEP.

All DEP Proposals selected in the Initial Tier Ranking were bid in a price decrement at least 7.1 below avoided cost, and with an average price decrement 14.01 below avoided cost. Following the Evaluation Model calculation, the estimate Net Benefit of Proposals was at least 5.58 $/MWh and averaged 10.35 $/MWh. All Proposals selected were highly competitive and would potentially provide value to ratepayers.

Figure 30

Primary Competitive Tier Proposals			
	Total MWs	Average Price Decrement below Avoided Cost	Average Net Benefit
DEC	1270.22	12.36	9.94 $/MWh
DEP	469.52	14.01	10.35 $/MWh

2. Competitive Tier Reserve

The Competitive Tier Reserve contained the next best Proposals in the Net Benefit ($/MWh) ranking determined by the Evaluation Model, and equaled one times the MW goal for each Silo. Proposals selected for this Tier were considered competitive Proposals with the potential to be selected as Finalists, however the MPs were not required to post Proposal security at the time of the Initial Tier Ranking. This Tier was created by the IA specifically to benefit MPs by limiting the financial burden associated with Proposals less competitive than the best-ranked Proposals, but still considered viable for future consideration.

The DEC Competitive Tier Reserve contained 10 Proposals totaling 543.84 MW, which complied with the one-times the MW goal standard for Tier size. All Proposals selected had a price decrement that was at least 6.38 below avoided cost, and had, on average, a price decrement 7.04 below avoided cost. Following the Evaluation Model calculation, the estimated Net Benefit for Proposals was at least 4.0 $/MWh, and on average 4.91 $/MWh. These Proposals were still highly competitive, and would potentially provide value to ratepayers.

The DEP Competitive Tier Reserve contained eight Proposals totaling 612 MW. The IA selected more than the MW size goal for this Tier for the same reasons it over-selected in the Primary Competitive Tier. All Proposals selected had a price decrement at least 4.67 below avoided cost, and on average had a price decrement 5.93 below avoided cost. Following the Evaluation Model calculation, the estimated Net Benefit for Proposals was at least 0.94 $/MWh and averaged 2.2 $/MWh. All of the Proposals remained below the avoided cost threshold.

Figure 31

Competitive Tier Reserve Proposals			
	Total MWs	Average Price Decrement Below Avoided Cost	Average Net Benefit
DEC	543.84	7.04	4.91 $/MWh
DEP	612	5.93	2.2 $/MWh

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3. Release List

The release list contained the least competitive Proposals. MPs with Proposals selected to the release list had the option to keep their project in CPRE by being included on the Reserve Tier. The table below depicts the response of MPs with Proposals when notified that their Proposal was identified for release, but could be on the Reserve Tier.

Figure 32

Silo	Release List Proposals	Proposals Moved to Reserve from Release
DEC	23	23
DEP	3	2

C. PROPOSAL SECURITY

1. Overview

Proposal security was required from all third-party MP Proposals. As per the RFP, Proposal security equaled $20/kW, based on the facility's inverter nameplate capacity. Proposal security was required within seven business days of MP's notification of a Proposal's selection for the Primary Competitive Tier. The Proposal security was accepted as cash, a Surety Bond, or a Letter of Credit ("LOC"). The IA provided acceptable Surety Bond and LOC forms on the IA Website as part of the RFP.

Third-party MPs had the option to withdraw their Proposal by not posting Proposal security. If an MP did not post Proposal security within the seven-business day window, the IA confirmed via the confidential Message Board that the MP intended to withdraw the Proposal from consideration. This discouraged the withdrawal of Proposals during the final contracting stages of Tranche 1 and encouraged only "shovel ready" projects to seek Step 2 review. This procedure was consistent with the design of CPRE so Tranche 1 ended with the identification of finalists by the IA, and all other Proposals would be released so the unsuccessful MPs would have their Proposal security released to be available for other projects. Additionally, the use of Proposal security greatly increased the likelihood of PPAs being executed, in contrast to what has occurred in other jurisdictions when developers are permitted to withdraw at the 11th hour.

As projects were eliminated or withdrawn from the Primary Competitive Tier, the IA proceeded to move additional Proposals into the Primary Competitive Tier; these selections were made based on the Initial Tier Ranking. When a Proposal was selected to advance to the Primary Competitive Tier, the IA notified the Proposal MP via the confidential Message Board and advised the MP of the seven-business day deadline for Proposal security (sometimes referred to as "bid security"). The following is an example of a message sent in this instance on the Website:

> *Proposal [X] has been moved from the reserve list to the primary competitive tier. In order to proceed, the MP must now provide the bid security for this project, as identified in the RFP. Please use the "upload documents" feature on the message board to provide the security bond or another acceptable form of security.*

The MP should use the message board to advise the IA if the security will be in the form of cash and IA will provide instructions. To facilitate timely evaluation of the proposal the security should be received without delay, preferable by COB on February 7, 2019. Pursuant to the terms of the RFP, the security must be provided no later than February 12, 2019.

All Proposal security forms were uploaded by MPs to the Cure Documents folder within the Proposal Books on the IA Website. Upon submission, the IA confirmed the validity of the file and sent the relevant documents to the Duke Legal Team for review. If the Duke Legal Team declared the form to be insufficient, the IA allowed the MP to make the appropriate revisions. Below is a message by the IA to an MP in such a case:

Duke personnel has reviewed the security form for this proposal and found two deficiencies. Please revise the document in two business days, by end of COB, Friday, February 15, 2019, and post the document using the "upload documents" button on the message board of the RFP website.

The deficiencies are: 1. surety bond effective date is in brackets. 2. Date of CPRE in first recital is shown as May 11, which is incorrect.

Needed cures: 1. remove brackets around the effective date on the first page. 2. Change the issuance date (on the bottom of the first page) from May 11, 2018, to July 10, 2018.

Once a Proposal's security was accepted by the Duke Legal Team, the Proposal was moved from Step 1 evaluation to Step 2 T&D review.

2. DEC

Within the DEC Initial Primary Competitive Tier, 60% of third-party Proposals declined to provide Proposal security. This resulted in only 15 Proposals totaling 833 MW left in the Initial Primary Competitive Tier for Step 2 T&D evaluation. The IA then advanced more projects into the Primary Competitive Tier. Using the Initial Tier ranking, the T&D Team completed preliminary evaluations of all Competitive Tier Reserve and Release List Proposals to determine the viability of each project before requesting Proposal security and moving them to Step 2 T&D evaluation. A Proposal was eliminated if: it did not have a queue number, it did not have a viable interconnection, or it was in a pre-identified constrained area and had a distribution factor above 3%. Seven Proposals were eliminated during this part of the evaluation process. Additionally, three Proposals identified as duplicates of higher-ranked projects and were removed from consideration.

In total, 22 of the 33 Proposals from the Competitive Tier Reserve or release lists were moved into the Primary Competitive Tier. Of those Proposals, four were submitted by Duke's Affiliated or DEP/DEC team and were sent to the T&D Evaluation team for Step 2 evaluation. The remaining 18 Proposals were required to provide Proposal security before advancing; 12 declined. The six Proposals which provided Proposal security were sent to the T&D Evaluation team for Step 2 evaluation. In total, 47 of the 57 DEC Proposals in the Initial Tier Ranking were moved to the Primary Competitive Tier at a point in time in the evaluation process. Of those 47 Proposals, 33 were third-party Proposals and were required to provide

Proposal security; 21 declined. Ultimately, a total of 26 Proposals were sent to the T&D Evaluation team for Step 2 evaluation.

3. DEP

The DEP Initial Primary Competitive Tier included eight Proposals, of which six were required to post Proposal security and one declined. The remaining seven Proposals totaled 394.62 MW, just under five times the DEP MW goal. The IA considered this to be a sufficiently robust set of Proposals and therefore did not move any further Proposals into the Primary Competitive Tier prior to the completion of Step 2.

XI. STEP 2 EVALUATION PROCESS - T&D OVERVIEW

The goal of the Step 2 evaluation process was to calculate the final Net Benefit ($/MWh) of each Primary Competitive Tier Proposal. The main burden of this step was on the T&D Team to assign an estimated upgrade cost to each qualifying proposal. The purpose of this section is to document the steps taken by the IA and the Duke T&D Evaluation team to complete the system upgrade cost analysis for each Proposal. [14] This work was completed at the end of May 2019. This discussion is presented as a chronology of events, from those actions taken prior to Proposal submission. From this process the IA developed recommendations for the T&D evaluators to be employed in Tranche 2.

A. ACTIVITY PRIOR TO PROPOSAL SUBMISSION

1. Portfolio Study Example

MPs expressed interest in learning more about the methodology the IA planned to use to complete the portfolio analysis. Such analysis was critical as multiple Proposals competed for the same network resources, thus necessitating allocation of line capacity between competing Proposals.

The IA prepared an example of its approach to portfolio analysis, based on previous engagements. This example was specific to the Duke CPRE process. In early September 2018, this example was reviewed with the Commission Public Staff and with Duke personnel. This review resulted in several modifications that better adapted the analysis for this project. The portfolio study example was finalized on September 19, 2018, and posted on the IA website Document page.

Separate Competitive Tiers were established for DEC and DEP by the IA and shared with the T&D Team to begin the Step 2 analysis. The Step 2 process included an analysis of potential electrical interdependency of these Proposals was performed. It was apparent from a review of the Points of Interconnection ("POI") specified by the MPs that several of the Proposals in the Competitive Tier were electrically interdependent. The potential system impact of interdependencies were identified as the system upgrade costs for each Proposal were determined. The maps below show the geographic location

[14] The Duke T&D Evaluation team members all completed the separation protocol training and executed a confirming affidavit. No member of the T&D Evaluation team had involvement with the development of any Proposal from the Duke Companies Proposal Team or any affiliate of DEC or DEP that submitted a Proposal.

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of the selected projects, and there was no electrical interdependency among the final Proposals, thus, sharing of network upgrade costs between Proposals was not needed.

2. Transmission Guidance Provided to Bidders

The T&D Team created a locational guidance document for MPs to better understand the available transmission capability and assist them in selecting viable points of interconnection. This guidance is included as Appendix B and was part of a webinar presented on May 10, 2018. A copy of the materials was available on the Document Page of the IA Website.

Notwithstanding the locational guidance, several MPs proposed non-late stage facilities in areas that were identified as constrained. The IA will not speculate on why an MP would participate in CPRE knowing their project was in a constrained area and therefore would have transmission upgrade costs assigned. Figure 33 below is a map of all DEC Proposals and the pre-identified constrained areas. Figure 34 shows all winning Proposals in DEC. Note that all winning Proposals were outside of the constrained areas. One successful DEP Proposal will interconnect at transmission level service and is shown in Figure 35. This was a late stage project.

Figure 33

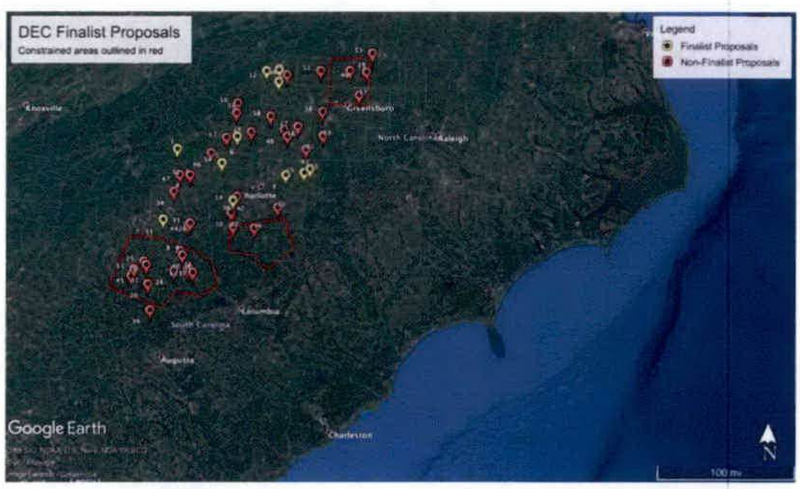
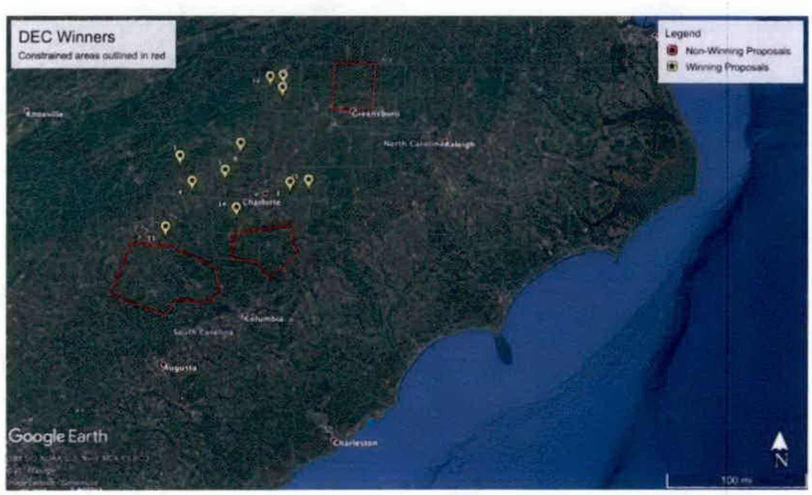


Figure 34



3. Distribution Guidance Provided to Bidders

MPs were advised that projects smaller than 20 MW would be evaluated as requiring distribution level service. Locational guidance was provided for projects that could interconnect at distribution level via materials posted on the IA Website or linked from the Website, as well as during the May 10, 2018 webinar. Specifically, a document entitled "Method of Service Guidelines" was identified by Duke and a link to the materials was included on the IA Website.

One of the two DEP winners is a 7.02 MW project that will interconnect at distribution level. The maps shown in Figure 35 and 36 show this project's location in a constrained area. The project was in the final Competitive Tier because it is well priced and a "late stage" project, meaning the MP accepted responsibility for system upgrade costs in the Proposal and only minor additional costs were imputed to the Proposal.

Figure 35

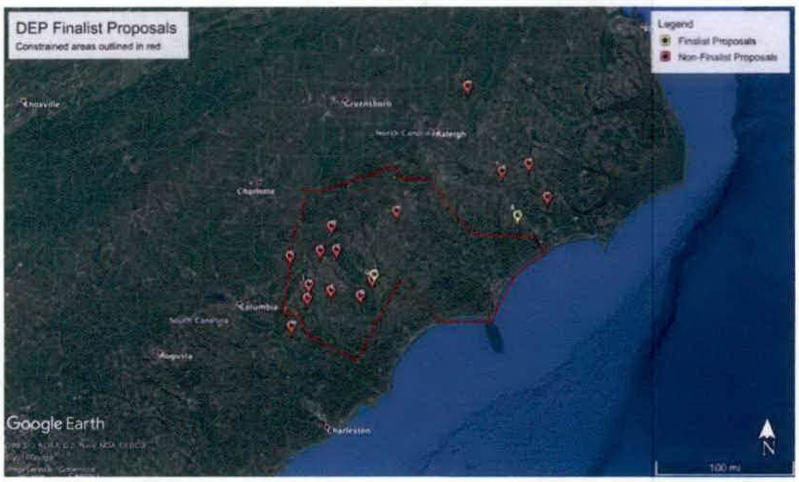
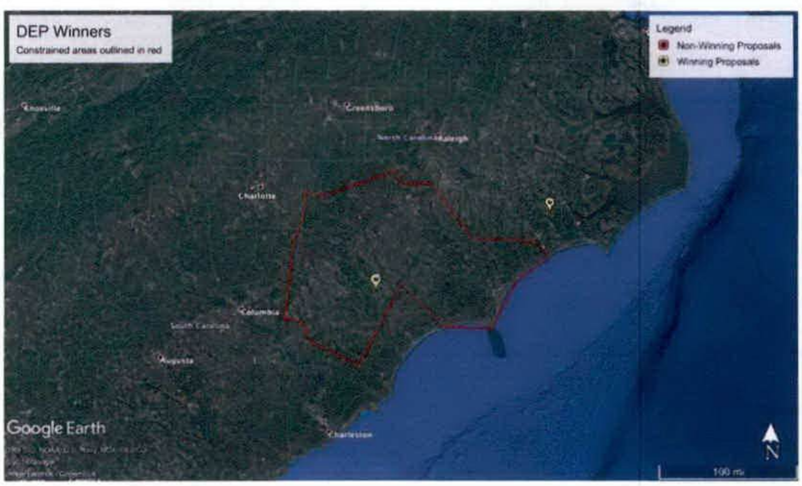


Figure 36



B. FLOW CHART OF STEP 2

In response to a request from the Commission Public Staff, the IA produced a flow chart showing the iterative approach to this cost determination was formulated. This flow chart was provided on the IA Website on September 19, 2018, and is included as Appendix C.

The flow chart was shared and discussed during face to face meetings with the subject matter experts on the T&D Team. As the team name suggests, Duke personnel with subject matter expertise in the areas of either transmission or distribution were assigned to the team. During the Step 2 evaluations, Proposals were separated depending on whether the associated projects would interconnect at either transmission or distribution levels and were reviewed by personnel experienced in the respective areas. The flow chart was followed throughout the actual analysis of Proposals to ensure that all Proposals were evaluated using the same process and standards.

C. ANALYSIS REPORT FORMAT

As part of the practice of treating each Proposal in a fair and equitable manner, a standard document was used to record and present the analysis results for each Proposal. A draft standard document was presented to both T&D Teams for consideration and modification. A mock Proposal was selected, and the Distribution team completed an example analysis to test the applicability of using this standard format. This example was shared with the T&D Team which adopted a similar approach.

D. COMMUNICATION DOCUMENTATION

After the Proposal submission period closed on October 9, 2018, a "T&D EVAL" folder and confidential Message Board was opened on the DEC Silo of the IA Website for data sharing with the members of the T&D Evaluation team. This platform ensured that the exchange of files, and the file contents, had a time and date stamp, and that all Proposal data was shared securely. All members of the team shared access to these files, and this process continued until the ranking of the Competitive Tier became final.

At the same time CPRE Proposals were being evaluated, the day to day operation of Duke transmission continued. Some Duke Account Managers had dual responsibilities in addressing non-CPRE requests for transmission service and being on the T&D Evaluation team. To avoid even the appearance of CPRE ranking information being released, the IA Website provided restricted access to separate folders, thereby isolating evaluation information access on a "need to know basis." This approach prevented Duke Account Managers from viewing ranking information of Proposals, while the T&D Evaluation team, via a confidential file system, received the information needed to complete evaluations. These files are preserved on the IA Website for future review and confirmation.

Beginning on October 9, 2018, all voice or email messages between the IA evaluation team members and the T&D team were documented in a communication log with daily postings to the confidential evaluation files on the IA Website. Communication records were organized by week and posted to the "T&D Communication Log" folder on the Evaluation page of the IA Website.

All direct communication from members of the T&D Evaluation team to MPs concerning CPRE topics was prohibited. Instead, T&D Team members were instructed to provide questions to the IA, who in turn posted them on the confidential Message Board of the Website. This ensured complete documentation of all exchanges. There were no observed instances of MPs inappropriately approaching T&D Evaluation team members.

E. LATE STAGE PROJECTS

Late Stage projects were recognized in Tranche 1 as a special class of Proposals. To qualify for late stage status, a project was required to have an executed state jurisdictional Facility Study agreement as of the date of Proposal submission. A project that obtained Late Stage status retained its original queue position and original network upgrade costs, if any, even if it was not selected as a winning project. Late Stage status was an advantage for a project with little to no network upgrade costs identified in their existing System Impact Study. For a project already assigned significant network upgrade costs, foregoing Late Stage status allowed for sharing of costs in the CPRE pooling process. The advantage to Late Stage status was that a project retained its original queue position, even if it was not selected as a winning project.

Considerable discussions and interactions by the IA and Account Managers, Duke attorneys, and T&D Team members was necessary to make determinations as to Late Stage eligibility. Numerous questions and confirmations required MP's responses on the Message Board because of confusion about some projects. This process started in mid-October and was not competed until mid-December.

F. INTERCONNECTION VERIFICATION AND VALIDATION

The process of verifying and validating the information submitted by the MPs proved to be arduous due to confusion about queue identification numbering, whether projects were FERC-jurisdictional, and the precise POI of projects. The IA managed the confirmation process with assistance from Account Managers, T&D Team members, Duke attorneys, and the MPs. Because the identity and location of projects proposed into the CPRE program was to remain unknown to most Duke personnel, including those on the Duke Evaluation Team, information from Proposals was only provided when there was uncertainty about a Proposal, and then only to the Duke personnel with subject-matter expertise to assist the IA so the required separation protocols were maintained. Proposal verification started shortly after the close of bidding in October 2018, and continued into mid-January 2019. Those issues needing verification and validation are discussed below.

1. Facility Study Agreement Status

There were several instances where the facility study agreement for a project was executed by the developer, but the final acceptance was not executed by Duke. In other instances, the study was not complete, though the MP contended that it was. Each of these instances had to be resolved before a Proposal was included in the Step 2 evaluations.

2. Project Size

The CPRE maximum Proposal size for transmission connection was 80 MW; the distribution connection maximum was 20 MW. Project size was established in the interconnection request and could not be expanded, but could be reduced up to 10 percent. Confusion concerning project size was largely a result of lack of specificity on the Proposal form. Instead of using a uniform term, such as "Project Size," the Proposal form required "capacity" size in different contexts. In cases where the Proposal form intended for MPs to submit project size, some bidders submitted nameplate MW, inverter capacity, or output MW to POI, resulting in inconsistent project capacity data. The appropriate MW capacity was established by the T&D Team through interaction with the MP on the Message Board. As a result of this process, this section of the Proposal form will be revised for Tranche 2 ("Lessons Learned").

3. Transition from FERC to State

There were several examples where MPs desired to transition their FERC projects to State jurisdiction in order to participate in CPRE. This transition involved consultation with Duke attorneys for verification. Additionally, there were instances in which proper paperwork had not been filed to accomplish this transition, or the projects did not qualify for State jurisdiction. In each instance, the MP was informed of the final determination and did not challenge the result.

4. Queue History

The online Proposal form required identification of the queue number associated with the project. There were numerous instances where the MP used a queue number that was no longer valid, used the same queue number for multiple projects, or used a queue number that was invalid. In some instances, the MP presented the queue number provided by a Duke account manager, though it was determined the queue number was invalid. Similarly, there were instances of confusion as to the appropriate queue number to be used among differing Duke options and the FERC queue numbering system. The IA and the T&D Evaluation team resolved each issue prior to the start of the Step 2 evaluations, and prepared revised protocols for assigning queue numbers so the confusion will not reoccur.

5. Ownership Transition

It is common for some developers to initiate project development and then sell their project to another MP prior to completion of the project. Ownership transfers are required to be filed with Duke. Unfortunately, the documentation of ownership transition was not always filed or recorded properly. Each instance of inaccuracy in ownership documentation was investigated by the IA and the T&D Evaluation team and proper documentation was recorded prior to the start of the Step 2 evaluations.

6. Analysis Uncertainties

The T&D Evaluation team and the Account Managers identified several Proposals where the RFP data did not align with the existing information for the project. These included two Proposals which required clarification on their ability to successfully interconnect at the POI indicated on the Proposal Form, two Proposals where the intended POI was unclear, and several Proposals where the size presented on the Proposal Form differed from what was given at other points in the submission process.

7. Concluding Proposal Cures

The initial cure process was crucial to attaining the basic Proposal data needed for the ranking process. The majority of this work was completed by mid-November 2018, which allowed the Proposal ranking process to go forward. A few cures remained that were resolved in mid-December. These remaining issues did not delay the initial ranking analysis but did modify subsequent rankings.

As the Proposal cures were being resolved, it proved a challenge that Account Managers were not privy to the Proposal ranking data. Account Managers could only respond to specific questions from the T&D Evaluation team, and were also hampered in completing their daily tasks by their lack of CPRE Proposal knowledge. Both the T&D Evaluation team and the Account Managers were disadvantaged by this lack of shared knowledge.

G. STEP 2 PROCESS

1. DEC Transmission Proposals

At the conclusion of Step 1, Proposals were selected by the IA and sent to the T&D Team to begin Step 2 analysis starting on November 22, 2018. 18 Proposals totaling approximately 800 MW were included in the initial Step 2 analysis.

For each Proposal reviewed in Step 2, only information necessary to determine system impact cost was extracted from the Proposal submissions and provided to the T&D Team, and no Proposal pricing or calculated net benefit was provided. The information provided to the T&D Team is listed in Figure 37.

Figure 37

Name	Date modified	Type	Size
x_118-01_Facility_Description	11/21/2018 12:23 ...	Microsoft Word D...	12 KB
x_118-01_Project_Map	11/21/2018 3:26 PM	Adobe Acrobat D...	410 KB
x_118-01_Single_Line	11/21/2018 12:21 ...	Adobe Acrobat D...	460 KB
x_118-01_Single_Line_Drawing	11/21/2018 12:21 ...	Adobe Acrobat D...	460 KB
x_118-01_Site_Description	11/21/2018 12:22 ...	Adobe Acrobat D...	29 KB
x_118-01_Site_Plan	11/21/2018 3:26 PM	Adobe Acrobat D...	492 KB
x_118-01_Transmission_Project	11/21/2018 12:22 ...	Microsoft Word D...	22 KB

The T&D Team reviewed the contents of these files and identified issues for which additional information was needed from the MP. The T&D Team shared requests with the IA via a confidential Message Board on the IA Website and the IA, in turn, interacted with the MP to collect the information and pass it to the T&D Team. [15] This approach ensured that the T&D Team did not to have direct CPRE correspondence with the individual.

[15] Some requests were made via email and were then recorded in the communication log

2. DEP Transmission Proposals

Proposals for DEP were selected and sent to the T&D Team. Eleven (11) Proposals, totaling over 700 MW, were sent on November 29, 2018 with the same data identified in Figure 37. The IA used the same process as described above for collecting clarifying information from MPs when necessary.

3. Distribution Service Analysis

The two distribution Proposals in the Competitive Tier for DEC were delivered to the T&D team on November 29, 2018 along with the Figure 37 data.

H. THRESHOLD COST ESTIMATES

A review of the location of projects confirmed there were a number in the identified constrained areas where system upgrade costs would certainly be incurred. To avoid excess analysis, the IA prepared a table with an estimated maximum upgrade cost each Proposal could bear without exceeding avoided cost. If the analysis indicated that a long transmission line upgrade or a significant substation would be needed, the system upgrade costs were estimated and compared to the threshold values previously calculated by the IA. This quickly eliminated Proposals that would be above avoided cost, thereby streamlining the transmission analysis.

Threshold values of 600, 1,200 and 1,800 megawatts were established and calculated. Theses threshold values were established based on the 600 MW of CPRE generation that is to be added in Tranche 1.

I. MEGAWATT REDUCTIONS AVAILABLE

On the Proposal Form, MPs were asked if they would be willing to have their project sizes reduced by up to 10% if interconnection constraints were present, without changing the associated decrement price. This size reduction would not result in a change in the dollar per megawatt hour Proposal price. 31 MPs expressed their willingness to accept such a reduction if necessary. On December 12, 2018 a list of MPs willing to accept a reduction was sent to both the DEC and DEP segments of the T&D Team to be available should the IA determine it would be appropriate to reduce one or more Proposal in order to meet the Tranche 1 goals. The Tranche 1 evaluations were completed without the need to reduce the size of any Proposal.

J. BASE CASE FORMULATION

1. Overall Base Case Discussion

The T&D Team reviewed and established the base case after receiving the listing of ranked Proposal list on November 22, 2018. The process for confirming the base case required review of all projects in serial queue, elimination of duplicate projects, and elimination of untimely projects.

2. Review all Projects in Serial Queue

Initially included in each base case were all projects with a queue position established prior to October 9, 2018. Any project that bid into CPRE was removed from this initial base case, with the exception of Late Stage projects.

3. Eliminate Duplicate Projects

Some developers held queue positions for the same project with different configurations, such as different project sizing. Where there were multiple projects identified for a single location, only one could be built. Using engineering judgment, the IA and the T&D Team eliminated projects that could not proceed. At the NCUC's May 2019 technical session the IA suggested that between 50% and 80% of the projects in the queue would not be built. The IA believed that the base case should more accurately reflect the projects likely to be built.

4. Eliminate Untimely Projects

Tranche 1 required in service date, referred to as the Commercial Operation Date ("COD") of January 1, 2021. However, the IA and the Duke Evaluation Team recognized it would be inappropriate to eliminate an attractive Proposal if it could be in service shortly after the expected COD date. Accordingly, it was established that if a project could be completed by July 1, 2021, it would be considered as reaching a timely COD. Any project deemed not able to be in-service by this date could be excluded from further consideration. The construction timeline used for this determination was the normal completion times for the system components needed. The DEC T&D Team identified the transmission upgrades required for all Proposals analyzed. These upgrades were then evaluated and a determination was made as to whether the necessary upgrades could be completed by the required date.

The realistic COD cannot often be determined until after the network upgrade equipment requirements have been established. The causal connection between upgrades needed and the time required to construct will be further discussed in more depth below.

5. DEC Base Case

The DEC base case was formulated by excluding all combined cycle plants bid before October 9, 2018 that did not have an executed Interconnection Agreement. Subsequent studies of any plants excluded from the base case were adjusted such that those generators were not responsible for the costs associated with the upgrades caused by CPRE winners with later queue dates/positions. All other queued projects that were not duplicates from the same project were included in the DEC base cases.

Four transmission planning regions existed within DEC. Due to the size of DEC's generation queue, four base cases—corresponding to the four transmission planning regions—were created. Queued generation on the seams of each region were included in the respective base cases so as not to mask potential issues. The approach of using geographical groupings (based on the existing regional planning responsibilities) to create multiple base cases allowed for a systematic approach to assessing the impact of additional generation in different areas of the system.

6. DEP Base Case

The DEP CPRE Tranche 1 Base Case included all non-bidding and late stage requests, both FERC and State, with queue dates through October 9, 2018. There was one exception; a gas-fired combined-cycle plant which had a mutually exclusive alternative. Thus, combined cycle plants Q398 and Q399 were included in the base case and Q428 was excluded.

Due to the significant amount of solar generation in DEP, impacts from additional generation span the entire DEP region. Thus, all requests in DEP were modeled in a single DEP-wide base case.

7. Distribution Base Case

The Distribution Base Case differed from the others in that each project was evaluated based upon the loading of the line to which it was connecting and the substation loading into which the line connects.

K. COST ANALYSIS COMPLETED

The analysis approach evolved over time and was not finalized until mid-January 2019. The teams and the IA were in agreement as to the components of the required analysis.

TRANSMISSION

1. Standard Analysis Results Document

The format for the analysis report was proposed by the IA, tested, and was utilized successfully by the T&D Team as a way to document the analysis results for Proposals in the Competitive Tier. The following topics are included in each bid interconnection cost analysis:

- Proposal Information
- Study Purpose
- Study Conclusions
- Interconnection Configuration for the Proposed Proposal
- System Location of Proposed Proposal
- Analysis Structure and Assumptions
- Transmission or Distribution System Delivery Impacts
- Transmission or Distribution Facilities Estimate Including Upgrade Project Description
- Estimated Cost and Construction Time of Network Improvements

Individual analysis reports were completed for each Proposal in the Competitive Tier.

2. Analysis Results for Each Proposal

The T&D Evaluation team received the Proposal ranking in late November of 2018, 7 weeks after the Proposal closing date. At this point, the analysis of the individual Proposals began. The analysis results were produced in three steps: Analysis Content, Analysis Process and Results, and Track Progress and Status for All Proposals.

3. Analysis Content

The analysis content was driven by the bid analysis document. Each section of the analysis document helped to form the basis for the necessary network upgrades for each Proposal. To help the T&D Team understand and produce the required analysis and documentation of the analysis results, the IA met with the team approximately once a week. Each meeting had predetermined discussion topics that led to individual assignments, with results covered in subsequent meetings. These meetings began in February of 2018 and continued through mid-May 2019.

4. Analysis Process and Results

a. Evaluate in Ranked Order

The process for determining costs for each Proposal started with their ranked order. Proposals that were highest ranked had the lowest Proposal costs and were studied first; each Proposal was analyzed individually.

b. Apply Distribution Factor Test

If a Proposal location was within a previously identified constrained zone, a quick test was applied to determine whether the loading of constrained lines was likely to be too high as a result of connecting said project. Bidding into a constrained area did not disqualify a Proposal from being selected.

The Distribution factor ("DFAX") is a measure of the percentage of a facility's output that flows on a transmission element. Three percent (3%) is a commonly accepted threshold in the industry for assessing whether generators, loads, or transfers may materially impact the flow on a line or transformer.

Proposals in pre-identified constrained areas were screened against a 3% DFAX threshold on constrained facilities. Proposals that had > 3% DFAX on one or more constrained facilities in a pre-identified constrained area were excluded from further evaluation. The basis for this exclusion was unrelated to any impact on the cost of the Proposal (cost of upgrade may be spread across multiple projects) and was solely based on the inability to address constraints by July 1, 2021. While CPRE did not prohibit submission of Proposals in constrained areas, CPRE supporting documentation (i.e. locational guidance) indicated that Proposals in these constrained areas would have an increased likelihood of being subjected to system impact upgrades based on the level of activity in the queue. Proposals that did not have > 3% DFAX on one or more constrained facilities in a pre-identified constrained area were further evaluated, however projects whose necessary upgrades could not be completed by July 1, 2021 were removed from consideration.

c. Apply Standard System Planning Models

Both thermal overload and reactive capability analyses were completed using standard System Planning guidelines and models. The results of these analyses were reported in detail in the standard document for each Proposal. Four DEP Proposals completed bid analysis documents: two for distribution projects and two for transmission projects. Twelve bid analysis documents were completed for DEC Proposals: all were transmission projects.

d. **Determine Network Upgrade Equipment Requirements**

The analysis indicated whether there were any electrical deficiencies following the addition of the bid project. From there, the network upgrades needed to replace the deficiencies were determined. Standard unit cost tables were prepared based upon a project's completed history. The standard costs were then applied to each Proposal using the same costs for each construction unit for each Proposal.

e. **Evaluate Impact on Commercial Operating Date of Upgrade Requirements.**

After the extent of the upgrade requirements was known, the time taken to complete the field construction was predicted. It was important to understand this length of time when determining whether a Proposal could be operational by the time required in the RFP. The standard Proposal cost analysis document did not adequately recognize the importance of the construction timing requirement; the evaluation team suggests changing this document for Tranche 2.

f. **Complete Reactive Capability Evaluation**

The check performed by Duke Energy transmission planners was to confirm the plant design provided by the developer, or to advise the MP on the MW limitation.

Note that the DEC and DEP power factor requirements were published on OASIS in their respective Facility Interconnection Requirements documents. Developers were expected to design their plants to meet these requirements. The check performed by Duke Energy transmission planners was to confirm or correct the plant design provided by the developer.

The Evaluation Team also conducted a reactive capability evaluation. The following is an example of language used in one of the reports; "The maximum allowable size for a capacitor bank associated with a facility was 3.3 Mega-Volt Amperes Reactive ("MVAR"), which allowed the MP to compensate only for plant losses. With or without a 3.3 MVAR capacitor bank installed and in service, the requested MW output met the reactive" capability requirements set forth in DEC's FCR document, and the reactive power range was between 8.9 MVAR lagging and 5.6 MVAR leading.

g. **Track Progress and Status for All Proposals**

During the Proposal cost evaluation process, it was necessary to track status and progress for each individual Proposal. Individual records were maintained for DEC and for DEP. For all evaluation participants to have equal access to the same data, these files were maintained centrally and made available to authorized individuals on a regular basis.

DISTRIBUTION

As discussed below, there were three distribution Proposals that were bid into DEP: 67-01, 67-02, and 83-04. There was one such Proposal in DEC: 118-04. The process for considering distribution Proposals differs from the method that was used for transmission Proposals and will be covered separately below.

1. Analysis of Distribution Content

The distribution Proposals were restricted to a maximum of 20 MW and were required to connect at a distribution voltage. Because of their smaller size, distribution projects fit into more locations on the electric system. Thus, these projects were evaluated on the impact that they would make on a single circuit or on a single substation. Once the Proposal location was known, the analysis of electrical impact could begin. Distribution Proposals were also evaluated for their power flow impact on the transmission system. The same report document outline used for transmission was also used for distribution, but the smaller sizes of the distribution Proposals led to differences in analysis content and emphasis.

2. Distribution Analysis Process

The Distribution evaluation team had only four Proposals to evaluate. Coupled with the smaller amount of required analysis, this resulted in a significantly smaller workload. To assist in providing guidance for the Distribution team, the IA participated in team meetings approximately every other week. Discussion topics were prepared by the IA, which led to specific assignments and follow up items.

The overall analysis process, despite its smaller scope, was quite similar to that followed by the T&D Team. For example, the distribution analysis process was driven by the documentation requirements of the analysis template. The Distribution team was the first to thoroughly test the viability of the analysis document format.

L. VERIFICATION OF COST ANALYSIS RESULTS

One of the IA's critical responsibilities was ensuring that all MPs were treated justly and evenly. Additionally, the analysis process needed to align with industry standards and conform to normal evaluation processes used by Duke. The verification process began once all bid evaluation results were available. In mid-April 2019, the IA sent a request for in-depth verification data to both the Transmission and Distribution analysis teams, and the subsequent verifications occurred separately.

TRANSMISSION ANALYSIS VERIFICATION

As a part of the verification process, the Evaluation teams, through the IA, made informational requests of the MPs and used their responses to develop transmission network upgrade costs specific to each individual bidder. These requests were organized to investigate three main issues: Basis for Standard Costs, Testing of Load Flow Results, and Distribution Factor Validation.

1. Basis for Standard Costs

A review of the standard cost units applied to the network upgrade costs for the individual Proposals showed that "Modify Relay and Communication Equipment" was by far the most used cost. Thus, it was selected as the unit for more in-depth analysis.

DEP transmission Proposals did not have any upgrade cost adders for the two Proposals analyzed. Therefore, the focus was on DEC for this analysis. In the 12 winning DEC Proposals, the cost for communication equipment applied to the Proposals differed as follows:

- 4 Proposals connecting at 100 kV had costs of $225 K
- 1 Proposal connecting at 44 kV had a cost of $192 K
- 6 Proposals connecting at 100 kV had costs of $450 K

A request was made of the T&D Team to provide an explanation of these differences. Their response is provided below:

Only 2 of the 12 bids (83-06, 83-07) had scoped estimates since they had completed Facilities Study (and an executed IA). The other 10 bids relied on the standard cost template—for which there isn't really a "standard" cost when it comes to relay/communication modifications since those are project and station specific. The per station estimate in the standard cost template is high more often than not but does not exceed the per station estimate associated with 83-07. Furthermore, some of the bids are on radial lines and others are on network (or network capable) lines, which influences the number of stations to which project may need communication. For the purpose of CPRE, a $225 K estimate is indicative of communication needs to a single station, whereas a $450 K estimate is indicative of communication needs to two stations. Any other estimates are indicative of a scoped estimate rather than an estimate based on the standard cost template.

As solar projects completed Facilities Studies, the relay/communication modification estimates likely lowered as a result of having more points of data. Nonetheless, any estimate was subject to project/station specific variance that could not be determined until detailed scoping and estimating has occurred, which did not happen until after a System Impact Study was performed. Recent Facilities Study Estimates are provided in Figure 38.

Figure 38

Queue #	Estimate
NC2017-03020	$73,569
NC2017-03020	$73,569
NC2017-03016	$52,728
NC2017-03016	$52,728
NC2017-03009	$57,380
NC2017-03009	$72,702
NC2017-02981	$25,742
NC2017-02981	$25,742
NC2017-02980	$38,924
NC2017-02980	$38,924
NC2016-02976	$117,450
3164	$96,689
3164	$126,241
3164	$110,437
8346	$141,620
10191	$117,321
10191	$100,120
10191	$83,274
42690	$95,508
42690	$95,855
42696-01	$423,844
42893-01	$76,520
42893-01	$42,435

The above explanation speaks to the variability of communication costs and showed that in many cases modifications were needed at multiple stations. The table provided illustrates actual data was variable but within the range of the standard cost for the "Modify Relay and Communication Equipment Standard".

2. Testing of Load Flow Results

A second area that was identified for more intensive investigation was the load flow results for two Proposals, one Proposal (143-05) that was selected as a winning bid and one Proposal (234-02) that was not selected as a winning bid. A request was made by the IA to provide the load flow results for Proposal 143-05. An excerpt of the provided load flow is shown in Figure 39.

Each line of the table contains information associated with an identified contingency; the green area includes Proposal 143-05, and the blue area contains the base case data. The "% Diff" column contains a calculation that provides a delta between the individual contingencies with and without the addition of the generation addition of Proposal 143-05. Note the little difference and thus little system impact as a result of the addition of this Proposal.

Figure 39

2021s CPRE 143-05						2021s CPRE Base					
New Rating	Rating	Pre-Cont	Post-Cont	Percent	Occurrences	Rating	Pre-Cont	Post-Cont	Percent	Occurrences	% Diff.
117	117	95.3	106.3	90.1	-	-	-	-	-	-	-
24.2	24.2	10.9	21.9	90.3	-	24.2	10.9	21.9	90.3	-	**0**
42.9	42.9	19.4	39.4	91.7	-	42.9	19.4	39.4	91.7	-	**0**
42.9	42.9	19.3	39.4	91.8	-	42.9	19.3	39.4	91.8	-	**0**
85	85	38.3	78.6	92.5	-	85	38.3	78.6	92.5	-	**0**
85	85	38.3	78.6	92.5	-	85	38.3	78.6	92.5	-	**0**
84	84	39.1	78.6	93.6	-	84	39.1	78.6	93.6	-	**0**
84	84	39.1	78.6	93.6	-	84	39.1	78.6	93.6	-	**0**
22.9	22.9	10.4	21.9	95.8	-	22.9	10.4	21.9	95.8	-	**0**
42.1	42.1	23.6	40.6	96.4	-	42.1	23.6	40.6	96.4	-	**0**
183	183	70.9	167.1	91.3	-	183	70.9	167.1	91.4	-	**0.1**
129	129	74.4	119.8	92.1	-	129	74.5	120	92.3	-	**0.2**
41.6	41.6	25.9	39.6	95.1	-	41.6	25.9	39.6	95.3	-	**0.2**
41.9	41.9	28.8	41.8	99.7	-	41.9	28.8	41.8	99.9	-	**0.2**
292	292	154.2	266.7	90.4	-	292	155	268.1	90.9	-	**0.5**
292	292	154.2	266.7	90.4	-	292	155	268.1	90.9	-	**0.5**
85	85	38.3	78.2	92	-	85	38.3	78.6	92.5	-	**0.5**
84	84	39.1	78.2	93.1	-	84	39.1	78.6	93.6	-	**0.5**

The losing Proposal, 234-02, was also examined for analysis accuracy. A report produced by the T&D Team shows the comment below for Proposal 234-02:

> *The tap line that 234-02 (83-10) and 336-03 are proposed on cannot accommodate both projects. If both projects are built, the project deemed to have the later queue position or to be less favorable will have to upgrade nearly 5 miles of 100 kV with an assumed cost on the order of $7.5 MM. Either project is also subject to constraints that have been identified on the DUK/SCEG interface that would require an Affected System Study with SCEG to determine potential adverse impacts on a neighboring system. The upgrades on the DUK side of the DUK/SCEG interface cannot be completed by 7/21.*

The requested load flow results for this Proposal, which are included below, illustrate the overload condition.

Figure 40

Monitored Element		Contingency	Limit	FlowInit	
306001 3CLARK H 115 308584 3BIGCOWHEADP 115 1		CLARKHILL-JST_MCCRMCK	119	217.5	Clark Hill 115 kV
309800 3MCCORMICKPV 115 339150 3JST-SC 115 1		CLARKHILL-CH_BGCWHD	119	217.5	Clark Hill 115 kV
306242 BUSH RIV 100 308226 NEWBERRYPV(A 100 1		CLINTONB_ANGSB	65	106.7	Champion 100 kV
306242 BUSH RIV 100 308579 TRINITYPV 100 1		CHAMPIONWH-BR_NWBRRY(D)	146	234.8	Champion 100 kV
306232 3BUSH R 115 307892 3NWBYC6 115 1		NEWBERRYWA	79	123.5	Newberry 115 kV

The results shown on line 5 at the bottom of the chart indicate that the Newberry – Bush River 115 kV line would be overloaded following the addition of this Proposal.

3. Distribution Factor Validation

The previous section discussed the application of the distribution factor, specifically how any distribution factor over 3% was an industry accepted indicator of significant contribution. Continuing with the analysis of failed Proposal 234-02, the IA requested distribution factor calculation results for the Newberry - Bush River 115 kV line. The chart below shows the distribution factor calculation results for each of the five lines shown in the table above.

M. STEP 2 PROCESS CONCLUSIONS

Based upon the entire body of work that was required to complete the system upgrade cost analysis for both transmission and distribution Proposals, the following conclusions are offered:

- The analysis process was the same for all bidders, being evenly and fairly applied to all Proposal s
- The T&D Team successfully adopted the standard Proposal cost analysis report format suggested by the IA. Modifications were identified by the team and were incorporated into the final document. These modifications were made to tailor the format to Duke requirements and standard practices.
- All T&D Team members worked well and focused on the tasks required to produce Proposal cost analysis results in a timely manner. Sufficient resources were available to complete the required tasks.
- The IA felt that communication with both teams and with the Account Managers was open and honest with a joint dedication to achieving quality and timely results.
- The verification tests proposed by the IA demonstrated a firm foundation for accurate cost analysis.
- CPRE tranche 1 was an excellent learning experience. Participants were open to suggested modifications in approach and were willing to attempt alternative solutions. The resulting analysis process will serve as a solid foundation going forward.

XII. SUBJECT MATTER AREAS

A. LEGAL TEAM REVIEW

The IA's legal team performed several tasks for Tranche 1 of the CPRE program. Prior to Proposal submission, the legal team prepared a Site Control Acknowledgement Affidavit. Following the Proposal closure date, the Legal Team reviewed the following documents for completeness: Site Deed, Site Lease, Site Control Acknowledgement, Title Insurance Copy, Title Insurance, Title Insurance Report, Boundary Survey, Description of the Site, Easements, Environmental Students, Facility Descriptions, Facility Permits, Other Permits, the Project Map, Project Map with Landmarks, and the Sitemap.

A compilation of this review was organized and submitted to the IA. Based on the Legal Team's review of the documents, the Proposals were scored by category as follows: permitting will be complete at the commercial operations date, project site control for the full term, and site control to the point of the interconnectivity. The Legal Team reviewed the above documents again for accuracy and to determine how they scored. A large portion of the Legal Team's time during the scoring process was spent reviewing easements for the transmission path and looking at leases and deeds to verify control coincided with the duration of the project.

B. FINANCIAL TEAM REVIEW

The Financial review conducted for CPRE Tranche 1 evaluated the credit-worthiness factors identified in the RFP (see Appendix F, item 6 – "Credit Worthiness"). The purpose of the financial review, as stated in the RFP, was to determine the "financial assurances to meet schedule and milestones in PPA." The credit worthiness of a Proposal was assigned five percent of the Proposal score, equal to 50 points of the total maximum score of 1000 points.

The financial review compiled information from the Proposal including information regarding ownership, plans for Proposal and performance security, and credit ratings. The Financial Review was conducted on all Proposals that advanced to the Step 2 evaluation. Given that Proposal security was required for all third-party Proposals that were advanced to the Step 2 evaluation, Duke's credit requirements and potential damages were secured by the Proposal security:

> *Proposal Security Amount represents a fair and reasonable pre-estimation of the damages due to Duke Energy..." and "represents a reasonable estimate of Duke Energy's losses in the event of (i) Bidder's withdrawal of the Bid following its selection for further evaluation in the Step 2 Evaluation Process, or (ii) Bidder's failure to execute the Agreement with Duke Energy for the Bid if selected as a winning Proposal or failure to provide Performance Assurance as required under the Agreement.*

The Financial Review assigned points based on the method of Proposal security selected by each MP advanced to the Step 2 evaluation. Credit-worthy MPs were assigned the maximum score (50 points). Non-credit worthy MPs were evaluated based on the various forms of Proposal security (cash, Letter of Credit, or Surety Bond) submitted to ameliorate credit risk. A non-credit worthy MP who posted cash for the Proposal security was assigned 50 points. A non-credit worthy MP who posted a Letter of Credit or a Surety Bond for Proposal security was assigned 45 points. Bidders who dropped out of Tranche 1 for failure to post Proposal security or for other reasons were not evaluated.

C. PROJECT SUFFICIENCY TEAM REVIEW

The IA Project Sufficiency Team was responsible for performing a detailed technical evaluation of each Proposal. The technical evaluation included a complete review of the project design and equipment specifications as well as a review of the experience of the MP's Project Team. This due diligence review was completed to confirm that any project the IA recommended for a PPA was technically capable of providing the service proposed.

To begin the evaluation, the PST reviewed each submitted Proposal form and identified the "pre-coded" data fields in the on-line Proposal form needed for evaluation of the project. The IA created an Evaluation File system, which was then used to develop a file repository for the PST evaluation of individual Proposals. The "Custom Reports" tool on the IA website was utilized to draw relevant data from each submitted Proposal.

The PST developed five custom reports:

1. Generating Facility (technical description of the site)
2. Solar Design (design and equipment specifications)
3. Storage Design (design and technical specification)
4. Project Status Summary
5. Proposal Summary

The PST also reviewed documents uploaded to the CPRE website by MPs, which included:

- Description of the project site
- Facility Description
- Inverter Warranty
- Operations (project costs)
- Project Map
- PV Ongoing Maintenance
- Single Line Drawing
- Site Map
- Site Plan
- Solar Information
- Specification Sheet (solar panels)
- Storage Spec Sheet
- Storage Experience
- Renewable Facilities Experience

In its initial examination, the PST reviewed each Proposal and its associated uploaded documents to determine whether the response was "complete and conforming," that is whether it provided all of the required information and met the RFP criteria. The PST found a number of deficiencies or questions about the project design. For example, some of the MPs entered the total installed DC rating in MW DC instead of kW DC. In some instances, data entries were left blank or the information that was entered required clarification. In each case where deficiencies or questions were noted, the PST posted messages to the MP's confidential Message Board providing the MP the opportunity to cure or clarify the information provided. Ultimately, all of the submitted Proposals were corrected and deemed conforming. No Proposals were rejected in the initial review and no Proposals were withdrawn by an MP.

Following the preliminary ranking of complete and conforming Proposals, the PST proceeded through its evaluation in the Initial Tier Ranking order. All Proposals were reviewed for the sufficiency of the project, with projects receiving a full technical review as they were included in the Competitive Tier. This approach permitted the best-ranked Proposals to proceed to the Step 2 review without delay, and those drawn from the Competitive Tier Reserve were reviewed sequentially.

The PST completed the relevant sections or subsections of the Sample Scoring Sheet for each of the Proposals. The PST addressed the following subsections: Experience of the Project Team, Equipment to be used, Required Control Equipment, and Quality of Project Design. A complete breakdown of scoring requirements can be found in Appendix F of the RFP.

XIII. ACQUISITION PROCESS AUDIT

A. OVERVIEW

The IA conducted an audit of the CPRE Tranche 1 Asset Acquisition program. The Asset Acquisition program was designed for Duke to acquire Renewable Energy Resources consistent with the CPRE requirements to be developed through either a Renewable Resource Asset Transfer plus Engineering Procurement and Construction ("EPC") agreement, a Build Own Transfer ("BOT") agreement, or a Renewable Resource Asset Transfer Agreement. The DEP/DEC team could submit Proposals [16] chosen to be sponsored from the Offers presented on the AA Silo of the IA Website, and projects to be developed directly by Duke. Proposals for direct development by Duke were required to be submitted no later than October 8, 2018, which was at least one day before other MPs. The deadline for developers to submit Asset Acquisition Proposals was October 9, 2018. Asset Acquisition Proposal were evaluated by the DEP/DEC team and if selected, were converted by the DEP/DEC Team into a $/MWH price that was evaluated by the IA in the same exact same manner as other PPA proposals. The DEP/DEC team was required to submit its sponsored Asset Acquisition proposal via the IA Website on November 16, 2018. The time between October 9, 2018, and November 16, 2018 was used by the DEP/DEC team to evaluate the Asset Acquisition Proposals.

Proposals for sponsorship by the DEP/DEC team were identified to the IA and the Proposal data was directly transferred to either DEC or DEP, as appropriate. This transfer avoided errors in the transfer of data and ensured that each sponsored project was evaluated with data presented to the DEP/DEC team by the developer.

The DEP/DEC team selected five projects Duke would agree to acquire and sponsor in CPRE. Once submitted on the IA Website by the DEP/DEC team, the sponsored projects were evaluated using the same standards as all other Proposals. The IA's initial ranking of Proposals was adjusted once the sponsored projects were received and evaluated.

The AA Audit focused on the review of the design and execution of the Duke AA program. The review of the Duke Evaluation process included meetings with the Duke DEP/DEC Team to confirm the data collected on the IA Website was consistent with the information necessary for the DEP/DEC team to review offers from developers during the development of the on-line Proposal Form and after offers from developers. The criteria used by the IA in the review of the Asset Acquisition Offers included confirming the Offer was in compliance with CPRE, whether the Offer would meet the Required Commercial

[16] To avoid confusion, "Proposal" is used for projects submitted in DEC or DEP. "Offer" is used for projects submitted for acquisition consideration.

Operating Date ("RCOD"), and whether the project was capable of operation within the CPRE requirements

MPs were permitted to propose a project for a PPA and also to be acquired by Duke. Part of the IA's review included comparison of the five Duke-sponsored AA Proposals that were sponsored with the PPA submissions by MPs of the same projects. In every case when a project was proposed for a PPA by a developer and also submitted as a sponsored project for acquisition, the Duke-sponsored Proposal was found to provide greater Net Benefit.

B. AUDIT OBJECTIVE

As a requirement of the Duke CPRE Tranche 1, the IA performed an audit of the Duke Asset Acquisition Offer evaluation, assessment, and selection process. This audit was to determine whether the offers submitted to the Duke DEP/DEC team were complete and compliant with the CPRE requirements for eligibility. Further, IA reviewed the projects selected for acquisition to determine whether the DEP/DEC team materially modified the projects before submitting them into the CPRE program.

MPs could elect to submit Proposals for a PPA to DEC or DEP, as an Asset Acquisition Offer conforming to one or more of the AA structures, or the MP could offer a project as both seeking a PPA and an Asset Acquisition Offer. Twenty AA Offers were submitted in the CPRE Tranche 1. Figure 41 summarizes the submissions.

Figure 41

	Asset Transfer with EPC	Build Own Transfer ("BOT")	Asset Transfer
Proposed	9	7	4
Sponsored (DEC)	3	0	0
Sponsored (DEP)	0	2	0

C. THE AUDIT

Subsequent to the submission of projects being sponsored for acquisition, the IA Audit team met with members of the DEP/DEC team for the purpose of reviewing the selection process. The review included review of the criteria for selection, identification of the ranking of each offer, why certain projects were not selected for acquisition, identification of any design change requested by the DEP/DEC team, and final contracts with each project selected for acquisition.

Duke provided the following information to the IA:

- Evaluation Methodology Overview: described the process implemented to review, evaluate and rank all AA Offers received. This included non-economic (technical) and economic evaluation criteria.
- Assessment process summary: rank ordered the 20 AA Offers.
- Selection process for each of the five sponsored AA Offers.
- A summary of Capacity Cost in normalized $/MW AC, Total Energy in MWh, and COD for the 5 sponsored projects.

The IA also reviewed the non-economic and economic evaluation criteria used in evaluation and scoring for each of the 20 AA Offers and found the criteria to be appropriate.

1. DEP/DEC Team Evaluation Methodology Overview

The DEP/DEC team developed an evaluation process to review, evaluate, and rank the AA Offers. This process included both a technical (non-economic) evaluation and an economic evaluation with detailed criteria and a point system to score each Offer. The technical evaluation was used to assess the Offers to determine if the Offer met development, technical, and quality standards. An economic evaluation was conducted only if the Offer passed the technical evaluation.

The criteria for the technical (non-economic) evaluation included:

a. Status of site control
b. Quality of system design (optimal DC/AC ratio, NCF, constructability)
c. Design standards meet DEC/DEP requirements
d. Zoning and entitlements/community outreach
e. Site investigation/environmental studies
f. Project schedule
g. MP experience
h. Status of interconnections

Each of the non-economic criteria had a ten-point scoring system. All scores were multiplied by five, with a total of 400 points available. A minimum score of 200 points was required for the non-economic evaluation. If the resulting score was less than 200 points, the Offer was eliminated, and an economic evaluation of the Offer was not conducted. If the Offer's score was greater than 200 points, a detailed economic evaluation was conducted.

The DEP/DEC team conducted financial modeling using inputs such as project capex, project production estimates, and project operations and maintenance cost. The economic evaluation was assigned a maximum point score of 600 points and the Offers were ranked based on the combined non-economic and economic score of the Offer. The offers for acquisition by BOT or EPC were compared side by side. The DEP/DEC team considered project risk, including but not limited to environmental risk, development risk, construction risk, cost and schedule risk. Eight Proposals did not pass the non-economic evaluation and were eliminated.

The final Offer selection was based on the combined economic and non-economic evaluations. The Duke AA Evaluation Methodology was comprehensive and balanced. The CPRE guidelines included examples of technical scoring criteria and the DEP/DEC team criteria were consistent with the CPRE program guidelines. The non-economic criteria for the technical evaluation, including the weighting and the scoring, were reasonable and appropriate to meet Duke's specification, standards, and quality for a Company-owned asset. The scoring and weighting were similar to the scoring and weighting used by the IA in evaluating and ranking the PPA Proposals; in both cases the non-economic scoring had a 400-point maximum score and the economic score had a 600-point maximum. The AA evaluation criteria were applied consistently to each of the 20 AA Offers.

2. Assessment Process

The DEP/DEC team created individual Excel spreadsheets to document the evaluation and scoring of each Offer. DEC received a total of six Offers and DEP received 14. From the 20 individual spreadsheets the IA prepared a summary Excel spreadsheet of the 20 AA Offers in rank order that included the Offer scoring, the disposition of the Offer, and highlights (notable deviant scores) of the reasons for the disposition of the Offer. The Offers were ranked and scored as follows:

Figure 42

DEC					
Masked Offer #	**Non-Economic**	**Economic**	**Total**	**Observations:**	**Disposition**
111-11	210	420	630	Secured proper zoning and permits (2/10) - Status of Interconnection (0/10) - Economic (7/10)	project was sponsored
111-12	265	360	625	Economic Criteria (6/10)	project was sponsored
111-13	260	300	560	Status of interconnection (0/10) - Economic Criteria (5/10)	project was sponsored
111-14	250	120	370	Economic Criteria (2/10)	project was not selected to be sponsored
111-15	190	N/A	190	Site Investigation - Interconnection - Economic - (0/10) -	project did not pass non-economic evaluation
111-16	135	N/A	135	Site Control - Quality of system - Zoning Permits - Site Investigation - Interconnection Study - Economic Criteria - (0/10) -	project did not pass non-economic evaluation

Figure 43

DEP					
Masked Offer #	**Non-Economic**	**Economic**	**Total**	**Observations:**	**Disposition**
11-1	200	480	680	Zoning permit - Site Investigation - Interconnection status -(0/10)- Economic Criteria (8/20)	project was sponsored
11-2	295	360	655	Interconnection Status (0/10) - Economic Criteria (6/10)	project was sponsored
11-3	250	300	550	Interconnection Status (0/10) - Economic Criteria (5/10)	project was not selected to be sponsored
11-4	300	240	540	Project Schedule (0/10) - Economic Criteria (4/10)	project was not selected to be sponsored
11-5	325	180	505	Economic Criteria (3/10)	project was not selected to be sponsored
11-6	275	180	455	Project Schedule (0/10) - Economic Criteria (3/10)	project was not selected to be sponsored
11-7	210	240	450	Interconnection Status (0/10) - Economic Criteria (4/10)	project was not selected to be sponsored
11-8	225	180	405	Zoning permit - Site Investigation - Interconnection Status - (0/10) - Economic Criteria (3/10)	project was not selected to be sponsored
11-9	190	N/A	190	Site Control - Site Investigation - Project schedule (0/10)	project did not pass non-economic evaluation
11-10	175	N/A	175	Site Control - Site Investigation - Interconnection Status - (0/10)	project did not pass non-economic evaluation
11-11	175	N/A	175	Zoning Permit - Interconnection Status - (0/10) - Site Investigation (2/10) - Quality of system (3/10)	project did not pass non-economic evaluation
11-12	175	N/A	175	Zoning Permit - Interconnection Status - (0/10) - Site Investigation (2/10) - Quality of system (3/10)	project did not pass non-economic evaluation
11-13	125	N/A	125	Site Control - Quality of System - Zoning Permit - Site Investigation - Interconnection Studies - (0/10)	project did not pass non-economic evaluation
11-14	125	N/A	125	Site Control - Quality of System - Zoning Permit - Interconnection Status - (0/10)-	project did not pass non-economic evaluation

Since the evaluation was completed in a step function process where projects were eliminated due to the non-economic factors and only the technically viable projects were advanced to the economic evaluation, there was no need to re-rank the projects. There was no single criterion that eliminated an Offer, but rather a number of criteria that varied for each Offer contributed to an Offer's elimination. Eight projects were eliminated because they did not pass the minimal 200-point score in the non-economic evaluation. Of those eight projects, project site control and zoning was a common factor for their elimination. Of the remaining 12 Offers, 7 were not selected to be sponsored primarily because the project economic evaluation resulted in less competitive pricing. A total of 5 projects were selected to be sponsored: 3 projects in DEC and 2 projects in DEP.

The DEP/DEC team indicated that the only design changes or modifications made from the initial Offers were inverter selections. All MPs included non-company approved inverters in their original interconnection application, and the five Duke-sponsored Proposal MPs were informed that the inverters would need to be updated. The IA conducted a review and comparison of the Duke-sponsored Offers and the corresponding MP PPA and affirmed that there were no apparent design changes or modifications from the initial Offers, except for 11-1.

In response to the IA's inquiry as to why the Self-Build team selected only five projects, the Self-Build team indicated that there was a total capital investment that was authorized for CPRE Tranche I participation (self-build proposal and sponsored asset acquisition Offers) and sponsoring more than the five would have increased the likelihood of exceeding the authorized capital. The authorized amount was not requested by or shared with the IA.

3. Selection Process

Figure 44 presents the five Duke-sponsored Proposals. [17]

Figure 44

Proposal #	Total Energy (MWh)	COD
	DEC	
111-11	159,546	12/31/2020
111-12	129,670	12/31/2020
111-13	166,675	12/31/2020
	DEP	
11-1	196,557	12/31/2020
11-2	205,041	12/31/2020

As stated above, each of the five Duke-sponsored Proposals had a corresponding and competing PPA Proposal from a Market Participant for the same facility. There was no requirement in the RFP for an MP to offer the same facility design in its PPA Proposal for a specific facility, nor was there a requirement

[17] Proposal numbers are "blinded."

that an MP offer a PPA Proposal corresponding to its AA Proposal to Duke. In this instance, there was a corresponding PPA Proposal for each Duke-sponsored Proposal.

With the exception of one of the five Duke-sponsored Proposals, which will be discussed later, the IA determined that each Duke-sponsored Proposal was essentially consistent in design and anticipated performance with the corresponding MP PPA Proposal for the same facility. This review was accomplished through several steps including:

- Review of the AA Silo on the CPRE website (submission documents, cure documents, correspondence, etc.);
- Review of the materials provided to the IA by Duke personnel in response to this Audit;
- Comparison of the Proposal Forms for each Duke-sponsored Proposal with the Proposal Form for its corresponding MP PPA Proposal; and
- Review and comparison of the annual energy, load profiles, capacity, and capacity factor of each Proposal.

In this analysis the IA compared the essential components of each of the five "pairs" of the Duke-sponsored and the corresponding PPA Proposals. The purpose of the analysis was to determine any differences between the Duke-sponsored Proposals and the corresponding MP PPA Proposals since each was derived from the same facility.

The IA reached four conclusions from the analysis of Duke-sponsored and MP PPA pairs. First, in four of the pairs, the Duke-sponsored Proposal had a significantly higher Net Benefit than its corresponding MP PPA Proposal. Given that the capacities, capacity factors, and energy profiles were virtually identical with each pair, the difference in Net Benefit was entirely explained by the lower prices offered in the Duke-sponsored Proposal.

Second, in the fifth pair, the capacity of the Duke-sponsored Proposal and the MP PPA Proposal was consistent. However, the Net Benefit of the Duke-sponsored AA Proposal was greater than the MP's PPA Proposal. The IA sought to understand why there was a larger pricing differential in this pair versus the other four pairs.

Third, the IA analysis of the fifth pair concluded that the energy and capacity benefits showed that the "raw" benefit (costs avoided by the Proposal) on a $/MWh basis was virtually identical for both the Duke-sponsored Proposal and MP PPA Proposal. The total annual energy for the Duke-sponsored Proposal for this facility was 7% greater than the annual energy projected by the MP PPA for the same facility, thus providing an explanation of the greater pricing variance for the Duke-sponsored Proposal in this pair as compared to the pricing variance for the other four pairs in which the Duke-sponsored Proposal included the same quantity of energy as its corresponding MP PPA Proposal.

In summary, the energy profiles of the fifth pair were nearly identical resulting in nearly identical $/MWh benefits for this pair regardless of the scale of the energy. The IA concluded that the higher quantity of energy in the Duke-sponsored Proposal reasonably explained the greater pricing differential in this pair as compared to the pricing differential in the other four pairs.

D. AUDIT CONTRACT REVIEW

The IA reviewed the status of contracts for each of the sponsored Proposals when the IA met with the DEP/DEC team and confirmed there were no binding commitments between the DEP/DEC team and the relevant developers. The DEP/DEC team confirmed that MPs were asked to submit a redline copy to the standard agreements provided in the RFP along within their AA Proposals. The DEP/DEC team confirmed that they had reviewed all redlined documents provided with Offers and would commence final contract negotiations when it was known if a sponsored Proposal was selected as a finalist.

The IA also reviewed the AA Silo of the Website for review of contract communications. This included communications in writing on the Message Board and communications contained in cure documents uploaded by the MPs. The written messages included the scheduling of, and action items from, several telephone conference calls between the parties. [18]

The IA Website clearly documented and preserved all such information exchanges and negotiations between Duke and MPs regarding such topics as:

- Commercial details including progress payments in the asset transfer contracts to establish the final negotiated $/kW price of each Proposal
- PVsyst [19] input/output forms
- Reference projects of similar or greater size than the proposed project
- Development and construction scope to be performed in-house and to be subcontracted by the MP
- Complete and detailed financial information on the MP and its financing partners
- The existence of a Fee-in-Lieu-of-Taxes ("FILOT") agreement in place with the authority having jurisdiction [20]
- An unredacted version of the lease agreement to allow Duke to confirm the structure of the lease

Based on this review, the IA concluded that communications between Duke and the MPs were well documented, unbiased, and consistent with Duke's evaluation and ranking of Proposals.

E. ACQUISITION AUDIT CONCLUSIONS

The Duke AA Evaluation Methodology was a comprehensive and balanced process. The Proposals submitted by the DEP/DEC team were compliant with the requirements of the CPRE program. The evaluation criteria were applied on a consistent basis to each of the 20 Asset Acquisition Offers submitted. The non-economic and economic criteria, as well as the weighting and the scoring, were reasonable and appropriate to meet Duke's specifications and standards for a Company-owned asset. Duke's scoring and weighting were similar to the scoring and weighting used by the IA in evaluating and ranking the PPA

[18] Duke offered to share meeting notes from the telephone conference calls if the IA requested them.

[19] PVsyst is a solar photovoltaic preliminary design tool for use by architects, engineers and researchers.

[20] Duke stated that such an agreement is integral to determining whether the project meets Duke's economic and project schedule requirements.

Proposals. In both cases the non-economic scoring had a 400-point maximum score and the economic score had a 600-point maximum. The five Proposals with the highest combined non-economic and economic scores were selected to be sponsored by Duke.

The DEP/DEC team provided the opportunity for comments on draft form agreements at the time MPs submitted projects for acquisition. The DEP/DEC team did not have non-negotiable pro-forma agreements for developers, as was done with the pro-forma PPA for the DEP and DEC solicitations. Similarly, there was no binding letter of intent or MOU that bound the MP to abide by the form agreement or hold their asset acquisition bid price. That shortcoming was highlighted when one MP withdrew the Offer behind a Duke-Sponsored Proposal on June 26, 2019: 12 days before the end of the contracting period. Because there was no binding commitment, the developer was not penalized for withdrawing the Offer, and the DEP/DEC team was without recourse to enforce the commitments received from the developer. As identified in the "Lessons Learned" section above, the IA and Duke will recommend improvements to the Asset Acquisition structure, such as a letter of intent or MOU between Duke and the developer of an Asset Acquisition project that will improve the certainty and clarity of the process.

XIV. FINALISTS

Twelve Proposals were selected as winners for DEC at the end of Step 2 on April 9, 2019. The projects ranged from seven MW to 80 MW for a total group of selected proposals totaling 515 MW. Two of those selected Proposals included storage. On July 8, 2019, one of the 12 winning Proposals for DEC withdrew. The identity of the MPs that withdrew are identified in Confidential Attachment 1.

After being selected as a finalist for DEC, one of the MPs indicated a desire to amend the PPA price bid due to changes in the cost of materials. The IA declined to permit the change. Subsequently the MP asserted the desire to withdraw claiming that Duke personnel affirmatively declared that the interconnection for the associated project would not be completed in time to meet the in-service date the MP identified in its Proposal. The claim was erroneous. The MP defaulted by failing to complete the PPA proffered by Duke. With both requests for the right to withdraw the MP requested release of the Proposal security. The IA declined to support the release of the Proposal security. At that time there were no longer any competitive and available Proposals in DEC to consider as a replacement. Therefore, the final result for DEC from Tranche 1 of CPRE is 464.5 MW of renewable capacity.

Three Proposals were quantified as potential winners in DEP at the end of Step 2. The RFP established that up to 80 MW would be selected, with the possibility of exceeding that amount by up to 5%. The selection of all three finalist Proposals would result in a total of 167 MW being selected, which was unacceptable. For this reason the IA recommended Duke accept two Proposals in DEP for a total of 87 MW. The best ranked Proposal was from a small project, which necessitated selecting the next best ranked Proposal in order to get close to the Tranche 1 goal for DEP. On June 26, 2019, Duke Energy informed the IA that the ultility self-developed Proposal (which was a conversion of an Asset Acquisition Proposal) that was selected as a winning Proposal in DEP was withdrawing along with another utility self-developed conversion of an Asset Acquisition Proposal. The reason for the withdrawal of the DEP Asset Acquisition Proposal is described in the report above, that is the developer and Duke were unable to agree on a final price for the project. The IA reviewed the ranking of DEP projects and immediately contacted the parties representing the next most competitive and available Proposal. They were able to proceed to contracting and executed a PPA within the timeline required by the RFP. Therefore, the final result for DEP from Tranche 1 of CPRE is 85.72 MW of renewable capacity.

XV. CONCLUSIONS

The Tranche 1 experience identified opportunities for improvement for Tranche 2. While an improved process should produce an even more robust response from the marketplace, none of the issues identified in this report should be understood to be a fatal flaw in the initial program design. Indeed, the IA believes Tranche 1 was successful in establishing a viable process for competitive procurement of resources.

The IA is hopeful that the Commission, Duke, and stakeholders will embrace the recommended changes presented as Lessons Learned, and further implementation of improvements before the Tranche 2 Proposal date.

APPENDIX A

APPENDIX A

SAMPLE PRICE SCORING SHEET

SCORING SHEET

Bid Scoring Categories	Bid Score	% of Bid Score	Description	Individual Categories	Maximum Scoring	Section Score
1. Price Score		60%	Includes fixed and variable bid costs	The price score will be calculated on the basis of the bid's projected total cost per MWH	600	
2. Project Development Criteria		15%	Respondent must show sufficient evidence of ability to provide services included in proposal for the contract term Evidence of operational capability to provide proposed services	-Demonstrate that permitting will be complete to meet COD -Experience of project team -Project Site control for full term -Site control to POI for full term	30 30 50 50	
3a. Facility Project Characteristics 3b. Transmission Project Characteristics		15%	Evidence of equipment designed to meet specifications Interconnection Transmission Rights	-Equipment to be used -Required control equipment (TBD) -Quality of project design -Submitted completed interconnected request and obtained a queue number	30 30 30 50	
4. Project Characteristics		4.5%	Value of Project Characteristics	Demonstrates ability to meet performance guarantee and liquidated damages pursuant to the PPA	45	
5. Historically Underutilized Businesses		.5%	Ownership by Minorities (to be defined)	Ascertain that at least 51% of venture is owned by eligible minority	5	
6. Credit Worthiness		5%	Financial assurances to meet schedule and milestones in PPA	-Confirms meeting all Duke credit requirements -Project financing confirmed -Bond rating -Net tangible worth -Liquidity	50 /or/ 20 10 10 10	
Total Score	1,000	100%			1,000	

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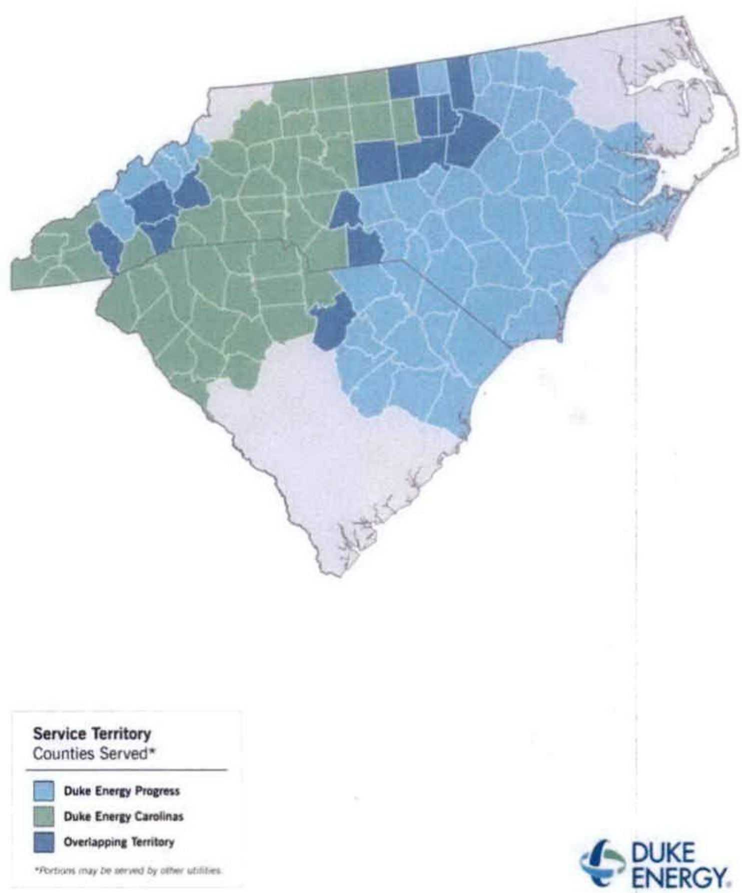
APPENDIX B
LOCATIONAL GUIDANCE

Overview

Duke Energy offers energy services to approximately 7.4 million customers in the Carolinas, Florida, Ohio, Kentucky and Indiana. The Carolinas area is comprised of Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). The DEC service territory is approximately 24,000 square miles and serves 2.5 million residential, commercial and industrial customers. Primary transmission voltages in DEC are 500kV, 230kV, 161kV, 100kV, 66kV, and 44kV. The DEP service territory is approximately 32,000 square miles and serves 1.5 million residential, commercial and industrial customers. Primary transmission voltages in DEP are 500kV, 230kV, and 115kV.

Carolinas Service Territory



APPENDIX B

Planning the Transmission System

The analysis performed by Duke Energy in planning the transmission system is based on good utility practice and NERC Reliability Standards. The analysis is performed to ensure reliable service can be provided to all customers considering that outage events (lightning, car accidents, equipment failure, faults, etc.) that cause transmission and generation elements to be removed from service can and do occur. Outage events can impact the voltage levels and the power flows on the transmission system in ways that would stress the system beyond its capabilities if the system were not properly planned, resulting in customer outages or poor power quality. Addition of new transmission and distribution connected load and generation requires ongoing analysis to ensure continued operation within limits. When analysis indicates limits will be exceeded, modifications or upgrades to the system must be identified to ensure continued reliable operation. The decisions to upgrade or modify system elements are made by applying reliability standards on an equivalent basis to all interconnection requests, and selected solutions to system issues are identified to minimize costs to the total body of Duke Energy customers.

When a new generation project requests transmission interconnection, Duke Energy is required to assess the impact of the new generation on the electric system. The assessment identifies locations where modification or upgrade of the transmission system will be necessary to maintain reliable service to all interconnected electricity customers, including consideration of possible outage events. The assessment includes the impacts of distribution-interconnected generation projects, which also affect transmission system loadings.

As a result of analyses performed to date, Duke Energy has identified areas where modification and upgrade of the system would be required if generator projects in the queue were to be interconnected. The areas where proposed projects have already indicated a need for transmission upgrades are identified on the constrained area maps. In other words, projects already under consideration, located in constrained areas, have resulted in demands exceeding the transmission grid capability and, if they are pursued to commercial operation, will require additional transmission capacity. Any new or additional transmission or distribution interconnection requests submitted in these constrained areas, after those currently in the queue for analysis, will possibly contribute to additional upgrade needs that may add project costs.

The need for transmission system upgrades is subject to the final disposition of the individual projects, i.e., whether or not they are pursued to commercial operation. Thus, the need for transmission system upgrades can be subject to change as additional projects are analyzed or individual projects decide not to continue with the interconnection process. Therefore, the identification of constrained areas should be considered a snapshot based on conditions known at the time. However, developers of potential projects in the identified constrained areas should be aware that there is a risk of additional transmission grid upgrades, which could result in additional costs and lead time requirements for the project. This would include distribution interconnected projects, which also impact transmission system loadings.

APPENDIX B

DEC Generator Interconnection Requirements - Overview

Transmission level projects participating in the DEC CPRE are likely to interconnect to either the 100 or 44 kV system. Unless a project is interconnecting directly to an existing 100 kV station, the project will interconnect via a tap to a single 100 or 44 kV transmission circuit. For 100 kV projects tapping a single circuit, this design will typically include a three-way gang operated air break switch in line with the main line and a breaker (or circuit switcher) on the tap line at the point of change in ownership. For 44 kV projects tapping a single circuit, this design will typically include a 4-pole bent in line with the main line, disconnect switches, and a breaker (or circuit switcher) on the tap line at the point of change in ownership. For both 100 kV and 44 kV projects, the design will include a transfer trip scheme for faults anywhere on the main or tap line.

Transmission level projects participating in the CPRE may be permitted to interconnect directly to an existing 230 kV station. Any 230 kV interconnections not directly into an existing station require the generation aggregated at a new station to exceed 120 MW.

For additional details, refer to the DEC Facility Connection Requirements located under Generator Interconnection Information at the DEC OASIS website[21].

Constrained Areas in DEC

For DEC, the constrained area map (Attachment 1) represents areas of the transmission system where there are either known transmission constraints that would be aggravated by increased generation or transmission constraints that are created by queued generation. These transmission constraints have been identified by either Transmission Planning or System Operations and have been confirmed through transmission studies of one or more generator interconnection requests. Transmission upgrades to mitigate the constraints already identified would exceed $10 million, and lead time is dependent upon the scope of work but would exceed 1 year, and possibly be as long as 3-4 years. Generator interconnection requests in areas not identified as constrained may also require transmission upgrades, but transmission studies are required in order to make this determination.

There are three constrained areas identified in DEC. In Guilford and Rockingham counties, off-peak conditions can drive post-contingency thermal loading issues on 100 kV lines that emanate from Dan River. Increased generation in these two counties will make the 100 kV lines in the Dan River area more susceptible to both off-peak and on-peak loading issues. The other two constrained areas shown are areas on DEC's system with the highest penetration of queued solar generation. The six county area near DEC's southern border including Newberry, Laurens, Greenwood, Abbeville and portions of Greenville and Anderson counties has over 1600 MW of queued solar generation. The other is a three county area

[21] https://www.oasis.oati.com/duk/index.html

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located near the DEC/DEP border including Chester, Lancaster and Union (NC) counties that has over 600 MW of queued solar generation.

A DEC constrained infrastructure list is available that documents the individual transmission lines and substations that are in the constrained areas.

Additional transmission line mapping information can be found at the Energy Zones Mapping Tool website[22].

DEP Generator Interconnection Requirements - Overview

To connect to the DEP 230 or 115 kV transmission system, a generating plant should be at least 20 MW in size. Plants between 20 and 100 MW will typically be tapped off a 230 or 115 kV transmission line. This design will typically include line switches added to the main line on either side of the tap, a single radial breaker in the tap line, and a transfer trip scheme for faults anywhere on the main or tap line. DEP will typically build and own the transmission tap line and the breaker station adjacent to the generator substation. To connect to the DEP 500 kV system, a generating plant must be at least 500 MW.

If the total generation at a single site (or within a one mile radius) exceeds 100 MW, then a full transmission switching station (e.g. a three-breaker ring bus) will be required. If the total tapped generation along an entire line exceeds 200 MW, then a full transmission switching station (e.g. a three-breaker ring bus) will be required somewhere on the line (location to be determined on a case-by-case basis considering specific local conditions). If a generating plant connects to a DEP switching station, the generator owner will typically build and own the radial transmission line from the generating plant to the DEP switching station.

For additional details, refer to the DEP Facility Connection Requirements located under Generator Interconnection Information at the DEP OASIS website[23].

Constrained Areas in DEP

For DEP, the constrained area map (Attachment 1) represents areas of the DEP transmission system where additional generator interconnections have a high likelihood (depending on ultimate development decisions) of causing transmission problems requiring significant, expensive, and long-lead-time transmission upgrades. The constrained areas were determined by Transmission Planning from prior studies and knowledge of the DEP transmission system. Generator interconnections in regions that are not identified as constrained are not guaranteed to be without transmission problems. Studies will

[22] https://ezmt.anl.gov/
[23] https://www.oasis.oati.com/cpl/index.html

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determine if there are any issues requiring transmission upgrades caused by generator interconnection requests in areas not identified as constrained.

In the greater Cumberland and Richmond County regions of North Carolina, extending across the state line into much of DEP's service territory in South Carolina, significant solar generation additions in the 2014-2017 timeframe, on both the transmission and distribution systems, have loaded the DEP transmission system to its limits. Any new generation in this area will cause transmission line overloads. Identified solutions exceed $100 million in transmission upgrades and would take at least 4 years to complete.

In the greater Brunswick County region of North Carolina, existing limits on the transmission system can cause limitations in operation of the Brunswick nuclear generators. These thermal and dynamic stability limitations require that the output of the Brunswick nuclear generators be substantially reduced following the outage of any one transmission line in the area. This includes forced outages or planned maintenance outages of transmission lines in the Brunswick County region. Any additional generation in this region would cause additional, unacceptable limitations in operation of the Brunswick nuclear generators without the addition of costly transmission solutions. The estimated cost of the identified transmission solution for this issue exceeds $100 million and would take at least 5 years to complete.

A DEP constrained infrastructure list is available that documents the individual transmission lines and substations that are in the constrained area.

Additional transmission line mapping information can be found at the Energy Zones Mapping Tool website[24].

Connecting Smaller Generators to the DEC and DEP Distribution Systems

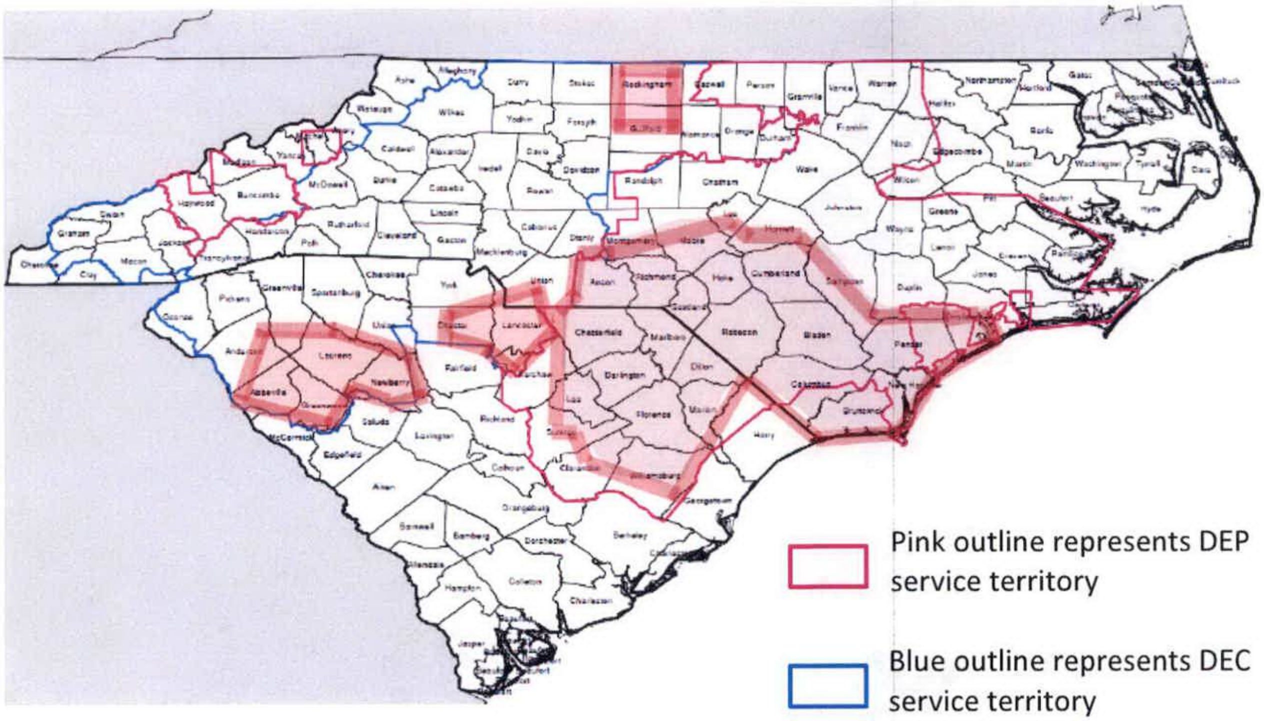
Guidelines for the connection of smaller generators to the DEC and DEP Distribution Systems are provided in the Duke Energy Method of Service Guidelines[25]. In general, projects between 10 and 20 MW may be able to connect directly to a retail substation depending the voltage class of the distribution circuit, the voltage class of the transmission line serving the retail station, and other specific local factors described in the guidelines. Projects less than 10 MW may be able to connect to a general distribution circuit depending the voltage class of the distribution circuit, the voltage class of the transmission line serving the retail station, and other specific local factors described in the guidelines.

[24] https://ezmt.anl.gov/

[25] https://www.duke-energy.com/home/products/renewable-energy/generate-your-own

APPENDIX B

Attachment 1
DEC and DEP Constrained Areas



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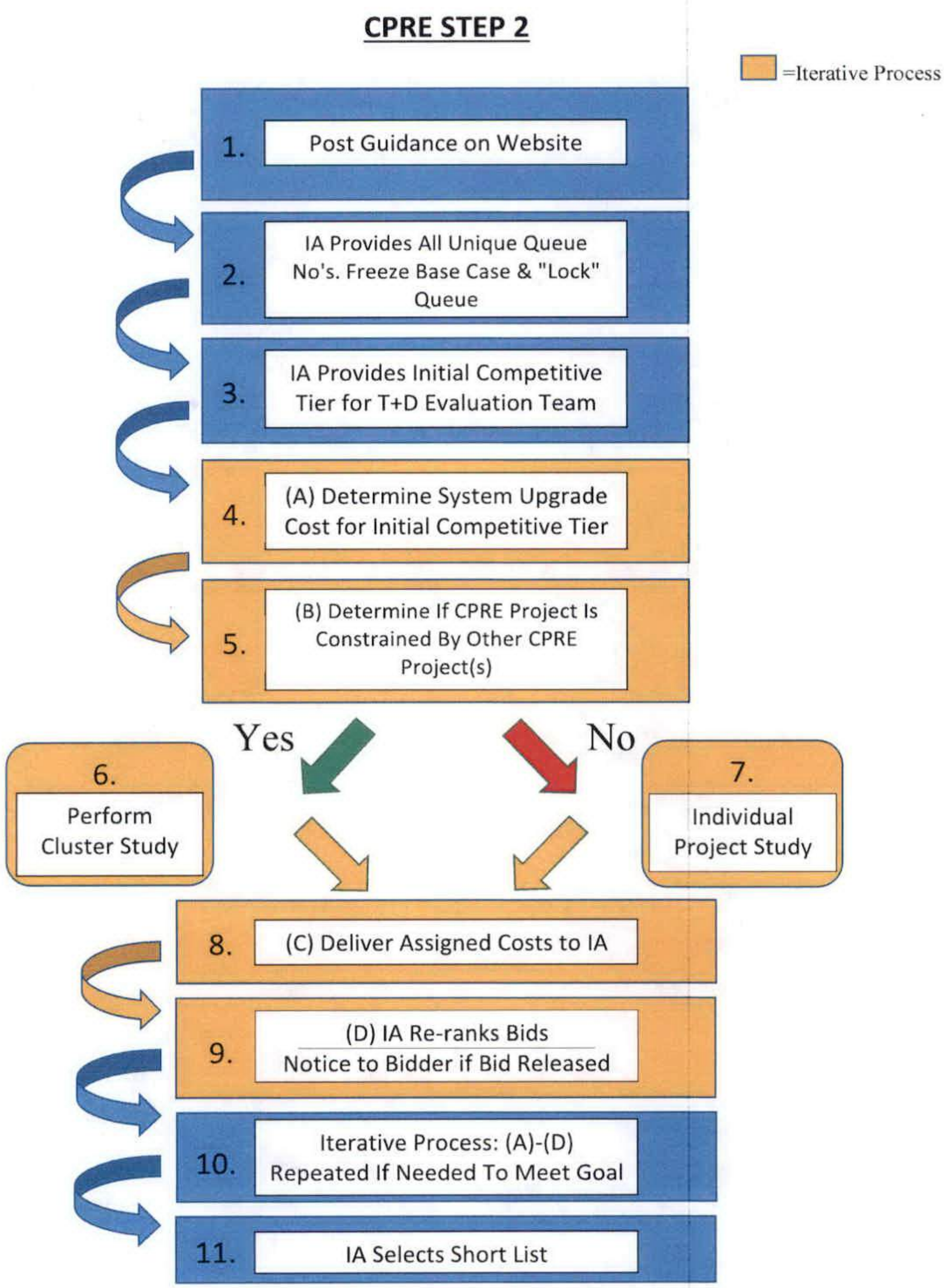
APPENDIX C
FLOW CHART OF STEP 2 ITERATIVE PROCESS



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ATTACHMENT 1

ATTACHMENT 1

TRANCHE 1 FINAL RESULTS

Report page 3

DEC

Proposal #	Contracting Party	Parent Company	Location	MWs AC	Storage Included ?
118-01	Partin Solar, LLC	Southern Current, LLC	Elkin, NC	50	
143-06	Carolina Solar Power, LLC	Duke Energy Renewables	Cleveland County, NC	50	
83-07	Duke Energy Carolinas, LLC	Duke Energy	Catawba County, NC	69.3	
60-01	X-Elio Energy SC York, LLC	X-Elio North America INC	York, SC	30	
57-23	Sugar Solar, LLC	Cypress Creek Renewables	Yadkinville, NC	60	
336-02	Westminster PV1, LLC	Ecoplexus, Inc.	Rutherfordton, NC	75	✓
336-01	Oakboro PV1, LLC	Ecoplexus, Inc.	Oakboro, NC	40	✓
143-04	Carolina Solar Power, LLC	Duke Energy Renewables	Surry County, NC	22.6	
83-06	Duke Energy Carolinas, LLC	Duke Energy	Gaston County, NC	25	
258-02	JSD Management, LLC	JSD Management, LLC	Woodruff, SC	20	
143-05	Carolina Solar Power, LLC	Duke Energy Renewables	Cabarrus County, NC	22.6	
			DEC Total:	**464.5**	

DEC Winning Proposals that Withdrew

Proposal #	Contracting Party	Location	MWs AC	Storage Included?
93-01	Stanly Solar, LLC	Albemarle, NC	50	

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ATTACHMENT 1

DEP

Proposal #	PPA Contracting Party	Parent Company	Location	MWs AC	Storage Included?
67-1	Cardinal Solar, LLC	National Renewable Energy Corporation	Marion, SC	7.02	
188-1	Trent River Solar, LLC	Silver Creek Intermediate, LLC	Pollocksville, NC	78.7	
			DEP Total:	**85.72**	

DEP Winning Proposals that Withdrew

Proposal #	Contracting Party	Location	MWs AC	Storage Included?
95-2	Duke Energy Carolinas, LLC	Richlands, NC	79.8	

Docket No. EMP-105, Sub 0
Public Staff - Friesian Panel
Cross-Examination Exhibit No. 5

I/A

Solar Capacity by County

County	Number of Solar Facilities	Capacity (MW AC)	Friesian Constrained Counties
Robeson	59	205.63	√
Cumberland	107	192.40	√
Bladen	18	184.51	√
Duplin	39	164.69	√
Nash	62	162.11	
Hertford	14	150.00	
Northampton	18	144.71	
Currituck	16	140.07	
Scotland	23	135.80	√
Anson	14	130.04	√
Wilson	27	128.89	
Halifax	18	110.68	
Catawba	158	109.01	
Vance	38	108.24	
Edgecombe	14	106.46	
Wayne	92	103.64	
Lenoir	27	98.64	
Rutherford	62	93.68	
Cabarrus	224	91.84	
Martin	15	86.62	
Pitt	30	84.39	
Franklin	46	83.17	
Cleveland	74	82.87	
Union	152	81.56	
Johnston	225	79.48	
Richmond	12	69.69	√
Columbus	35	63.74	√
Beaufort	24	62.07	
Wake	1,601	53.95	
Rowan	222	53.52	
Pender	52	49.10	√
Chatham	405	47.36	
Montgomery	21	47.02	√
Pasquotank	11	42.69	
Perquimans	8	41.21	
Bertie	5	39.92	
Moore	160	39.83	√
Washington	4	38.23	
Harnett	103	36.95	√
Alamance	157	36.47	
Granville	44	35.09	
Randolph	130	34.18	
Lee	45	32.29	
Warren	13	32.24	
Rockingham	67	31.30	
Guilford	358	31.15	
Davie	46	30.96	
Sampson	17	25.84	√
Jones	8	25.53	
Onslow	47	23.51	√

County	Number of Solar Facilities	Capacity (MW AC)	Friesian Constrained Counties
Durham	488	22.60	
Craven	40	21.87	
Person	45	21.47	
Tyrell	2	20.01	
Davidson	65	19.36	
Orange	479	18.72	
Gaston	133	17.41	
Mecklenburg	958	15.81	
Hoke	12	15.69	
Caswell	26	15.42	
Gates	4	15.00	
Greene	9	14.02	
Buncombe	899	13.42	
Burke	54	12.43	
Yadkin	28	12.42	
Lincoln	87	12.31	
Stanly	34	10.49	
Camden	6	10.02	
Forsyth	297	9.67	
Iredell	179	8.49	
Clay	22	8.19	
Henderson	167	8.07	
Cherokee	33	7.65	
Alexander	29	6.33	
New Hanover	272	5.59	√
Pamlico	8	5.04	
Chowan	2	5.00	
Surry	48	4.97	
Stokes	55	4.32	
Brunswick	119	4.21	
Avery	12	3.25	
Haywood	72	3.07	
Caldwell	26	1.32	
Wilkes	46	0.60	
Jackson	54	0.52	
McDowell	59	0.38	
Macon	51	0.36	
Transylvania	53	0.29	
Carteret	36	0.21	
Madison	24	0.20	
Polk	33	0.18	
Dare	15	0.15	
Ashe	5	0.13	
Watauga	9	0.13	
Swain	17	0.11	
Alleghany	2	0.10	
Yancey	8	0.09	
Mitchell	12	0.08	
Graham	5	0.03	
Hyde	2	0.01	
Total	**10,308**	**4,460**	

Source: NCSEA, Installed Renewable Energy Systems, Solar by County

Online at: https://energync.org/maps/

Access date: December 13, 2019

Solar Capacity By State - 2018

Year	State Code	Generators	Facilities	Nameplate Capacity (Megawatts)	Summer Capacity (Megawatts)
2018	US	3,388	2,774	32,238.7	31,878.4
2018	CA	795	557	11,837.6	11,707.8
2018	NC	562	529	4,007.9	3,998.1
2018	AZ	117	75	2,067.3	2,072.2
2018	TX	53	52	1,943.1	1,948.8
2018	NV	61	34	1,926.0	1,900.2
2018	FL	50	50	1,401.6	1,399.5
2018	GA	49	46	1,026.2	1,017.2
2018	UT	31	30	859.1	859.1
2018	NJ	258	213	771.9	764.8
2018	MA	297	285	744.9	736.6
2018	MN	322	163	741.5	733.9
2018	NM	59	56	562.2	561.4
2018	CO	73	64	532.6	531.3
2018	VA	24	24	462.0	392.5
2018	MD	61	61	355.2	271.4
2018	SC	39	38	353.0	351.1
2018	OR	45	45	312.8	312.5
2018	NY	107	101	268.6	264.5
2018	ID	9	8	240.0	240.0
2018	IN	61	61	216.3	216.2
2018	AL	6	6	196.9	194.1
2018	TN	16	15	180.6	177.8
2018	MS	5	5	160.6	160.6
2018	HI	39	17	124.1	124.1
2018	VT	34	34	100.6	100.5
2018	AR	5	5	100.0	100.0
2018	MI	15	14	99.3	98.2
2018	WY	1	1	92.0	92.0
2018	CT	32	29	86.1	86.8
2018	OH	25	24	84.8	83.6
2018	MO	19	18	62.1	62.1
2018	PA	29	26	59.7	57.8
2018	IL	9	9	40.9	40.6
2018	DE	10	10	33.4	33.3
2018	RI	14	14	31.6	31.6
2018	OK	7	7	30.5	30.5
2018	KY	6	6	26.3	26.3
2018	WI	16	16	23.9	23.9
2018	WA	2	2	19.7	19.7
2018	NE	6	5	17.9	18.0
2018	MT	6	6	17.0	17.0
2018	IA	5	5	9.2	8.9
2018	ME	2	2	5.6	5.6
2018	KS	4	4	4.0	4.2
2018	LA	1	1	1.1	1.1
2018	SD	1	1	1.0	1.0

Source: EIA 860- 2018 Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State

Duke Energy Carolinas, LLC's and
Duke Energy Progress, LLC's
Competitive Procurement of Renewable Energy Program

Attachment 3

Initial CPRE Program Plan (Rule R8-71(g))

Duke Energy Carolinas, LLC's & Duke Energy Progress, LLC's Initial Competitive Procurement of Renewable Energy (CPRE) Program Plan

Contents

1. Introduction

Duke Energy Carolinas, LLC ("DEC"), and Duke Energy Progress, LLC ("DEP"), (collectively "Duke Energy" or "the Companies") together present this initial Program Plan in support of the Companies' Competitive Procurement of Renewable Energy ("CPRE") Program ("the Program"). The purpose of the CPRE Program is to meet the requirements of N.C. Gen. Stat. § 62-110.8, as enacted by North Carolina Session Law 2017-192 ("HB 589"). The Companies' CPRE Program Plan establishes DEC's and DEP's initial plans for meeting the aggregate obligation to procure and/or develop 2,660 megawatts ("MW")[1] of new renewable energy in a manner that ensures continued reliable and cost-effective electric service to customers throughout the DEC and DEP service territories in North Carolina and South Carolina. This initial CPRE Program Plan meets the requirements of North Carolina Utilities Commission ("Commission" or "NCUC") Rule R8-71(g), and will be updated on or before September 1 annually during the CPRE Program Procurement Period.[2]

2. CPRE Compliance Plan

2.1. Implementation of Aggregate CPRE Program requirements

NCUC Rule R8-71(g)(2)(i): an explanation of whether the electric public utility is jointly or individually implementing the aggregate CPRE Program requirements

Under N.C. Gen. Stat. § 62-110.8(a), the Companies are responsible for procuring renewable energy and capacity through a competitive procurement program with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs.

To meet the CPRE Program requirements, the Companies must issue requests for proposals to procure, and shall procure, energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW. The CPRE RFP Solicitations issued to procure the 2,660 MW "CPRE Total Obligation" must be reasonably allocated over a term of 45 months beginning when the Commission approves of the CPRE Program.

Renewable energy facilities eligible to participate in the CPRE RFP Solicitation(s) include those facilities that use renewable energy resources identified in N.C. Gen. Stat. § 62-133.8(a)(8) but shall be limited to electric generating facilities that use renewable energy resource(s) with a nameplate capacity rating of 80 MW or less that are placed in service after the date of the electric public utility's initial competitive procurement. The renewable energy facilities to be developed or acquired by the Companies or procured from a third party through a power purchase agreement under the CPRE Program must also deliver to the Companies the environmental and renewable attributes associated with the power.

Per N.C. Gen. Stat. § 62-110.8(b), electric public utilities may jointly or individually implement these aggregate competitive procurement requirements. The Companies plan to jointly implement the aggregate CPRE Program requirements by offering joint CPRE RFP Solicitations to procure the aggregate 2,660 MW of renewable energy facility capacity within 45 months of Commission approval of the CPRE Program.

[1] The final amount of capacity procured will depend on the amount of "transitional" capacity that have entered into power purchase agreements ("PPAs") and interconnection agreements with DEC or DEP during the CPRE Program Procurement Period. Any transitional capacity over 3,500 MW would adjust the CPRE target down from 2,660 MW and any transitional capacity under 3,500 MW would adjust the CPRE target up from 2,660 MW. *See* N.C. Gen. Stat. § 62-110.8(b)(1).

[2] Capitalized terms that are not otherwise defined in this CPRE Program Plan shall have the meaning set forth in N.C. Gen. Stat. § 62-110.8 and NCUC Rule R8-71(b), as adopted by the Commission's November 6, 2017 *Order Adopting and Amending Rules* issued in Docket No. E-100, Sub 150.

The Companies can satisfy the CPRE Program requirements through any of the following:

(i) renewable energy facilities to be acquired from third parties and subsequently owned and operated by the Companies;

(ii) Self-developed renewable energy facilities to be constructed, owned, and operated by the Companies up to a 30% cap identified in N.C. Gen. Stat. § 62-110.8(b)(4)[3]; or

(iii) the purchase of renewable energy, capacity, and environmental and renewable attributes from renewable energy facilities owned and operated by third parties that commit to allow the Companies rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the Companies' own generating resources.

2.2. Projected Uncontrolled Renewable Energy Generating Capacity

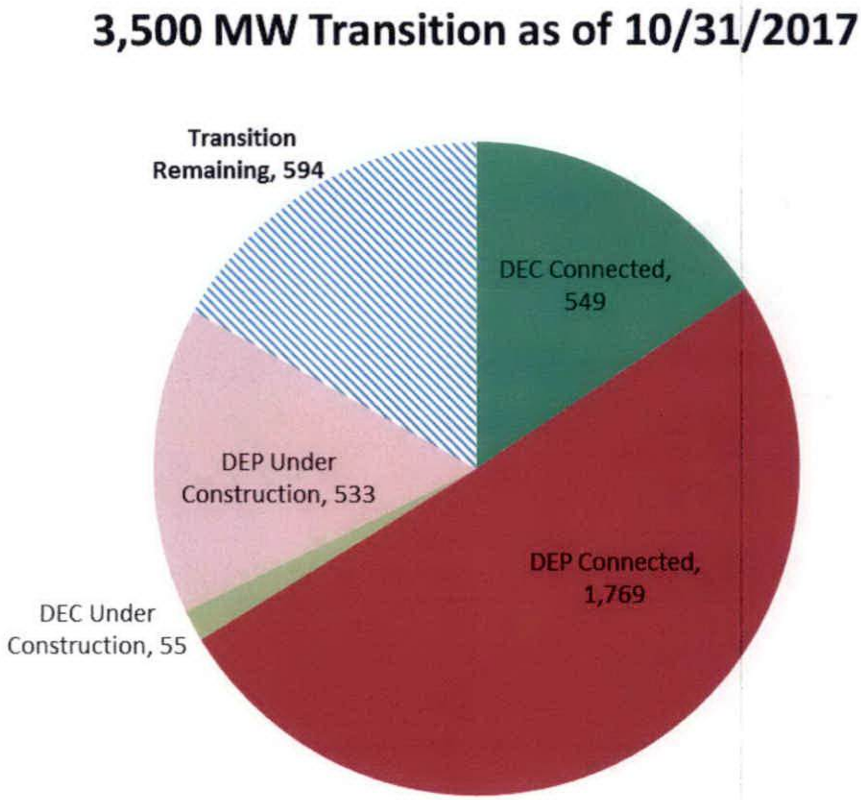
NCUC Rule R8-71(g)(2)(v): an estimate of renewable energy generating capacity that is not subject to economic dispatch or economic curtailment that is under development and projected to have executed power purchase agreements and interconnection agreements with the electric public utility or that is otherwise projected to be installed in the electric public utility's balancing authority area within the CPRE Program planning period

As prescribed by N.C. Gen. Stat. § 62-110.8(b)(1), if prior to the end of the initial 45-month competitive procurement period, the Companies have executed PPAs and interconnection agreements for renewable energy capacity within their Balancing Authorities ("BAs") that are not subject to economic dispatch or curtailment and were not procured pursuant to N.C. Gen. Stat. § 62-159.2 ("Transition MW") having an aggregate capacity in excess of 3,500 MW, the Commission shall reduce the competitive procurement aggregate amount by the amount of such exceedance. If the aggregate capacity of such Transition MW is less than 3,500 MW at the end of the initial 45-month competitive procurement period, the Commission shall require the Companies to conduct an additional competitive procurement in the amount of such deficit.

As of October 31, 2017, approximately 2,900 MW of third-party solar not subject to economic dispatch or curtailment is installed or under construction, leaving a Transition MW deficit of approximately 600 MW, as seen in Figure 1.

[3] The Companies voluntarily agree to recognize both Self-developed Proposals, as well as third-party PPA Proposals offered by any Duke Energy affiliate bid into the CPRE RFP Solicitation(s), as being subject to the 30% cap.

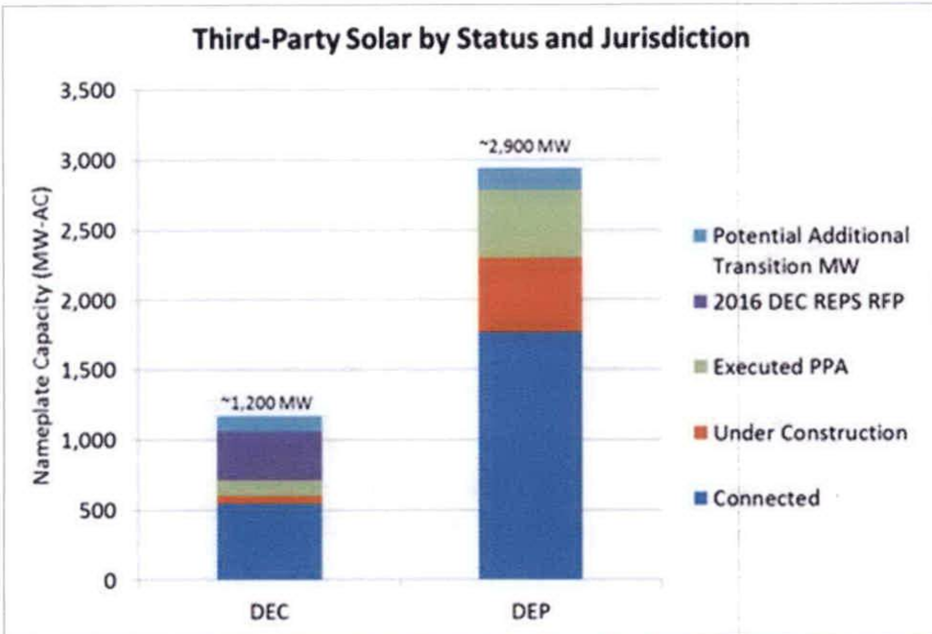
Figure 1. Status of Transition Renewable Energy Capacity by BA as of October 31, 2017



In addition to this 2,900 MW of Transition MW projects that are installed/under construction today, additional Transition MW may be provided by a number of projects that have already obtained a PPA or established a legally enforceable obligation ("LEO") to sell to the Companies under the Commission-approved Docket No. E-100, Sub 140 or Docket No. E-100, Sub 148 standard offer avoided cost contracts or negotiated avoided cost contracts ("legacy PURPA contracts"), and other pre-existing renewable energy procurement programs and solicitations within North Carolina and South Carolina. At this time, the Companies project the 3,500 MW Transition MW cap will be met and could grow to as high as 4,100 MW (~1,200 DEC and ~2,900 DEP) by the end of the CPRE Program Procurement Period, depending on how many additional Transition MW projects materialize, rather than choosing to bid into the CPRE RFP.

Potential additional transition MW shown in Figure 2 include projects that have established a LEO to sell to the Companies, with a materialization factor applied to estimate successful project completion, as well as potential DER Tier 1 capacity under the South Carolina Distributed Energy Resource Program Act.

Figure 2. Interconnected Third-Party Solar Capacity by Status and Jurisdiction as of October 31, 2017



2.3. Planned RFP Solicitations

NCUC Rule R8-71(g)(2)(ii): a description of the electric public utility's planned CPRE RFP Solicitations and specific actions planned to procure renewable energy resources during the CPRE Program planning period

The Companies plan to issue the "Tranche 1" CPRE RFP Solicitation approximately three months following Commission approval of the Program Guidelines. Assuming Commission approval occurs in mid-February 2018, the target issuance date for the Tranche 1 CPRE RFP Solicitation will be in May 2018.

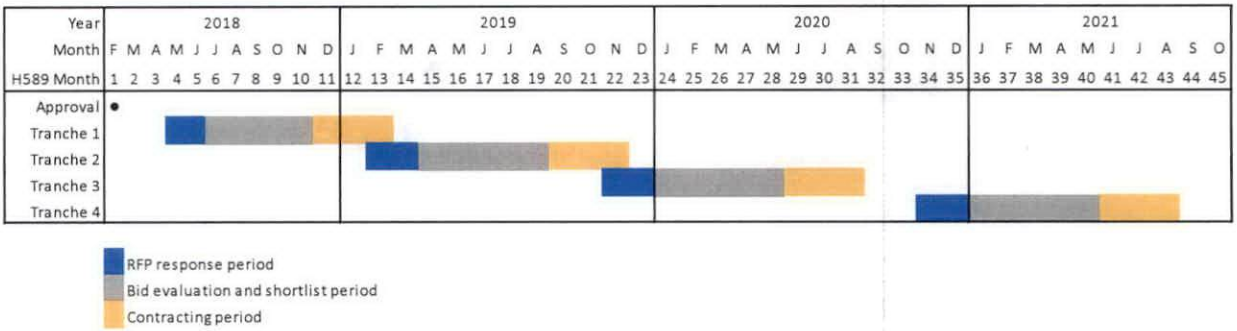
The Tranche 1 RFP Solicitation will seek to procure approximately 680 MW of renewable energy capacity from facilities that have submitted Interconnection Requests as of the Tranche 1 RFP proposal due date. The RFP will solicit facilities across DEC and DEP in both North Carolina and South Carolina. Wind energy facilities will not be accepted in the first solicitation due to the moratorium placed on wind energy facilities in HB 589 and the fact that no wind energy facilities are currently in the Companies' interconnection queues. This does not prohibit wind energy facilities from being included in the future CPRE Program solicitations.

Renewable energy facility proposals must commit to deliver 100% of the facility's output to the purchasing utility (DEC or DEP), which includes all energy, capacity, and environmental and renewable attributes ("Renewable Resource") generated by the facility.

In consideration of the steps required to procure cost effective facilities within the desired timeframe, as well as the need to procure 2,660 MW of renewable energy facilities within the CPRE Program Procurement Period, the Companies are proposing to perform four solicitations following the schedule in

Figure 3. [4] It is expected that PPA proposals will be executed within the first 30 days of the contracting period, and that Asset Acquisition proposals could take up to 90 days.

Figure 3. Planned CPRE RFP Solicitation Schedule (Tranches 1-4)



2.4. Allocations of Resources

NCUC Rule R8-71(g)(2)(iii): an explanation of how the electric public utility has allocated the amount of CPRE Program resources projected to be procured during the CPRE Program Procurement Period relative to the aggregate CPRE Program requirements

As prescribed by N.C. Gen. Stat. § 62-110.8(c), the Companies have the authority to determine the location and allocated amount of each CPRE RFP Solicitation, as well as the CPRE Total Obligation to be procured within their respective service territories taking into consideration:

(i) the State's desire to foster diversification of siting of renewable energy resources throughout the State;

(ii) the efficiency and reliability impacts of siting of additional renewable energy facilities in each public utility's service territory; and

(iii) the potential for increased delivered cost to a public utility's customers as a result of siting additional renewable energy facilities in a public utility's service territory, including additional costs of ancillary services that may be imposed due to the operational or locational characteristics of a specific renewable energy resource technology, such as nondispatchability, unreliability of availability, and creation or exacerbation of system congestion that may increase redispatch costs.

For purposes of this initial CPRE Program Plan, the Companies are planning to allocate and procure the CPRE Program Total Obligation through the Tranche 1-4 CPRE RFP Solicitations, discussed above, by soliciting up to the amounts of Renewable Energy Resource capacity shown in Figure 4.

Figure 4. Planned CPRE Solicitation Targets by Tranche

	DEC (Approximate MW)	DEP (Maximum MW)
Tranche 1	600	80
Tranche 2	700	100
Tranche 3	700	80
Tranche 4	340	60

[4] For Tranche 1, proposals must be capable of being placed in service prior to January 1, 2021. Subsequent CPRE RFP Solicitation Tranches may request commercial operation dates after the conclusion of the CPRE Program Procurement Period.

For the reasons discussed below, the Companies' Tranche 1 CPRE RFP Solicitation will offer to procure approximately 600 MW in DEC and up to 80 MW in DEP with the final allocation of renewable energy facility capacity procured through the Tranche 1 Solicitation being determined by the economic and qualitative analysis performed through the proposal evaluation process.

The Tranche 1 CPRE RFP Solicitation results as well as the Companies' system operational experience integrating additional renewable energy resource capacity into the DEC and DEP BAs and distribution and transmission system operations will inform the manner in which future CPRE Program Plans propose to allocate the remaining CPRE Program Procurement between the DEC and DEP service territories. This initial CPRE Program Plan took into consideration the factors prescribed by N.C. Gen. Stat. § 62-110.8(c), as follows:

<u>(i) Fostering Diversification of Siting of Additional Renewable Energy Resources</u>[5]

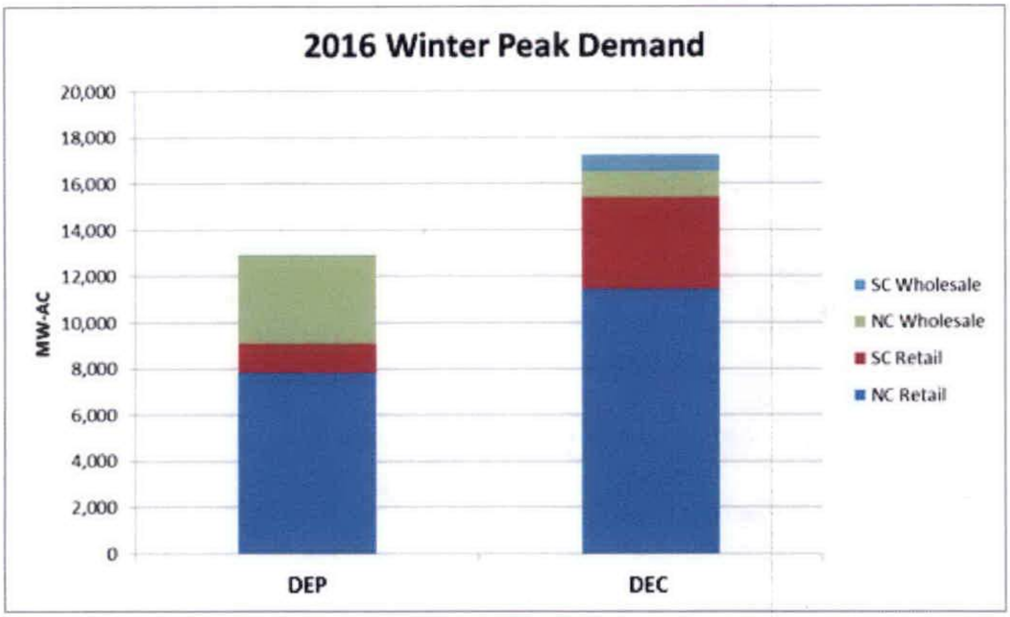
The Companies' primary Tranche 1 objective is to procure cost-effective renewable energy resource facilities that allow DEC and DEP to reliably dispatch, operate, and control the facilities in the same manner as utility-owned generating resources, while diversifying the siting of renewable energy facilities across the Companies' BAs. The CPRE Program recognizes the State's desire to foster diversification of additional renewable energy facilities and to more effectively integrate additional utility-scale solar and other resources into the Companies' system operations. The Companies have developed the initial CPRE Program Plan allocations to meet the goals of diversifying the locations and avoiding inefficient or unreliable over-concentration of additional renewable energy facilities, and improving planning for the siting of additional facilities across the Companies' BAs and within their respective service territories throughout North Carolina and South Carolina.

<u>Adding CPRE Utility-Scale Solar in DEC will Foster Improved Diversification as Existing Utility-Scale Solar is Concentrated in DEP</u>

DEP is a smaller BA than DEC. In 2016, the DEC winter peak load was approximately 17,250 MW in comparison to the DEP winter peak load of approximately 13,000 MW, as seen in Figure 5.

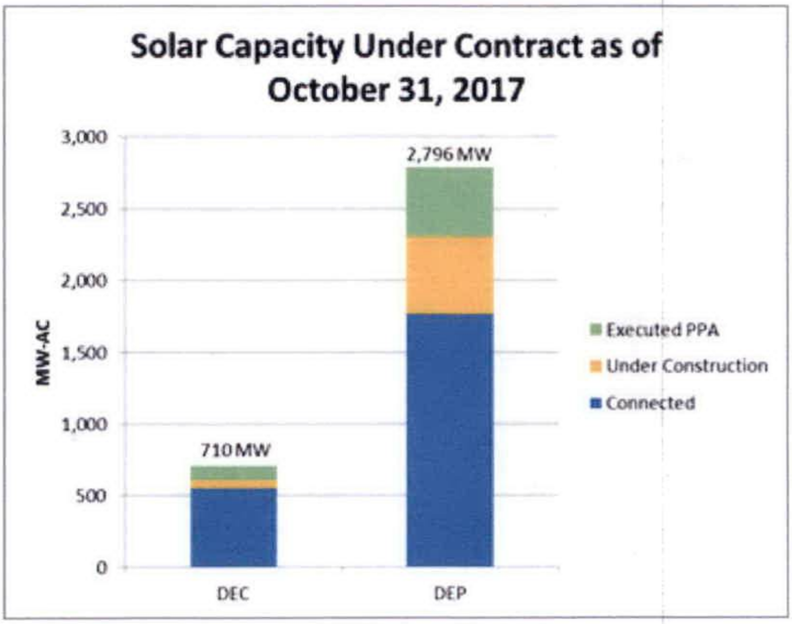
[5] The Companies anticipate that a large percentage of the renewable energy facilities bidding Proposals into the Tranche 1 CPRE RFP Solicitation will be utility-scale solar generating facilities, and have primarily analyzed the need for additional diversification of siting for utility-scale solar resources. The Companies may consider the need to analyze diversification of siting of other renewable energy resource technologies in future CPRE Program Plans, depending on interest from other technologies in the Tranche 1 CPRE RFP Solicitation.

Figure 5. 2016 Peak Load by BA[6]



While DEP is a smaller BA, the Companies have experienced a significantly greater concentration of utility-scale solar development in DEP compared to DEC. As of October 31, 2017, the Companies are contractually obligated to purchase from third-party owners approximately 3,500 MW of solar under REPS and legacy PURPA contracts in addition to operating 225 MW of utility-owned solar. As shown in Figure 6, this utility-scale solar growth has been especially significant in DEP, where approximately 80% of the total MW under contract are located. As of October 31, 2017, 588 MW of utility-scale solar projects are under construction, of which 533 MW, or 91%, are in the DEP service territory.

Figure 6. Solar Capacity under Contract as of October 31, 2017

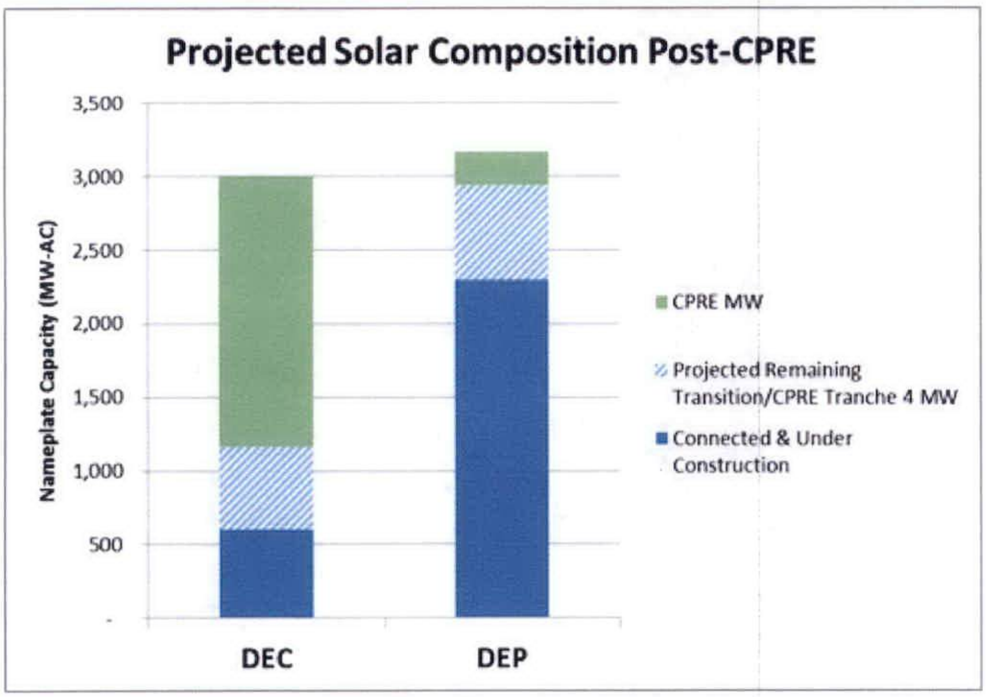


[6] Peak demand values shown in Figure 4 are for 2016 winter peak production demand allocators from the 2016 Cost of Service study.

If the total solar energy capacity in DEC and DEP were to be spread across the service territories based on their respective utilities' peak load, the DEC service territory should have approximately 60% of the solar energy capacity rather than its current ~20%.

To achieve the goals of diversifying the siting of renewable energy facilities throughout the Companies' service territories in a manner that promotes efficiency, reliability, and mitigates cost impact on the Companies' customers, the Companies' Tranche 1 RFP, as well as the planned total CPRE Program procurement allocation (provided in Figure 4), seeks proposals primarily in the DEC service territory in North Carolina and South Carolina. If the Transition MW proceed as expected (see Section 2.2) and the CPRE targets shown in Table 1 are met with primarily or all solar capacity, the resulting composition is an approximately even split of solar capacity between DEC and DEP, as shown in Figure 7.

Figure 7. Projected Solar Capacity by BA Post-CPRE[7]



<u>(ii) System Operations and Reliability Impacts</u>

In developing the proposed allocation of CPRE Program resources between the DEP and DEC service territories, the Companies also considered the operational efficiency and reliability impacts of siting additional renewable energy facilities within the DEC and DEP BAs. As discussed in Section 2.5 (i), the highly concentrated levels of uncontrolled legacy PURPA contract solar that are currently installed, under construction, and under contract to be installed in the DEP BA has caused the Companies to primarily allocate the planned CPRE Program procurement towards the larger DEC BA, where significantly less utility-scale solar is installed today. The Companies' planned CPRE Program allocation between the DEC and DEP BAs is also supported by the growing levels of operationally excess energy and increasingly steep ramping requirements in the DEP BA.

[7] The projected amounts in Figure 7 assume the solicitation amounts in Figure 4. The Projected Remaining Transition/CPRE Tranche 4 category would be split between the Transition MW and the CPRE MW depending on how the Transition MW differs from 3,500 MW. Figure 7 also assumes that all renewable energy procured through CPRE will be solar, though non-solar renewable energy procurements are possible through CPRE.

Independent BA System Operations Basics

DEP and DEC are each independent BAs responsible for maintaining compliance with North American Electric Reliability Corporation ("NERC") reliability standards to ensure reliable operations on their systems, as well as managing power flows between their systems and other utility systems. DEP and DEC must independently control their respective network resources to meet system loads and maintain compliance with reliability regulations within their separate BAs. Each BA must independently comply with NERC's mandatory Reliability Standards on a unified basis across the entire BA that encompass territory in both North Carolina and South Carolina.

DEP's and DEC's system operators independently plan and operate each BA's generating resources to reliably meet increasing and decreasing intra-day and day-ahead system loads within reliability and generating unit availability and operating limits. These reliability requirements place the burden on the DEP and DEC BAs to balance generation resources (including new dispatchable CPRE renewable energy facilities), unscheduled energy injections (existing QF and renewable energy contracts), and load demand in real-time, all of which is essential to providing reliable firm native load service. To meet this objective, DEP and DEC must independently plan for and maintain a "Security Constrained Unit Commitment" of baseload and load-following assets, regulation resources, operating reserves, and spinning reserves, working together to ensure real-time frequency support and balancing.

The Companies' baseload[8] and must-run regulation units[9] represent the foundational resources necessary to meet load requirements, provide reliability, and meet mandatory NERC Reliability Standards. In the aggregate, the operationally constrained minimum reliable output of these generators represents the Lowest Reliability Operating Level ("LROL") of the BA's Security Constrained Unit Commitment. These essential generating resources cannot be de-committed in real time nor on an intra-day basis, because they must run within specified engineering levels and provide essential frequency and regulation support to the BA, and because they are needed to meet upcoming peak demands, such as the evening peak demands and next day peak demands. The LROL represents the level on the BA at which continued energy injections into the BA above the BA's load causes the BA to have operationally excess energy.[10]

Integration of Additional Solar in DEP Increasingly Causing Operationally Excess Energy

Solar generators, by their nature, deliver variable quantities (i.e., low forecast certainty) of energy into the BA during a limited portion of the 24-hour load cycle, generally between 10 a.m. and 3 p.m. Figure 8 below is representative of DEP's non-summer load shape with 2,200 MW of solar installed, and illustrates the operationally excess energy expected in the DEP BA once solar capacity installations reach 2,200 MW.

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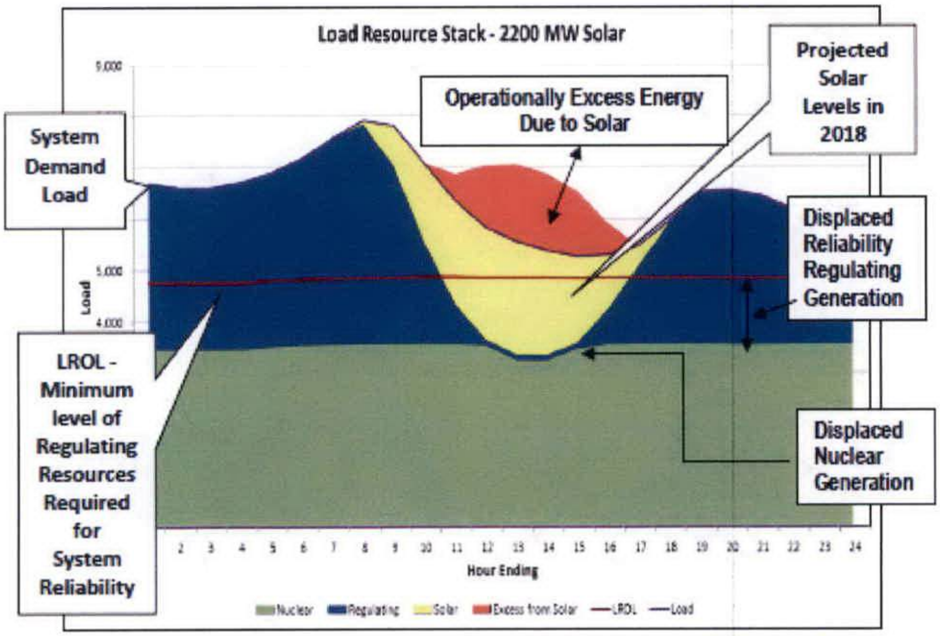
[8] The Companies' baseload units are firm native load generating resources such as nuclear, coal, and large natural gas combined cycle units that form the foundation of reliable service to meet the core system demand.

[9] Must-run regulation and regulation reserves resources are generating resources that must run to provide load balancing regulation and frequency regulation support to maintain reliability by supporting system frequency to the required target of 60 Hz in compliance with mandatory NERC Reliability Standards.

[10] The Companies testified to the importance of managing system operations to maintain the LROL of the BA's Security Constrained Unit Commitment in the 2016 avoided cost proceeding. *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Pre-filed Direct Testimony of John S. Holeman, III, at 7-8, 12-13 Docket No E-100, Sub 148 (filed February 21, 2017).

Figure 8 shows that solar generation is not online during the morning or evening system peaks. Following system load demand throughout the day on the chart shows that as solar facilities ramp up to inject their peak outputs of energy during mid-day hours when the sun is normally providing highest irradiance, the real system load demand is at a lower mid-day level. In response to actual load demand, the BA reduces its network resources to the LROL, but cannot reduce network resources to a level lower than the LROL, because the BA must have resources ready to ramp up to meet the evening load peak and the next morning's peak demand. This results in operationally excess energy occurring during the mid-day period.

Figure 8. Operationally Excess Energy Due to Solar in DEP



The significant concentration of solar generation installed in the DEP service territory is already causing the DEP BA to experience increasing amounts of operationally excess energy. Through October 31, 2017, the DEP BA experienced 71 days and 238 hours, representing over 61,000 MWh, of operationally excess energy. The hours in which the DEP BA has experienced operationally excessive energy events has also increased significantly over 2016 levels. Through October 31, 2017, the DEP BA has experienced a 127% increase in excess energy hours relative to 2016. The amount of operationally excessive energy will grow significantly as the solar facilities under the Transition MW in the DEP service territory continue to come online. For example, based on currently operational facilities and projections of solar generators under development, the DEP system is currently projected to experience increasing levels of operationally excess energy growing to approximately 370,000 MWh by year 2021 – concentrated between the hours of 10 a.m. and 3 p.m.[11]

Similar to the DEP BA, the DEC BA will also begin to experience operationally excess energy and potential reliability challenges if significant additional solar generation is added to that service territory through future legacy PURPA contracts and allocated CPRE renewable energy facility capacity. However

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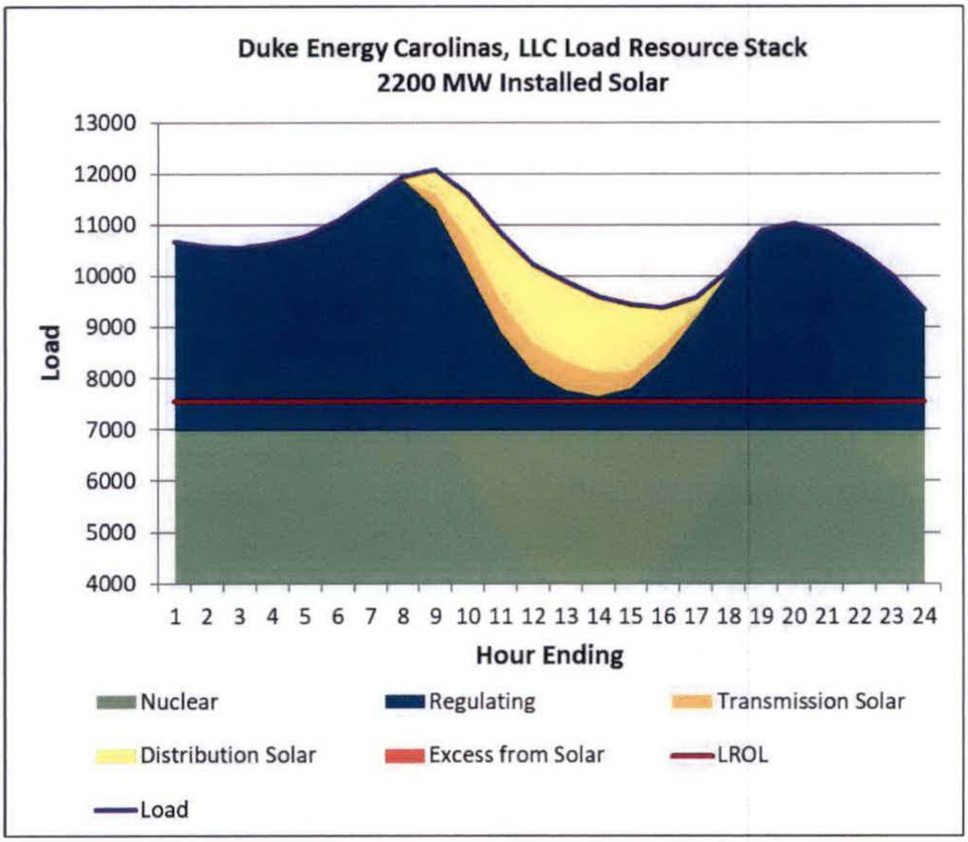
[11] The Companies testified to the projected operationally excess energy in the DEP BA in the 2016 avoided cost proceeding. *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Pre-filed Direct Testimony of John S. Holeman, III, at 25 Docket No E-100, Sub 148 (filed Feb. 22, 2017).

the DEC BA can currently reliably accommodate additional solar generation, as the DEC BA is larger than the DEP BA and currently has significantly less installed solar—approximately 600 MW of solar generation operating on its system as of the end of 2017. As Figure 9 demonstrates, the DEC BA is not projected to begin routinely experiencing such operationally excessive energy occurring on its system until DEC has greater than 2,200 MW of installed solar capacity on its system. Inasmuch as the DEC BA is projected to be capable of reliably accommodating approximately 2,200 MW of solar installed capacity, the Companies have allocated the CPRE Program development primarily to DEC.

Figure 9. Projections of Operationally Excess Energy Due to Solar Installed in DEC

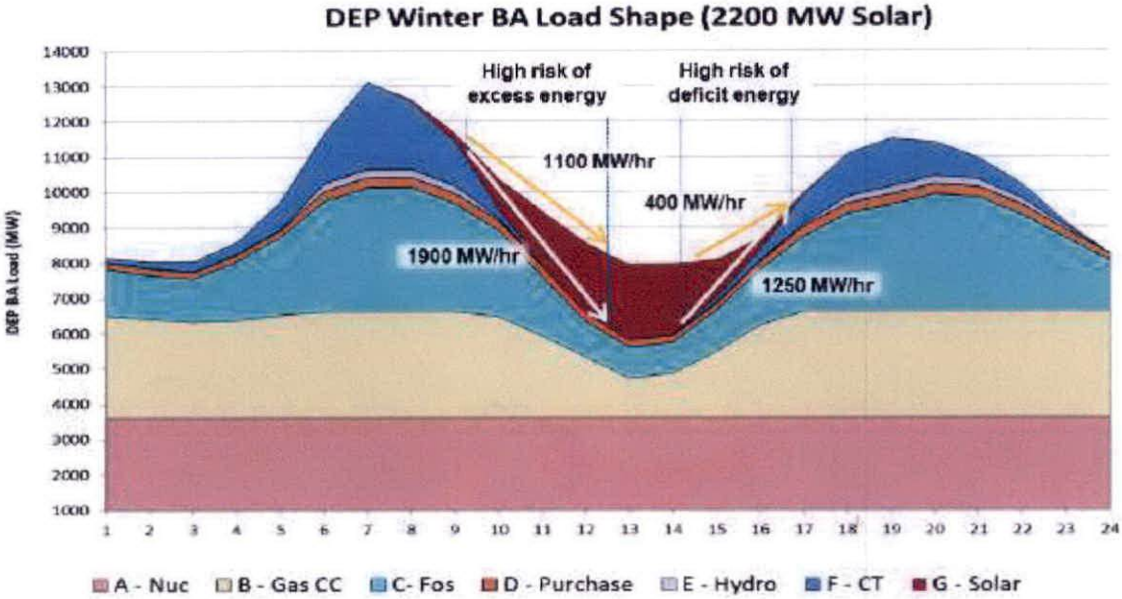


Integration of Additional Solar in DEP Increasingly Causing Extreme Ramping Requirements

High solar penetration also requires an increase in ramping capability for mid-morning and late-afternoon time periods. Figure 10 shows the steep ramps on the DEP system once it has 2,200 MW of solar facilities. Figure 10 demonstrates the extreme and challenging ramping requirements that DEP is increasingly experiencing due to the high levels of unscheduled and unconstrained solar generation installed in the DEP BA[12] Further increases of solar generation in the DEP BA will continue to increase the risk of future potential NERC noncompliance and associated reliability risks, unless DEP has adequate dispatch control rights to proactively plan and dispatch generation resources on its system.

[12] The Companies testified to the growing ramping challenges that DEP system operators are facing in the 2016 avoided cost proceeding. *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Pre-filed Direct Testimony of John S. Holeman, III, at 14-18 Docket No E-100, Sub 148 (filed Feb. 22, 2017).

Figure 10. DEP Winter BA Load Shape Load Shape at 2,200 MW Solar



Continued addition of solar generation in the DEP BA will exacerbate existing reliability challenges and increase the potential future risks of NERC noncompliance. The DEP BA's growing experience managing operationally excess energy and increasingly steep ramping requirements as additional unscheduled and uncontrolled solar generation above 2,200 MW comes online will also increase the likelihood of emergency curtailment in DEP.[13] These reliability issues also support the Companies planned CPRE Program allocation between the DEC and DEP BAs.

<u>(iii) Potential for Increased Delivered Cost; Ancillary Services</u>

The Companies are still developing the modeling to quantify the increased delivered costs and additional ancillary services needed to maintain NERC Balancing Authority compliance due to siting additional renewable energy facilities in DEC or DEP. The Companies plan to provide information on how this consideration impacts the planned allocation of Renewable Energy Resource procurement in future CPRE Program Plans.

<u>Allocation of Resources</u>

In summary, the growing concentration of legacy PURPA solar Transition MWs installed in the DEP BA, associated operational challenges and reliability risks on the DEP system and growing risks of uncompensated system emergency curtailments in DEP, and projections of DEP's and DEC's respective ability to reliably accommodate additional solar energy have informed the Companies' decision to allocate CPRE development primarily in the DEC service territory. The Companies anticipate that the designated allocation of CPRE Program capacity may evolve over the CPRE Program Procurement Period, and the Companies intend to meet the CPRE Program requirements in a manner that ensures continued reliable electric service to customers while procuring cost-effective renewable energy resource capacity located within the DEC and DEP service territories. The Companies will update the planned allocation, if it is determined that changes are appropriate, through subsequent CPRE Program Plan filings.

[13] The Companies anticipate growing potential risks for and financial impacts to sellers associated with DEP curtailing (without compensation) operationally excessive energy to comply with mandatory NERC reliability standards through utilization of emergency condition dispatch down rights.

2.5. Locational Designation

NCUC Rule R8-71(g)(2)(iv): if designated by location, an explanation of how the electric public utility has determined the locational allocation within its balancing authority area

In addition to providing the Companies the authority to allocate the CPRE Total Obligation between DEC and DEP, the Companies may also plan for and provide to market participants more granular information designating the required or preferred location of additional renewable energy resources within the Companies' respective service territories. For purposes of the Tranche 1 CPRE RFP Solicitation, the Companies have not designated specific locations or zones where projects must be sited in order for market participants to bid Proposals into the Solicitation. However, the Companies do plan to publish information intended to provide guidance to market participants on areas that have known transmission and distribution limitations as a result of the amount of existing or approved renewable energy facilities in the area. The goal of providing this "grid locational guidance" is to minimize the need for costly network upgrades to integrate CPRE renewable energy facilities and to provide information to market participants for use when planning development activities for renewable energy facility Proposals to be submitted into the CPRE RFP Solicitation(s). The grid locational guidance information may be in the form of a map and/or a table of circuits and/or substations that have "no availability" for additional connections.

3. CPRE Program Guidelines and Pro forma PPA

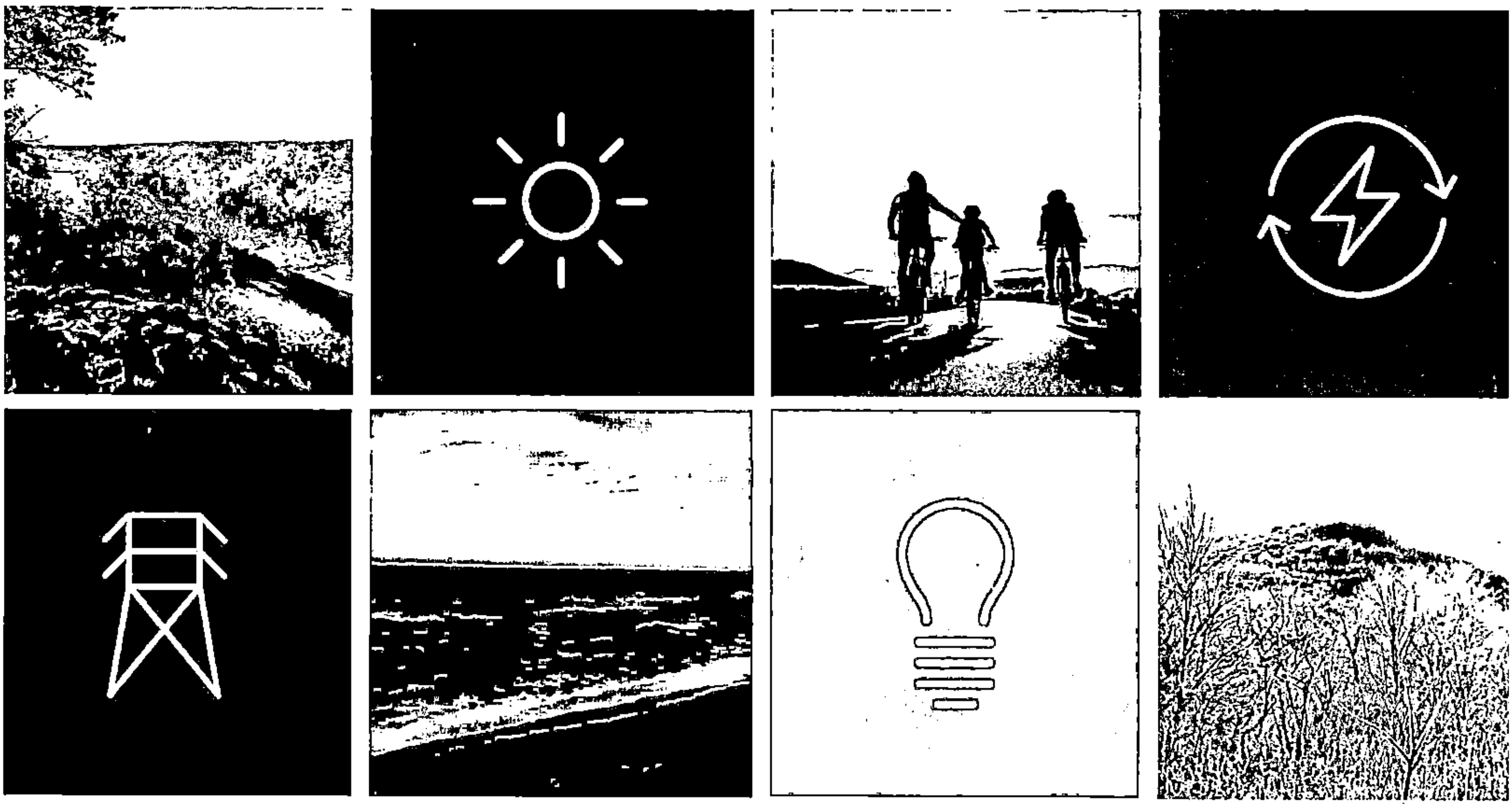
NCUC Rule R8-71(g)(2)(vi): copy of the electric public utility's CPRE Program guidelines then in effect as well as a pro forma power purchase agreement used in its most recent CPRE RFP Solicitation

The Companies' initial CPRE Program Guidelines and proposed pro-forma PPA are included as Attachment 1 and Attachment 2, respectively, to the November 27, 2017 Petition for CPRE Program approval. The Companies anticipate issuing final versions of these documents to the IA selected by the Commission for posting at least 60 calendar days prior to the initial Tranche 1 CPRE RFP Solicitation issuance date, as provided for in NCUC Rule R8-71(f)(1)(ii).

Docket No. EMP-105, Sub 0
Public Staff - Friesian Panel
Cross-Examination Exhibit No. 47
I/A

North Carolina
Clean Energy Plan

Transitioning to a 21st Century Electricity System



POLICY & ACTION
RECOMMENDATIONS

October 2019

THE GREAT SEAL OF THE STATE OF NORTH CAROLINA
MAY 20, 1775
APRIL 12, 1776
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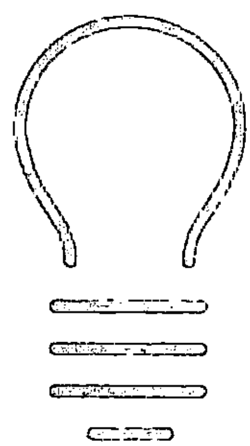
DEQ
NORTH CAROLINA
Department of Environmental Quality
State Energy Office



A strong clean energy economy creates good jobs and a healthy environment.

Acknowledgements

This North Carolina Clean Energy Plan (CEP) is prepared by the North Carolina Department of Environmental Quality (NCDEQ) to foster and encourage the utilization of clean energy resources and the integration of those resources to facilitate the development of a modern and resilient electric grid as directed in Executive Order 80 which was signed by Governor Roy Cooper on October 29, 2018.

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NCDEQ is also thankful to contributors who participated in this process in special ways. These special contributors to the CEP development process include the following:

<u>Facilitated Workshop Presenters:</u>
North Carolina Clean Energy Technology Center, Duke Nicholas Institute for Environmental Policy Solutions, UNC Chapel Hill School of Law, Energy Production and Infrastructure Center at UNC Charlotte, North Carolina Sustainable Energy Association, North Carolina Electric Cooperatives, Advanced Energy Economy, Gridlab, Duke Energy, Resources for the Future, Environmental Defense Fund's Cities Initiative, CERES, Litz Strategies and Georgetown Climate Center, Natural Resources Defense Council and E4 Carolinas.

<u>Facilitated Workshop Hosts:</u>
Nature Research Center at NC Museum of Natural Sciences and NCSU's McKimmon Conference and Training Center.

<u>Regional Listening Session Hosts:</u>
UNC Charlotte, The Collider in Asheville, The Rocky Mount Event Center, Fayetteville State University, Western Piedmont Council of Governments in Hickory, Museum of the Albemarle in Elizabeth City, Cape Fear Community College in Wilmington, and NCA&T State University.

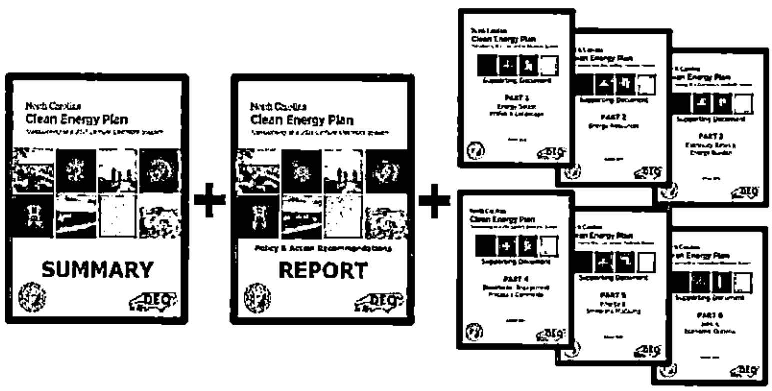
<u>Energy Modeling Organizations:</u>
Resources for the Future, Natural Resources Defense Council, NC State University, Environmental Protection Agency, Georgetown Climate Center, NC Sustainable Energy Association.

In addition, other organizations offered technical information and guidance during the development of the CEP such as National Governor's Association, U.S. Department of Energy, National Association of State Energy Officials, Virginia's Department of Mines, Minerals and Energy, Massachusetts' Department of Energy Resources, New Jersey's Department of Environmental Protection and New York State Energy Research and Development Authority.

A very special thanks to all NCDEQ staff that contributed to the development of the CEP.

Preface

The Clean Energy Plan was written by the Department of Environmental Quality as directed by Executive Order No. 80.[1] DEQ was tasked with the creation of a CEP to encourage the use of clean energy resources and technologies and to foster the development of a modern and resilient electricity system. The purpose of the CEP is to outline policy and action recommendations that will accomplish these goals. The CEP is made up of the main document titled *Policy and Action Recommendations* and six supporting documents.



Part 1: Energy Sector Profile and Landscape
Part 2: North Carolina's Energy Resources
Part 3: Electricity Rates and Energy Burden
Part 4: Stakeholder Engagement Process and Comments
Part 5: Energy and Emissions Modeling
Part 6: Clean Energy Jobs and Economic Outlook

The CEP uses best available data, analysis, and stakeholder input to examine what our electricity system should look like in 2030 and what values we must retain moving forward. It identifies achievable goals, proposes modern policies and strategies to achieve the goals, and identifies activities needed to adjust the regulatory framework to accommodate 21st century customer expectations, public policy goals, energy needs, economic development opportunities, and societal outcomes related to climate change.

The policies and strategies identified here are intended to provide policy makers, regulatory bodies, local governments, and others with a high-level implementation plan for achieving the goals and targets set in the CEP. When viewed collectively, these strategies should help develop a broad, clear picture of the actions North Carolina can undertake to maximize energy, economic and environmental benefits.

Promising strategies and actions will require further deeper dives and detailed analysis when considering proposing new legislation or amending existing policies and procedures. The CEP presents short term (less than 12 months), mid-term (1-3 years), and longer term (3-5) actions to ensure the State's energy needs are served in a cost-effective, reliable and sustainable manner. The longer term action (3-5 years) also consists of assessing the accomplishments made, consideration of technology advancements, and a relook at the strategies and actions to take in the future. In summary, these policies and strategies will provide stakeholders a common understanding of the vision and direction which we want to move towards.

[1] https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf

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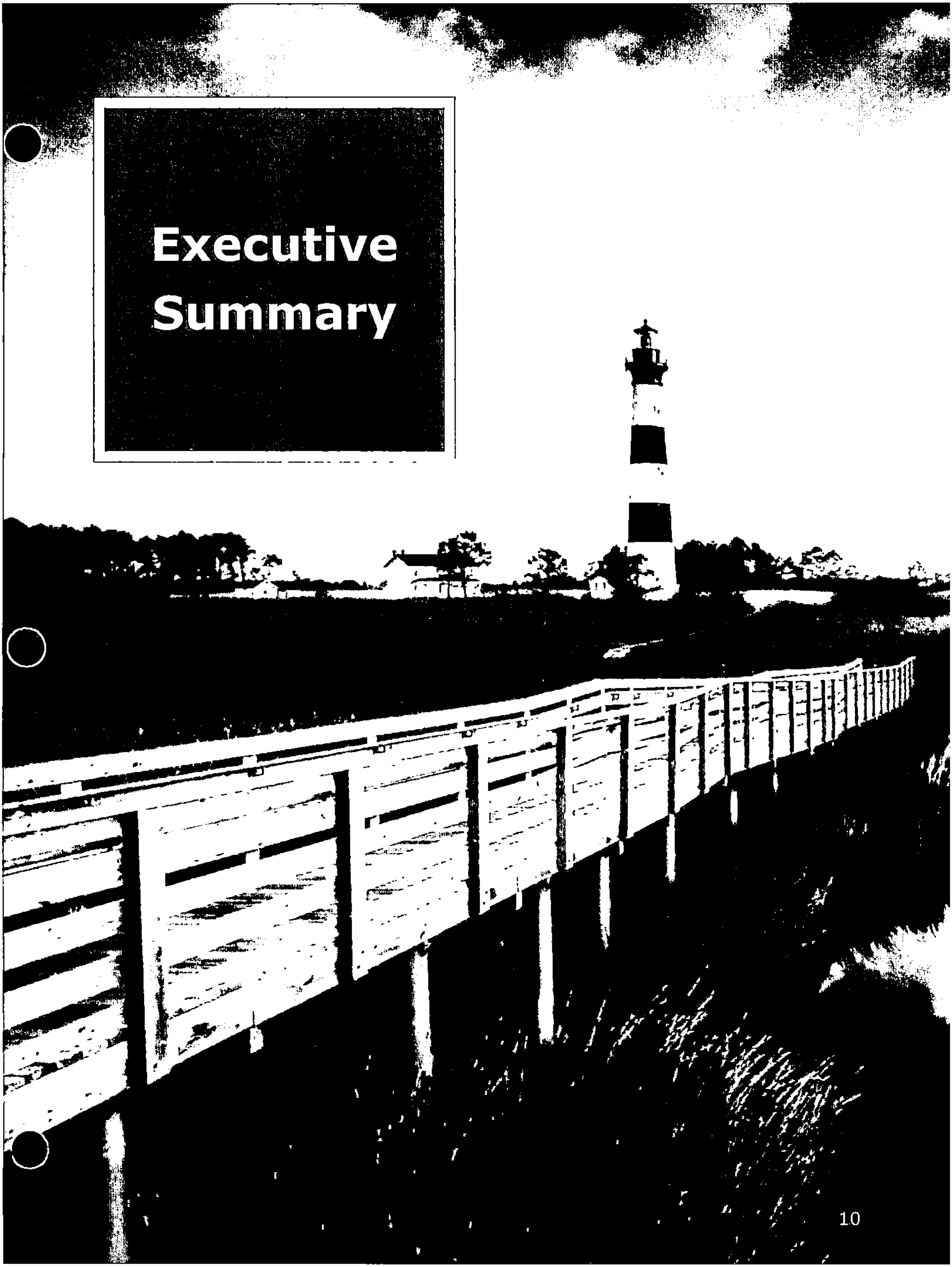
Executive Summary



EXECUTIVE SUMMARY

Climate change is an increasing threat to the health, safety and prosperity of North Carolinians. At the same time, the clean energy economy is creating opportunities to create jobs and propel North Carolina to be globally competitive. On October 29, 2018, Governor Roy Cooper signed an executive order calling for a 40 percent reduction in statewide greenhouse gas emissions by 2025. The order tasked the Department of Environmental Quality with developing a clean energy plan for North Carolina.

After an extensive stakeholder engagement process, including meetings and public comment periods, the plan was presented to Governor Cooper on September 27, 2019. Over the last 10 months, utilities, policymakers, regulators, universities, non-profits, the public, and industry experts have offered their expertise to help craft the plan, which is a holistic vision for the clean energy future of our state. More than 160 stakeholder groups helped develop this shared vision for North Carolina's energy future.

- Multiple sessions were held over a period of six months in geographically diverse venues across the state.
- Feedback was collected through facilitated workshops, regional listening sessions, at energy related events and through online/direct input – culminating in a draft report that was released for public comment.

Building on Existing Accomplishments

North Carolina has built an impressive record on clean energy, but to continue that leadership the strategies laid out in this plan must inform the legislative and policy changes the state adopts.

The rapid pace of economic, environmental, and technological change has created an opportunity for North Carolina to pursue a modern, 21st century electricity system. By leveraging the State's existing energy resources, innovative public and private sector partners and a competitive workforce, North Carolina is positioned to help drive a larger transition to a clean energy economy. The Clean Energy Plan is presented as a framework to accelerate that process.

Drivers of Transformation

The declining costs and large-scale deployment of renewable energy systems and the rapid advancement of information management, communications, and consumer product devices are transforming both the electricity supply and public demand for our electrical grid. These forces are driving decarbonization of the electric power sector while creating economic development opportunities in both urban and rural areas of the state.

North Carolina will need to design policies that provide certainty in the marketplace with enough flexibility to support innovation and creativity to adapt to the rapidly changing demands for electricity. New technologies can drive cost savings for customers, notably incentives and rate structures must modernize to achieve the values and goals prioritized in this document.

Clean Energy Plan Goals

- Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050.
- Foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes.
- Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.

Key Recommendations

The Clean Energy Plan (CEP) is designed to be a living document that can be modified as needed. While it lays out a vision through 2030, the intention is for revisions to be made every 3-5 years.

Recommendations in this document are divided into action items intended to fall into one of three categories: short-term (1 year), medium-term (1-3 years), and long-term (3-5 years). Many of these recommendations and action items are interconnected, but not interdependent.

To successfully transition to a clean energy future, North Carolina must establish a 21st century regulatory model that incentivizes business decisions that benefit both the utilities and the public in creating an energy system that is clean, affordable, reliable, and equitable. The following overarching recommendations are critical to the transition and will drive the priorities identified by the stakeholders:

- Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.

- Develop and implement policies and tools such as performance-based mechanisms, multi-year rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy.

- Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.

Next Steps

This plan is intended to guide the direction North Carolina takes in adapting to a changing economy, climate, and market and help shape what change looks like, the timeframe in which change happens, and how changes impact ratepayers.

OVERVIEW OF STRATEGY AREAS & RECOMMENDATIONS

Carbon Reduction (A)

A. Decarbonize the electric power sector **Page 55**

- A-1. Deliver a report that recommends carbon-reduction policies and the specific design of such policies that best advance core values, such as GHG emission reductions, electricity affordability, and grid reliability. The report will evaluate policy designs for the following carbon reduction strategies:
    1. Accelerated coal retirements,
    2. Market-based carbon reduction program,
    3. Clean energy policies, such as an updated REPS, clean energy standard, and EERS, and
    4. A combination of these strategies.

    Legislature, State Agencies, Academia
- A-2. Require integrated resource plans and distribution system plans to use portfolios and action plans that incorporate a cost of carbon into the portfolio or plan that is selected for use by the utility.

    Utilities Commission, Investor Owned Utilities, State Agencies

Utility Incentives and Comprehensive System Planning (B-C)

B. Modernize utility tools and incentives **Page 65**

- B-1. Launch a North Carolina energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation.

    Governor's Office, Legislature,
- B-2. Encourage use of pilot programs or other methods for testing and evaluating components of a performance-based regulatory framework.

    Utilities Commission, Investor Owned Utilities
- B-3. When authorizing "securitization" as a utility financing tool, include uneconomic generation assets in the scope of what can be securitized

    Legislature, Utilities Commission
- B-4. Initiate a study on the potential costs and benefits of different options to increase competition in electricity sector, including but not limited to joining an existing wholesale market and allowing retail energy choice.

    Legislature, State Agencies

C. Require comprehensive utility system planning processes **Page 74**

- C-1. Establish comprehensive utility system planning process that connects generation, transmission, and distribution planning in a holistic, iterative and transparent process that involves stakeholder input throughout, starting with a Commission-led investigation into desired elements of utility distribution system plans.

    Utilities Commission, State Agencies, Investor Owned Utilities, Co-Ops/Public Utilities, Local Government, Academia, Businesses

- C-2. Expand cost-benefit methodologies used to make decisions about resources and programs to include societal and environmental factors

  Utilities Commission, Co-Ops/Public Utilities
- C-3. Implement competitive procurement of resources by investor-owned utilities

  Utilities Commission

Grid Modernizations and Resilience (D-E)

D. Modernize the grid to support clean energy resources **Page 82**

- D-1. When evaluating proposals for grid modernization, consider whether the following outcomes are supported:
  - Demonstrated net benefits for all proposed investments, including presentation of all costs and benefits used in utility analyses
  - Enhanced transparency of regionally appropriate DERs, grid needs and opportunities for DERs to interconnect
  - Increased customer access to their usage data and sources of energy
  - Facilitation of greater utilization of storage, demand-side resources, grid operation/management devices, and the bi-directional flow of power
  - Measurement of performance to ensure anticipated benefits are delivered and accounted for
  - Increased deployment of clean energy

  Utilities Commission, Co-Ops/Public Utilities
- D-2. Use comprehensive utility planning processes to determine the sequence, needed functionality, and costs and benefits of grid modernization investments. Create accountability by requiring transparency, setting targets, timelines and metrics of progress made toward grid modernization goals.

  Utilities Commission, Co-Ops/Public Utilities

E. Strengthen the resilience and flexibility of the grid **Page 87**

- E-1. Require utilities to develop projects focused on DERs, community solutions, and microgrids at state facilities and critical infrastructure locations (e.g. hospitals, shelters) to enhance resilience.

  Utilities Commission, State Agencies, Investor Owned Utilities, Co-Ops/Public Utilities, Local Government
- E-2. Coordinate resilience planning with disaster recovery operations center and require NC Emergency Management's Recovery Support Functions to address cybersecurity concerns in conjunction with energy resiliency issues.

  Utilities Commission, State Agencies, Investor Owned Utilities, Co-Ops/Public Utilities
- E-3. Develop a method to quantify the human costs of power outages, and integrate these costs when evaluating grid modernization plan components related to resiliency.

  Utilities Commission, State Agencies, Academia

Clean Energy Deployment and Economic Development (F-H)

F. Enable customers to choose clean energy **Page 92**

F-1. Consider revisions to clean energy programs authorized by HB 589 to ensure successful delivery of desired outcomes, such as increasing customer access to clean energy.

Legislature, State Agencies

- F-2. Enact a statewide commercial Property Assessed Clean Energy (PACE) and Pay as You Save Program
  Legislature, Governor's Office, State Agencies, Local Government, Academia
- F-3. Develop a green energy bank or statewide clean energy fund to catalyze the development and expansion of clean energy markets by connecting private capital with clean energy projects.
  Governor's Office, Local Government, Academia
- F-4. Require utilities to offer virtual or group net metering to enable greater access to community solar.
  Legislature
- F-5. Increase the existing REPS or create a new policy with zero-emitting resource targets without carve-outs for specific resources
  Legislature, Utilities Commission

G. DER interconnection and compensation for value added to the grid **Page 101**

- G-1. Develop rates that provide accurate price signals to demand-side resources about costs and value to the grid, such as Time of Use (TOU) or real time pricing. In the long term, consider establishing new rate and compensation structures for DERs based on the value of grid services that can be provided by DERs, such as a "value of DER" tariff.
  Utilities Commission, Co-Ops/Public Utilities
- G-2. Consider ways to provide greater transparency of system constraints and optimal locations for distributed resources
  Utilities Commission

H. Clean energy economic development opportunities **Page 107**

- H-1. Identify and advance legislative and/or regulatory actions to foster development of North Carolina's offshore wind energy resources
  State Agency
- H-2. Create and foster statewide and regional offshore wind collaborative partnerships with industry, the public, stakeholders, and neighboring states to bring economic growth to North Carolina.
  Governor's Office, State Agencies, Investor Owned Utilities, Local Government, Academia, Businesses
- H-3. Conduct an assessment of offshore wind supply chain and ports and other transportation infrastructure to identify state assets and resource gaps for the offshore wind industry.
  State Agencies, Local Government, Businesses
- H-4. Develop pathways to expand renewable natural gas recovery and usage
  Academia, State Agencies, EPC

Equitable Access and Just Transition (I-J)

I. Address equitable access and energy affordability **Page 112**

- I-1. Include non-energy equity-focused costs and benefits in decisions regarding resource needs, program design, cost-benefit analyses, and facility siting.
  Utilities Commission, State Agencies, Investor Owned Utilities, Co-Ops/Public Utilities, Local Government

- I-2. Examine the feasibility and proper design of a low-income rate class and associated rate structures, including but not limited to the elimination or reduction of fixed charges for ratepayers with high energy burdens.

  Academia, NCUC
- I-3. Expand energy efficiency and clean energy programs specifically targeted at underserved markets and low-income communities.

  Legislature, State Agencies, Others

J. Foster a just transition to clean energy **Page 120**

- J-1. Ensure inclusion and meaningful involvement of historically marginalized individuals (people of color and people living in poverty) in decision-making regarding siting electricity generation assets and implementing programs that would affect their energy bills, health, and access to clean energy and energy efficiency opportunities.

  Utilities Commission, State Agencies
- J-2. Launch an EE Apprenticeship program within Apprenticeship NC to expand access to clean energy careers.

  Academia
- J-3. Create long term jobs with family sustaining wages and benefits in renewables and grid infrastructure industries for low income communities and workers displaced by the transition to a clean energy economy.

  Legislature, Governor's Office, State Agencies, Investor Owned Utilities, Co-Ops/Public Utilities, Local Government, Academia, Businesses

Energy Efficiency and Beneficial Electrification (K-L)

K. Increase use of energy efficiency & demand side management programs **Page 125**

- K-1. Establish an Energy Efficiency Advisory Council (EEAC) to oversee implementation of the EE Roadmap recommendations

  Governor's Office
- K-2. Enable customers to have greater access to their energy data through new functionalities, such as those available through Green Button "Download My Data" Button

  Legislature, Utilities Commission, State Agencies, Investor Owned Utilities, Co-Ops/Public Utilities
- K-3. Establish minimum EE goals within existing REPS or establish an energy efficiency resource standard (EERS)

  Legislature, Utilities Commission
- K-4. Enhance education and awareness around energy efficiency opportunities in K-12 schools and community colleges through an "Energy Efficiency Everywhere (E3)" project

  Academia
- K-5. Require utilities to develop innovative rate design pilots to encourage customer behavior that helps achieve clean energy goals, such as peak demand reduction, better utilization of renewable resources, and strategic storage deployment.

  Utilities Commission, Co-Ops/Public Utilities
- K-6. Increase EE awareness on the North Carolina Building Code Council

  Legislature, State Agencies

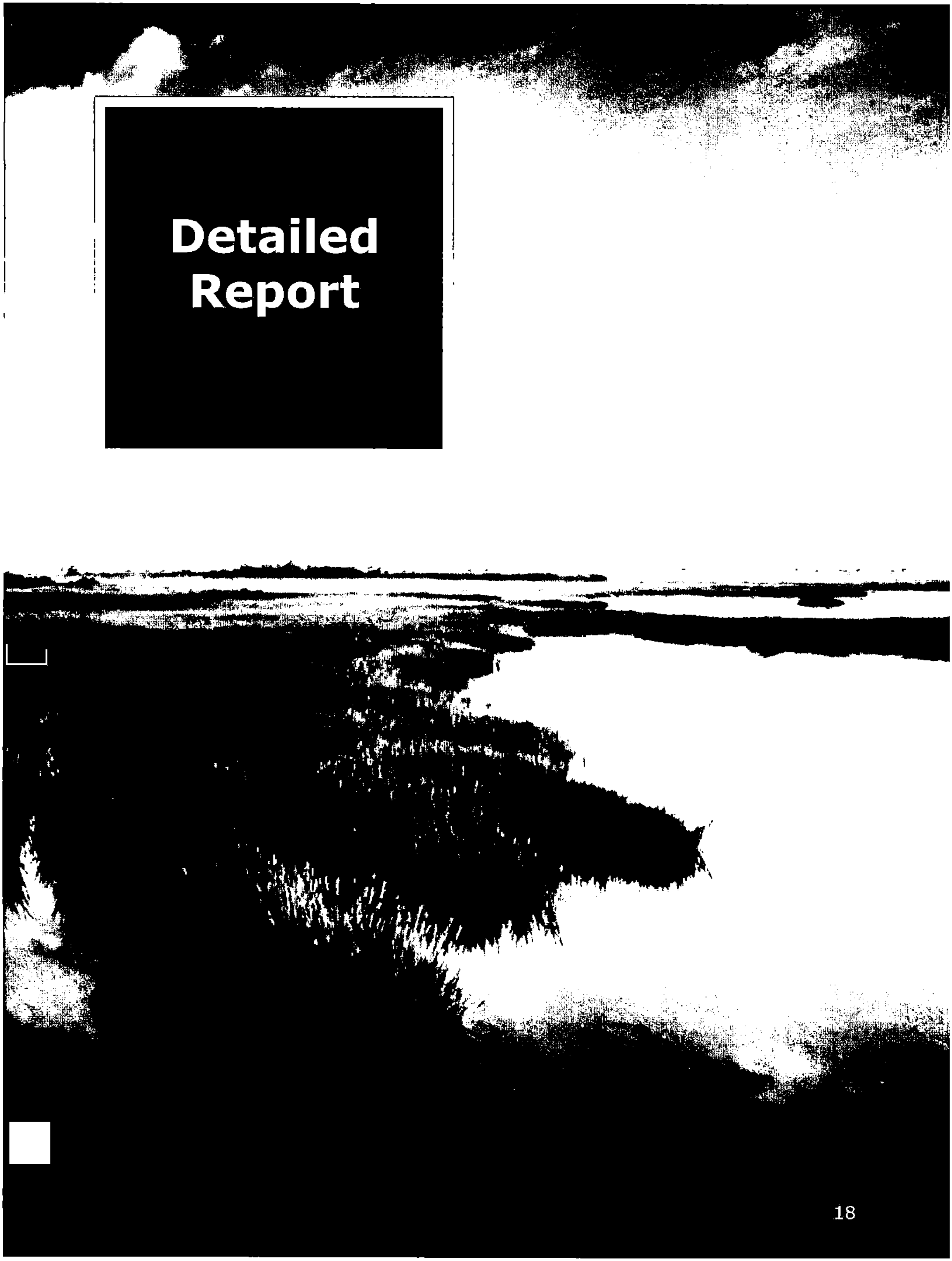
L. Create strategies for electrification

- L-1. Require utilities to develop innovative rate design pilots for electric vehicles to encourage off-peak charging of vehicles and to test effectiveness of different rate structures at shifting customer usage of the grid and encouraging the adoption of electric vehicles.

  Utilities Commission, Co-Ops/Public Utilities
- L-2. Conduct an analysis of the costs and benefits of using electrification to reduce energy burden and GHG emissions in consumer end-use sectors in NC, such as in homes, buildings, transportation, industrial and agricultural operations.

  Academia

Detailed Report



1. NC's Current & Anticipated Energy Landscape

The electricity consumed in NC (NC) homes, businesses, and industries is mostly generated at central power stations, transported through a network of high-voltage transmission lines, and distributed via local poles and wires to customers. Figure 1 shows the current capacity levels and electricity generation by resource type. These resources produced 3% of the nation's power output, ranking NC as the 8th largest electricity generating state for both 2017 and 2018..[1] Traditional fuel resources such as coal, natural gas, and nuclear stations represented about 90% of the annual output. NC's coal-fired and natural-gas fired power plants are ranked 11th and 5th in the nation, respectively, for the amount of electricity generated in both 2017 and 2018..[2]

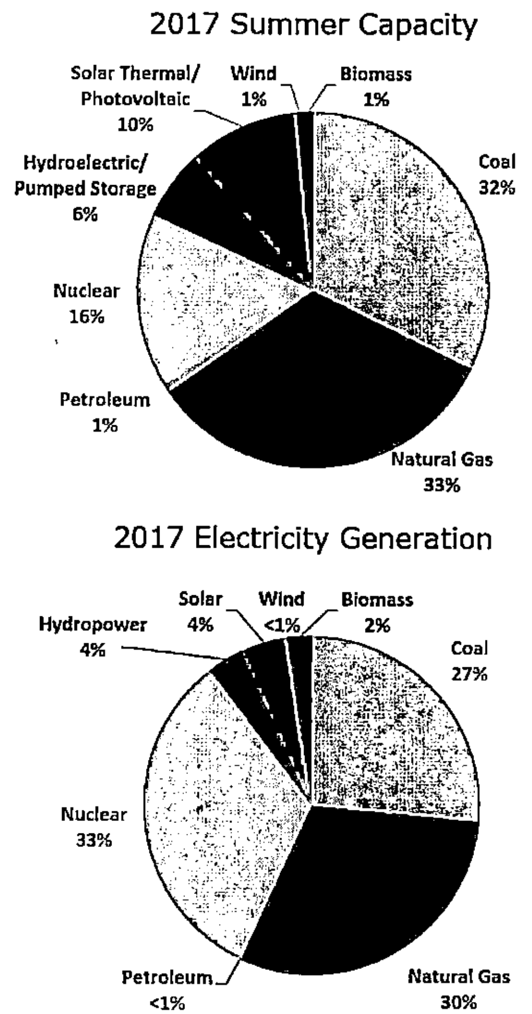


Figure 1: NC's Electricity Statistics by Resource Type

Since the enactment of the NC Renewable Energy and Energy Efficiency Portfolio Standard (REPS).[3], the capacity of clean energy resources has increased dramatically. NC's interpretation of the 1978 federal mandate, the Public Utility Regulatory Policies Act (PURPA), provided historically generous and long term "avoided cost" contracts for utility scale solar projects and is another growth driver of utility-scale solar in the state..[4] NC's Business and Energy Tax Credits provided a 35% state tax credit for renewable energy projects. These credits doubled every year after the REPS was established in 2007 and grew to $245

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[1] U.S. Energy Information Administration, Electricity Data Browser, https://www.eia.gov/electricity/data/browser/
[2] Ibid
[3] Session Law 2007-397, "NC's Renewable Energy and Energy Efficiency Portfolio Standard (REPS), August20, 2007, http://www.ncuc.commerce.state.nc.us/reps/reps.htm.
[4] EIA. (2019). Retrieved from https://www.eia.gov/todayinenergy/detail.php?id=27632

million in 2016, the last year of the program..[5] When coupled with a 30% federal solar tax credit, project developers were able to cut the cost of a renewable facility in half. The collective impact of state and federal policies and precipitous decline in solar costs led to NC being ranked 2nd in the nation for the most installed solar photovoltaic (PV) capacity. This infrastructure produced between 10 and 11% of the nation's total solar electricity output, ranking NC as the 2nd highest solar producing state each year from 2017 through 2019 (as of May)..[6] Independent power producers accounted for over 92% of NC's solar generation, while utilities represented about 6% and commercial sector represented 2% of the state's solar electricity generation.

The state subsidy for solar PV expired in 2015 and the federal tax credit is slated to expire in 2021..[7] Going forward, the next phase of growth in the clean energy sector will be determined by legislation passed in 2017 called the Competitive Energy Solutions for NC, also known as House Bill (HB589)..[8] This bill creates new programs for competitive renewable energy (RE) procurement, solar rebates and leasing, community solar, and special studies related to RE. The solar capacity projected to be added to the system is about 4,000 megawatts (MW) by 2025 (essentially doubling the capacity shown in Figure 1 if all the requirements in the legislation are fulfilled).

The 2018 latest Integrated Resource Plans (IRPs) filed by NC's investor owned utilities (IOUs) indicate that the capacity of solar PV will remain at about the same level from 2025 to 2030. The capacity of energy storage is planned to increase from the current level of 1 MW to 246 MW by 2025 and 291 MW by 2030. The IRPs suggest that an additional 7,200 MW of natural gas capacity will be part of NC's portfolio (18% increase relative to Figure 1) and 4,000 MW of coal capacity will be retired (12% decrease relative to Figure 1).

In the wake of continuing declining costs of renewable generation and battery storage options, NC regulators and policy makers will be called upon to evaluate the economic viability of traditional infrastructure projects whose costs will be borne by ratepayers for years to come. As NC makes capital investment decisions for future capacity additions, it will be important to select the cost-effective system that maintains affordability, reliability, equity, grid efficiency, and economic viability. In just the past year, many states and utilities have made groundbreaking announcements, some of which are highlighted below:

- Georgia state regulators approved Georgia Power's long-term IRP, authorizing the utility to own and operate 80 MW of battery energy storage, and add 2,260 MW of new renewables (primarily solar), growing its renewable generation to 5,390 MW by 2024 and increasing the company's total renewable capacity to 22% of its portfolio. The Georgia plan also calls for retiring five coal units, based on its Public Service Commission's analysis on coal units' economics and concluded that keeping them was costly to ratepayers, and reducing its use of natural gas, from almost half to about a third of its portfolio by 2024. Georgia Power's IRP also includes energy efficiency

[5] NCDOR. (2016). Article 3B – Business and Energy Credits. Retrieved from https://files.nc.gov/ncdor/documents/reports/2-3B-RenEngyProp2016.pdf
[6] U.S. Energy Information Administration, Electricity Data Browser, https://www.eia.gov/electricity/data/browser/
[7] U.S. Department of Energy. (2019). Expired, Repealed, and Archived NC Incentives and Laws. Retrieved from https://afdc.energy.gov/laws/laws_expired?jurisdiction=NC
[8] House Bill 589, Session Law 2017-192, NC General Assembly, 2017, https://www.ncleg.net/gascripts/BillLookUp/BillLookUp.pl?Session=2017&BillID=h589&submitButton=Go

targets 15% above previous IRPs. The utility said it added new programs for both residential and commercial customers, including an income-qualified efficiency pilot designed to help up to 500 residents reduce household energy demand by 20%.

- The Tennessee Valley Authority (TVA) recently published its 2019 Final IRP, calling for up to 14 GW of new solar energy, 5,300 MW of energy storage and 2.2 GW of energy efficiency savings by 2038. TVA plans to retire some of its coal plants, and will consider retirement of additional coal and gas-fired combustion turbines if determined cost-effective.
- Southern Company, the third largest utility in the U.S., set a long-term goal of low to no carbon operations by 2050 on an enterprise-wide basis, with an interim goal of 50% reduction by 2030. The company also committed to seeking approval of low-carbon and carbon-free resources that are in the best interest of its customers.
- Both of the primary IOUs servicing NC have set emission reduction goals. Duke Energy recently announced an entity wide goal of reducing CO_2 emissions by at least 50% from 2005 levels by the year 2030 and net-zero carbon emissions by 2050.[9] Dominion Energy has set a goal to reduce CO_2 emissions 80% by 2050 and methane emissions from natural gas assets 50% by 2030.[10]
- In Colorado, Xcel Energy's recent requests for proposals have set record-low prices, receiving solar-plus-storage bids as low as $36 per megawatt hour (MWh), compared to $25 per MW-hour for standalone solar. Xcel plans to retire 660 MW of coal capacity ahead of schedule in favor of renewable sources and battery storage options, and reduce costs in the process.
- In the Midwest, MidAmerican will be the first utility to reach 100% RE by 2020 without increasing customer rates. Indiana's NIPSCO will replace 1.8 gigawatts (GW) of coal with wind and solar.
- In Oklahoma, NextEra Energy Resources will develop the largest hybrid renewable project in the United States, a 700 MW facility that will serve 21 utility members and other customers of Western Farmers Electric Cooperative.
- Dominion has expressed the possibility of developing more than 2,000 MW of offshore wind off the Virginia coast. Dominion's Power Generation Group subsidiary plans to invest $1.1 billion through 2023, $300 million of which will be used towards its offshore wind.

As RE and distributed energy resources (DER) costs continue to fall and penetration rises, these assets will reach a point where they can be treated as a true grid resource, providing services that benefit both the customer and the utility. Intelligently managed DERs could offer a vision of a world where demand may be as easily dispatchable as supply. NC regulators and policy makers will be called to 1) evaluate the amount of RE and DERs that can be technologically integrated, 2) resolve grid balancing and operability issues that come with increasing quantities of non-dispatchable generation, and 3) ensure fair and equitable methods to pay for the transitioning power grid. Additionally, the forthcoming utility proposal for smart grid initiatives and grid modernization will require a substantial investment, posing a challenge to keep rates low and still maintain reliability.

Our state enjoys some of the lowest retail electricity prices in the nation, with a ranking in the bottom 10 states for the past several years. NC's average residential rate has been about 6% less than the South Atlantic region and about 11% less than the nation as a whole since 2015. Despite having low rates, NC is number 25 in the nation for average monthly residential bills (the total amount that customers pay for

[9] https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050
[10] Dominion Energy comment letter to DEQ on the draft Clean Energy Plan.

electricity service per month)..[11] In other words, in 26 states residential customers have lower bills than their NC counterparts. This is one of the reasons that low-income households continue to pay a significant portion of their annual income on energy bills. In 2018, 15% of NC's residents (1.4 million) were living below 100% of the federal poverty level (FPL). On average, these individuals spent 18 to 33% of their annual income on energy bills, of which about 20% went to pay electric bills. Comparatively, the energy burden for those at 200% above the FPL ($50,000) was only 7%..[12] Public policy focusing on energy rates, equitable access, and a just transition to clean energy economy is needed to address the current disparity.

Moving forward, electricity prices for generation are projected to decline rapidly while the transmission and distribution related prices will increase to accommodate both grid scale RE and DERs. According to the Annual Energy Outlook (AEO) 2019 forecast, it is projected that the total electricity price (sum of generation, transmission, and distribution) will decline slightly or remain the same relative to the 2018 levels (see Figure 2).

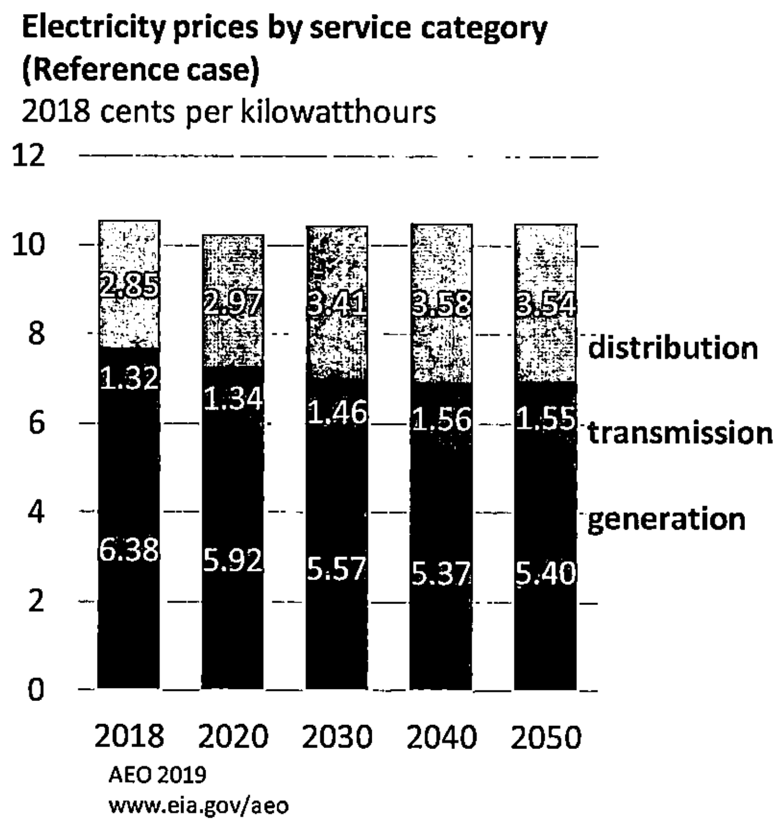

Figure 2: Electricity Prices by Service Category (Reference Case)

In the coming years, our infrastructure will be challenged to deliver smart and resilient energy, due to the technological changes and climate impacts and that are on the horizon. It is neither feasible nor prudent to build out the entire transmission or distribution system simultaneously, but there is a growing recognition that changes are needed sooner than planned, to stay ahead of the rapidly changing industry. Therefore, it is important for NC to establish a vision for what the modern gird should look like for NC.

With this vision, we can;

- meet the state's rapidly changing electricity market,
- deploy advanced technologies
- find value in the electric distribution system,
- create additional revenue mechanism for the utilities, customers, and system integrators, and

[11] 2017 data from EIA, Table 5.a. http://www.eia.gov/electricity/sales_revenue_price/

[12] For more information on energy burden of low-income households, see Supporting Document Part 3: Electricity Rates and Energy Burden.

- develop a competitive and vibrant new energy economy, where jobs of the future are both created and retained.

1.1 Nuclear Energy

Since the start-up of NC's first nuclear reactor in 1975, nuclear-generated electricity has become a substantial part of the states' energy landscape and it now provides approximately one-third of the electricity consumed in the state. Duke Energy operates a total of five reactors at three NC nuclear power plants, with licenses to operate between 2036 and 2046 as issued by the Nuclear Regulatory Commission. In its 2018 IRPs, Duke Energy reported that no new nuclear generation units are planned, with no anticipated nuclear retirements over the IRP planning period. Duke Energy noted that capacity uprates (an increase in the peak operating output of a facility, totaling 56 MW) are planned for the Brunswick and Harris plants during 2019 to 2028. Additional details regarding this resource, including benefits and concerns associated with its application, are highlighted in Supporting Document Part 2.

The CEP examines energy resource availability and technology trends over a planning horizon of ten years through 2030. During this time period, NC's current fleet of nuclear reactors are expected to continue to supply baseload electricity. The carbon policy analysis discussed later in the plan assumes continuous generation from the existing nuclear fleet, emitting zero tons of carbon emissions per unit of energy generated. As the expiration dates for existing power plants near, the State will need to evaluate extending the licenses (as desired by Duke Energy) for an additional twenty years or replace with other generation sources.

Several smaller scale nuclear technologies are currently being developed which may be considered by the State as options in the future. One such nuclear technology is the small modular reactor (SMR) with generating capacity of 300 MW or less. SMRs are anticipated to be less capital intensive than conventional nuclear plants which average around 1,000 MW per plant, may offer easier financing, and require shorter construction times due to in-factory fabrication. The micro-reactor, with capacity ranging between 1 and 20 MWs, can be factory-fabricated and integrated with distributed energy sources. Both technologies are under development. The U.S. Department of Energy projects that SMRs and micro-reactors could be introduced by the mid-2020s. The technical feasibility, safety and cost effectiveness of these emerging technologies will need to be considered as part of future energy portfolio for NC.

1.2 Natural Gas

Natural gas is used by the electricity generation sector as fuel for three primary types of generator systems: (1) natural gas combined cycle systems (NGCC), (2) simple cycle gas combustion turbines (NG CT) and (3) as a replacement fuel for coal in steam boilers. Between 2000 and 2017, the capacity of NC's natural gas power plants tripled as the State transitioned from coal due to (1) increased supply of natural gas from shale formations, (2) lower natural gas fuel prices, and (3) increased environmental regulations on coal-fired power plants. Since 2010, electricity generation from natural gas has increased 4.5 times. NGCC power plants are now providing about 30% of NC's electricity needs.

There are plans to build two new natural gas pipelines to bring shale gas produced in West Virginia to NC. The first pipeline is the Atlantic Coast Pipeline (ACP) which is a joint venture between Dominion Energy, Duke Energy, Piedmont Natural Gas, and Southern Company Gas. The determination of the route and the federal approval occurred during the previous administration. The project is on hold pending a Fall 2019 decision by the U.S. Supreme Court to determine whether or not to hear the case over a dispute regarding federal permits. The second pipeline is the Mountain Valley Southgate Pipeline which filed for approval in November of 2018. It is in earlier stages of development. Both projects are facing significant opposition from local communities and environmental groups.

Natural gas is composed primarily of methane, which is a greenhouse gas (GHG) with a warming potential 25 times greater than carbon dioxide (CO_2). In 2016, NC's natural gas power plants emitted about 15.7 million metric tons (MMT) as CO_2 equivalent GHGs, and emissions are expected to increase in the future.[13] During natural gas extraction, process and transmission activities, significant amounts of methane can escape into the atmosphere. The US EPA estimated that nationally, methane emissions from these non-combustion activities was approximately

164 MMT GHGs in 2016..[14] Based on the volume of natural gas consumed for electricity use in NC, it is estimated that 0.95 MMT GHGs are emitted in other states due to our usage..[15] Additionally, in state emissions from the operation of the natural gas transmission and storage system, including natural gas consumed by compressor stations and fugitive emissions, are estimated to be 1.34 MMT GHGs for 2016.

The Intergovernmental Panel on Climate Change's (IPCC) special report on the impacts of global warming of 1.5 °C above pre-industrial levels calls for reaching net zero CO_2 emissions globally around 2050 and concurrent deep reductions in emissions of non- CO_2 forcers, particularly methane..[16] In the "Systems Transitions" chapter, the IPCC notes that new natural gas power generation should be deployed in tandem with carbon sequestering technologies. Similarly, the U.S. Fourth National Climate Assessment calls for "replacing conventional, CO_2-emitting fossil fuel energy technologies or systems with low- or zero-emissions ones (such as wind, solar, nuclear, biofuels, fossil energy with carbon capture and storage, and energy efficiency measures), as well as changing technologies and practices in order to lower emissions of other GHGs such as methane, nitrous oxide, and hydrofluorocarbons.".[17]

In NC, significant growth in natural gas electricity production is planned. Between now and 2022, Duke Energy plans to bring two new NGCC units online. After that, the projection relies on the Duke Energy IRPs for capacity additions. The IRPs indicate approximately 4,000 MW of new NGCC power will come

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[13] NC Greenhouse Gas Inventory (1990-2030), NC Department of Environmental Quality
Division of Air Quality, January 2019, accessed at https://deq.nc.gov/energy-climate/climate-change/greenhouse-gas-inventory.

[14] Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2016, EPA 430-P-18-001, U.S. Environmental Protection Agency, Washington, D.C., February 6, 2018.

[15] According to the Energy Information Administration, NC consumed 1.6% of U.S. total natural gas production. Of this amount, 56% was consumed to generated electricity in the state.

[16] The Intergovernmental Panel on Climate Change, SPECIAL REPORT - Global Warming of 1.5 °C, August 2018. https://www.ipcc.ch/sr15/

[17] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II,* Chapter 29: Reducing Risks Through Emissions Mitigation [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

online between 2024 and 2030 and an additional 1,800 MW of NG CT will be built. The significant planned capacity additions are expected to increase natural gas supplied electricity from about 50,000 thousand MWh in 2018 to about 77,000 thousand MWh in 2030. Based on the current projections, natural gas will become NC's dominant source of electricity production as certain coal plants retire, contributing to most of the State's remaining GHG emissions (estimated to be 43 MMT by 2030 or 47% below 2005 levels). The current "business as usual" approach will not achieve the goal to reduce power sector GHG emissions 70% below 2005 unless the additional generation need is met by clean energy sources.

In the coming years, NC regulators will be making decisions regarding the utilities' requests to add new natural gas capacity to the generation fleet. These decisions will need to consider the drivers of electricity system transformation, including declining cost of clean energy technologies and the goal to decarbonize the power sector. They will also need to consider the rapidly changing market dynamics that could lead to stranded natural gas assets, and the best means to assure grid reliability and electricity affordability for ratepayers. The CEP identifies several recommendations and mechanisms to enable consideration of clean energy technologies that support NC's growing economy. Examples include incentivizing utilities for developing alternatives to capital intensive infrastructure projects, comprehensive energy system planning that considers generation, transmission and distribution system in tandem, consideration of the social cost of carbon in least cost analysis, developing clean energy policies and market-based carbon reduction program, and others.

1.3 Biomass

Electricity generated from biomass is eligible for Renewable Energy Credits (REC) as part of REPS. According to the NC Renewable Energy Tracking System (NC-RETS), in 2017, 20.2% of the State's RECs were from woody biomass..[18] According to Duke Energy's 2018 IRP, the capacity growth of biomass projects peak in 2020 at 406 MW, then steadily decline to 52 MW in 2032. The National Renewable Energy Laboratory (NREL) evaluated the levelized cost of energy (LCOE) projections for biomass plants and forecasts it to be relatively flat through 2050 due to the low heat content of biomass fuels..[19]

Currently, the wood pellet industry does not contribute to NC's energy generation portfolio and does not advance NC's clean energy economy. The wood pellets harvested from NC increase the state's carbon output during logging, processing and transportation and are burned for fuel elsewhere, mostly Europe. There are currently no known plans for the industry to become a contributor to NC's energy sector in the coming years. If this trend reverses, NC should not support activities that would increase emissions from its electricity generation sector for the reasons cited below.

Stakeholders have raised concerns regarding whether biomass or products derived from NC forests, is carbon neutral. We acknowledge the science regarding carbon neutrality and accounting methods are contentious issues. Biomass combustion releases carbon into the atmosphere at a faster pace than if the

[18] NC Renewable Energy Tracking System (NC-RETS), Feb 2019, https://www.ncrets.org/
[19] Annual Technology Baseline-LCOE, NREL, 2018, https://atb.nrel.gov/electricity/2018/index.html?t=cb&s=pr

forests were left intact to absorb and sequester carbon dioxide emitted from anthropogenic sources. Biomass energy is carbon neutral if growing the biomass removes as much CO_2 as is emitted into the atmosphere from its combustion.[20]

The method for accounting this complex issue has been studied by EPA and other national experts. EPA's Science Advisory Board remains deadlocked after years of debate on the best way to advise regulators on how to account for emissions from burning biomass. Meanwhile, in a 2018 publication, scientists concluded that the use of wood as fuel is likely to result in net CO_2 emissions and may endanger forest biodiversity.[21] Due to this uncertainty, large scale use of NC's natural resources to meet foreign markets' carbon reduction goals by taking advantage of current accounting of methodology should be challenged at the national and international level.

1.4 Biogas

NC ranks third in the nation with the most biogas potential.[22,23] Biogas refers to the recovery of methane gas from anaerobic digestion of municipal and solid waste generated from swine operations, landfills, dairy farms, wastewater treatment plants, and food waste operations. It is also commonly referred to as renewable natural gas (RNG) because the principal constituents are methane and carbon dioxide. NC's REPS program offers RECs for electricity generated from landfill gas and animal waste, including swine operations. In 2017, 5.9% of the State's RECs were from Landfill gas, and 3.6% were from animal waste.[24]

RNG can play an important role in reducing methane emissions, a potent GHG with global warming potential 25 times greater than carbon dioxide. Reducing methane emissions can have a larger impact on the environment than other carbon reduction initiatives. The IPCC special report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global GHG mitigation pathways identifies this resource as one of the primary energy pathways.[25]

Agriculture is NC's top industry, accounting for $91.8 billion of the $538 billion gross state product and 17% of the state's workforce. The agricultural community sees RNG production as a new "home-grown" industry with the potential to increase employment and revenue generation potential for rural and agricultural communities, create more advanced, sustainable waste management solutions and produce bioenergy that offsets GHG emissions.

For NC, the agriculture sector accounted for 7% of the State's 2017 gross GHG emissions and waste management operations (landfills and wastewater plants) accounted for 6%. Combined, emissions from

[20] Depending on the type of tree, forests may take decades to draw the same amount of carbon back out of the air.
[21] https://www.scientificamerican.com/article/congress-says-biomass-is-carbon-neutral-but-scientists-disagree/
[22] Department of Energy National Renewable Energy Laboratory, Energy Analysis: Biogas Potential in the United States, August 2013. https://www.nrel.gov/docs/fy14osti/60178.pdf
[23] Department of Energy and US Department of Agriculture concluded the Biogas Opportunities Roadmap http://www.usda.gov/oce/reports/energy/Biogas_Opportunities_Roadmap_8-1-14.pdf) in 2014, subtitled "Voluntary Actions to Reduce Methane Emissions and Increase Energy Independence."
[24] NC Renewable Energy Tracking System (NC-RETS), Feb 2019, https://www.ncrets.org/
[25] The Intergovernmental Panel on Climate Change, SPECIAL REPORT - Global Warming of 1.5 °C, August 2018. https://www.ipcc.ch/sr15/

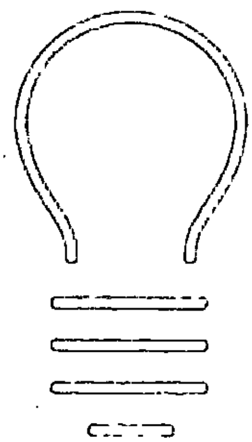
these activities equated to almost 40% of the total GHGs emitted from the State's electricity sector.[26] By 2030, emissions from the agriculture and waste management sectors are projected to be almost half of the total emissions from the electricity sector. RNG projects in the State have the potential to significantly reduce these emissions. Furthermore, RNG can reduce reliance on natural gas.

Stakeholders have expressed concerns over air and water pollution from swine operations' use of biogas technology that rely on lagoons and sprayfield waste management systems. Pollution to waterways, odors, and public health concerns for nearby and downstream communities, including those felt disproportionately by minority populations, are the reasons for opposition to biogas production.

States like California, Washington, Oregon and New York recognize RNG in meeting their GHG emission reduction goals. The private sector also incorporates biogas into their GHG mitigation plans. For example, UPS plans to convert 40% of their ground fleet to use alternative fuel, including RNG, by 2025. NC's agriculture to energy projects have been frontrunners in the country, and are pioneering the development and utilization of RNG. For example, Smithfield Foods plans to reduce its absolute GHG emissions by 25% by 2025, equivalent to 4 MMT. Smithfield Foods and Dominion Energy recently formed a joint venture Align Renewable Natural gas and are investing $250 million over the next decade to expand RNG on a wide scale. The City of Raleigh's Neuse River Resource Recovery Facility is incorporating an advanced anaerobic digestion process to reduce the overall biosolids content and accommodate future growth. The recovered RNG is planned to be used for the City's Go Raleigh bus fleet or sold to a third party as revenue, and is a key component of the City's GHG emission reduction strategy.

It is anticipated that over the coming years, new projects will be tested and applied at swine farms, food and solid waste operations, landfills and wastewater treatment plants. Technological advancements are expected to lead the industries to becoming cleaner and more efficient. The RNG industry is young and can help our state realize the benefits of decreased carbon emissions, improved resiliency (through alternative fuel supply and microgrid applications during disaster), less reliance on imported energy fuels or sources that are weather dependent, and economic development in the most impoverished areas of the state.

[26] NC Department of Environmental Quality, NC Greenhouse Gas Inventory (1990-203), January 2019. https://files.nc.gov/ncdeq/climate-change/ghg-inventory/GHG-Inventory-Report-FINAL.pdf



2. Drivers of Power Sector Transformation

The declining cost of clean energy and energy storage technologies, along with rapid advancement of information management, communications, and consumer products is transforming our electrical grid. These forces are leading the decarbonization of the electric power sector while creating economic development opportunities in urban and rural areas of the state. The four key drivers of power sector transformation in the 21st century are described below.

Key Drivers of Power Sector Transformation
• Decentralization • Digitization • Decarbonization • Development

2.1 Decentralization Driven by Declining Costs

The costs of clean energy technologies have declined rapidly in the last decade. Lazard's latest annual Levelized Cost of Energy Analysis (LCOE 12.0) shows a continued decline in the cost of generating electricity from alternative energy technologies, especially utility-scale solar and wind. In some scenarios, alternative energy costs have decreased to the point that they are now at or below the marginal cost of conventional generation (see Figure 3). Lazard's data shows that since 2009, solar PV and wind costs have dropped 88% and 69%, respectively..[27] By 2024, Wood-Mackenzie predicts that wind energy will continue to cost less than new combined-cycle natural-gas facilities on an LCOE basis in 20 states, and will grow to 28 states by 2027. For battery storage, Lazard's latest annual Levelized Cost of Storage Analysis (LCOS 4.0) shows significant cost declines across most use cases and technologies, especially for shorter duration applications, such as utility-scale solar PV plus storage (see Figure 4)..[28] Lazard also projects that by 2020, the cost of lithium-based storage could decline by 38%. An overview of key technologies enabling decentralization of the power grid is provided in the discussion below.

[27] "Lazard's Levelized Cost of Energy Analysis – Version 12.0", Nov 2018, accessed at https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf
[28] Ibid

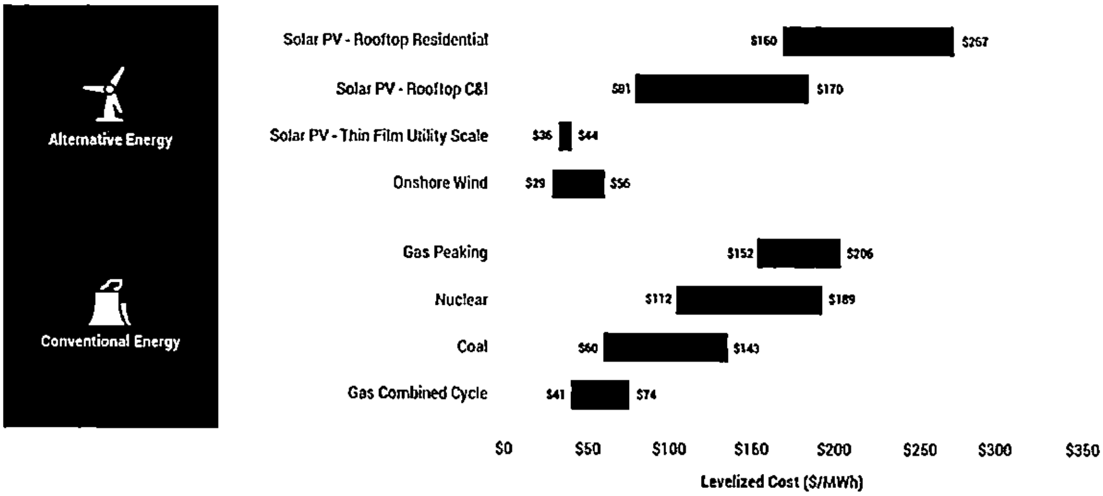


Figure 3: Lazard's Unsubsidized Levelized Cost of Energy for Alternative and Conventional Technologies, version 12.0

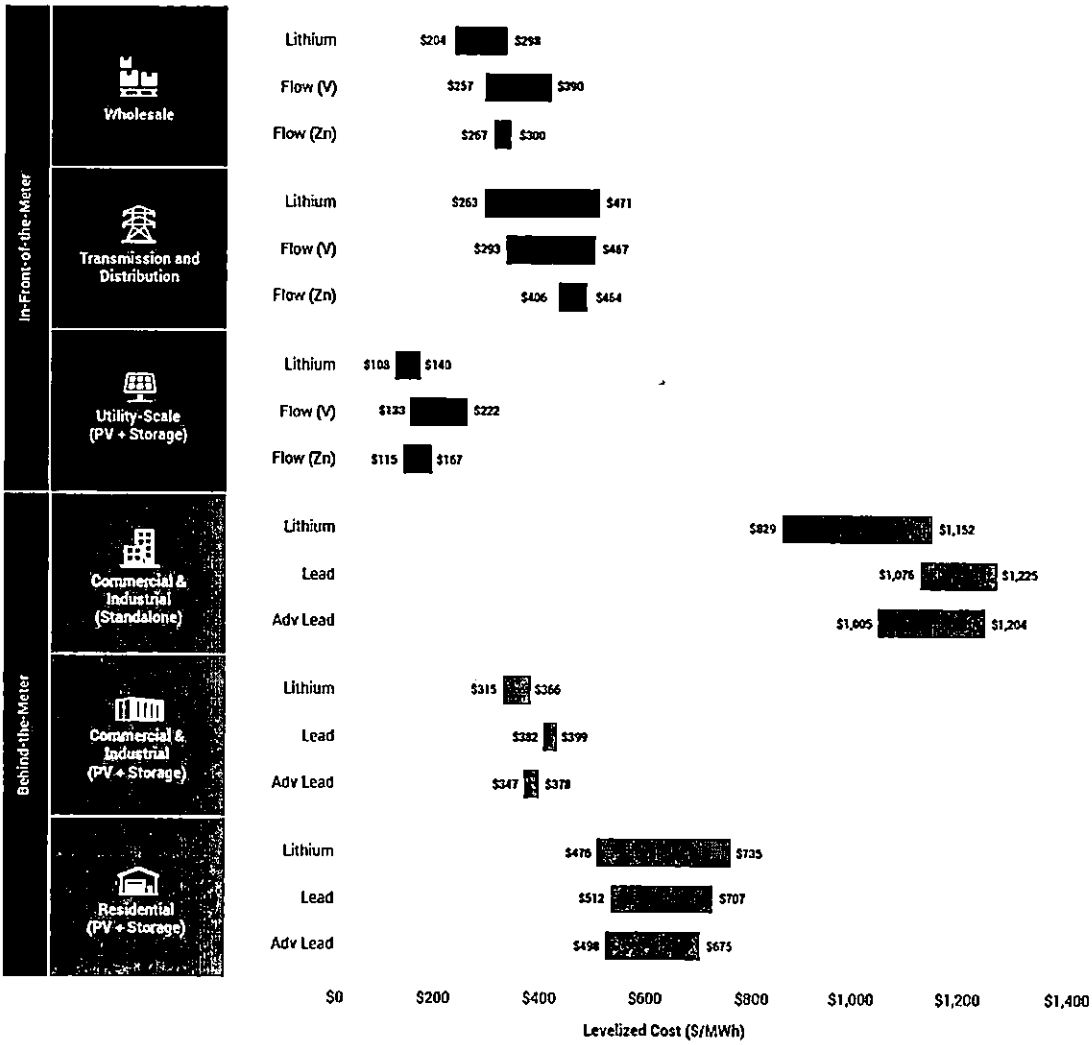


Figure 4: Lazard's annual Levelized Cost of Storage Analysis (LCOS 4.0)

2.1.1 Utility Scale Renewables

The Energy Information Administration (EIA) forecasts that non-hydroelectric renewables will be the fastest growing source of electricity generation. In April 2019, U.S. monthly electricity generation from renewable sources exceeded coal-fired generation for the first time..[29] Renewable sources provided 23% of total electricity generation, compared to coal's 20%. EIA's January 2019 Short-Term Energy Outlook (STEO) forecasts that electricity generation from utility-scale solar generating units will grow by 10% in 2019, and by 17% in 2020. Wind generation is predicted to grow by 12% and 14% during the next two years..[30]

This projected growth is a result of new generating capacity the industry expects to bring online. In 2017, renewables represented almost 50% of the new utility-scale electric generating capacity added to the U.S. power grid. Solar is the third-largest clean energy source in the U.S. power sector, having surpassed biomass in 2017. The U.S. electric power sector plans to add more than 4 GW of new solar capacity in 2019, and almost 6 GW in 2020, a total increase of 32% from the operational capacity at the end of 2018. There are now more than 2 million solar installations in the U.S., with an additional 2 million anticipated by 2023..[31] Figures 5 illustrates historical and projected solar capacity additions for the US.

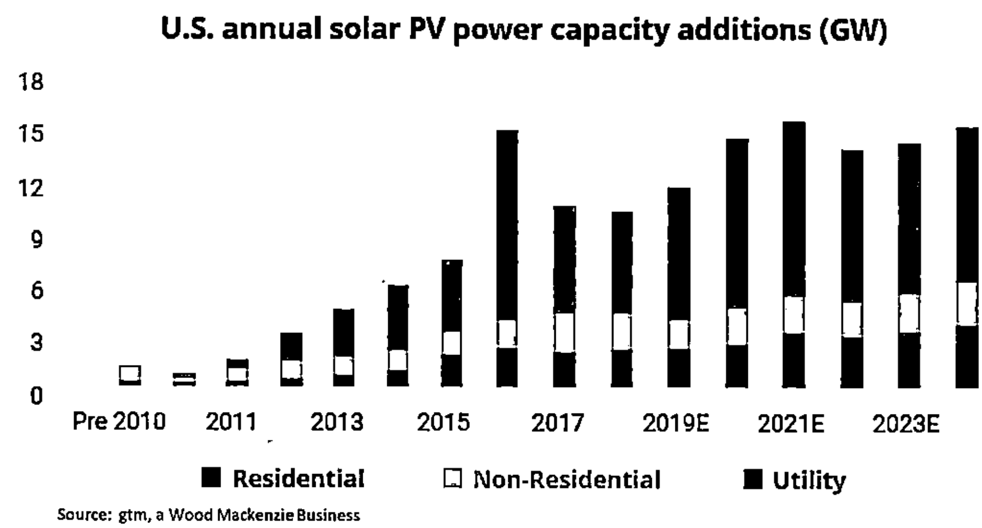


Figure 5: Solar Photovoltaic (PV) Capacity Additions

According to the Solar Energy Industries Association, NC is currently ranked 2nd in the nation for cumulative total installed solar capacity. Figure 6 (next page) shows the rise and leveling off of solar installations in the state, with utility scale projects dominating the capacity growth. How the utilities comply with HB 589, taking into consideration grid operational needs, customer demands, and cost, will determine the level of solar capacity added in the coming years.

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[29] U.S. Energy Information Administration, Electric Power Monthly

[30] U.S. Energy Information Administration, Current Issues and Trends. https://www.eia.gov/electricity/issuestrends/

[31] https://www.greentechmedia.com/articles/read/how-distributed-energy-is-reshaping-the-energy-landscape#gs.r0dwgu

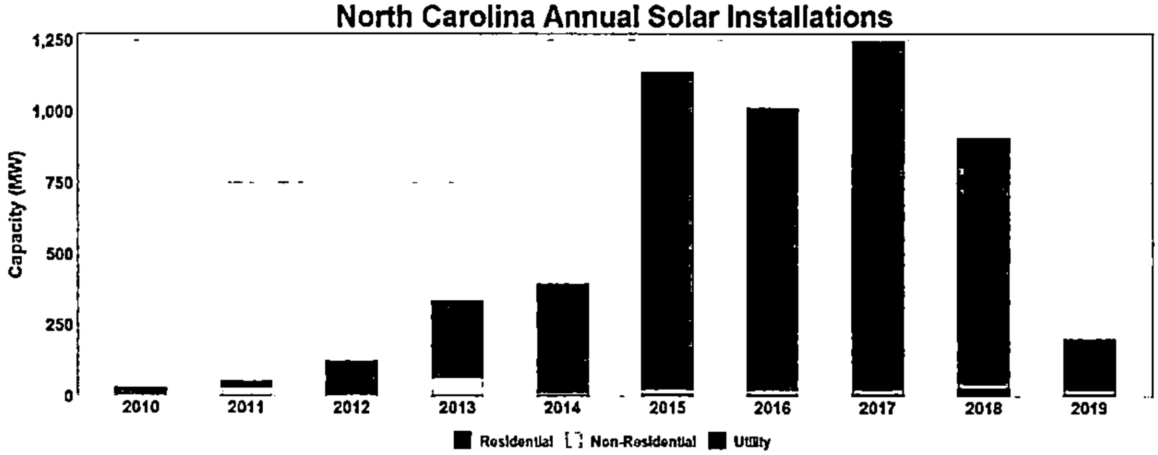

Figure 6: NC Annual Solar Installations .[32]

Wind turbines now operate across 41 states and 2 U.S. territories. The U.S. wind industry installed 841 MW of new wind power capacity in the first quarter of 2019, a 107% increase over installations in the first quarter of 2018. It is estimated that through calendar year 2019, installed capacity for wind energy generation will grow, likely doubling the installations completed in 2018. This drastic expansion should continue for the next few years as developers install projects prior to the expiration of the Production Tax Credit..[33] The U.S. EIA predicts that wind capacity additions in 2019 will total 12.7 GW, exceeding annual capacity additions for the previous 6 years..[34] The long-term outlook for offshore wind (OSW) energy generation is similar – the U.S. Department of Energy (DOE) reports a total project pipeline of 25,434 MW as of June 2018, of which 3,892 MW is in project-specific capacity and 21,542 MW of undeveloped lease area potential capacity..[35] As of the date of this Report, only one utility-scale wind energy facility is in operation in NC; the 208 MW nameplate capacity Amazon Wind Farm near Elizabeth City.

The states of Virginia, Maryland, Massachusetts, New Jersey and New York are advancing offshore wind projects. In Virginia, Dominion Energy began construction of a two-turbine OSW as a demonstration project in the second quarter of 2019..[36] New Jersey selected a company in June 2019 through a request for proposal (RFP) to build a 1,100 MW wind farm off the coast of Atlantic City. In July 2019, New York

[32] NCSEA

[33] The PTC provides operators with a tax credit per kWh of renewable electricity generation for the first 10 years a facility is in operation.

[34] U.S. EIA. Tax Credit Phase Out Encourages More Wind Power Plants to be Added by End of Year. http://www.eia.gov/todayinenergy/detail.php?id=39472#. Accessed on May 17, 2019.

[35] 2017 DOE Offshore Wind Technology Market Update.

[36] Washington Post. Utility taking cautious approach as Virginia offshore wind project gets underway. July 1, 2019. https://www.washingtonpost.com/local/virginia-politics/utility-taking-cautious-approach-as-virginia-offshore-wind-project-gets-underway/2019/06/28/540493c6-99c3-11e9-916d-9c61607d8190_story.html?noredirect=on&utm_term=.ac52d8c0fb89. Accessed July 31, 2019.

State reached an agreement to build two large OSW projects off the coast of Long Island, the largest combined OSW contracts executed by any state to date, totaling 1,696 MW,.[37,38]

2.1.2 Distributed Generation

Distributed generation represents electricity that is generated on the customer side of the electric meter or near the point of use instead of at central power plants. Examples of distributed renewables include small-scale solar systems, rooftop solar, and small wind turbines. EIA forecasts that small-scale solar generating capacity will grow by 44% between 2018 and 2020, or 9 GW. The increased deployment is partly due to the plummeting costs of distributed solar, with residential system prices dropping more than 60% since 2010. Additionally, advanced inverters (devices that convert the direct current that solar panels provide into the alternating current that flows on the power grid) are improving the performance and management of small-scale distributed generation by handling unanticipated grid conditions.

2.1.3 Energy Efficiency and Demand Response

Energy efficiency (EE) measures are technologies and processes that use less energy to perform the same function (e.g., energy-efficient lightbulbs and major appliances). Demand response activities are performed by customers to reduce electricity use at times of high-priced peak electricity consumption. Both of these demand side management approaches decrease the overall electricity demand from the grid, which in turn, avoids the cost of building new generation and transmission lines, saves customers money, and lowers pollution from electric generators. EIA's annual survey of electric utilities tracks the incremental annual electricity savings and costs from utility-run EE programs. Incremental energy savings are the additional energy savings from new participants in EE programs during the current reporting year. The amount of incremental energy saved through EE programs increased from 26.5 million MWh in 2014, to 29.9 million MWh in 2017. At the same time, incremental spending on EE programs has remained flat in recent years.

Demand response programs typically offer customers a rebate or lower energy costs for reducing energy use during specified hours or allowing the utility to cycle its air-conditioning systems when needed. These programs are increasingly being implemented through price signals and advanced software systems that can automatically reduce energy consumption across building fleets at periods of peak energy demand. However, since implementation of EE is a customer choice and not a requirement, the electricity system may not be able to fully rely on customer behaviors to reduce demand.

2.1.4 Battery Storage

Lithium ion batteries currently dominate the world of advanced energy storage. Other forms of storage technologies include compressed air, thermal storage, and pumped hydro storage. Energy storage systems reduce the need for peaker power plants, improve the resilience of the power grid, and can be paired with

[37] New York Times. New York Awards Offshore Wind Contracts in Bid to Reduce Emissions. July 18, 2019. https://www.nytimes.com/2019/07/18/business/energy-environment/offshore-wind-farm-new-york.html. Accessed July 31, 2019.
[38] Utility Dive. New York awards record 1,700 MW offshore wind contracts. July 19, 2019. https://www.utilitydive.com/news/new-york-awards-record-1700-mw-offshore-wind-contracts/559091/. Accessed on July 31, 2019.

intermittent renewable generation systems to operate as virtual power plants. The use of utility-scale battery storage units (1 MW or greater power capacity) has grown in recent years. Operating utility-scale battery storage power capacity has more than quadrupled from the end of 2014 (214 MW) through March 2019 (899 MW). Assuming planned additions are completed and no existing operating capacity is retired, EIA predicts that utility-scale battery storage power capacity could exceed 2,500 MW by 2023 (see Figure 7). The total deployment of utility and non-utility energy storage is projected to reach 4,500 MW and represent a $4.8 billion market by 2024.[39]

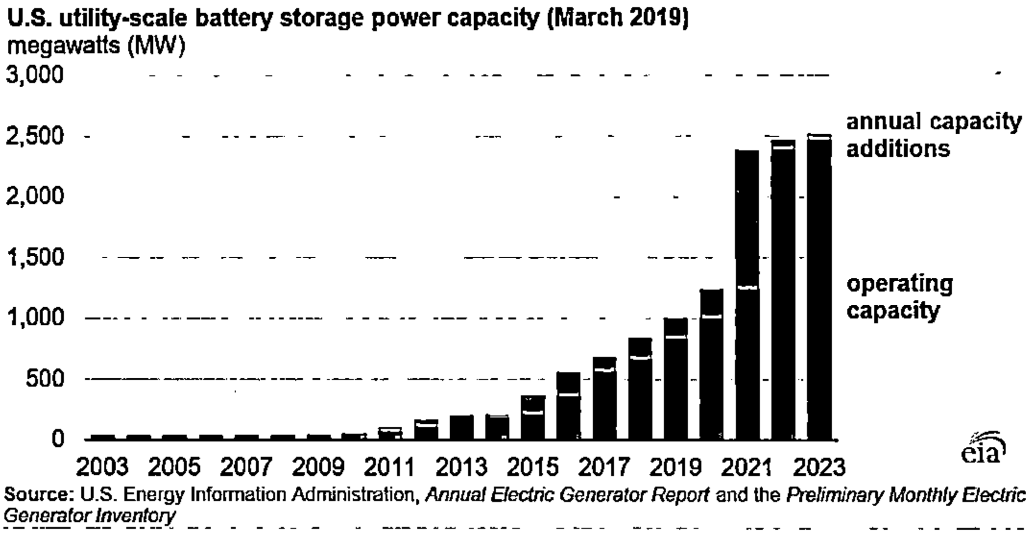

Figure 7: Battery Storage Capacity Additions

The growth in utility-scale battery installations is the result of supportive state-level energy storage policies and the Federal Energy Regulatory Commission's (FERC) Order 841 that directs power system operators to allow utility-scale battery systems to engage in wholesale energy, capacity, and ancillary services markets. Rapidly declining costs are also increasing deployment of these systems.

As of March 2019, the largest utility-scale battery storage sites operating in the US provide 40 MW of power capacity, and are located in Alaska and California. Based on the current inventory of battery storage projects planned for construction, EIA reports that a 409 MW facility in Parrish, Florida will start commercial operation in 2021. This project will be the largest solar-powered battery system in the world and will store energy from a nearby Florida Power and Light solar plant.

In NC, only about 1 MW of battery storage capacity has been installed as of 2018, however several battery projects are planned. The 2018 IRPs for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) indicate that a combined total 291 MW of battery storage is expected to be installed by 2033. Cypress Creek, a large NC solar developer, plans 12 MWh of battery storage facilities coupled with solar for the Brunswick Electric Membership Corporation. As part of a community solar project, a 500 kW Li-ion battery combined with a 1 MW solar project is planned for the Fayetteville Public Works

[39] Wood Mackenzie P&R/ESA, U.S. energy storage monitor Q2 2019, https://www.woodmac.com/research/products/power-and-renewables/us-energy-storage-monitor/

Commission..[40] Duke Energy recently received approval for a solar PV plus storage project in Hot Springs by the NC Utilities Commission (NCUC). This project will include 2 MW of solar and a 4 MW battery and is intended to improve electric reliability in the town, which is on a constrained transmission line..[41]

NC does not have any programs specifically designed to facilitate energy storage installations. However, there are policies in place that have energy storage deployment implications. HB589 includes a number of PV deployment program goals for NC..[42] In addition, NCUC dockets implementing one of HB589 programs – Competitive Procurement of Renewable Energy (CPRE) – have topics relevant to energy storage. One docket in particular deals with energy storage protocol that is a part of the CPRE power purchase agreements. In docket hearings, it was noted that electric grid ancillary services, like frequency regulation and voltage control which are particularly suited to batteries, have no transparent market value in NC, making it difficult to monetize the value of these services for a developer considering installing battery storage..[43] Comments made by the NCUC Public Staff regarding the lack of energy storage market transparency state that market participants and Duke Energy generally agree that energy storage can provide many grid benefits, such as frequency regulation, operational reserves, and firm capacity; however, there is no mechanism to pay market participants for these services. Further review would be needed to determine how market participants can be compensated for those services, recognizing that they are bundled in the payment system that Duke Energy uses today. Although price declines will contribute to increasing energy storage in NC, policies may also be necessary to integrate energy storage onto the NC electric grid supporting a timely shift to clean energy.

2.1.5 Microgrids

Localized grids that can disconnect or "island off" from the utility power grid are called microgrids. Microgrids consist of distributed energy resources (DERs) and control systems that operate autonomously when called upon, increasing grid flexibility and resiliency..[44] The types of technologies used in microgrid applications include solar PV, battery storage, fossil fuel generators, fuel cells, combined heat and power systems and smart controls. There are roughly 160 microgrids with 1.6 GW of capacity operating in the US today, and capacity is estimated to reach 4.3 GW by 2020. According to the third quarter report, *U.S. Microgrids 2016: Market Drivers, Analysis and Forecast*, GTM sees US microgrid market opportunity doubling from $836 million in 2016, to $1.66 billion in 2020..[45]

Figure 8 shows the owners and application types of microgrid installations. The military is pursuing microgrids for energy security or to achieve RE goals, and is estimated to contribute to 52% of microgrid

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[40] NC State University, DeCarolis et al. (2018). *Energy Storage Options for NC.* p.4. Retrieved from https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2019/02/NC-Storage-Study-FINAL.pdf.
[41] Utility Dive. (2019). *NC approves Duke's first solar+storage residential microgrid.* Accessed at www.utilitydive.com/news/north-carolina-approves-dukes-first-solarstorage-residential-microgrid/554770/ .
[42] HB589 is discussed in the Clean Energy Plan section NC Energy Policy Landscape.
[43] NC Utilities Commission. May 1, 2019. Docket E-2 Sub 1159, E-7 Sub 1156 Hearing, p. 14.
[44] U.S. Department of Energy. (n.d.). The role of microgrids in helping to advance the nation's energy system. https://www.energy.gov/oe/activities/technology-development/grid-modernizationand-smart-grid/role-microgrids-helping
[45] US Mircrogrid Market Growing Faster than Previously Thought: New GTM Research, August 29, 2016, Elisa Wood, https://microgridknowledge.com/us-microgrid-market-gtm/

capacity deployed as of July 2019..[46] The second largest users of microgrids are data centers in commercial applications, representing 26% of capacity added to date..[47] Community microgrids are also on the rise, especially in the Northeast and Alaska, influenced by societal and environmental needs.

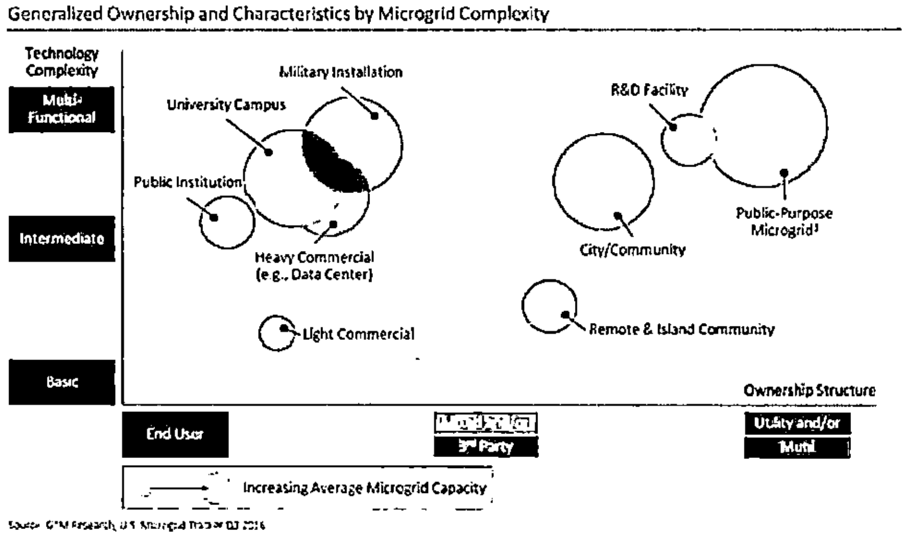


Figure 8: Microgrid Applications and Ownership Types

2.1.6 Electric Vehicles

The car industry is also undergoing a transformation, with almost every automaker planning to introduce more electric vehicle (EV) models and citing 2025 as the projected year when the upfront cost of an EV will reach parity with internal combustion engine (ICE) vehicles. In 2017, EVs represented 1.1% of new U.S. vehicle sales, or 200,000 vehicles. By 2025, J.P. Morgan estimates that EVs and hybrid EVs (HEVs) will account for an estimated 38% of all new vehicle sales (see Figure 9)..[48] The U.S. DOE projects that by 2040, EVs could make up over 50% of new car sales, largely driven by plummeting battery costs..[49]

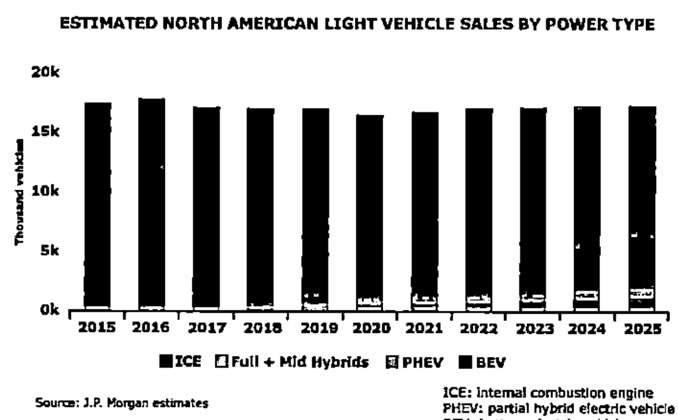


Figure 9: Projected Growth in Vehicle Sales

High rates of EV adoption present an opportunity to reduce GHG emissions, grow and smooth electricity demand, and cut fuel costs for consumers. However, there is growing concern that if not managed adequately, accelerated EV

[46] US Mircrogrid Market Growing Faster than Previously Thought: New GTM Research, August 29, 2016, Elisa Wood, https://microgridknowledge.com/us-microgrid-market-gtm/
[47] Ibid.
[48] Ibid
[49] U.S. Department of Energy. (2014). Evaluating electric vehicle charging impacts and customer charging behaviors—experiences from six smart grid investment grant projects. Retrieved from https://www.smartgrid.gov/files/B3_revised_master-12-17-2014_report.pdf

growth could significantly affect electricity usage and peak demand. Many states are exploring innovative planning approaches to deploy charging infrastructure and develop rates and utility business models to accommodate their residents' and business needs.

2.2 Digitization Driving Grid Operations and Grid Flexibility

With the continuous supply of smart devices and digital communications entering the market, a growing number of electricity customers are demonstrating interest in the ability to control their usage, control their bills and source their energy. Technology is enabling participation by customers through new capabilities and controls into homes, buildings, and end-use equipment. With the proliferation of electric devices, appliances, heat pumps, and EVs, customers can participate in a range of services by participating in smart charging programs or shifting their use to off-peak times. This increased use of technologies and DERs is moving from the traditional one-way system to one that is bi-directional and more complex. DERs are physical and virtual assets that are deployed across the distribution grid, typically close to load, and usually behind the meter. They include solar, energy storage, EE, combined heat and power (CHP/cogen), and demand management, and can be used individually or in aggregate to provide services to the electric grid..[50]

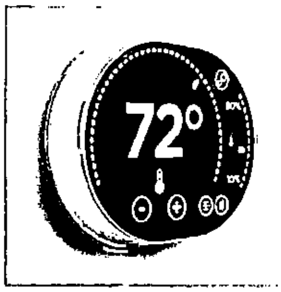
In a well-designed system, DERs can provide positive net value to the grid, such as avoided infrastructure investments, improved resilience, and increased integration of clean energy. Through these capabilities, customers can help mitigate or in certain cases, reduce electricity cost when they offer services to the utility. For example, customers who choose EE measures that shape their load to complement grid resource availability are contributing to keeping costs down for all customers because peaking loads contribute to grid infrastructure investment..[51]

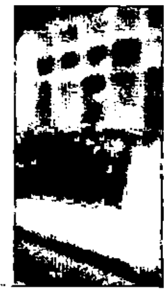
At the heart of digitization and DER integration is distribution system planning (DSP). DSP is a process that identifies and characterizes areas of the grid that must adapt to changing technologies and markets, and serves as a valuable planning tool to guide utility investment, foster customer and marketplace activity, and provide value to the grid and the entire system. Utilities are already being asked to use DSP to reveal value opportunities on the system. NC's rural electric cooperatives have been early adopters of advanced technology, and are leading the way to increased reliability, two-way communication, load management, and grid operation. Service providers are also recognizing that new electric loads are flexible, and can be managed as grid resources by establishing the right price signals (e.g., customer choosing to use equipment during off-peak hours). However, since the use of DERs and EE are a customer choice and not a requirement, the electricity system may not be able to fully rely on these DER assets or behaviors to reduce demand.

[50] Distributed Energy Resources 101: Required Reading for a Modern Grid, Advanced Energy Economy, February 2017, https://blog.aee.net/distributed-energy-resources-101-required-reading-for-a-modern-grid

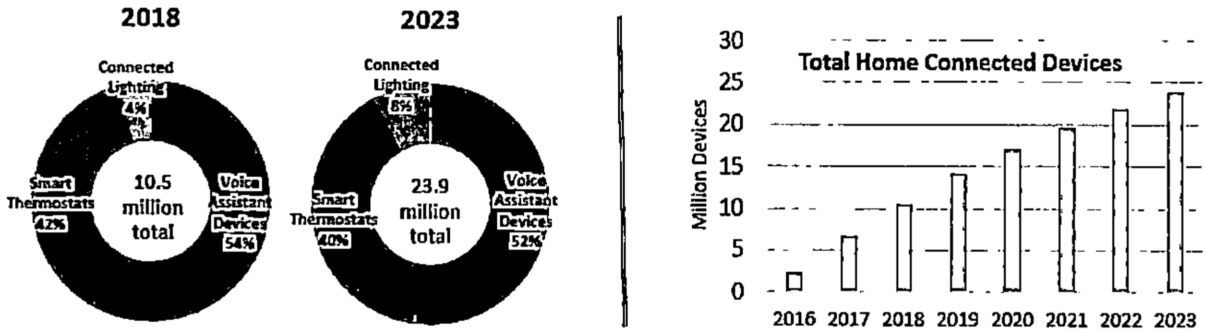
[51] Trends in Technology and Policy with Implications for Utility Regulation, Regulatory Assistance Project, C. Linvill, J. Shernot and J. Shipley, April 2018.

2.2.1 Smart/Connected Devices





Homes and businesses are increasingly connecting devices and appliances to the internet or allowing them to communicate. This function allows for more frequent and user-specified control of the devices—resulting in greater system EE and demand response operation. Over the next few years, millions of new households are expected to install smart thermostats, smart light bulbs, and smart home controllers. Figure 10 illustrates the projected growth for three types of smart devices (connected lighting, smart thermostats, and voice assistant devices) between 2018 and 2023. The number of households with smart home devices is expected to more than double in the next two years.



Source: gtm, a Wood Mackenzie Business

Figure 10: Projected Growth in Smart Home Devices

2.2.2 Smart Grid - Advanced Metering and Sensor Technologies

Throughout the country, advanced metering infrastructure (AMI) is enabling two-way communication between customers using smart devices and electric utilities (or third-party providers). AMI is an integrated system of smart meters and data-management systems. Transmission and distribution automation technologies are using data to change how electricity flows through the power grid, reshaping and modernizing the traditional grid. Figure 11 illustrates the AMI penetration levels for residential customers as of 2016. According to 2017 EIA data, 51% of NC residential customers have AMI, and an additional 30% have automated meter reading which provides one-way meter-to-utility data flow..[52] As a result of the trend towards a more customer-centric grid, NC utilities are implementing more AMI; the way these advanced technologies are transmitted, distributed, and managed accommodate the desire for two-way energy flow.

[52] EIA Annual Electric Power Industry Report, Form EIA-861 detailed data files, available from https://www.eia.gov/electricity/data/eia861/

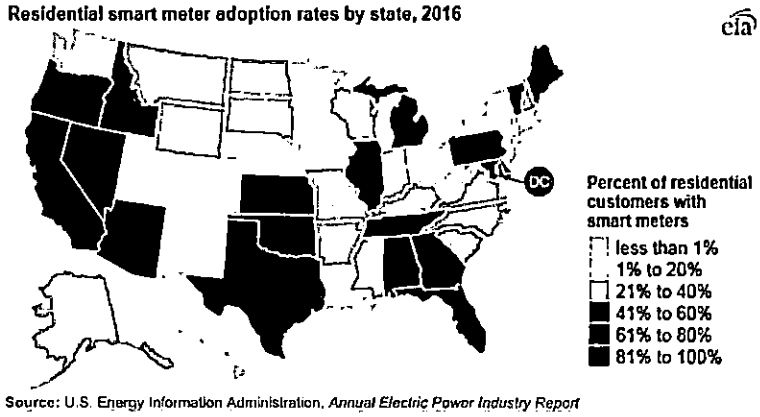


Figure 11: AMI Adoption Rates as of 2016

Advances in sensor technologies are enabling accurate, real-time conditions of the grid to be monitored, and are quickly becoming a fundamental component of the smart grid. Utilities employ sensors to monitor real-time two-way flow of electricity on the grid, improve reliability, provide real-time alerts about system disruptions, enhance responsiveness to outages, and support the integration of clean energy technologies..[53]

2.2.3 Big Data Systems and Communication Tools

Advanced meters, sensors, and devices operating on the power grid generate large amounts of digital data, many transmitting readings in small time intervals and requiring a significant volume of data storage capacity. As the number of smart devices increases, the data collection, management and interpretation of the modern grid will increase the role and value of big data and analytic software systems and services. The estimated economic growth opportunity in North America for this transition is estimated to triple from $390 million in 2016 to about $1.2 billion in 2025..[54]

Digital communication systems are providing the foundational infrastructure to support the technologies in a modernized grid. Advanced communication networks provide not only the capability to use the traditional electric power infrastructure to deliver data, but also enable utilities or grid operators to receive, interpret, and act on the data in near-real time. This flexibility enables assets across the grid to communicate with one another and respond to dynamic changes in electricity demand and supply.

[53] U.S. Department of Energy. (n.d.). Synchrophasor applications in transmission systems. Retrieved from https://www.smartgrid.gov/recovery_act/program_impacts/applications_synchrophasor_technology.html; Southern California Edison. (n.d.). Remote fault indicators. https://www.edison.com/content/dam/eix/documents/innovation/RFIFactSheet-R2.pdf

[54] Utility analytics. Use cases, platforms, and services: Global market analysis and forecasts. (2016). Retrieved from Navigant Research website: https://www.navigantresearch.com/research/utility-analytics

2.3 Decarbonization Driven by Customer Desires

There is no doubt and scientific consensus supports the fact that GHGs emissions, which include carbon dioxide and methane, are contributing to global climate change. The effects of climate change pose significant risks to the communities, economies, and the environment. In the *2018 National Climate Assessment*, 13 federal agencies concluded that: (1) the most recent decade was the nation's warmest on record; (2) human activities, especially emissions of GHGs, are the dominant cause of the observed warming since the mid-20th century; (3) human-induced climate change is projected to continue and it will accelerate significantly if global GHG emissions continue to increase; and (4) the widespread and potentially irreversible impacts of a changing climate require an urgent effort to both reduce emissions and build resilient communities. North Carolinians understand that climate change is underway and are concerned about its impacts on current and future generations..[55]

The electric power sector is the leading emitter of GHGs in our state, contributing to about 35% of statewide emissions in 2017..[56] The power sector will continue to be NC's leading GHG emitter until about 2025, when transportation-related emissions are expected to surpass the power sector. NC's Clean Smokestacks Act, REPS, and market drivers have decarbonized the electric power sector at a faster pace than many other states. US power sector emissions have declined by 28% since 2005, due primarily to achievements in energy conservation, as well as switching among fossil fuels (coal to gas) and adding non-carbon sources..[57] According to the most recent statewide inventory, GHG emissions from the electric power sector have declined 34% relative to 2005 levels. It is estimated that with full implementation of HB589, the GHG emissions will decrease by about 50% by 2025, and remain at this level until 2030. To continue on the decarbonization path, many states have implemented market-based carbon reduction programs and/or adopted aggressive renewable energy and EE standards. Some states have established 100% renewable energy goals by 2040 or 2050.

Recognizing the urgency to take action to reduce GHGs and the desire to reduce power bills, North Carolinians are asking for more options to procure and deploy clean energy technologies and invest in EE measures. From rooftop solar to electric vehicle chargers, customers have more choices now than ever before – and this technology trend is projected to continue. The appetite for acquiring residential roof top solar continues to be unmet as evidenced by the recent sellout of the rebates within hours of being offered by Duke Energy as part of HB589 implementation.

Corporate priorities have also been driving increased customer demands. Today, 17 of the state's 30 largest private employers have set targets to procure more RE or reduce their energy consumption, and 37 companies doing business in NC have set a goal to be powered by 100% RE. These companies cross a wide range of industries, including major technology, service, and manufacturing companies. These businesses have moved beyond soft factors such as community relations and good publicity, and instead adopt fundamental strategic drivers to achieve their clean energy goals, including customer and

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[55] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.
[56] NC Greenhouse Gas Inventory (1990-2030), January 2019, NC Department of Environmental Quality, deq.nc.gov/GHGinventory
[57] EIA Today in Energy, October 28, 2018. https://www.eia.gov/todayinenergy/detail.php?id=37392

shareholder demand, competitive advantage, attracting and retaining talent, operational efficiency, supply chain disruption, lower costs, and core values. For example, Apple is driving its entire supply chain to run on clean power, and announced that by 2020, it and 44 of its suppliers will generate or procure at least 5 GW of clean energy. In August 2019, Fifth Third Bank opened its 80 MW Aulander Holloman Solar Facility in eastern NC, adding to the company's announcement at the Nasdaq opening bell on March 7, 2018, to be the first Fortune 500 company to commit to purchase 100% solar power. Access to inexpensive, reliable, clean energy impacts decisions made by these companies about where they locate and expand, and whether they close existing facilities.

Many local governments across the State are setting environmental goals based on the interests of their constituents. In 2018, Asheville passed a resolution to transition municipal operations to 100% renewable energy by 2030. The Charlotte City Council unanimously passed a low-carbon resolution in 2018, and approved a Strategic Energy Action Plan to achieve it. In 2019, the city of Raleigh adopted a community-wide goal to reduce GHG emissions 80% by 2050, and began preparing an action plan to support this goal. Over 30 municipalities in the state have made public commitments to GHG reduction goals and/or clean energy targets. Local governments are motivated to reduce their carbon emissions because they see how infrastructure is suffering from being repeatedly battered and flooded during climate change-intensified hurricanes. They see how bad air and water quality is triggering health conditions in their jurisdictions. They also see how transitioning to a clean energy can provide a much-needed economic boost in their areas. Clean energy jobs in NC have been growing at nearly twice the state average and employ veterans at nearly twice the economy-wide rate. There is great interest in the manufacturing industry, as components of wind turbines and solar panels are constructed in NC. Cities see how electrifying our vehicles creates opportunity by supporting new business ventures for EV charging stations and ancillary infrastructure, while also improving local air quality.

Low-income and energy-burdened customers and communities are not able to take advantage of existing programs for clean energy or EE due to up-front costs and financing challenges, physical challenges related to the quality of the building or ownership status of their housing, or simply a lack of access to high-integrity service providers. Energy burdened communities are paying a disproportionately high amount of their income on energy bills and simply struggle to pay unaffordable energy bills. For those living with incomes below 50% of the federal poverty level (FPL), 33% of their annual income is spent on energy bills (energy burden), of which about 20% goes to pay electric bills. Many of the energy burdened communities are directly impacted by the health and pollution impacts resulting from energy production, generation, transportation. These compounding factors mean that these communities are the least able to reap benefits of investments in clean energy and EE while being most impacted by the legacy energy industry. Programs such as community solar and home weatherization offer some opportunities to directly reduce electric bill; however, public policy focusing on energy rates and an equitable and just transition to a clean energy economy is needed.

The agriculture community is also interested in responsible farmland management, creating solar energy benefits education and incentive program, and ensuring value to the farmer to optimize the use and sustainability of farms, forests, and solar production/decommissioning in NC. Significant potential exists to increase EE of agricultural operations and buildings, leading to reduced operating costs for NC's farmers.

2.4 Economic Development Driven by the New Energy Economy

NC has experienced rapid population increase (18.5% from 2000 to 2010, and an additional 10% from 2010-2018) and a large economic shift over the past 20 years from manufacturing towards a more service-oriented industry. These trends are likely to continue; the NC Department of Commerce projects that the service economy will contribute more than 90% of the new jobs in NC from 2017 to 2026.

As the electric power industry evolves from a highly centralized, capital-intensive industry to a more decentralized, distributed industry featuring independent power producers, rooftop solar installers, distributed clean energy aggregators, and other new businesses and business models, economic development can come from both jobs and investments that drive tax revenue in local communities.

NC is one of the 10 top states for clean energy jobs in the nation.[37] According to one of the most comprehensive national energy-related employment survey, NC had a total of 110,913 clean energy jobs in 2018 including solar (8,912), wind (908), clean vehicles (7,280), and EE (86,559).[38] Energy storage now represents 1,477 jobs in NC and "grid technology/other" claims 7,607 jobs (note some overlap in total numbers).[39] Reflecting national trends, the majority of NC's clean energy jobs are in construction (44%) followed by professional services including education and consulting (21%) and manufacturing (17% of total jobs).[40] Meanwhile, the NC Department of Commerce estimates that nearly 300,000 people in NC currently work in related clean economy industries, including clean energy generation, EE, and clean transportation. While not all of the industries in the Commerce study are 100% "clean," these industries employ the workforce needed to transition to a clean economy and employ workers in a wide range of occupations, with jobs available at all education, skill, and wage levels.[41]

While jobs are important to all communities, the revenues generated by clean energy investments and infrastructure projects can have even longer lasting benefits in both rural and urban counties. New RE projects and facilities can create ongoing revenue streams in their local communities.

Additional revenue can also be generated from exports. More than 20% of the clean energy goods and services generated in NC are exported to other states or nations, bringing new revenue into our state. Firms engaged in clean energy product manufacturing or production lead out of state exports, with approximately 53% going to other markets..[58] Research and development activities also have a strong out-of-state presence, with 38% of work destined for broader markets..[59] Moreover, NC can reduce its energy imports through clean energy generation and locally-driven EE projects.

The total economic impact of clean energy development in NC is estimated at $28.2 billion over the period of 2007-2018 including direct impact of $14.8 billion investment in clean energy development (which includes labor costs) and secondary impacts of $14.5 billion which include $2.9 billion in energy

[58] NCSEA. (2016). 2016 Clean Energy Census. Retrieved from https://energync.org/wp-content/uploads/2017/03/NC_Clean_Energy_Industry_Census_2016.pdf
[59] Ibid

costs savings.[60] The cumulative contribution to NC's Gross State Product from 2007-2018 is $16.9 billion, including $1.4B tax revenue over this period.[61]

Going forward, employers in NC are projecting 5% growth in employment over the next twelve months, driven largely by 8.3% growth in the EE sector.[62] Through the CEP stakeholder engagement process and collaborative partnership efforts, businesses have expressed a number of factors they deem important to achieve robust growth of NC's clean energy economy, and the role that clean energy and clean transportation play in attracting talent and industry to the state. For example, the burgeoning OSW industry alone is expected to create a new supply chain that is estimated at approximately $70 billion by 2030.[63]

Business interest in clean energy aligns with the need for cost savings, return on investments, risk management, attracting talent, meeting shareholder and customer expectations, driving innovation and staying competitive.[64] Business leaders have called for increased investment in EE programs, increased customer access to clean energy, accelerated deployment of electric vehicles and advanced development of energy storage. These companies believe that NC can leverage these recommended actions to attract new investment to the state, spur innovation, save money for ratepayers, attract new businesses and create jobs in NC.[65]

These recommendations must be balanced with maintaining NC's attractive lower energy costs. The business sector is keen to preserve low energy rates to reduce the cost of doing business in NC, especially energy-intensive sectors such as manufacturing, as the state navigates the path towards a clean energy future.

Today many states are surpassing NC with more aggressive REPS, renewables adoption, EE policies, utility regulatory reforms, and investment activity The corporate drivers alongside the national rankings create an opportunity for NC to take new steps to sustain and grow the economic benefits that clean energy can afford, while continuing to attract businesses, talent and investment to the State.

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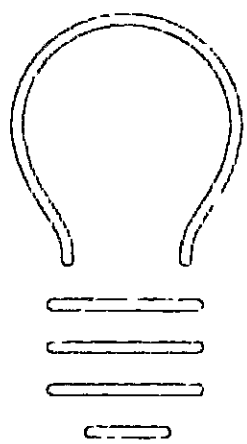
[60] RTI. (2019). Economic Impact Analysis of Clean Energy Development in NC—2019 Update.
[61] Ibid.
[62] Wood Mackenzie/SEIA. (2019). U.S. Solar Market Insight Report, Q2 2019.
[63] Special Initiative on Offshore Wind. Supply Chain Contracting Forecast for U.S. Offshore Wind Power, http://www.ceoe.udel.edu/File%20Library/About/SIOW/SIOW-White-Paper---Supply-Chain-Contracting-Forecast-for-US-Offshore-Wind-Power-FINAL.pdf. Accessed on May 31, 2019.
[64] Ceres. (2019, April 2). Letter to Governor Cooper.
[65] Ibid



3. CEP Development: Stakeholder Process

In preparation of the plan, the Department of Environmental Quality (DEQ) created an open and inclusive process to engage stakeholders. DEQ sought their input to generate a series of policy recommendations that addresses the needs of NC communities. Participants included elected officials, private citizens, industry groups, utilities, technology developers, businesses, non-governmental organizations, and leaders of the academic and faith communities. All of them offered solutions and a shared vision for NC's energy future.

The public engagement process, carried out from February to July 2019, was comprised of four types of events, referred to as methods. Method 1 was a series of facilitated stakeholder workshops, which were day-long events attended by 60-80 experts and key stakeholders with a vested interest in clean energy. Method 2 involved more general public outreach, achieved through regional listening sessions. These events were half-day sessions intended to educate members of the public about the CEP development process and to receive feedback and comments. Method 3 involved combining CEP-related activities with existing venues or events to collect feedback. Method 4 was the online comment portal, where members of the public who were unable to attend any of the in-person events could respond to specific questions and submit general comments.

This section summarizes the outputs of the facilitated workshops and other engagement methods, and is structured around three central themes shown in Figure 12. The six facilitated workshops in Raleigh provided the structural framework for the CEP. The workshops were designed and executed based on successful energy planning activities conducted in other states. Technical support was provided by the internationally-recognized utility regulatory experts, Regulatory Assistance Project (RAP), and facilitation support was provided by the Rocky Mountain Institute (RMI). Each workshop was organized to obtain feedback on specific topics identified by the participants.

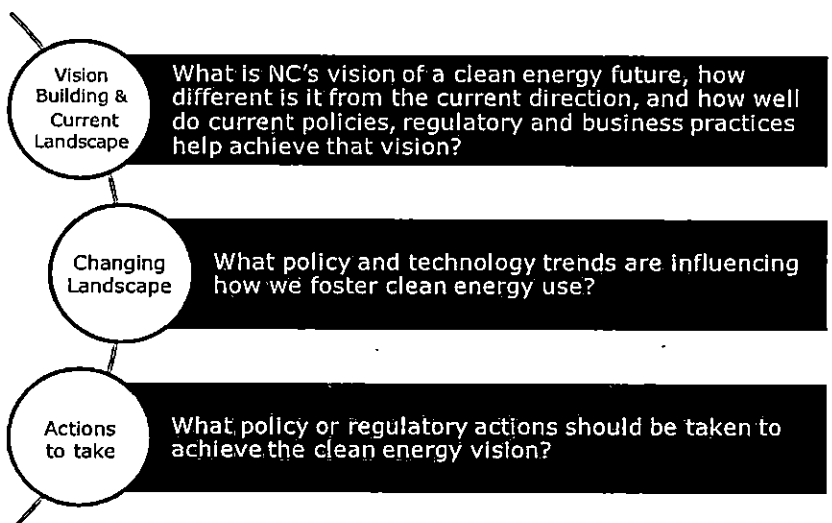


Figure 12: Facilitated Workshop Themes of Discussion

DEQ engaged with stakeholders from a variety of backgrounds and disciplines to understand their vision for NC's clean energy future. Throughout the series of workshops and public meetings, DEQ and participating stakeholders identified needs, issues, barriers, solutions, unrealized opportunities, equity concerns and required actions. Stakeholders and members of the public engaged in the process, which helped DEQ better understand their vision for a clean energy future in NC. Throughout the stakeholder and public engagement process, participants were given information about future energy demand, generation and supply strategies, and national trends in power grid modernization to help frame the discussion around issues relevant in NC. Rate impacts, economic and job opportunities, environmental and health impacts were also considered. The public engagement process culminated with stakeholders recommending and prioritizing policy, regulatory, administrative, local government, public, and business actions for achieving NC's clean energy future.

The draft CEP was released on August 16, 2019. The public comment period ran through September 9, 2019. DEQ received 660 comments, including 35 letters and 625 responses submitted through the online process. DEQ reviewed and evaluated all of the comments submitted and incorporated responses relevant to the goals of the CEP and priorities identified by the stakeholders.

3.1 Stakeholder Views on NC's Electricity System

During the 20th century, NC's electricity system consisted of large, centralized, fossil fuel-based plants that were owned and operated by electric utilities. During this period, strong growth in electric consumption necessitated the investments in continuously operating, large and long-lasting generating assets. The developing electricity system quickly became an essential service affecting the public interest. Under The Regulatory Compact, a single vertically integrated provider that owned and operated all three elements of the electricity system (generation, transmission, and distribution) was allowed to serve all consumers at lower cost with greater efficiency and reliability than multiple competing providers offering the same service. The result was a system of for-profit utilities operating in defined geographic service areas as protected monopolies, serving customers at a just and reasonable price that covered operating costs, plus a return on the capital invested in rates set by the NCUC. In return, the utility is required to serve anyone located within its service territory in a manner that is safe, reliable, and nondiscriminatory. The system allows the opportunity to recover reasonable operating costs and to earn a return on prudent capital investment, but not on operating costs. This arrangement has enabled build-out of generation capacity to meet peak-load demand, and a one-way flow of electricity from suppliers to customers.

75% of CEP stakeholders AGREED that NC's current electricity system is set up to achieve what it was intended to achieve in the last 100 years.

The 21st century electric grid is seeing declining load growth due to customer-enabled EE measures, demand response measures, a shift to less energy-intensive industries, and proliferation of behind the meter generation systems. The average annual growth in electricity consumption in the U.S. has declined from about 10% in the 1950s to less than 1% over the past decade. Data shows that economic growth indices have decoupled from the electricity generation sector at both state and national levels. This flexibility has opened doors for innovation, energy and environmental policy-making, greater customer choice, and new deployments in RE and DERs. Combined with declining technology prices and societal interests in addressing climate change, social equity and inclusion of underrepresented communities, the new electricity system is becoming much more transactional, bi-directional, and enabling customers to not only be recipients of services, but also suppliers of services to the grid.

66% of CEP stakeholders AGREED that NC's current electricity system can accommodate increasing levels

57% of CEP stakeholders DISAGREED that NC's current electricity system supports procurement of clean energy from a regulatory/utility

In this new era, the traditional electricity system is facing aging infrastructure, decline in utility revenue linked to generation investments and quantity of energy sales, growing demand for clean energy and data services, and reliability and resiliency concerns due to natural and physical threats such as weather related events and cyber-attacks. There is concern that the traditional regulatory framework will not continue to serve the public interest, could push consumer prices upward without a corresponding increase in value for customers, and potentially expose the State to excessive risk, costs and environmental damage.

Historically, NC has taken progressive and bold policy actions related to the electricity sector. As one of the first states in the nation to address air pollution from coal-fired power plants in 2002, NC enacted landmark legislation, the Clean Smokestacks Act, to cap emissions of nitrogen oxide and sulfur dioxide. The compliance strategy deployed by the affected utilities resulted in the closure of inefficient coal units and the operation of technologically advanced, well-controlled and most efficiently operated units in the nation. The legislation provided additional co-benefits such as decreased fine particulate emissions, carbon dioxide emissions, mercury emissions, and other hazardous air pollutants. In 2007, NC became the first state in the Southeast to enact a REPS.[66] Along with state and federal renewable energy tax credits, and favorable PURPA conditions, the REPS program propelled NC to become a solar industry leader, bringing associated jobs and economic development opportunity in rural areas of the state. In 2017, HB 589: Competitive Solutions for NC was enacted, which requires competitive procurement of renewable energy, creates a Green Source Advance program for large businesses, universities and the military to directly procure renewable energy, and creates a solar rebate and leasing programs program among other things.

[66] SB3

Through these policy actions, the State has created a robust clean energy industry that continues to evolve. However, despite the planned reforms under HB589, uncertainty exists over increased investments in new natural gas facilities, how solar will be developed in the state going forward, unclear direction on the scope of large scale battery storage, wind generation, and electric vehicle programs, lack of options for rooftop solar, and concerns over inequitable access to clean energy, energy burden to low-income communities, and a just transition from traditional energy jobs. Customers are also raising questions about the power sector being the largest contributor of NC's GHG emissions and how much carbon reduction is technologically feasible while maintaining affordability and reliability.

71% of CEP stakeholders DISAGREED that NC's current electricity system gives customers options for controlling energy use / source.

60% of CEP stakeholders DISAGREED that NC's current electricity system suitably addresses equity concerns.

The CEP stakeholders have communicated that the cost of electricity will continue to increase if nothing changes, while the current regulatory frameworks will inhibit the utility from pursing new technologies and limit the ability of third-party businesses from selling innovative technologies and services to customers. Furthermore, the stakeholders conveyed that a new regulatory framework can change the trajectory of costs by avoiding system costs and by forcing the utility to find more value from the electric distribution system and creating additional revenue streams from innovation and technology deployment.

3.2 Stakeholder Vision and Values to Uphold in a 21st Century Electricity System

Executive Order 80 (EO 80) and DEQ define clean energy resources to include solar, EE, battery storage, wind, efficient electrification, and other zero-emitting technology options capable of quickly decarbonizing the power sector and modernizing the electric power sector. The stakeholders involved in the public engagement process agreed with this direction, and outlined a vision aligned with this definition. The vision for NC's energy future is a clean, affordable, modern, resilient and efficient energy system, through the increased deployment of both grid scale and distributed energy resources, such as solar, EE, battery storage, wind, electrification, and other innovative solutions while giving customers more options and control, providing equitable access to clean energy opportunities, and helping customers reduce and control energy use at fair rates. In order to achieve a clean energy future that achieves this vision, NC's energy policy and regulations should work toward an integrated energy system that:

- Properly incentivizes the utilities, independent power producers, and consumers
- Recognizes the combined benefits of bidirectional flow of energy between the central grid and distributed energy resources
- Serves as a catalyst for innovation, new business development, and economic growth in the state
- Invests and retains capital in local communities, creates a 21st century workforce, and justly transitions to clean energy jobs
- Strengths out resiliency to natural threats and decarbonizes the electric power sector

In achieving this vision, the stakeholders prioritized the values to uphold and promote going forward, shown in Figure 13. Responses were submitted by 459 individuals across all engagement events, who were asked to rank their top three values from a list of 27. Participants emphasized community and social values in many comments and points of discussion during public engagement events, and stressed the need for a CEP that addresses decarbonization of the electricity sector. Among these stakeholders that represented business and industry groups, local government sector, private citizens, environmental groups, higher education, utilities, trade associations, and others, there was overwhelming consensus around the Environment and Carbon Reduction value, at 20%. It was ranked in the top three values in all submitted surveys from all events, and was prioritized by all sectors that were involved in the stakeholder process, including business groups, manufacturing, environmental organizations, educators, and members of the public. Affordability, Reliability, and Environmental Justice were also of high priority to participants, each at 7%.

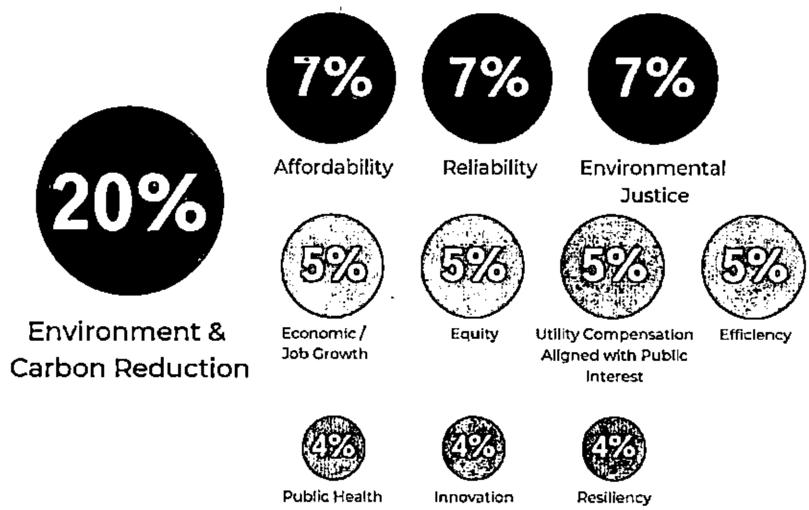
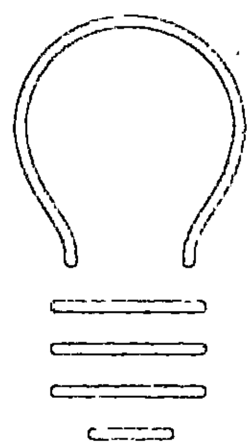


Figure 13: Stakeholder Voting Results on Values to Uphold in the Electricity System
459 respondents

To help achieve this vision and maintaining our core values, the stakeholder conveyed that NC should work toward an integrated energy system that:

1. recognizes the combined benefits of the central grid and DERs,
2. invests and retains capital in local communities,
3. creates jobs of the 21st century, and
4. serves as a catalyst for innovation, new business development and continued economic development in the state.

Future energy policy and regulations should strengthen our resiliency to natural threats, quickly decarbonize the electric power sector, and properly incentivize utilities, independent power producers, and consumers to make this vision a reality.



4. Detailed Policy and Action Recommendations

The CEP examines a time horizon of about ten years, with an outlook to 2030. This period was selected because the availability of technologies and energy resources are generally well known, and market trends can be reasonably predictable. The uncertainty of forecasts increases greatly beyond ten years; it is recommended that a similar planning process be carried out in periodic intervals in the future (e.g., every 3-5 years) as new technologies are developed, cost information is updated, and results of past actions can be evaluated to chart potential paths to take in the future.

The CEP defines three goals to achieve, as shown in Figure 14 on the next page. Each of these goals is based on clean energy's ability to reduce GHG emissions, grow NC's economy, and foster long-term energy affordability. These goals will not be achieved overnight, nor through implementation of one or two actions; rather it will require a collection of actions to set us on a path of modernization that prepares our residents, governments, and businesses to be competitive, proactive, and responsible stewards of our environment.

The policies and action recommendations identified here are intended to provide policy-makers, regulatory bodies, local governments, higher education entities, and the private sector with a high-level implementation plan for achieving the long-term goals and performance measure targets listed below. The recommendations generally represent the collective input of stakeholders from a wide range of perspectives. When viewed collectively, these strategies should help develop a clear picture of the steps that can be taken to maximize the economic and environmental benefits of clean energy. Decision-makers should use these strategies to inform their policy agendas and their investments. In summary, the CEP serves as a playbook of viable energy policies, and a roadmap to where NC wants to go.

Three overarching recommendations, listed below, are considered critical to the transition to a 21st century regulatory model that incentivizes business decisions that benefit both the utilities and the public in creating an energy system that is clean, affordable, reliable, and equitable. These key recommendations are considered central to the transformational shift that is necessary to lay a new foundation for a clean energy future, and will also enable successful implementation of many other related recommendations identified in the CEP.

- Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options *(Recommendations A-1 and B-3).*
- Develop and implement policies and tools such as performance-based mechanisms, multi-year rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy *(Recommendations B-1 and B-2).*
- Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes *(Recommendations D-1, E-1, G-1, and I-1).*

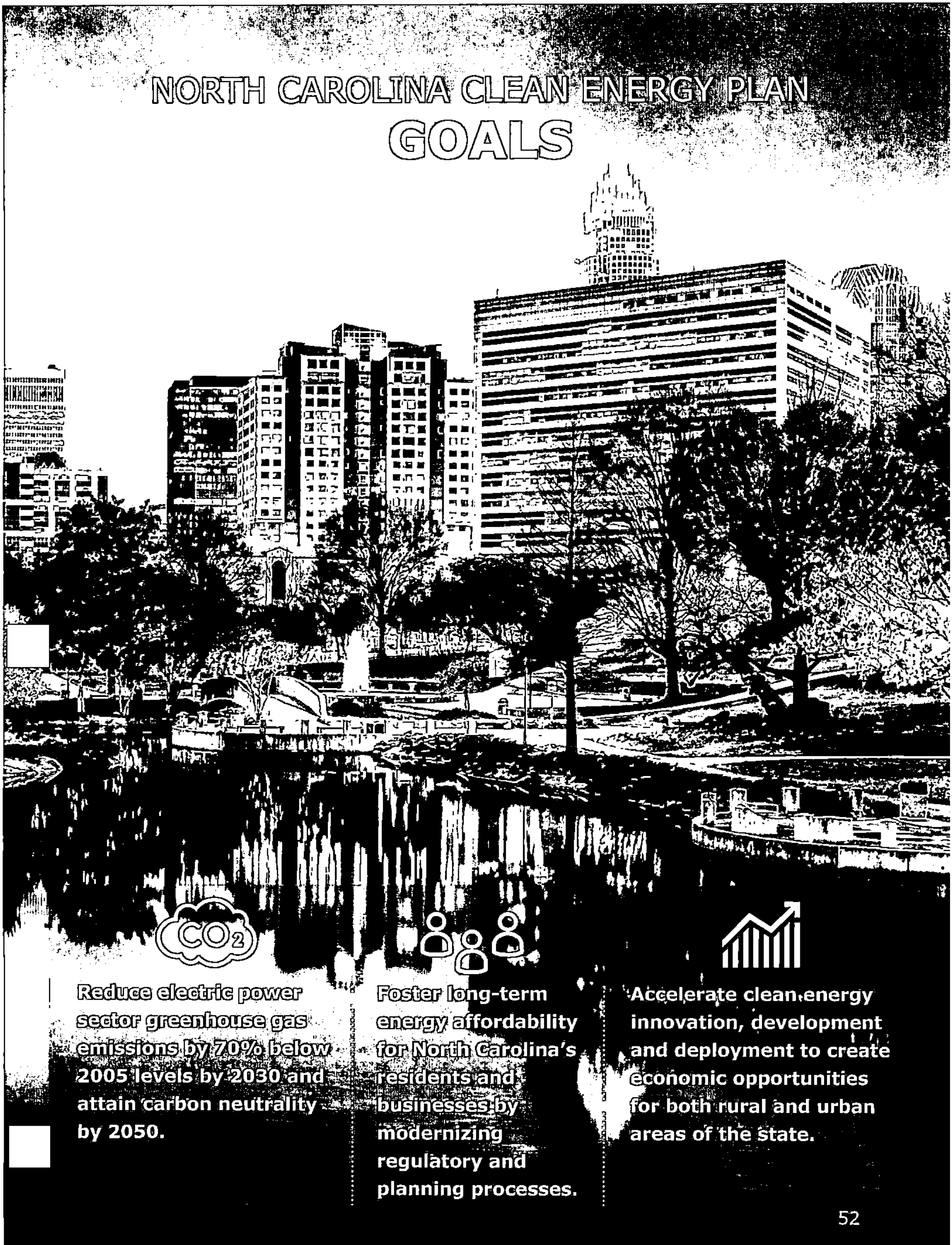


Figure 14: CEP Goals

The remaining portion of this section discusses recommendations organized into six strategy areas. For each strategy, the following information is provided: Background, Recommendation(s), Action(s) corresponding to each recommendation, implementing entity, and action schedule. The recommendations are grouped into six strategies shown in Figure 15 and summarized below.

- Carbon Reduction: focuses on the development of greenhouse gas mitigation policy designs for the electric power sector
- Utility Incentives and Comprehensive System Planning: addresses recommendations related to utility compensation methods, regulatory processes, and long-term utility system planning
- Grid Modernization and Resilience: identifies pathways to modernize the electric grid to support clean energy resources, and ways to establish and maintain grid resilience and flexibility
- Clean Energy Deployment and Economic Development: focuses on methods to increase customer access to clean energy resources, regulatory processes related to the way clean energy resources are valued, and emerging areas that can create economic opportunities
- Equitable Access and Just Transition: addresses methods to relieve the energy burden on low income communities, provide job training, and develop a clean energy workforce
- Energy Efficiency and Electrification Strategies: identifies approaches to electrify the transportation sector and end-use sectors

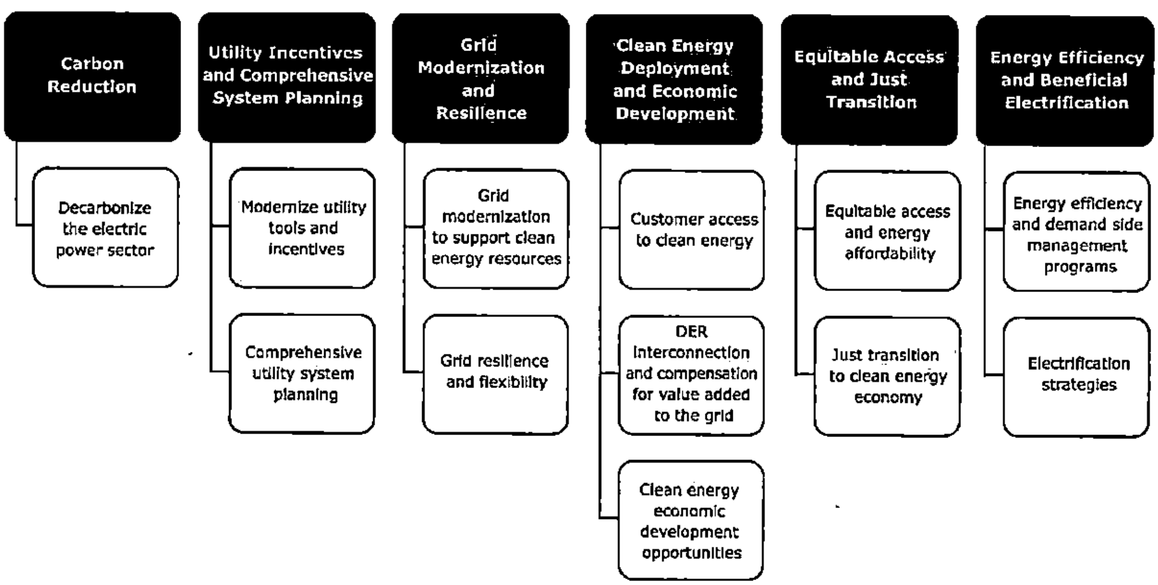


Figure 15: CEP Strategy Areas

The CEP presents short-term (less than 12 months), mid-term (1-3 years), and longer-term actions (3-5 years) to work towards the goals identified above. These time periods, shown in Figure 16, serve as indicators of priority items and activities that need to occur before related action(s) can take place.

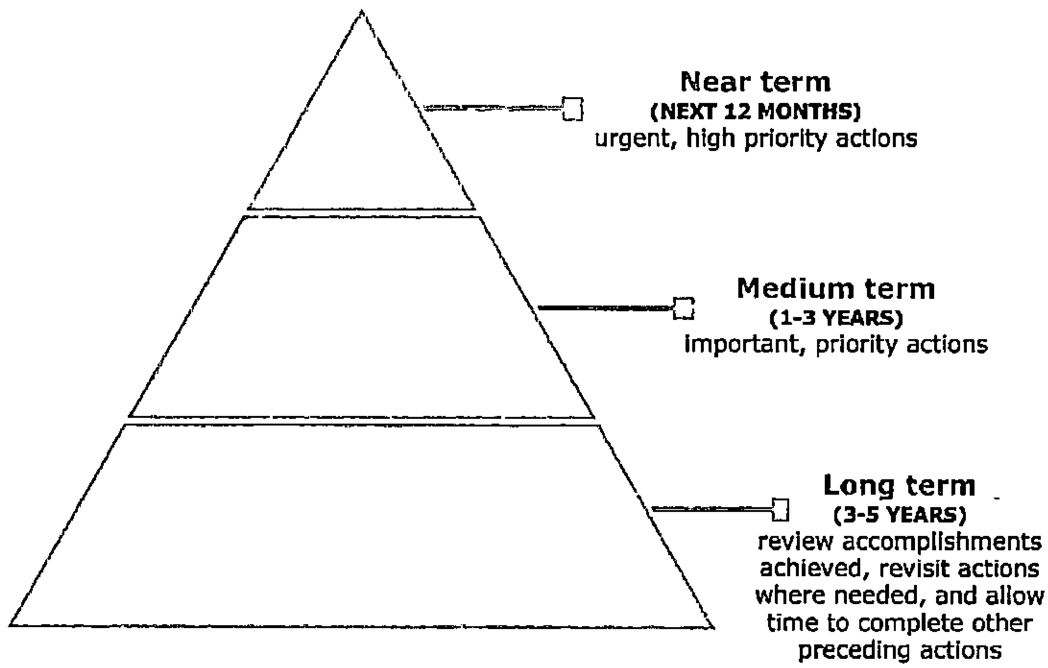


Figure 146: CEP Action Schedule

- Short term actions: considered essential to enable other positive outcomes to occur and are within the existing ability or authority of the implementing organization.
- Medium term actions: considered just as important but may take longer to initiate or implement.
- Long term actions: recognizes that it may take several years to take effect due to the level of complexity, difficulty or authority needed to implement. Some long-term actions also consider resources required for the implementing organization to carry out the activities.

Strategy Areas & Recommendations

4.1 Carbon Reduction

Carbon Reduction

A. Decarbonize the electric power sector

A-1

Deliver a report that recommends carbon-reduction policies and the specific design of such policies that best advance core values, such as GHG emission reductions, electricity affordability, and grid reliability. The report will evaluate policy designs for the following carbon reduction strategies:

1. Accelerated coal retirements,
2. Market-based carbon reduction program,
3. Clean energy policies, such as an updated REPS, clean energy standard, and EERS, and
4. A combination of these strategies.

A-2

Require integrated resource plans and distribution system plans to use portfolios and action plans that incorporate a cost of carbon into the portfolio or plan that is selected for use by the utility.

Strategy Area		Recommendation	Legislature	Utilities Commission	Governor's Office	State Agencies	IOU	CO-Ops / Public Utilities	Local Government	Academia	Businesses
Carbon Reduction	A. Decarbonize the electric power sector	A-1	•			•				•	
		A-2		•		•	•				

SHORT TERM MEDIUM & LONG TERM

A. Decarbonize the electric power sector

Background and Rationale

NC's GHG emissions goal under EO 80 is to reduce emissions by 40% from all economic sectors by 2025. During the CEP public engagement process, NC stakeholders recommended setting an additional goal to "decarbonize" the electric power sector by 2050. While this goal is a steep challenge, many other US cities and states have set this same decarbonization target. In fact, several electric utilities have set this same goal.[67,68] Duke Energy currently has a goal of reducing CO_2 emissions from their electricity generation fleet by at least 50% from 2005 levels by the year 2030 and net-zero carbon emissions by 2050.[69] Duke Energy generates most of the electricity consumed in NC. Dominion Energy serves over 120,000 customers in northeastern NC, and has set a goal to reduce CO_2 emissions 80% by 2050 and methane emissions from natural gas assets 50% by 2030.[70]

NC has already reduced significant amounts of GHG emissions from the electric power sector. The State's Clean Smokestacks Act, REPS, PURPA and market drivers have decarbonized the electric power sector at a faster pace than many other states. According to the most recent statewide inventory, GHG emissions from the electric power sector have declined 34% relative to 2005 levels.[71] These reductions have been achieved in the absence of explicit carbon policies in the State. DEQ estimates that with full implementation of HB589, the GHG reduction level from the electric power sector will reach roughly 50% by 2025 and remain at this level out to 2030.

In order to further decarbonize the electricity generation sector as recommended by the CEP stakeholders, NC could choose (1) clean energy programs that remove uneconomical fossil generation and increase the use of cleaner energy resources, (2) carbon policy driven approaches that include targets for emission reductions and create a market for generating revenue, or (3) a hybrid approach that combines both clean energy and carbon policies.[72] Many states have proposed and implemented similar policies and programs that increase clean electricity generation while also reducing emissions of CO_2.

Table 4 shows the different approaches evaluated in support of the CEP. These approaches are based on the results of high level, predictive, electricity sector modeling exercises conducted by Resources for the Future, Georgetown Climate Center, Natural Resources Defense Council, and NC State University. DEQ conducted an analysis using the Eastern Regional Technical Advisory Committee's (ERTAC's) Electric Generating Unit Tool. These modeling exercises and analysis projected the impacts to the electricity

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[67] Xcel Energy. (2018). "Xcel Energy aims for zero-carbon electricity by 2050". December 4, 2018. Retrieved from https://www.xcelenergy.com/stateselector?stateSelected=true&goto=%2Fcompany%2Fmedia_room%2Fnews_releases%2Fxcel_energy_aims_for_zero-carbon_electricity_by_2050

[68] Southern Co. (2018). "Planning for a low-carbon future". Southern Company. April 2018. Retrieved from https://www.southerncompany.com/content/dam/southern-company/pdf/corpresponsibility/Planning-for-a-low-carbon-future.pdf

[69] https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050

[70] Dominion Energy comment letter to DEQ on the draft Clean Energy Plan.

[71] NC Greenhouse Gas Inventory (1990-2030), NC Department of Environmental Quality, Division of Air Quality, January 2019, accessed at https://deq.nc.gov/energy-climate/climate-change/greenhouse-gas-inventory.

sector from applying five different program and policy scenarios that reduce CO_2 emissions. The scenarios are described in Table 4.

Table 4: Policy Scenarios Modeled for the Electricity Sector

Scenario Name	Description
Accelerate Fossil Retirement	All coal power plants retire by 2030 and the generation shifts to non-emitting sources
Expand REPS or Clean Technology Standard	Requires a certain percentage of a utility's retail electricity sales must come from non- or low-emitting resources, energy efficiency, or demand side measures.
Market-Based Carbon Reduction Program	NC establishes a carbon reduction program that is linked with similar programs in other states and sets an initial CO_2 budget that declines each year by 3.0%.
Market-Based Carbon + Clean Tech	A linked market-based carbon program in a combination with a clean energy technology standard.

Part 5 of the CEP Supporting Documents, titled Energy and Emissions Modeling, discusses in detail the electricity sector modeling, the scenarios modeled, and the resulting impacts on the electricity sector. This includes 2030 CO_2 emissions estimates, electricity price impact (where available), and expected clean energy generation levels for each scenario identified above. Key highlights are discussed below.

Highlights from Electricity Sector Modeling

Modeling analyses seek to answer key questions for evaluating potential policy actions. Given assumptions about the future (e.g., costs of new technology, fuel prices, electricity demand), models first establish a reference or business-as-usual case that projects how the electricity sector would evolve in the absence of new policy. Will carbon emissions increase or decrease and by how much? What power plants are likely to serve electricity demand in the future and will new generation sources be required? Are existing power plants economical to retire? What share of the generation mix will be provided by each type of generation? What are the expected impacts on electricity prices? Reference cases are important because they provide a point of comparison for policy scenarios that project the impacts of new policy actions.

While a reference case gives policy makers and stakeholders a sense of the future electricity sector assuming least-cost decision-making, policy cases seek to identify the benefits and costs of new programs, policies or actions. The modeling efforts detailed in Part 5 examined three types of policy actions, alone or in combination:

1. Clean technology standard, renewable energy standard, or energy efficiency resource standard aimed at increasing the amount of electricity purchased and produced by specified technologies or increasing the amount of energy savings;
2. Carbon trading program limited to NC or linked to other similar state programs that make up the multistate Regional Greenhouse Gas Initiative (RGGI); and
3. A policy that requires coal retirements and requires replacement capacity to be met with renewables.

Each of the modeling organizations completed at least one reference case, and at least one policy case to help understand the potential benefits and costs of specific policy actions. While the models and modeled inputs vary across the different analyses, it is nevertheless possible to make some general, overarching observations:

- To achieve significant reductions beyond business as usual, the modeling suggests additional action will be needed. The modeling indicates that without additional policy action, NC's carbon emissions are likely to increase or decrease slightly by 2030, depending on the analysis.
- Emissions reductions can be achieved at low cost through a market-based carbon reduction program, especially when the program is linked to those in other states.
- Market-based carbon policies combined with policies to increase energy efficiency and renewable energy can further reduce carbon emissions and increase deployment of clean energy resources in NC.
- The particular design of new policies is important and has noticeable impacts on potential emissions reductions, wholesale and retail electricity cost impacts, capacity needs, generation mix, increase in clean energy resources, implementation costs, electricity imports, and economic benefits for the State.

Additional modeling analysis would help identify the particular policy designs of a market-based carbon reduction program and complementary policies--such as updating NC's REPS, establishing a clean energy standard, or passing an energy efficiency resource standard--to maximize benefits and minimize costs. Policy design includes elements such as level of stringency, parties covered by the policy, compliance timeline, mitigation of imported fossil generation, and strategies for investing any revenue generated.

NC Carbon Reduction Goal for the Electricity Sector

Based on the urgent need to reduce greenhouse gas emissions, quantitative and qualitative analyses, and stakeholder input, the CEP recommends an electricity-sector goal of 70% reduction in GHG emissions relative to 2005 levels by 2030 and carbon-neutral by 2050. In achieving this goal, NC's values such as electricity affordability, equity, and reliability should be fully considered.

Recommendations

A-1. Deliver a report that recommends carbon-reduction policies and the specific design of such policies that best advance core values, such as GHG emission reductions, electricity affordability, and grid reliability. The report will evaluate policy designs for the following carbon reduction strategies:

1. **Accelerated coal retirements,**
2. **Market-based carbon reduction program,**
3. **Clean energy policies, such as an updated REPS, clean energy standard, and EERS, and**
4. **A combination of these strategies.**

Based on current and projected operations of NC's power plants, emissions of CO_2 may decrease by 47% by 2030. Electricity sector modeling (summarized in Part 5 of this Clean Energy Plan) provided during development of the CEP indicates that NC will not reduce power sector greenhouse gas emissions 70% below 2005 levels by 2030 without new policies. New policies are needed to achieve the levels of greenhouse gas emissions required to meet this goal and a carbon-neutral power sector by 2050. The policy design of carbon-reduction policies is critical to achieving outcomes consistent with the core values of a significant and timely decline in greenhouse gas emissions, affordable electricity rates, expanded clean energy resources, compliance flexibility, equity, and grid reliability.

Identifying the policy design of potential carbon and clean energy policies for NC involves consideration of the following, informed by modeling as well as stakeholder input and analysis: projected impacts on emission reductions of carbon dioxide and other pollutants, monitoring and record keeping requirements, wholesale and retail prices, grid reliability, compliance flexibility, shifts in generation between fossil fuel, clean energy and imports, equity, compatibility with federal regulatory requirements, legal authority, and timeline for implementing the strategies identified.

In addition to the design elements discussed above, the individual policies have unique design elements that should be addressed as discussed below.

An accelerated coal retirement policy design must consider uneconomical fossil fuel resources, incremental benefits of retirement compared other options, whole sale and retail rate impacts, planned lifespan of fossil resources at issue, cost-recovery associated with early retirements, economic and environmental impacts of replacement energy resources, effects on electricity imports and exports, and requirements for approval of new fossil fuel units. The elements of this policy should consider the NCUC Order of August 27, 2019 (described below) and outcomes from recommendations B-1 and B-3 that examines utility financing tools to accelerate retirement of uneconomic generation assets.

Key policy design elements for a market-based carbon reduction program include level of emission limit, the scope of covered sources, distribution of emission allowances, investment of revenue generated from the program, linking the program with similar programs in other states, technical platforms for administering the program, and mechanisms for protecting ratepayers.

Clean energy policy design elements for complementary policies include the type of applicable technologies, the level of adoption required, compliance flexibility, any incentives for particular technologies, compliance timelines, duration of the policy, and mechanisms for protecting ratepayers.

On August 27, 2019, the NCUC ordered DEC and DEP to conduct several different analyses related to its IRPs which must be submitted by November 4, 2019..[73] The first involves modeling of 2030 CO_2 reduction goals to be performed for their IRPs. Duke Energy is required to analyze carbon reduction strategies including, 1) the implementation plan that results from DEC and DEP's current CO_2 reduction goals, 2) modeling of the draft CEP reduction goal, and 3) a comparison with Duke's current plans for CO_2 emissions reductions to the Governor's EO 80 which states that "The State of NC will strive to accomplish the following by 2025: Reduce statewide GHG emissions to 40% below 2005 levels." The NCUC also ordered DEC and DEP to provide an analysis showing whether continuing to operate each of its coal plants is the least cost alternative compared to other supply side and demand side resource options or fulfills some other purpose. The order also requires a more thorough analysis in its IRPs related to the benefits of purchased power, alternative supply side resources, DSM and EE programs, batteries, and a comprehensive set of resource options and combinations of resource options. Considering the timing associated with this order, the policy design recommendations should fully consider the utility's submissions and related NCUC decisions when developing any policy designs.

Electricity sector modeling indicates that market-based carbon reduction programs, clean energy policies or a hybrid of both approaches are effective policies for achieving emission reductions in a low-cost manner as well as other core values for the electricity sector. The design of these policies is critical to their impact on emissions, generation, costs, equity, and other factors.

Table A-1: Actions for Recommendation A-1

Entity Responsible	Action	Timing (Short; medium, or long term)
DEQ / Academia	DEQ will enlist assistance from academic institutions to deliver a report to the Governor by December 31, 2020, that recommends carbon reduction policies and the specific design of those policies to best advance core values—including a significant and timely decline in greenhouse gas emissions, affordable electricity rates, expanded clean energy resources, compliance flexibility, equity, and grid reliability. The report will evaluate policy designs for the following: (1) accelerated coal retirements, (2) a market-based carbon reduction program, (3) clean energy policies such as an updated REPS, an EERS	Short term

[73] Order of August 27, 2019, "In the Matter of the Biennial Integrated Resource Plan and Related 2018 REPS Compliance Plans", NCUC Docket E-100, Sub 157

	and clean energy standard, and a (4) a combination of these policy options.	
Legislature/DEQ	Take legislative and regulatory action to implement the policy designs recommended in the above report.	Medium term

A-2. Require integrated resource plans and distribution system plans to use portfolios and action plans that incorporate a cost of carbon into the portfolio or plan that is selected for use by the utility.

Investor owned utilities in NC must submit an IRP on a regular basis. An IRP is a plan for meeting future electricity needs that reviews all available supply-side and demand-side options and shows how the resource portfolio for electricity generation, transmission and distribution is expected to evolve over a specified planning period, typically 15 years. The resource portfolio chosen for the plan must result in a least cost system. In other states, utilities have recently begun to develop distribution system plans. These plans examine how DERs, including EE, demand response, distributed generation, batteries, and electric vehicles, may impact the grid, including providing reliability and resiliency services.

The utility commissions of multiple states are now requiring the use of a carbon price, a social cost of carbon, or a zero emissions credit in order to facilitate a resource planning process that accounts for the global impact of GHG emissions from fossil fuel combustion. This type of approach allows market based decision making in the resource planning process. States using this type of approach include California, Minnesota, Washington, New York, Colorado, and Illinois. Each state has a different approach to estimating and including these costs.

On September 17, 2019, Duke Energy announced new goals of reducing carbon emissions from their electric generation fleet by 50% by 2030, and achieving "net-zero" carbon emissions by 2050. At the time that this Plan was finalized, the details of how the company's new goals would affect future resource plans and other actions taken by the company were not clear..[74]

In recent years, the IRPs submitted by Duke Energy Carolinas (DEC), Duke Energy Progress (DEP) and Dominion have included planning scenarios that contain a cost of carbon in response to proposed federal carbon regulations. Since June of 2014, the US EPA has been in the process of writing and finalizing regulations regarding CO_2 emissions from fossil fuel power plants. The current EPA methods have a very low social cost of carbon, ranging from $1 to $8 per ton. This low cost does not significantly impact the IRP process. When a carbon price of sufficient value is included in the planning process, low-emitting or zero-emitting resources are favored over higher emitting resources.

Duke Energy and Dominion are investing considerable amounts in the construction of new natural gas pipeline infrastructure. The cost of this infrastructure will be passed onto electricity ratepayers in NC. These costs are currently not accounted for in the IRP process. Also not accounted for are the costs of carbon emissions associated with the construction and use of the pipeline itself. The IRP process could be modified to include these costs in the costs for building natural gas power plants.

The base price and high price for CO_2 used in the 2018 IRPs for DEC and DEP are as follows:

- Base CO_2 Price – Intrastate CO_2 tax starting at $5/ton in 2025 and escalating at $3/ton annually that was applied to all carbon emissions ($20/ton in 2030).
- High CO_2 Price – Intrastate CO_2 tax starting at $5/ton in 2025 and escalating at $7/ton annually that was applied to all carbon emissions ($40/ton in 2030).

[74] https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050

The 2018 DEC and DEP IRPs present two base cases for planning; a carbon constraint resource portfolio and a no carbon constraint resource portfolio. While Duke Energy develops these two different resource portfolios, the NCUC requires a least-cost resource portfolio. The cost of carbon is not consistently incorporated into this least cost planning.

Table A-3: Actions for Recommendation A-3

Entity Responsible	Action	Timing (Short, medium, or long term)
NCUC and Duke Energy.	1) Establish a method to monetize CO_2 emissions to meet a CO_2 emission reduction goal of 70% by 2030. Begin including this carbon cost in IRPs starting in 2020. 2) Require the use of carbon pricing in any selected resource or action plan starting in 2020. This is occasionally being done voluntarily; for example, in the 2018 IRP, DEC selected a preferred portfolio with a carbon price, but DEP did not. 3) Include any costs associated with building a natural gas pipeline that will be passed on to NC electricity rate payers by the electric utilities.	Short term
DEQ	Serve as technical resource to the NCUC regarding above activities.	Short term

Strategy Areas & Recommendations

4.2 Utility Incentives & Comprehensive System Planning

Utility Incentives & Comprehensive System Planning

B. Modernize utility tools & incentives

- **B-1** Launch a North Carolina energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation.
- **B-2** Encourage use of pilot programs or other methods for testing and evaluating components of a performance-based regulatory framework.
- **B-3** When authorizing "securitization" as a utility financing tool, include uneconomic generation assets in the scope of what can be securitized.
- **B-4** Initiate a study on the potential costs and benefits of different options to increase competition in the electricity generation, including but not limited to joining an existing wholesale market and allowing retail energy choice.

C. Comprehensive utility system planning

- **C-1** Establish comprehensive utility system planning process that connects generation, transmission, and distribution planning in a holistic, iterative and transparent process that involves stakeholder input throughout, starting with a Commission-led investigation into desired elements of utility distribution system plans.
- **C-2** Expand cost-benefit methodologies used to make decisions about resources and programs to include societal and environmental factors.
- **C-3** Implement competitive procurement of resources by investor-owned utilities.

Strategy Area		Recommendation	Legislature	Utilities Commission	Governor's Office	State Agencies	IOU	CO-Ops / Public Utilities	Local Government	Academia	Businesses
Utility Incentives and Comprehensive System Planning	B. Modernize utility tools and incentives	B-1	•		•						
		B-2		•			•				
		B-3	•	•							
		B-4	•			•					
	C. Require comprehensive utility system planning processes	C-1		•		•	•	•	•	•	•
		C-2		•				•			
		C-3		•							

SHORT TERM   MEDIUM & LONG TERM

B. Modernize utility tools and incentives

Background and Rationale

The traditional utility regulatory model in the US effectively achieved many of the policy objectives it was meant to. The ability to raise low-cost capital allowed regulated IOUs to build out a nationwide electric grid, and the regulatory model in use for the past 100+ years has led to reliable, nearly universal service, at generally stable rates. However, new public policy priorities and emerging trends are forcing reconsideration of the utility's responsibilities, now expanding to include new expectations for environmental performance, carbon reduction, customer choice, resilience, equity, and adapting to (or enabling) sector-wide innovation, among others, while retaining long-standing responsibilities such as reliability and affordability. These new demands are highlighting the limitations of the traditional utility incentive methods, forcing the industry to rethink how regulations can be updated to achieve new policy goals, as well as meet evolving grid and customer needs.

In NC, as in many other states, the existing regulatory structure encourages utilities to sell more kilowatt-hours of electricity and to invest in utility-owned capital infrastructure. These incentives do not necessarily lead to the least-cost and highest-value solution for customers. For example, distributed technologies now have the potential to substitute for conventional utility infrastructure solutions, but the current utility business incentive structure discourages utilities from selecting those options even if it would save customers money. The combination of declining load growth in the state,.[75] significant cost declines for distributed resources, and necessary upgrades to system infrastructure is putting increasing strain on the current utility business. The state's utilities need a way to maintain their financial health and ability to access low-cost capital in a future where customers have growing options to reduce energy use, shift to on-site energy production, and are demanding more control over where their energy comes from. For example, in recent years the cost of clean energy has fallen so much that there is now evidence that existing utility coal assets in NC are no longer economic, meaning that customers would actually save money if the utility was able to accelerate the closure of those units and invest in renewable generation to meet demand instead..[76]

These trends are not unique to NC. A growing number of states are investigating the appropriate steps to take to move toward a regulatory model that better aligns utility profit-making incentives with societal objectives and removes the bias toward capital investments..[77] Revisiting how a utility earns revenues is a foundational step that can impact the successful implementation of all other strategy areas in this report. Indeed, many stakeholders in the CEP process identified the successful implementation of actions in this strategy area as enabling most of the other recommendations in the Plan.

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[75] The NC Utilities Commission reported that between 2016 and 2017, electricity sales from the State's three investor owned utilities declined by 2.7% while the growth rate of new customers increased by 0.34 – 1.57%. NC Utilities Commission, Major Activities Through December 2018 With Statistical And Analytical Data Through 2017, Volume XLIX, 2018 Report.

[76] Gimon, Eric, et al. *The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources*, Energy Innovation and Vibrant Clean Energy, March 2019. Available at: https://energyinnovation.org/wp-content/uploads/2019/03/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL.pdf

[77] States include Hawaii, Minnesota, New York, Illinois, Rhode Island, Colorado, and Nevada.

Recommendations

B-1. Launch a NC energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation.

Updating NC's energy regulatory framework for 21st Century public policy goals, customer expectations, utility needs, and technology innovation will help the state realize its clean energy future. NC faces challenges on issues such as regulatory incentives, integration of distributed generation, transparent and efficiency regulatory processes, and holistic resource planning. Through the course of meetings and conversations for development of this Clean Energy Plan, some stakeholders called for an ongoing process outside traditional legislative and energy regulatory forums to work through large energy policy topics.

This energy process can involve an ongoing series of meetings among representatives of key stakeholder groups to find common ground on transformative energy-related topics. Through this process, stakeholders can tackle pressing issues by identifying shared principles and priority action areas and then working together to develop specific policy recommendations for delivery to the NC General Assembly, NC Utilities Commission, and other bodies, as appropriate. The group should address performance-based ratemaking as an action area and develop specific objectives and implementation recommendations for a new outcome-driven regulatory framework in NC. Under this action area, multi-year rate planning,.[78] performance incentive mechanisms,.[79] revenue decoupling,.[80] shared savings mechanisms,.[81] and retirement of uneconomic generation assets.[82] should be addressed.

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[78] Multi-year rate plans (MYRP) fix the time between utility rate cases and compensate utilities based on forecasted efficient expenditures or external market factors rather than historical costs of service. Multi-year rate plans use an attrition relief mechanism (ARM) to provide timely, predictable rate escalation during the period between rate cases. This escalation is based on cost forecasts, industry cost trends or both, rather than the utility's specific costs. MYRP are an effective tool at incentivizing utilities to control costs between rate cases and have been used successfully by a variety of jurisdictions. See citation below for examples. While MYRP can be implemented in isolation, they are often paired with performance incentive mechanisms, which can help ensure that undesirable outcomes are avoided (e.g., utilities cutting costs that are actually beneficial to ratepayers in an effort to increase profits) and that desirable outcomes are achieved (e.g., reduced interconnection time, carbon emissions reductions, etc.). See Lowry, Mark, et al. State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities, Lawrence Berkeley National Laboratory. July 2017.

[79] Performance incentive mechanisms create a financial incentive for a utility to achieve performance outcomes and targets consistent with customer and public policy interests.

[80] Revenue decoupling breaks the link between the amount of energy a utility delivers to customers and the revenues it collects. Decoupling mechanisms help to remove the utility's current incentive to sell more energy in order to increase revenue by making adjustments based on actual sales to ensure that the utility earns its revenue requirement.

[81] Shared savings mechanisms reward the utility for reducing expenditures from a baseline or projection by allowing the utility to retain some of the savings as profit, while passing some savings to consumers.

[82] Tools to accelerate retirement of uneconomic generation assets adjust rates to speed up the depreciation of an asset so the utility and its customers are not left with stranded costs when an asset retires early; securitization can refinance uneconomic utility-owned assets by creating a debt security or bond to pay down an early-retiring plant's

Additional priority action areas may include energy sector planning, regulatory processes, and customer options around clean energy generation and energy savings. Additional priority action areas may include energy sector planning, regulatory processes, and customer options around clean energy generation and energy savings.

The energy process can be facilitated by an objective third-party with extensive experience in the energy sector, involvement with similar processes in other states, and an understanding of NC's energy sector. To develop recommendations with broad buy-in, the process can include representatives from various stakeholder groups and produce work products for public input before submission to the applicable body.

Table B-1: Actions for Recommendation B-1

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Governor's Office	Convene an energy process to align energy regulatory incentives with 21st Century public policy goals, customer expectations, utility needs, and technology innovation, by addressing topics such as performance-based ratemaking, multi-year rate planning, and revenue decoupling.	Short term
Legislature	Implement legislation recommended by the stakeholder process.	Short to medium term

undepreciated capital balance. There are potentially multiple ways to define "uneconomic" and a decision to pursue retirement of utility assets will need to be closely analyzed by the NCUC. For purposes of the discussion in this report, uneconomic assets are those that could have their output replaced by other resources (or a combination of resources) at an all-in cost that is lower than the existing resource's current costs (both capital and operating costs). That is, ceasing operation of an existing power plant and replacing it with another resource would result in lower costs and risks to ratepayers.

B-2. Encourage use of pilot programs or other methods for testing and evaluating components of a performance-based regulatory framework.

Shifting to a more performance-based regulatory framework will require some extent of flexibility. Depending on the outputs that result from the investigatory process described in the prior recommendation, pilot programs and phased approaches to policy implementation provide opportunities to test and refine specific regulatory mechanisms, such as performance incentive mechanisms and new procurement practices. In order to be adaptive, there should be processes for evaluation built in to ensure new mechanisms are working as intended. Performance metrics that measure and track utility data for certain outcomes are a key, no-regrets tool to ensure that utility performance is improving after implementing a given regulatory change. For example, testing a shared savings mechanism before full-scale implementation will provide an opportunity to ensure that the savings retained by the utility and given to customers are well-balanced. Alternatively, using a phased approach to the development of new performance incentive mechanisms could result in better informed targets and incentive levels that don't under- or over-compensate the utility.

Table B-2: Action for Recommendation B-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Require utilities to design pilots or other phased approaches to testing regulatory mechanisms that result from investigatory process on utility business model reform*	Medium term
IOUs	Co-develop pilot proposals or phased implementation approaches to test new regulatory mechanisms with NCUC and stakeholders	Medium term

*Depending on the approaches recommended by the stakeholder process, the NCUC may need to be given explicit authority by the legislature to pursue this recommendation.

B-3. When authorizing "securitization" as a utility financing tool, include uneconomic generation assets in the scope of what can be securitized

As of the writing of the Clean Energy Plan, pending legislation (Senate Bill 559), would create a new financing tool known as securitization that may be used to recover storm restoration costs. Using this financing tool, the utility could issue storm recovery bonds with lower financing costs that are secured through a dedicated storm recovery charge that is separate and distinct from the utility's base rate. Securitization typically benefits utilities and customers. Utilities benefit because they receive an immediate source of cash from the bond proceeds and customers benefit because the cost of securitized debt is lower than the utility's cost of debt, which reduces the impact on their monthly bills.

As described in the recommendation above, states are allowing securitization to be used to accelerate the retirement of uneconomic generation assets.[83] Instead of issuing storm recovery bonds, a bond that is equal to a retired plant's undepreciated capital balance would be sold to the public market. Proceeds from bond sales could then be invested in clean energy projects that still earn a return for the utility or invested in assistance for communities' transitioning away from generating fossil fuels.

Stakeholders in the Clean Energy Plan process identified securitization as an effective tool to help the state meet the carbon reduction goals included in this plan. Any legislation allowing securitization to be used as a financial tool by the utility should therefore include generation assets as eligible for cost recovery and require utilities to use freed-up capital to invest in clean energy. Legislation should direct NCUC to initiate a rulemaking to determine securitization details, such as:

- Requirements for utility applications and approval
- Which utility costs should be able to be recovered by securitization bonds
- How certain percentages of freed-up capital should be spent, subject to legislative direction regarding investments in clean energy
- Restrictions on bond terms (e.g.,15–20 year term length, 3% interest rate)

Table B-3: Action for Recommendation B-3

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Legislature	Expand scope of costs eligible for securitization in legislation to include uneconomic generation assets; direct NCUC to initiate and oversee proceeding focused on the uses of securitization	Short term
NCUC	Initiate and oversee rulemaking to determine details of securitization use cases	Short term

[83] States include Colorado, New Mexico, Michigan, Wisconsin, and Montana.

B-4. Initiate a study on the potential costs and benefits of different options to increase competition in the electricity sector, including but not limited to joining an existing wholesale market and allowing retail energy choice.

Since the 1990s, states across the country have been looking at ways that greater competition in electricity generation can provide customers more reliable energy at lower costs. This has led to the emergence of competitive wholesale and retail markets in several regions, sometimes referred to as the movement toward "restructured" or "deregulated" markets. Wholesale markets can be found in Texas, California, the Mid-Atlantic, parts of the Midwest, and the Northeast, covering approximately two-thirds of the US population. At the retail level, thirteen states and the District of Columbia have implemented some form of electricity consumer choice.

However, states do not necessarily need to have both competitive wholesale and retail electricity markets. A number of states that are part of restructured wholesale markets do not have full retail access, such as Kansas, Oklahoma, and Minnesota. It is also possible for states to have retail electricity choice but not participate in a wholesale electricity market. For example, Georgia and Oregon both have retail electricity choice for large commercial and industrial consumers, but those states are not part of any restructured wholesale power market.[84]

In the 1990s, federal lawmakers introduced wholesale electricity markets following a period of poor generator performance and escalating prices as new, high-cost generating plants came online.[85] The wholesale markets were designed to meet short- and long-term requirements for grid reliability at the lowest cost. Federal policymakers saw competition among electricity suppliers as a means to control prices by attracting new sources of private investment for newer, less expensive technologies.[86] The clearing price for electricity in wholesale markets is determined by an auction in which generation resources offer a price at which they can supply a specific number of MWh of power. This results in lowest-cost power sources, wherever they are located, providing electricity to wherever it is needed, spanning over a wide region.

Many states that pursued restructuring of the generation aspect of the utility business also required that utilities divest their ownership in generation capacity. That capacity was converted from utility ownership to independent power producer status, effectively transitioning those assets from the traditional cost-of-service regulation model to a market-based model under which they earn a market price for their output.[87]

[84] Zhou, Shengru. *An Introduction to Retail Electricity Choice in the United States.* United States: N. p., 2017. Web. https://www.nrel.gov/docs/fy18osti/68993.pdf

[85] A wholesale market refers to the buying and selling of power between generators and resellers. Resellers include electricity utility companies, competitive power providers, and electricity marketeers. For most regions within the United States, the operation of and transactions in wholesale markets are regulated by the Federal Energy Regulatory Commission. A wholesale market allows generators to connect to the grid and generate electricity after securing the necessary approval. The electricity produced by generators is bought by an entity that will often, in turn, resell that power to meet end-user demand.

[86] PJM Factsheet, "The Value of Markets", downloaded from: https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/the-value-of-pjm-markets.ashx

[87] Borenstein, S, Bushnell, JB. The U.S. Electricity Industry after 20 Years of Restructuring. Annu. Rev. Econ. 7: Submitted. Doi: 10.1146/annureveconomics-080614-115630.
Available at: https://ei.haas.berkeley.edu/research/papers/WP252.pdf

It is not necessary to require divestiture of generation assets by utilities in order for a state to pursue membership in a wholesale market, but it is an option that increases competition.

Increased competition in the supply of energy could potentially benefit North Carolina's utilities and customers by driving down electricity prices and generating innovation through increased competition among power generators, maintaining a more reliable grid by expanding generation options, and advancing a cleaner grid by leveraging regionally available renewable resources. However, these outcomes are not a given and therefore any action taken by the state to deregulate aspects of the utility industry should be studied, as recommended below.

NC explored deregulation in the early 2000s and determined to be in the state's best interest to remain in a regulated market. The NC Association of Electric Cooperatives and its members do not support deregulation due to its potential impact to serving members and contributing to a rural-urban divide.

States and utilities have widely used quantitative assessments to evaluate whether joining wholesale markets could be net beneficial for affected utilities and customers. Examples include:

- The Federal Energy Regulatory Commission (FERC) and Entergy's retail regulators held a technical conference in Charleston, South Carolina in 2009 that was attended by Entergy and many of the entities that purchase and/or sell energy in the Entergy region. FERC agreed to fund a study on the costs and benefits of Entergy and Cleco Power joining the Southwest Power Pool (SPP). The cost-benefit analysis was performed over a seven-month period, and included an open and collaborative discussion with stakeholders on the study framework, modeling approach, input assumptions, interim results, and qualitative issues. Based on the analysis performed, the study concluded that Entergy and Cleco Power joining the SPP RTO will yield significant economic benefits to the collective SPP/Entergy region..[88]

- The Mountain West Transmission Group (MWTG) is an informal collaboration of electricity service providers that are working to develop strategies to adapt to the changing electric industry. Based on the results of extensive evaluations, MWTG decided to focus its attention on seeking membership in an existing RTO. In January 2017, MWTG announced it was entering into discussions with SPP as the next step in exploring potential RTO membership. As part of the 5-stage new member integration process, SPP staff performed an analysis of the costs and benefits resulting from MWTG membership impacts to current SPP members..[89]

- Multiple utility-specific assessments of the costs and benefits of joining the Western Energy Imbalance Market (EIM) have been conducted since the EIM was created in 2014..[90] The EIM is a real-time power market in the Western United States that balances supply and demand over a large geographic area, finding the lowest-cost energy to serve demand. Individual utilities can decide to join the EIM and many have conducted studies of the costs and benefits of doing so.

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[88] "Cost-Benefit Analysis of Entergy and Cleco Power Joining the SPP RTO." Prepared for the Federal Energy Regulatory Commission by Charles River Associates and Resero Consulting. September 30, 2010. Available at: https://www.ferc.gov/industries/electric/indus-act/rto/spp/spp-entergy-cba-report.pdf

[89] "10-Year Costs and Benefits to SPP Members of Integrating Mountain West Transmission Group." Prepared by SPP Staff. March 19, 2018. Available at: https://www.spp.org/documents/56652/mwtg%20cba%20report%20for%20spp%20members%20mar-19-2018.pdf

[90] Recent examples of utility studies of joining the EIM can be found on the EIM website: https://www.westerneim.com/Pages/JoinEIM.aspx

The Legislature could authorize a study that assesses the costs and benefits of different options the state has to increase competition in electricity generation, to determine which if any, could provide greater benefits to NC customers than the status quo. It will be important for any such study to carefully examine the potential trade-offs of various options and the possible impacts of those options on NC's priorities, such as increasing clean energy deployment, enhancing affordability, and maintaining reliability.

The consultant-led study could also look at other options for increasing competition in electricity supply, such as in retail energy supply. Retail electricity choice in the United States allows end-use customers (including industrial, commercial, and residential customers) to buy electricity from competitive retail suppliers..[91] Similar to wholesale markets, retail electricity choice was introduced with the idea that increased competition would result in lower prices, improved service, and innovative product offerings. Some argue that a competitive environment also results in suppliers offering more clean energy options to customers as a way to differentiate themselves from their competitors.

Table B-4: Actions for Recommendations B-4

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Legislature / DEQ	Authorize a consultant-led study that assesses the costs and benefits of different options the state has to increase competition in electricity generation, to determine which if any, could provide greater benefits to NC customers than the status quo.	Medium or long term

[91] Zhou, Shengru. *An Introduction to Retail Electricity Choice in the United States.* United States: N. p., 2017. Web. https://www.nrel.gov/docs/fy18osti/68993.pdf

C. Require comprehensive utility system planning processes

Background and Rationale

Across the country, states are reforming the utility planning process. As the electricity system becomes more dynamic, there is a growing need to move towards more comprehensive planning processes that take into account the different layers of the grid. Streamlining traditionally disparate and serial tasks related to planning and procurement into a unified process can allow system planners to optimize investments in generation, distribution, and transmission.

Utilities and their customers, as well as third parties, can derive substantial benefits from comprehensive planning, including:

- Lowered system costs to reduce rate pressure in a low load growth environment;
- More cost-effective programs and procurements; and
- Enhanced utility, customer, and DER provider relationships as interest in DER continues to grow..[92]

Improved planning can give customers and developers the opportunity to propose, provide, and be compensated for grid services, while experiencing more efficient and predictable interconnection processes. Regulators can benefit from increased transparency and data access for optimal solution identification and more meaningful engagement with utilities and other stakeholders..[93]

NC's current path of incremental improvements to a traditional planning process is not adequate to meet the challenges of integrating high renewable and distributed energy penetrations, which are, in turn, necessary for the state to achieve goals set out in this plan related to economic growth, long term affordability and price stability, and carbon reductions. The state's current IRP process does not include explicit clean energy goals,.[94] which could inhibit the ability of the energy sector to achieve clean energy and environmental goals. Additionally, the current IRP process does not include transparency in its goal-setting and lacks rules governing stakeholder involvement prior to IRP submissions..[95] The NCUC is currently looking at ways to expand the scope of utilities' IRP processes, but there are more holistic approaches to planning for generation, distribution, and transmission resources that should be considered.

Duke Energy has acknowledged it needs to update its planning processes and has already begun developing an Integrated System Operations Plan (ISOP)..[96] Duke Energy has stated that it is important to

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[92] Volkmann, Curt. *Integrated Distribution Planning: A Path Forward*, GridLab, April 2019. (Volkmann, Integrated Distribution Planning: A Path Forward)
[93] Id.
[94] Notable legislative exceptions include HB 589 and Clean Smokestacks.
[95] Utility System Planning and Investment Stakeholder Group Memo.
[96] Duke Energy introduced its Integrated System Operations Planning (ISOP) initiative in its 2018 Integrated Resource Plans. ISOP is focused on developing modeling tools and analytical processes that will complement the existing IRP processes and tools and ultimately allow for optimizing capacity and energy resource investments across Generation, Transmission, Customer Delivery and Customer Solutions. An important objective of this effort is to enhance modeling of non-traditional solutions for Distribution and Transmission Planning so that multiple types of value can be captured. Duke indicates that they plan to hold stakeholder engagement sessions to share

get input from customers and other stakeholders as they seek to enhance and further integrate planning processes and are working toward launching a stakeholder process focused on an ISOP model, as announced at the Grid Modernization stakeholder webinar in April of 2019.[97]

NC can look to states already developing and implementing holistic planning processes, which balance the goals of the state, utilities, and stakeholders. Key examples include Minnesota, Nevada, and Hawaii:

- In 2015, the Minnesota Public Utilities Commission opened an inquiry into distribution planning (Docket 15-556), aiming to incorporate DER with the appropriate optimization tools and create a transparent grid leading to an enhanced grid, reduce costs, and a more flexible and DER capable system. Ultimately, the multi-year process now requires the regulated utilities (Xcel Energy) to develop DER growth scenarios for 10 years, evaluate non-wire alternatives, detail DER queue status, and file annual updates on their 5 and 10-year distribution investment plans.[98]

- Nevada's legislature passed a bill in 2017 (SB 146) to address distributed resources along with their cost, benefits, financial compensation mechanisms, integration, and barriers to adoption. The Public Utilities Commission began the rulemaking process in 2017 (Docket 17-08022) leading to an adopted Distributed Resource Plan regulation. The regulation requires a system load/DER forecast, locational net benefit analysis, hosting capacity analysis, and grid needs assessment, filed every 3 years with the IRP.[99]

- Hawaii's IOU (Hawaiian Electric) started developing its Integrated Grid Planning (IGP) process in 2018 (Docket 2018-0165), a program which incorporates generation, distribution, and transmission planning. The IGP process includes utilization of a capacity expansion model, a substation load and capacity analysis, hosting capacity analysis, and extensive stakeholder input. The IGP process will produce a 5-year action plan and a long-term pathway to achieve the legislative goal of 100% renewable energy.[100]

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information regarding ISOP with stakeholders and gather input regarding the approach, using a third-party facilitator selected jointly by Duke and the NCUC Public Staff.

[97] Utility System Planning and Investment Stakeholder Group Memo, Addendum: Duke Energy's Ongoing Integrated System Operations Planning (ISOP) Efforts.

[98] Minnesota Public Utilities Commission, "Order Approving Integrated Distribution Planning Requirements for Xcel Energy," August 30, 2018 ("Order Approving Integrated Distribution Planning Requirements for Xcel Energy").

[99] Nevada Public Utilities Commission, "Order on Commission's Investigation and Rulemaking to Implement Senate Bill 146." September 6, 2018.

[100] Hawaiian Electric, *Integrated Grid Planning*. Accessible at: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning

Recommendations

C-1. Establish comprehensive utility system planning process that connects generation, transmission, and distribution planning in a holistic, iterative and transparent process that involves stakeholder input throughout, starting with a Commission-led investigation into desired elements of utility distribution system plans.

To respond and adapt to the many trends and forces changing the electricity sector today, it is necessary that NC move to a more holistic, iterative, and transparent planning process that incorporates non-traditional market solutions, which could lower generation and infrastructure costs while still maintaining a clean, reliable, and affordable electricity system. Planning processes should be consistent, data-driven, and involve stakeholders' input and feedback throughout.

An improved planning process could be enabled by the NC legislature and overseen by the NCUC. Legislation could define goals, necessary steps, and what roles the NCUC will play, giving explicit authorization where it is currently vague or lacking under existing law.

One feasible way to get started on a process to move toward a more holistic electricity sector planning process would be to initially begin an investigation into the desired elements of an Integrated Distribution Plan (IDP). The links between IDP, IRP, and transmission planning could be explored throughout this investigation..[101] Options and best practices to consider through an IDP include:

- Explicit consideration of the impacts from all DER types, including EE and demand response, in load forecasting and transmission, distribution and integrated resource planning.
- Enhanced forecasting to reflect the uncertainties of DER growth and its impact on load and peak demands.
- Analysis of the distribution systems' constraints and needs, as well as the ability to accommodate DER without requiring upgrades (i.e., hosting capacity analyses).
- Identification of locational value for nodes on the distribution system where DER deployment could provide grid services..[102]
- Consideration of third-party DER or portfolios of DER to address grid needs as non-wires alternatives (NWA).
- Acquisition of NWA grid services from customers and third parties using pricing, programs or procurement.
- Active monitoring, management and optimization of DER.
- Streamlined DG interconnection processes using insights from the distribution system capacity analyses.
- Increased external transparency through enhanced data availability and meaningful stakeholder engagement..[103]

[101] The connections between these three types of planning processes, and ways to find synergies and streamline the processes in order to make them more efficient and effective are currently the subject of a Task Force of states convened by NARUC and NASEO. NC's NCUC, DEQ and Public Staff are participants in this Task Force and may have ideas and lessons learned from that process to bring to bear on any IDP process launched by the state.
[102] Analysis of locational value should include both the costs and benefits of the resource where it exists on the system and any impacts it might have on the bulk electric system.
[103] Volkmann, Curt. *Integrated Distribution Planning: A Path Forward*, GridLab, April 2019. (Volkmann, Integrated Distribution Planning: A Path Forward)

Ultimately, the State should move towards an Integrated System Operations Plan (ISOP) approach, which combines resource, transmission, distribution planning. The ISOP processes should include regularly scheduled plan submissions to allow for stakeholder intervention early and throughout the process. These submissions should utilize existing analytical tools, as well as improved data and modeling access for industry and stakeholders.

While the NCUC is addressing some of these new planning approaches in its current IRP proceeding (Docket No. E-100, Sub 157),[104] and the NC Transmission Planning Collaborative (NCTPC).[105] is focusing on enhancing transmission planning in the state, the NCUC should initiate a separate process to create the guidelines for future comprehensive system planning, initially focusing on distribution planning. The outputs of this process can then feed into existing processes, such as NCUC's IRP proceeding, Duke's ISOP efforts, and NCTPC's discussions, as appropriate.

Table C-1: Actions for Recommendation C-1

Entity Responsible	Actions	Timing (Short, Medium, or Long term)
NCUC	Initiate and oversee comprehensive system planning process with meaningful stakeholder participation, starting with integrated distribution planning, including identifying key steps and timelines	Medium term
All	Work with NCUC in designing and implementing comprehensive system planning process	Medium term
Co-ops and Municipal Utilities	NCEMC and ElectriCities develop a process and guidance for member companies to undertake more comprehensive planning	Medium term

[104] NCUC has scheduled a Technical Conference in late August 2019 that will focus on expanding the scope of the IRP process, including ways to identify the locational value of DERs.
[105] NC Transmission Planning Collaborative: http://www.nctpc.org/nctpc/

C-2. Expand cost-benefit methodologies used to make decisions about resources and programs to include societal and environmental factors.

State public utility commissions have typically employed a 'least cost' framework for assessing whether a utility's investment is prudent. Under the least cost framework, the optimal choice is the least cost investment after accounting for other factors such as reliability, state renewable energy or EE mandates, other legal obligations, and a range of risk factors. Least cost is not a rigid standard, however. The approach allows utility regulators to exercise discretion to choose among sources of information, desirable outcomes, and risk assessments. New information, changing market conditions, more stringent regulations, and emerging technologies can all alter the math..[106]

Identifying least cost investment options that will be in service over the next one to two decades is particularly complex due to the increased level of uncertainty regarding technology, markets, and regulation. If projections used in long-term planning do not consider the potential cost impacts of changing policy circumstances, such as the potential for policy shifts to require utilities to internalize environmental externalities, the planning process may not be producing the least-cost outcomes in the long-term.

To achieve NC's carbon reduction goals, utilities need to update planning assumptions, as well as program cost-effectiveness methodologies, to allow for more complete quantification of the operational benefits of energy and technology resources, including societal and environmental factors that may be hard to monetize. Benefit-cost analyses also should take into account locational and temporal values, when available, to provide a more granular assessment of proposed investments.

For resources to be more accurately accounted for in utility planning and programs, regulators should consider a range of non-energy benefits, including the following list. A final list of non-energy benefits will be derived from a process that includes stakeholder input and involvement

- Increased system resilience, reliability, and safety
- Reduced customer costs; especially for low-income, disadvantaged communities
- Increased customer satisfaction
- Health impacts
- Increased customer flexibility and choice
- Enhanced social equity or environmental justice
- Environmental benefits, such as avoided GHG emissions
- Economic development benefits, such as job growth
- Physical and cyber security

Rhode Island and California both have recently updated what benefits and costs should be considered in program evaluation and planning and could be considered by NC in an investigation into this topic:.[107]

[106] Public Comments submitted by Jonas Monast, UNC Chapel Hill, School of Law

[107] In addition, Arkansas, Connecticut, Minnesota, New Hampshire, Pennsylvania, and Washington all are exploring how to update current cost-effectiveness procedures to account for an expanded set of benefits and costs. See:

- In 2016, the Rhode Island Public Utilities Commission opened a docket to get stakeholder input on (a) new rate design principles and concepts, and (b) cost-effectiveness for EE and other types of DERs.[108] One of the reasons for opening the docket was to develop a cost-effectiveness framework that can be applied consistently across different types of ratepayer-funded resources and programs. After months of stakeholder discussions, the Working Group recommended expanding the Rhode Island Total Resource Cost (TRC) Test to include a broader range of benefits to better align with its applicable state policies. The new cost-effectiveness test was named "the Rhode Island Test" and includes: risk impacts, environmental impacts (including GHG emissions reductions), jobs and economic development impacts, societal low-income impacts, public health impacts, and energy security impacts. The Commission accepted the recommendations of the Working Group, and directed the utility company to use the new Rhode Island Test, to the extent possible, for evaluating the cost-effectiveness of EE, DERs, other Company investments and spending.

- California utilities' annual Grid Needs Assessment (GNA), which is part of its distribution planning efforts, describes the performance requirements for any DER solution identified, including the magnitude, duration and frequency of resources required to address each grid need. The GNA uses a Locational Net Benefits Analysis (LNBA) framework, which includes a broad range of system and societal benefits as the basis for determining the range of value at each location. These benefits include: reliability and resiliency, avoided GHG emissions, and other safety/societal benefits.[109]

Other resources are available to NC as it considers revisions to benefit-cost methodologies. For example, the National Standard Practice Manual (NSPM) is a framework for cost-effectiveness assessments of energy resources and is designed to help jurisdictions determine what resources meet their specific goals and standards.[110] Another resource is the newly released US EPA "health benefits per-kilowatt hour" tool which lays out region-specific values (in $/kWh) of the outdoor air quality-related public health benefits of investments in EE and clean energy (wind and solar).[111]

Table C-2: Actions for Recommendation C-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)

American Council for an Energy Efficiency Economy [ACEEE], *A New Tool to Improve Energy Efficiency Practices: The Database of State Efficiency Screening Practices [DSESP]*, July 2019.

[108] Rhode Island Public Utilities Commission, Investigation into the Changing Electric Distribution System and the Modernization of Rates in Light of the Changing Distribution System (Docket 4600), "Report and Order 22851," July 31, 2017.

[109] California Public Utilities Commission, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 (Rulemaking 14-08-013), "Decision on Track 3 Policy Issues, Sub-track 2," March 22, 2018.

[110] https://nationalefficiencyscreening.org/national-standard-practice-manual/

[111] https://www.epa.gov/statelocalenergy/estimating-health-benefits-kilowatt-hour-energy-efficiency-and-renewable-energy

NCUC	Initiate and oversee a process that is transparent and open to all relevant stakeholders to update benefit-cost methodologies used in decision-making about resources and programs; this process could be a separate PUC proceeding/investigation or be part of the comprehensive planning process referenced in the recommendation above and involve opportunities for stakeholder input and engagement*	Medium term
Co-ops and Municipal Utilities	Initiate and oversee a process involving the public and/or members to update benefit-cost methodologies used in decision-making about resources and programs	Medium term

* It is assumed that the NCUC has existing statutory authority to pursue this recommendation. In the event that it is determined that the NCUC does not have sufficient authority, legislation would be needed to provide the appropriate authority.

C-3. Implement competitive procurement of resources by investor-owned utilities

Many states, and the federal government through passage of laws like PURPA, the Energy Policy Act of 1992 and the Energy Policy Act of 2005, have recognized that the power generation aspect of electric utility services is a competitive industry, and no longer ought to be viewed as a "natural monopoly." Some states have chosen to deregulate the power generation side of the utility business, which has resulted in the creation of retail energy providers and regional transmission and generation dispatch entities such as PJM Interconnection. Others have modified their integrated resource planning processes to require utilities to consider non-utility generation in their planning processes by conducting competitive procurement of needed resources. In this instance, a completed IRP becomes the precursor for approval of the utility's proposed means for meeting identified resource needs. A competitive procurement model means that utility self-build options will be one option among many, with the utility pursuing the option (which may come from a competitive supplier) that meets the identified need at the least cost. This competition should result in the lowest cost investment being made, ensuring consumers benefit from ultimately lower bills.

Oklahoma and Colorado are two states that have moved to a competitive procurement model for resources. Oklahoma's utility regulations governing IRPs set out procedures for "establishing the need for additional resources serving as the basis for long-term competitive procurement of resources, including, but not limited to, utility construction of new electric generation facilities, the utility purchase of existing electric generation facilities, and the purchase of long-term power supplies.".[112] Similarly, Colorado stipulates that an IRP filed by a utility shall include "the proposed RFP(s) the utility intends to

[112] Oklahoma Corporation Commission, Subchapter 37. Integrated Resource Planning.

use to solicit bids for the resources to be acquired through a competitive acquisition process."[113] NC currently does not require utilities regulated by the Utilities Commission to undertake competitive procurement of identified system needs in the IRP process.

Table C-3: Actions for Recommendation C-3

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Amend IRP rules to include a requirement for regulated utilities to utilize competitive procurement processes to meet identified system needs	Medium term

* It is assumed that the NCUC has existing statutory authority to pursue this recommendation. In the event that it is determined that the NCUC does not have sufficient authority, legislation would be needed to provide the appropriate authority.

[113] Colorado Department of Regulatory Agencies, Part 3: Rules Regulating Electric Utilities, 3064. Contents of the Least-Cost Resource Plan

Strategy Areas & Recommendations

4.3 Grid Modernization and Resilience

Grid Modernization and Resilience

D. Grid modernization to support clean energy resources

D-1 When evaluating proposals for grid modernization, consider whether the following outcomes are supported:

- Demonstrated net benefits for all proposed investments, including presentation of all costs and benefits used in utility analyses,
- Enhanced transparency of regionally appropriate DERs, grid needs and opportunities for DERs to interconnect,
- Increased customer access to their usage data and sources of energy,
- Facilitation of greater utilization of storage, demand-side resources, grid operation/management, devices, and the bi-directional flow of power,
- Measurement of performance to ensure anticipated benefits are delivered and accounted for, and
- Increased deployment of clean energy.

D-2 Use comprehensive utility planning processes to determine the sequence, needed functionality, and costs and benefits of grid modernization investments. Create accountability by requiring transparency, setting targets, timelines and metrics of progress made toward grid modernization goals.

E. Grid resilience and flexibility

E-1 Require utilities to develop projects focused on DERs, community solutions, and microgrids at state facilities and critical infrastructure locations (e.g. hospitals, shelters) to enhance resilience.

E-2 Coordinate resilience planning with disaster recovery operations center and require NC Emergency Management's Recovery Support Functions to address cybersecurity concerns in conjunction with energy resiliency issues.

E-3 Develop a method to quantify the human costs of power outages, and integrate these costs when evaluating grid modernization plan components related to resiliency.

Strategy Area		Recommendation	Legislature	NCUC	Governor's Office	State Agencies	IOU	CO-Ops / Public Utilities	Local Government	Academia	Businesses
Grid Modernization and Resilience	D. Modernize the grid to support clean energy resources	D-1		•				•			
		D-2		•				•			
	E. Strengthen the resilience and flexibility of the grid	E-1		•		•	•	•	•		
		E-2		•		•	•	•			
		E-3		•		•				•	

SHORT TERM   MEDIUM & LONG TERM

D. Modernize the grid to support clean energy resources

Background and Rationale

Distributed energy resources, including EE, demand-side management, solar, and storage have the potential to provide valuable services to the electricity grid and lower costs on the system while providing customers with cleaner power and more control over their energy usage. These benefits along with the falling costs of the technologies themselves are increasing customer and third-party interest in purchasing or investing in these resources. In response, utilities across the U.S. are taking steps to modernize their electric grids, which includes augmenting the grid with software and communications technologies to help the grid meet the new customer, technological, and societal demands.

While NC's adoption of distributed solar generation is still at modest levels, there is growing concern that the grid needs to be upgraded and improved in order to accommodate DER growth and new load from the electrification of end-uses in a way that supports what customers want, maintains reliability, and keeps customer costs down. To carry this out, a thoughtful and methodical approach to grid modernization is needed due to the significant capital expenditures and potential risks proposals may carry. While investments to improve grid capabilities will likely be necessary to enable a clean and resilient electricity system, transparency in grid planning processes can help ensure third parties and customers understand why these investments are needed and what added value they provide to the system.

Recommendations

D-1. When evaluating proposals for grid modernization, consider whether the following outcomes are supported:

- **Demonstrated net benefits for all proposed investments, including presentation of all costs and benefits used in utility analyses,**
- **Enhanced transparency of regionally appropriate DERs, grid needs and opportunities for DERs to interconnect,**
- **Increased customer access to their usage data and sources of energy,**
- **Facilitation of greater utilization of storage, demand-side resources, grid operation/management devices, and the bi-directional flow of power,**
- **Measurement of performance to ensure anticipated benefits are delivered and accounted for, and**
- **Increased deployment of clean energy.**

Duke Energy is currently working on a Grid Improvement Plan which they intend to file in 2019 alongside their next rate case. The NCUC will be the entity responsible for approving the plan and granting cost recovery. The above outcomes emerged through the Clean Energy Plan's stakeholder process as important conditions to consider when evaluating grid modernization plans to maximize the potential benefits of grid modernization investments and to protect against potential utility capital bias.

For an investment to be net beneficial, the benefits (which can include both monetized and non-monetized benefits) from a particular investment should outweigh its complete set of costs. Transparency in cost benefit analyses that shows what costs and benefits are accounted for and their magnitude allows for a more diligent assessment of different technologies' cost-effectiveness. Some proposed investments, such as communication networks and grid automation equipment, may be necessary in order to enable other desired functionality of the grid. In evaluating the costs and benefits of such investments, the importance of sequencing and enabling future functionality should be considered.

As customers transform from mere consumers of energy to active participants in the electricity system, utilities are expected to facilitate additional choices and options for customers as they seek out DER and other services to manage their energy use and costs. Increasing access to data can provide customers with the granular information they need to make more informed decisions about their energy consumption and supply. A more distributed and diverse system will require utilities integrate both customer- and grid-facing technologies to enable a more dynamic grid, such as storage and programmable thermostats.

Operating a dynamic grid will require an increase in availability of transmission and distribution data to enable adequate system monitoring, control, and protection. Transparency of current and anticipated grid needs can streamline interconnection processes and better ensure that new technologies and distributed resources are connected to the grid in areas that can most benefit from them.

Moreover, grid modernization plans should integrate mechanisms for accountability that ensure new grid investments deliver optimized benefits to the grid, customers, and the industry as a whole.

While the NCUC is responsible for approving Duke Energy's Grid Improvement Plan, the same criteria can be applied to co-ops and municipal utilities, who are beginning to consider what grid modernization investments may be necessary on their own systems.

Table D-1: Actions for Recommendation D-1

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Use recommended outcomes listed above to guide evaluation of Duke's Grid Improvement Plan	Short term
Co-ops and Municipal Utilities	Take into consideration the recommended outcomes listed above when developing grid modernization plans	Medium term

D-2. Use comprehensive utility planning processes to determine the sequence, needed functionality, and costs and benefits of grid modernization investments. Create accountability by requiring transparency, setting targets, timelines and metrics of progress made toward grid modernization goals.

Establishing formal procedures and requirements for future grid modernization plans will result in a more streamlined and transparent process. For IOUs, providing a set of planning requirements prior to the submission of a grid modernization plan will ensure that technologies are deployed strategically and on an as-needed basis. Grid modernization should be directly linked to and informed by the more holistic planning process described above and should include needed improvements to both the distribution and transmission systems.[114] For example, requiring development of different DER penetration scenarios or a more granular system assessment (e.g., at the circuit level) can help identify which new investments are necessary to maintain reliability. Alternatively, improving the linkage between transmission, resource, and grid modernization planning may better identify solutions to transmission system constraints that could be prohibiting greater levels of renewable generation on the system in the eastern part of the state.[115]

Directing utilities to include detailed and clear analysis of cost and benefits in planning processes will ensure approved investments are net beneficial.[116] Making sure utilities establish performance metrics, targets, and accompanying timelines, will allow regulators to hold utilities accountable for plan implementation and ensure that new investments are delivering expected benefits in a timely manner. For municipal utilities and co-ops, these methods can be directly integrated into system planning processes.

California and Minnesota are looking for opportunities to better integrate their planning and grid modernization processes, as described below:

- California has established a Grid Modernization Guidance framework that defines the scope of what can be considered as grid modernization and establishes a structure and timing of grid modernization planning process, including the submission of a Grid Needs Assessment that results from the state's distribution resource planning process. The framework also provides guidance on how to evaluate the cost effectiveness of grid modernization investments and establishes submission requirements.[117]

[114] See "B: Require comprehensive utility system planning processes"

[115] The low cost of land in the eastern part of the state has led to large volumes of solar development to concentrate in one area of the state where the electrical infrastructure is constructed with smaller conductors. The demand for electricity in this area is low due to the absence of large commercial and industrial customers. According to Duke Energy, this has resulted in significant transmission congestion in the eastern area the state and is now causing an expectation for thermal overloads on the existing transmission lines which move power from east to the load centers west of the coast. Duke Energy states that at least 123 substations have the potential to back feed to the transmission system on certain days throughout the year due to solar systems on the distribution system, and 60% of the projects queued in the Duke Energy Progress service territory are currently interdependent to required transmission network upgrades. Relieving this congestion will require significant investment in the transmission network system.

[116] In reality, for various reasons utilities will request cost recovery for investments that do not come up in a comprehensive planning process. As with all utility investments, regulators will need to evaluate those investments carefully. By having clear expectations for an integrated planning process and explicitly linking grid modernization to the outcomes of that planning process, regulators can better assess the merits of future utility investment proposals.

[117] Ibid.

- Minnesota combined its grid modernization and distribution planning processes into one multi-year effort. Xcel Energy is required to file 5-year Action Plans for distribution system developments and investments in grid modernization based on internal business plans and insights gained from a DER futures analysis, hosting capacity analysis, and NWA analysis.[118]

Table D-2: Actions for Recommendation D-2

Entities Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Determine how grid modernization can be linked to and informed by comprehensive system planning processes; develop submission requirements, including expectations for grid needs assessments and clear cost-effectiveness parameters.	Long term
Co-ops, Municipal Utilities	Determine how grid modernization can be linked to and informed by other system planning processes	Medium term

[118] Order Approving Integrated Distribution Planning Requirements for Xcel Energy.

E. Strengthen the resilience and flexibility of the grid

Background and Rationale

New definitions and metrics have been developed to monitor the properties of the electric power system as it undergoes its dramatic evolution now and into the future. Two properties that have been important in the past and will be increasingly important in the future are resiliency and flexibility. The Department of Energy's Grid Modernization Laboratory Consortium (GMLC) has developed definitions of several key indicators.[119] The GMLC defines resiliency as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents."

Flexibility, on the other hand, is defined as "The ability of the grid (or a portion of it) to respond to future uncertainties that stress the system in the short term and may require the system to adapt over the long term." Flexibility can generally be viewed from two perspectives. First, from an operational viewpoint, flexibility can be thought of as the agility of the electrical network to adjust to known or unforeseen short-term changes, such as abrupt changes in load conditions or sharp ramps due to errors in renewable generation forecasts. Second, from a strategic investment perspective, flexibility can be considered as the ability to respond to major regulatory and policy changes and technological breakthroughs without incurring stranded assets. All of these factors are at play in NC.

In the United States generally and in NC specifically, there is a growing frequency and intensity of weather-related disasters. Between 1980 and 2019, more than 241 separate $1 billion disasters have cost the United States $1.6T, with nearly half of the cost coming in 2005, 2012, 2017, and 2018.[120] NC's distinctive geography – with mountains in the west and the Atlantic Ocean to the east – make it particularly susceptible to weather-related disasters in both the winter and the summer. NC is one of the four states[121] most heavily impacted by hurricanes, with the state impacted by a tropical cyclone every 1.3 years.[122]

The state of NC – like any state in the US – is also prone to cyberattack. This is a growing concern as the state becomes more reliant on third-party owned distributed generation.

[119] "Grid Modernization: Metrics Analysis Reference Document, Version 2.1," Grid Modernization Laboratory Consortium, May 2017. https://gmlc.doe.gov/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf

[120] Bloomberg, "U.S. Hurricane Season Is Unnecessarily Dangerous", 6/11/19, https://www.bloomberg.com/news/articles/2019-06-11/u-s-hurricane-season-is-unnecessarily-dangerous

[121] Hurricane Research Division (2008). "Chronological List of All Hurricanes which Affected the Continental United States: 1851–2005". National Oceanic and Atmospheric Administration., https://web.archive.org/web/20080921102626/http:/www.aoml.noaa.gov/hrd/hurdat/ushurrlist18512007.txt

[122] NC State Climate Office, https://web.archive.org/web/20100330154058/http://www.nc-climate.ncsu.edu/print/8

Recommendations

E-1. Require utilities to develop projects focused on DERs, community solutions, and microgrids at state facilities and critical infrastructure locations (e.g. hospitals, shelters) to enhance resilience.

A microgrid is a small electric system that combines local energy resources and control technologies to provide power to a defined area. Microgrids typically remain connected to the main grid, but they can operate independently. They are typically deployed at critical infrastructure locations such as hospitals, but they can also be deployed for all or part of a community. These microgrids allow entities to operate as small islands when the larger grid is experiencing a major outage, and thus they represent an excellent opportunity for providing greater resiliency in the face of weather-related disasters.

There are several interesting examples in NC. Ocracoke Island, which is accessible only by boat or plane, is powered by a small microgrid connected to the main electrical system through a transmission line fed from Cape Hatteras Electric Cooperative under the Pamlico Sound.[123] If a storm takes down the transmission line for any reason, the island can continue to function. The local microgrid, a cooperative venture between NC Electric Membership Corporation and Tideland Electric Membership Corporation, includes a 3 MW diesel generator and 62 rooftop solar panels that have a 17 kW capacity and are built to withstand winds up to 140 mph. Ten cabinets of Tesla batteries sit on a concrete platform built 4-feet high to stay out of the reach of storm surge. Fully charged, the batteries store 1,000 kWh and dispatch up to 500 kW. An inverter takes the DC power from the batteries to AC power for the grid. Homes and businesses throughout the community also have controllable HVAC and water heaters to help curtail and balance load.

Duke Energy was recently approved for a pilot microgrid in Hot Springs, NC, a remote town with a population of about 600 that is served by a feeder with a history of long-duration outages. Given that Duke Energy anticipated high costs for necessary equipment upgrades, it was proposed to construct a small microgrid that would allow the community to be islanded. The Hot Springs microgrid design includes a 2 MW ground-mounted solar array, a 4 MW battery storage system, and a microgrid controller.[124] The battery is sized to meet 100% of the town's peak load and to provide power for the 90th percentile of load for approximately four hours without any contribution from the solar panels.

Microgrids – used for both community-scale applications and critical infrastructure – could have significant benefits in many parts of NC. In many cases, these microgrids can utilize renewable resources and battery-based energy storage. As noted above, there are already excellent examples in which both IOUs and cooperatives have been able to benefit from the distributed resources installed as part of a larger microgrid. The state should encourage its IOUs and co-ops to consider additional microgrid projects to improve recovery from storm-related issues.

[123] https://www.cooperative.com/remagazine/articles/Pages/electric-co-op-transforming-microgrid.aspx
[124] https://microgridknowledge.com/hot-springs-microgrid-approved/

Currently, combined PV and energy storage are probably not economical in NC under most traditional cost-benefit calculations as confirmed by the recent energy storage study in NC..[125] If one places a value on the losses incurred from grid disruptions; however, PV+storage can potentially become a fiscally sound investment..[126] The state should examine the viability and benefit of installing several projects at state or locally owned facilities that are in particularly storm-prone areas. As these projects proceed, the state should disseminate the results to promote similar thinking in the private sector.

Table E-1: Actions for Recommendation E-1

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Initiate a docket to require utilities to develop additional projects focused on DERs, community solutions, and microgrids at critical infrastructure locations	Medium term
IOUs, Municipal utilities, co-ops	Consider locations for adoption of microgrids considering factors such as long-term maintenance cost and cost of recovery after major storms	Medium term
Local governments	Consider the full cost of outages when performing cost-benefit analysis for PV+Energy storage. Encourage projects for schools, first-responder facilities, etc.	Medium term
DEQ and Division of Emergency Management	Assist project implementation and leverage federal government infrastructure funding for state projects	Medium term

[125] https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2019/02/NC-Storage-Study-FINAL.pdf
[126] https://www.energy.gov/sites/prod/files/2018/03/f49/Valuing-Resilience.pdf

E-2. Coordinate resilience planning with disaster recovery operations center and require NC Emergency Management's Recovery Support Functions to address cybersecurity concerns in conjunction with energy resiliency issues.

The NC Disaster Recovery Framework (NCDRF) was developed by NC Emergency Management (NCEM) and is updated on an annual basis. The Framework describes the role of state agencies and their partners in assisting with recovery efforts and is designed to address the complex and unique nature of disasters. Successful recovery efforts rely upon the Whole Community. The NCDRF considers the impacts of grid-related disasters, including threats from tropical cyclones, winter storms, and cyberattacks. The framework is an evolution from the operational plan previously maintained by the state..[127]

The current framework is focused on how the state should respond to and recover from disasters. Inherently, the approach is focused on recovery. Recent studies have shown that every dollar spent on disaster preparedness can offset as much as six dollars spent on recovery efforts..[128] The state should thus consider how to integrate resiliency planning – both for storm-related outages as well as cyberattacks – into its disaster recovery planning, including how assets can best be deployed to reduce recovery efforts.

For example, microgrids installed at critical infrastructure such as hospitals and first-responder facilities can potentially make first response efforts more effective. The state should study the impact of such investments and potentially consider several pilots. Ultimately, such planning should be incorporated into the NCDRF.

Table E-2: Actions for Recommendation E-2

Entity Responsible	Action	Timing (Short, Medium, or Long-term)
NC Division of Emergency Management and Office of Recovery and Resiliency NCORR	Investigate the impacts of resiliency planning as part of the NC Disaster Recovery Framework. Determine if appropriate resiliency efforts can offset costs for disaster recovery.	Short term
DEQ, NCUC, Utilities, NCDOT	Participate and support in updating the NC Disaster Recovery Framework as needed.	Short term

[127] https://files.nc.gov/ncdps/documents/files/2018%20NC%20Disaster%20Recovery%20Framework_Final_0.pdf
[128] https://www.bloomberg.com/news/articles/2019-06-11/u-s-hurricane-season-is-unnecessarily-dangerous

E-3. Develop a method to quantify the human costs of power outages, and integrate these costs when evaluating grid modernization plan components related to resiliency.

The economic and human impact of recovery from a major storm can be incredibly significant. It has been estimated, for instance, that the true cost of Hurricane Katrina was over $250 billion once one includes damage and economic impact. Further, Katrina displaced some 770,000 residents..[129] Such events can have an extremely negative long-term impact on the economic health and culture of a region. As recent storm seasons have shown, NC is also prone to potential major impacts as well. The state is also susceptible to potential cyber threats, and the growing deployment of third-party owned, distributed energy resources potentially makes the state more vulnerable to cyber threats.

Investing in resources that provide greater resiliency can be very expensive. For example, grid-hardening measures and selective installation of microgrids may be excellent for preventing major long-term outages, but the cost must be borne by the ratepayers and those costs may be deemed too high for ratepayers to bear. If one begins to consider the total cost of outage prevention – including the regional economic impact and the impact on individual families that come from large storms – it is possible that the upfront cost of targeted resiliency measures can become more palatable. Similar arguments can be made for efforts to harden the grid against cyber threats. The state should encourage a deeper investigation into this question, and this investigation should be based on the true social and economic impacts of recent events in NC. This analysis should be conducted in a way that promotes social and economic equity, for example by being careful not to calculate the human cost of outages differently for communities of different economic means. The study should also include the impacts of potential cyber threats. DEQ has received a recent award from the US DOE that should help in this area.

Table E-3: Actions for Recommendation E-3

Entity Responsible	Action	Timing (Short, Medium, or Long term)
DEQ, UNC-Charlotte, NC State University, NCUC	Investigate the inclusion of the impact of storms and cyberattacks on the economy and society as a whole. Determine if this analysis can be used to modify the regulatory structure to encourage greater investment in DERs, microgrids, and grid-hardening approaches.	Medium term

[129] https://www.thebalance.com/hurricane-katrina-facts-damage-and-economic-effects-3306023

Strategy Areas & Recommendations

4.4 Clean Energy Deployment & Economic Development

Clean Energy Deployment and Economic Development

- **F. Customer access to clean energy**
  - F-1 Consider revisions to clean energy programs authorized by HB 589 to ensure successful delivery of desired outcomes, such as increasing customer access to clean energy.
  - F-2 Enact a statewide commercial Property Assessed Clean Energy (PACE) and Pay as You Save Program.
  - F-3 Develop a green energy bank or statewide clean energy fund to catalyze the development and expansion of clean energy markets by connecting private capital with clean energy projects.
  - F-4 Require utilities to offer virtual or group net metering to enable greater access to community solar.
  - F-5 Increase the existing REPS or create a new policy with zero-emitting resource targets without carve-outs for specific resources.
- **G. DER interconnection and compensation for value added to the grid**
  - G-1 Develop rates that provide accurate price signals to demand-side resources about costs and value to the grid, such as Time of Use (TOU) or real time pricing. In the long term, consider establishing new rate and compensation structures for DERs based on the value of grid services that can be provided by DERs, such as a "value of DER" tariff.
  - G-2 Consider ways to provide greater transparency of system constraints and optimal locations for distributed resources.
- **H. Clean energy economic development opportunities**
  - H-1 Identify and advance legislative and/or regulatory actions to foster development of North Carolina's offshore wind energy resources.
  - H-2 Create and foster statewide and regional offshore wind collaborative partnerships with industry, the public, stakeholders, and neighboring states to bring economic growth to North Carolina.
  - H-3 Conduct an assessment of offshore wind supply chain and ports and other transportation infrastructure to identify state assets and resource gaps for the offshore wind industry.
  - H-4 Develop pathways to expand renewable natural gas recover and usage.

	Strategy Area	Recommendation	Legislature	Utilities Commission	Governor's Office	State Agencies	IOU	CO-Ops / Public Utilities	Local Government	Academia	Businesses
Clean Energy Deployment and Economic Development	F. Enable customers to choose clean energy	F-1	•			•					
		F-2	•			•	•	•			
		F-3			•				•	•	
		F-4	•								
		F-5	•	•							
	G. DER interconnection and compensation for value added to the grid	G-1		•				•			
		G-2		•							
	H. Clean energy economic development opportunities	H-1				•					
		H-2			•	•	•		•	•	•
		H-3				•			•	•	•
		H-4			•					•	

SHORT TERM

MEDIUM & LONG TERM

F. Enable customers to choose clean energy

Background and Rationale

Utility customers in NC are increasingly demanding access to clean energy and EE options for meeting their electricity needs. Cities and counties across the state have adopted clean energy and carbon mitigation goals. Corporations and businesses continue to push utilities and policymakers to make it easier for them to meet their power needs with clean energy. Throughout the Clean Energy Plan public engagement process, participants reiterated and restated the desire for access to clean energy in different ways. Participants generally do not feel that the existing regulatory structure in NC gives customers sufficient and equitable access to clean energy..[130]

NC has made progress toward expanding customer access to clean energy in recent years. In particular, the passage of HB 589 created several new programs that have opened up new avenues for customers to choose clean energy, including community solar programs, solar rebates, solar leasing, and the Green Source Advantage program, which allows large businesses, the military, and universities to directly procure renewable energy. The Competitive Procurement of Renewable Energy (CPRE) program ensures that cost-competitive renewable energy is being brought onto Duke Energy's system which will increase the amount of renewable energy that all of the utility's customers receive through their standard utility service..[131] Participants in the CEP process acknowledged that improvements have been made in recent years to increase customer choice and access to clean energy, while also highlighting areas for continual improvement.

Some of the existing tensions regarding customers' ability to choose clean energy center around the affordability and accessibility of the existing programs. Some examples include:

- Solar rebate program: due to its popularity and the total capacity limits established under HB 589, this program became fully subscribed very quickly. In order to get a rebate, customers had to sign up within a narrow time window which meant that many potential customers were unable to access a rebate.

- Green Source Advantage program: the bill credit that participants receive under this program is revised every 5 years, which can make it challenging for participants to determine the economics of participating in the program. Further, this program is available exclusively to large commercial customers (based on specific demand thresholds), the UNC system, and military installations.

- Businesses do not have the ability to enter into their own on-site third-party PPAs for renewable energy. However, as established by HB 589 they do have the ability to enter into a lease agreement with a similar financing structure to a third party PPA.

- Community solar: HB589 required Duke Energy to develop a community solar program, but there is no statewide program in place meaning that customers of other utilities only have access to community solar if their utility opts to provides it. The state also does not allow virtual net metering, which would expand customer access to shared renewable energy.

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[130] See CEP participant survey responses.
[131] The CPRE program is discussed in greater detail in the next section.

The upfront cost of investing in customer-sited resources, like solar and EE, continues to present a barrier to adoption for many NC residents. In particular, low and moderate income residents face many challenges when trying to adopt clean energy. On top of that, many of these same communities face disproportionate burdens from energy production, generation, and use, and would benefit especially from measures that increase non-emitting sources of energy. Some of the recommendations included in this section address issues related to access to capital. Other recommendations directed at specifically enhancing equitable access to clean energy are included in the next section.

Customers in areas served by cooperatives and public utilities expressed similar desires to choose clean energy that is affordable. The programs being implemented under HB589 do not apply to these areas, although several cooperatives are creative in developing and implementing community solar programs for their members.

Recommendations

F-1. Consider revisions to clean energy programs authorized by HB 589 to ensure successful delivery of desired outcomes, such as increasing customer access to clean energy.

HB 589 created new ways for NC customers of Duke Energy to purchase clean energy as the source of their electricity, such as community solar programs, solar rebates, solar leasing, and the Green Source Advantage program. The NCUC has been taking action on utility proposals within each of these programs. Some of the programs are already being implemented, such as the solar rebate program. The Green Source Advantage Program was recently approved by the Commission and but has not yet been implemented by the utility..[132]

Participants in the CEP process, both within the facilitated workshops and through other means, expressed concern that the manner of implementation of these programs will not achieve the full potential for customers to participate. The reasons for this concern vary by program, and, given the early stage of implementation, it is too early to definitively determine whether changes to the programs are needed in order to achieve successful outcomes. The Legislature should revisit these programs in the future, assess whether the desired outcomes are materializing, and consider revisions if needed.

It should also be noted that successful implementation of these programs could be aided by addressing some of the underlying structural challenges built into the existing utility incentives and tools, as discussed in the prior section. In short, existing utility incentives to increase sales and to build utility-owned generation are in conflict with measures designed to increase customer-, third-party-, or community-owned generation resources or to reduce sales of electricity through conservation or behind-the-meter generation. If entities in the state are successful at implementing changes to address these existing challenges, the underlying incentives of utilities can be better aligned with the overarching goals of clean energy programs such as those created by HB 589.

[132] See NCUC August 5, 2019 Order approving Duke Energy's compliance filing: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=a6e3fb12-1347-476d-b612-b35a077ffa85

Table F-1: Actions for Recommendation F-1

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Legislature / DEQ	Revisit HB 589 programs and consider whether revisions are needed to ensure desired outcomes are achieved.	Short-term

F-2. Enact a statewide commercial Property Assessed Clean Energy (PACE) and Pay as You Save Program

The inability to finance EE upgrades and distributed renewable energy projects was identified by stakeholders in the Clean Energy Plan process as a major barrier that the state should address. The financing difficulties arise from a number of causes: the split incentive between landlords and tenants means that neither entity has the incentive to invest in EE or clean energy; for commercial customers, investments in the core business are often prioritized over energy upgrades even when they are cost effective; and external financing can be hard to come by, particularly for small businesses..[133] For residential customers, particularly lower income customers, the inability or unwillingness to take on personal debt in order to finance upgrades or new measures is a major barrier. Two financing mechanisms, Pay As You Save (PAYS) and Commercial Property Assessed Clean Energy (C-PACE), were identified as promising mechanisms to help address some of the barriers.

Pay As You Save is the name of a voluntary program design through which a utility can offer to make site-specific investments in EE upgrades at a customer's property. The utility recovers its cost for the investment with a charge on the customer's electricity bill, with the charge being lower than the estimated savings that result from the EE upgrade. As a result, the customer gains the benefit of net savings from the start of the program. A key feature of the PAYS model is that the cost recovery for the upgrades is tied to the utility meter, rather than an individual person. The PAYS model has been used successfully around the country as a way to remove barriers affecting customer segments that are hard to reach like renters and customers without access to upfront capital. One electric co-op in NC, Roanoke Electric, has been successfully using PAYS to upgrade roughly 200 homes per year. To date, no other NC utilities have offered an on-bill tariffed program like PAYS. Stakeholders identified the need for some kind of loss protection for utilities that might be concerned that their programs would not perform well, and thus they would need risk mitigation in order to offer such a program. A clean energy fund, discussed in the next recommendation, could offer a reserve fund to provide loss protection for utility tariffed on-bill programs like PAYS.

C-PACE is a mechanism targeted at the commercial sector and is strictly property-based financing, requiring no personal or corporate guarantees. A property owner works with a contractor to determine which clean energy upgrades make sense, and 100% of the financing (for both hard and soft costs) is

[133] Third-party financing often requires personal guarantees and/or some equity investment, both of which can be prohibitively difficult for small business owners.

provided as a loan through the PACE program. A local government entity (occasionally regional or statewide entities) sets up the program and services the loan, placing an annual assessment on the property for debt collections. With PACE, the financing is repaid as a line item on the property tax bill, which means that the obligation to repay the financing can transfer to a new owner upon sale of the property. C-PACE can remove or greatly reduce several of the barriers to investing in EE or clean energy that commercial property owners might face. PACE is already legislatively authorized in NC, but the state does not have any active programs. The NC Cities Initiative identified a few reasons for this, one being that NC local governments lack familiarity with using this kind of financing, and would benefit from the ability to delegate the administration of such a program and the financing mechanism to a central third party. In addition, state-level approval is needed for all local debt.

Table F-2: Actions for Recommendation F-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Utilities (IOU, Co-ops, Public utilities)	Develop voluntary on-bill pay as you save tariff, using Roanoke EMC as an example of successful application in NC	Short term
Legislature	If needed to ensure access for customers, direct utilities to develop a tariffed on-bill financing program like PAYS and make it available as an option for customers	Long term
Legislature	Consider setting up a loss reserve fund or a revolving loan fund to speed up implementation of PAYS	Medium term
Legislature	Re-authorize NC PACE law, which currently sunsets in July 2020	Short term
Legislature	Give local governments authority to delegate administration of C-PACE to a statewide or regional third party entity	Short term
Legislature / DEQ	Evaluate the feasibility of easing the requirement for state-level approval of local debt	Medium term

F-3. Develop a green energy bank or statewide clean energy fund to catalyze the development and expansion of clean energy markets by connecting private capital with clean energy projects.

Throughout the Clean Energy Plan stakeholder process, a diverse group of individuals and other energy collaborators identified a need for an NC clean energy fund..[134] A clean energy fund could bring capital dollars to clean energy projects in areas and markets that are not yet attractive to large investors. By helping to structure and underwrite deals with a reasonable return, a clean energy fund could simultaneously spur new projects and catalyze investment markets.

Participants in the CEP process identified particular needs for project funding in clean energy, EE, electric vehicle infrastructure, and other measures that reduce emissions. They noted particular need in rural and poorer communities of the state that otherwise lack access to necessary capital. Similar funds in other states have supported the installation of residential, community, municipal, and commercial solar systems; EE upgrades in public schools and homes; and infrastructure deployment for alternative fuel vehicles.

Table F-3: Actions for Recommendation F-3

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NGOs and Academia	Determine how to establish a NC Clean Energy Fund.[135]	Short term
Governor's Office	Publicly support a NC Clean Energy Fund if established	Short term

[134] These collaborations included the Cities Initiative and the EE roadmap process. The need for such a fund was also identified by the CEP stakeholder breakout group focused on Equitable Access and Just Transition.
[135] As of the writing of the Clean Energy Plan, DEQ is aware that the Nicholas Institute at Duke University is intending to engage with the Coalition for Green Capital, a leading expert and implementer of green banks, in Fall of 2019 to produce an in-depth report on the creation and design of a NC Clean Energy Fund.

F-4. Require utilities to offer virtual or group net metering to enable greater access to community solar.

Many customers want access to solar energy but they do not have the ability to put solar panels on their roof or property, or the ability to pay the significant upfront costs for an individual solar system. The community solar model allows customers to subscribe to a portion of a solar facility's output through their utility, or be a joint owner of such a facility, without having the facility physically located on their property. House Bill 589 required Duke Energy to offer at least 20 MW of community solar in each of its territories. These programs are under development and review at the Utilities Commission. Eleven of NC's electric co-ops offer a community solar program to their members.[136] Community solar can expand equitable access to clean energy by allowing individuals and businesses to participate regardless of whether they own their home, their income level, or the suitability of their property for solar development. CEP stakeholders attending the workshops as well as private citizens participating in the regional listening sessions expressed a strong desire to make these services available to communities interested in these programs.

One of the key elements of community solar programs is the subscriber compensation, which determines the value that subscribers are paid for their share of the generation from the project. Typically, this compensation is provided through a credit on the electric utility bill. The methodology for determining the credit to subscribers greatly affects the overall economics of the community solar project from the subscribers' perspective, and thus also affects the cost to subscribe and overall market demand for the program. If the result of the crediting methodology is that subscribing to community solar requires paying a premium on electric bills, it will make access to the program much more difficult for low- and moderate-income customers.

States and utilities are taking a variety of approaches to subscriber compensation within community solar programs but the majority are using some form of retail rate compensation or a value-of-solar methodology.[137] In order for retail rate compensation to be feasible, "virtual net metering" must be available. This means that net metering applies to community solar subscribers in proportion to their subscription to the solar array, and allows customers to receive credits from community solar as though the generation were on site. In NC, customers who have solar on their rooftops are eligible for net metering, meaning that they receive credits for the energy they send to the grid that helps to offset the energy they consume on-site. However, subscribers to a community solar array do not have this option because NC currently does not have a statutory requirement for utilities to provide virtual net metering. Rather, in NC the compensation is based on the utility's avoided cost rate, meaning that the credit received by subscribers is lower than the cost they pay for the energy they consume.

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[136] National Rural Electric Cooperative Association, see: https://www.electric.coop/wp-content/Renewables/community-solar.html?lipi=urn%3Ali%3Apage%3Ad_flagship3_feed%3BQhg%2BM6GlTBW3BEUMJftgjA%3D%3D&utm_source=Insights+Jan&utm_campaign=bd960c642c-EMAIL_CAMPAIGN_2017_12_14&utm_medium=email&utm_term=0_d0de398254-bd960c642c-126666693

[137] Cook, Jeffrey J., and Monisha Shah. 2018. Focusing the Sun: State Considerations for Designing Community Solar Policy. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-70663. https://www.nrel.gov/docs/fy18osti/70663.pdf

It should be noted that some states that offer a form of retail rate compensation for community solar subscribers do not offer the full retail rate. They do this to reflect the fact that some elements of the utility's costs to serve subscribers, such as some aspects of transmission and distribution, are not offset by the generation from the community solar array. For example, in Delaware the bill credit is based on the full retail rate if the subscribers are on the same feeder as the solar array, otherwise a supply service charge is subtracted from the credit that subscribers receive. It would be sensible for regulators and decision makers to consider the appropriate credit for subscribers in different utility service territories.

Table F-4: Actions for Recommendation F-4

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Legislature	Require utilities to develop virtual net metering for community/shared solar customers and direct the NCUC and other utility governing bodies to oversee appropriate development of compensation rates for subscribers	Short term

F-5. Increase the existing Renewable Energy and Energy Efficiency Portfolio Standard (REPS) or create a new policy with zero-emitting resource targets without carve-outs for specific resources

NC has been a leader on clean energy policy in the Southeast and is the only state in the region with a renewable energy portfolio standard. This policy has helped to drive much of the clean energy development in the state and has led NC to a #2 ranking in installed solar capacity in the US. That said, NC's REPS policy is one of the least aggressive in the country; several states increased their renewable energy targets to 50% and higher by 2030 and beyond in recognition of the economic and environmental benefits that can be realized. As modeling by DEQ and others shows, the state's "business as usual" policy landscape is not likely to result in clean energy development sufficient to increase deployment beyond the amount codified in HB589 or in sufficient quantities to meet the state's GHG reduction goals. In addition, customers are increasingly expecting that the electricity they purchase from their utility will come from clean sources.

Different options for increasing the amount of clean, zero-emitting generation on the grid were discussed by stakeholders in the Clean Energy Plan process. One option is to simply increase and extend the current REPS policy by adding targets for 2030 and 2050, maintaining the current resource carve-outs or establishing additional resource carve-outs. Another option is to allow the REPS to coexist alongside a new policy that would require a certain percentage of generation to come from zero-emitting resources by 2030 and 2050, without any carve-outs for specific technologies. The latter would allow all zero-emitting generation resources to compete to be the preferred option for meeting the target.

Table F-5: Actions for Recommendation F-5

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Legislature / NCUC	Expand the State's REPS by setting higher targets for 2030 and 2050 while maintaining existing technology carveouts, or develop a technology neutral policy that requires a certain amount of electricity sales to come from zero-carbon emitting sources by 2030 and 2050.	Medium term

G. DER interconnection and compensation for value added to the grid

Background and Rationale

As costs for clean energy and storage continue to fall, states, regulators and utilities around the country are grappling with ways to facilitate interconnection of these new resources to the electric grid while maintaining reliability and fairly compensating (and charging) distributed resources for the value (and costs) they bring to the grid. These challenges and opportunities are not unique to NC – other states and utilities have engaged in dockets and investigations into the value of distributed resources and initiated pilots to test out new compensation structures and rate designs.[138]

There is an interest among NC customers and developers for siting solar projects on the distribution grid and getting compensated by the utility for services provided. While there has been less development of smaller, distribution-connected projects to date, with the continuing cost declines for solar and storage it is likely that more customers will be interested in installing DERs and interconnecting to the distribution system. If given the opportunity, aggregators could work with multiple customers to create solar, storage and/or demand response programs that can provide value to the utility grid and savings to the participating customers.

NC already has significant amounts of distributed generation, primarily solar. The majority of the solar projects in the state are utility-scale, representing 36% of all PURPA capacity in the U.S from 2008 to 2017.[139] During the early development of solar, utilities in the state were able to study and connect large quantities of projects at low cost to the developer. As development continues, the upgrades necessary to connect new solar resources increases and, as these costs increase, the economics of solar development become more challenging.

Another issue currently slowing down development of solar is the delay in utility interconnection processes. As a result of projects concentrating in the same area, a serial study process (e.g., one project studied for interconnection after another) creates a long queue with each subsequent project relying on information related to the completion of the preceding project. Duke Energy states that at least 24 substations have 4 or more large scale projects that are requesting interconnection, with thirteen projects requesting interconnection at one substation. The NCUC is currently considering moving from a serial study process to a grouping study process for interconnection. Grouping studies resolve interdependency by studying all projects at the same time, thus eliminating the multi-year delays related to the serial queue studies. It also sets up methodologies for cost sharing between projects which is not permitted today, and may ultimately support the economics of more projects as a result of spreading the cost of upgrades across more volume. For example, when a project triggers an upgrade today, that project is responsible

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[138] Some suggested resources on this topic include: "The Role of Distributed Energy Resources in Today's Grid Transition," authored by GridLab and GridWorks for Utah Clean Energy, August 2018. Available at: https://gridlab.org/works/role-of-distributed-energy-todays-grid/ and
Orrell, AC, JS Homer, and Y Tang, "Distributed Generation Valuation and Compensation," Pacific Northwest National Laboratory, February 2018. Available at:
https://www.districtenergy.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=0103ebf1-2ac9-7285-b49d-e615368725b2&forceDialog=0
[139] Energy Information Administration. August 2018 Monthly Data. https://www.eia.gov/electricity/monthly/

for all of the upgrades which could be tens of millions of dollars. Under the grouping study procedure, numerous projects may share the costs of the upgrades.

The Competitive Procurement for Renewable Energy Program (CPRE) established under HB 589 (2017) created a competitive bidding process for renewable energy projects. Utilities provide locational guidance, and generators receive payments tied to the utility's avoided cost. This process does not require the developer to pay for the network upgrades, as these are funded by the utilities and put into rates. The necessary upgrades are determined by grouping all of the CPRE competitive bidders to be studied together and costs are then allocated to each of the participating projects. To receive an award, projects must meet a two-part test. First, the project price bid added to the levelized cost of system upgrades must be lower than the administratively determined avoided cost. Second, the project price combined with the cost of upgrades must also be among the lowest cost of the suppliers competing for the defined procurement volume. The CPRE process by law is administered by an Independent Administrator selected by the NC Utilities Commission (NCUC). Duke Energy expects that 1,460 – 1,960 MW of projects will be developed under the CPRE. Tranche 1 of CPRE was completed in July of 2019 and the median price was about $7 below the administratively determined avoided cost. Duke Energy estimates the expected nominal savings to customers over the 20-year term of these contracts to be over $260 million compared to relying on an administratively determined price.

The recommendations in this section focus on creating opportunities for DERs to access markets and value streams while allowing developers and customers interested in installing DERs to better understand the opportunities and constraints on the grid.

Recommendations

G-1. Develop rates that provide accurate price signals to demand-side resources about costs and value to the grid, such as Time of Use (TOU) or real time pricing. In the long term, consider establishing new rate and compensation structures for DERs based on the value of grid services that can be provided by DERs, such as a "value of DER" tariff.

DERs, which include distributed solar, but also things like storage, EE, demand response and electric vehicle charging, can help make the grid more flexible, resilient, reliable, and clean while also giving customers more control over their energy use. For the efficient deployment of DERs to be feasible in the future, rates and compensation structures will need to be in place that compensate DER customers for the benefits DER provides to the grid, charge those customers properly for their use of the grid, and allow utilities to recover the revenue required to maintain a safe and reliable system. Ideally, these rate and compensation structures would send price signals that encourage customers to install and operate DERs in a way that is beneficial to the system as a whole. Participants in the Clean Energy Plan process identified the development of such rate and compensation structures as important for the cost-effective deployment of these resources in the state.

States and utilities are approaching these issues in different ways. Many, including California, Minnesota, Maryland, and Arizona are moving toward time-varying rates which price electricity higher when demand is greater and when the system is more stressed. See adjacent table for an explanation of the types of time-varying rates.

Types of Time-Varying Rates	
Time-of-use (TOU) pricing	Different time periods throughout the day (e.g., peak period, off-peak period, mid-peak period) have different electricity prices. The time periods and prices remain the same from day to day.
Variable peak pricing	Time-of-use pricing, plus a feature whereby the price for the peak period changes daily to reflect system conditions and cost. Prices in other periods do not change from day to day.
Critical peak pricing	A limited number of times per year, the utility calls a "critical event" during which the grid is expected to be very stressed. Prices over the timeframe of the event (usually limited to a few hours) increase dramatically. Can be coupled with TOU rates or standard flat rates.
Critical peak rebate or peak time rebate	A limited number of times per year, the utility calls a "critical event" during which the grid is expected to be very stressed. During the timeframe of the event, customers are compensated for cutting back on electricity use. Can be coupled with TOU rates or standard flat rates.
Real-time pricing	Prices vary hourly throughout the day to reflect actual fluctuating electricity costs determined by wholesale prices.

These kinds of rate designs more precisely communicate the value of DER services, such as solar or storage that provides power to the grid during peak times, or demand response programs that help shave peaks. Time-varying rates are one way to enhance the potential value that DERs can provide to the system.

Another potentially complimentary approach is to create a separate tariff that creates a value stream for services provided by DERs. Implementation of such a tariff would provide utilities and third parties with more information about areas where EE and other DERs are valuable and send price signals to encourage the development of DERs. Development of such a tariff is a complex and technical process that involves a myriad of considerations. Some of those considerations include:

- how and whether to determine locational and temporal values,
- the number of years to offer compensation under such a tariff,
- what values to include in the methodology, and
- what resources should be eligible for the tariff.[140]

A foundational challenge for developing a value of DER tariff is the need for data that illuminates the surrounding distribution grid needs and potential value streams that DERs can provide. This type of advanced distribution system data can be made available through a variety of processes as deemed

[140] Hall et al, "Locational and Temporal Values of Energy Efficiency and other DERs to Transmission and Distribution Systems," Synapse Energy Economics, 2018. Available at: https://www.synapse-energy.com/sites/default/files/ACEEE-Paper-Values-EE-DER.pdf

appropriate by regulators, and requires investments in grid modernization equipment that are currently being discussed by other stakeholder initiatives in the state.

One approach to such a tariff, being taken in New York, bases the value on the utility's avoided costs plus other DER values including wholesale energy and capacity, distribution capacity, and environmental values. Depending on the structure of the tariff, other potential values that could be included are avoided losses, generation capacity, energy, ancillary services, transmission capacity, and distribution services such as voltage support, reliability and resilience.[141] It should be noted that in New York (and in other states, as well), net metering continues to be in place for solar customers while the value of DER methodology is being developed.[142] This approach for solar customers is appropriate for NC as well. Stakeholders and regulators will need to grapple with the considerations and data issues outlined above in determining whether and how net metering for solar customers can and should evolve.

Table G-1: Actions for Recommendation G-1

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Ensure utilities are offering time-varying rates that encourage DER deployment that is beneficial to the system and allows customers to take advantage of cost-saving benefits of DERs	Short term
NCUC	Open a docket to consider the need for the appropriateness, feasibility, and structure of a "value of DER" tariff	Short to medium term
Co-ops and Municipal Utilities	Encourage DER deployment by evaluating the feasibility and effectiveness of time-varying rates and implement and develop appropriate programs	Medium term

[141] For more information, see NYSERDA's website at: https://www.nyserda.ny.gov/All%20Programs/Programs/NY%20Sun/Contractors/Value%20of%20Distributed%20Energy%20Resources

[142] State of New York Public Service Commission, (2017, March). Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA04D9EF3-9779-477E-9D98-43C7B060DAEB%7D.

G-2. Consider ways to provide greater transparency of system constraints and optimal locations for distributed resources

Information and transparency about grid needs and constraints is a foundational requirement in order for non-utility actors to compete fairly in the provision of clean energy and grid services. In the current regulatory framework, information asymmetry means that third party providers of distributed resources like solar, storage, or electric vehicle charging face difficulties in choosing locations, types, and sizes of projects to propose or develop. These resources could provide tangible benefits to the utility system in the form of increased flexibility and cheaper and cleaner generation sources, and to individual customers, in the form of clean energy and reduced bills.

As discussed in the recommendations around comprehensive system planning, analyses to develop more detailed, location-specific information about grid needs and constraints is considered a central feature of integrated distribution planning and in determining grid modernization needs..[143] Equitable access to relevant information not only helps smaller scale developers of solar (under 1 MW) determine the best locations to propose projects, it can help customers who wish to install solar PV better understand the right size of a system to install in their particular location to avoid grid upgrade costs. It can also help third party installers of electric vehicle charging infrastructure determine the best locations for charging stations from the perspective of limiting impacts on the grid. The Commission could consider requiring an assessment of the full costs and benefits of conducting such an analysis in the context of an investigation into distribution system planning, as recommended above.

More detailed, location-specific information about grid needs and constraints also benefits developers and providers of larger scale DERs, such as those entities that wish to participate in the CPRE program. Duke Energy agrees that locational information is important for finding the right place on the grid for a new project, and if done right, this can save customers money..[144] More detailed information about the current capacity of substations and transmission lines to accommodate additional solar development would make proposals to the CPRE more precise and valuable to the utility system, making them potentially more likely to be chosen through the competitive process.

Projects developed outside of the CPRE would also benefit from increased transparency about grid needs and constraints. For those projects, the NCUC is currently considering moving to a grouping study process similar to that which is utilized in CPRE. There are likely multiple benefits from moving to a grouping study process, including eliminating multi-year delays and allowing cost sharing between projects.

It may also be worth considering other solutions in areas where the transmission system is so constrained by generation development that neither CPRE nor grouping studies can improve the economics. In this case the legislature could provide guidance to the NCUC to establish a process for utilities to build out clean energy transmission solutions, which could ultimately be put into rates for all customers while expanding the delivery of clean energy within the state.

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[143] Volkmann, Curt. *Integrated Distribution Planning: A Path Forward*, GridLab, April 2019. (Volkmann, Integrated Distribution Planning: A Path Forward)
[144] See Duke Energy comments to DEQ

Table G-2: Actions for Recommendation G-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Consider conducting a full assessment of the costs and benefits of requiring utilities to undertake analyses that would provide customers and third parties with greater transparency of grid constraints and needs (e.g., hosting capacity analysis) in the context of distribution system planning	Medium to long term
NCUC	Require Duke Energy to provide more detailed information about the current capacity of substations and transmission lines to accommodate additional solar development in the context of the CPRE program	Short term (e.g., before the next tranche)

H. Clean energy economic development opportunities

Background and Rationale

Similar to the economic growth experienced in the solar sector, significant opportunity exists to build the clean energy economy through the development of offshore wind energy projects and supply chain. Additionally, NC's potential to produce renewable natural gas (RNG) from swine waste, food and solid waste operations, landfills and wastewater treatment plants offer an opportunity to grow the rural economy and reduce GHG emissions.

Offshore wind energy (OSW) represents a low-cost, clean, and reliable energy resource for NC. Our state has the second-highest average wind speeds on the Atlantic coast and is well-positioned to participate in this rapidly growing global industry. OSW development provides an opportunity for hundreds of millions of dollars in economic development and thousands of new jobs in eastern NC, as well as a significant increase in clean energy generation and energy diversification for the state. State commitments to OSW in the Northeast have led to record-breaking bids of more than $100 million each for the right to further assess wind energy areas (WEAs) leased to OSW industry giants by the federal Bureau of Ocean Energy Management (BOEM) for development. Applying the best practices and lessons learned from over 18 GW of OSW installation within the European Union, this industry is expected to create a $70 billion supply chain and tens of thousands new jobs in the United States by 2030.

Development of OSW energy resources is underway off NC's coast. The Kitty Hawk WEA, located 24 nautical miles from Corolla, is over 122,000 acres in size and is under lease by Avangrid Renewables. According to the developer, the Kitty Hawk project will boast a capacity of 2,400 MW. Avangrid is finalizing its planning, assessment, and stakeholder outreach necessary to submit its formal Site Assessment Plan (SAP) to BOEM in the summer of 2019..[145] After receiving approval of the SAP, Avangrid will prepare a detailed plan for the construction and operation of a wind energy project and conduct environmental and technical evaluations. Construction and installation of the Kitty Hawk project could begin as early as 2023, and plans anticipate operations at the facility beginning in 2025. BOEM has identified two additional WEAs off the coast near Wilmington, and new OSW would increase interest in the OSW industry of developing those areas.

Executive and legislative mandates are in effect in many Atlantic states to attract OSW development. Mandates in the following states establish OSW procurement goals and in some cases timelines..[146] These procurement requirements, combined with any state-offered incentives, send clear market signals that both leverage and attract OSW industry investment.

Despite strong leadership on OSW from our northern neighbors, additional OSW development has stalled in NC in part because of a lack of strong pro-OSW market signals by the state. Additional OSW-related topics for further attention include local concerns around visibility and the need for onshore transmission

[145] For more information about the BOEM WEA selection and development process, see: https://www.boem.gov/Renewable-Energy-Program-Overview/ and the wind energy chapter in the accompanying Supporting Document on NC's Energy Resources.
[146] New York (by executive order, 9000 MW by 2035); New Jersey (by executive order, 3500 MW by 2030); Maryland (by legislation, 1200 MW); Connecticut (by legislation, 2000 MW); Massachusetts (by legislation and executive order, 3,200 MW by 2030); and Virginia (by legislation, 12 MW; by executive order, 2500 MW by 2026)

infrastructure to bring OSW-generated energy inland to load centers. The state should engage with Duke Energy and Dominion Energy on transmission infrastructure needs, addressing expedited siting, and permitting for right-of-ways to prepare NC's grid in order to deploy this valuable energy resource. In addition, the Utilities Commission could fast-track the process for determining the Certificate of Public Convenience and Need for OSW-generated wind resource development and necessary transmission.

Other Atlantic Coast states are gaining a competitive advantage and creating and sustaining high-wage jobs that could, and should be, available to NC's businesses and workforce. To capture these opportunities and ensure NC's competitive edge, the state must take proactive steps on OSW. A comprehensive assessment of state infrastructure (ports, rail, etc.) as well as supply chain assets and potential is a key next step. This assessment will provide a clearer picture of NC's capabilities and inform the state's path forward on OSW-related investments and economic development. In parallel, DEQ and other agencies will evaluate best practices from other states and identify OSW policy actions that make sense for NC.

Recommendations

H-1. Identify and advance legislative and/or regulatory actions to foster development of NC's offshore wind energy resources

A common characteristic among U.S. states realizing industry investment in development of offshore wind projects and the associated supply chain is the presence of state action incentivizing OSW. Capital flows toward certainty. OSW developers and manufacturers are attracted to states that have a high potential wind resources as well as a predictable and hospitable business environment.

While multiple Atlantic states have established strong OSW-related policies, the form of the policies vary. Several states have legislative mandates that require specific OSW procurement on a designated time frame. Virginia's legislature, for example, determined that OSW development is in the "public interest," a conclusion that enabled the state public utility commission to authorize an OSW pilot program. DEQ will work with other agencies and stakeholders to identify the design of legislation and/or regulatory action appropriate for NC.

Table H-1: Actions for Recommendation H-1

Entity Responsible	Action	Timing (Short, medium, or long-term)
DEQ	Based upon an evaluation of best practices for legislative and regulatory action that promote business certainty for the OSW industry, identify and advance strategic actions for NC.	Short term

H-2. Create and foster statewide and regional offshore wind collaborative partnerships with industry, the public, stakeholders, and neighboring states to bring economic growth to NC.

NC and its neighboring states seeking offshore wind development and economic opportunities would benefit from a regional effort to coordinate regional resources in a way that fosters development of a robust OSW industry and energy market in the Southeast. NC and partner states could evaluate their collective assets for OSW development, streamline state regulatory requirements, collaborate on educational programs and requirements for job training, and create a forum for sharing information and best practices related to OSW development. The partner states also could also coordinate engagement with federal agencies, such as BOEM.

Table H-2: Actions for Recommendation H-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Governor's Office or Cabinet-level executives	Work to establish a regional agreement for multi-state cooperation on OSW	Short term
OEMs, energy developers, IOUs, local government, research institutions, academic and training entities, etc.	Engagement with industry which may include: regional promotion of OSW assets for supply chain investment; developing and implementing best practices; coordinating communications; and identifying funding streams to facilitate research and other activities that enhance OSW and industry recruitment	Short term
OSW developers	Location of OSW component manufacturing, supply chain investment, facility, and jobs in NC	Medium term

H-3. Conduct an assessment of offshore wind supply chain and ports and other transportation infrastructure to identify state assets and resource gaps for the offshore wind industry.

An assets and capabilities analysis specific to the needs of the OSW industry would signal to developers and original equipment manufacturers (OEMs) that NC wants to participate in this industry. Such an analysis would evaluate existing supply chain and port infrastructure assets, assess NC business advantages and economic climate, evaluate current workforce readiness – building on the Department of Commerce's clean energy workforce assessment completed pursuant to §5 of EO 80. Additionally, the analysis would identify potential infrastructure and other investments necessary to provide services for cargo, transportation, trade related to OSW, and the transmission required to accommodate OSW-generated energy. Results of the study could include estimated manufacturing and supply chain jobs that could be created to serve the OSW industry, opportunities for rural economic development, benefits to local and state tax bases, and other economic benefits. The objective of conducting this type of analysis is to determine how NC can successfully position itself to compete in OSW as well as pinpoint our state's advantages to attract industry segments, such as blades, towers, and wind turbines (nacelles). More specifically, the assessment would evaluate:

1. The State Ports at both Wilmington and Morehead City to determine what infrastructure upgrades are needed to support OSW industry
2. The workforce assets in place, expected employment needs, and training requirements
3. The needs of industry partners related to manufacturing facilities
4. Items identified by the multistate partnership contemplated in *Recommendation H-2.*

Table H-3: Actions for Recommendation H-3

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Cabinet agency	Retain a consultant for a supply chain infrastructure assessment for the OSW in NC.	Short term
Dept of Commerce, NC Ports, Dept of Transportation, chambers of commerce, economic developers, local government	Engage key stakeholders in assessment and leverage assessment findings to recruit industry	Short to medium term
Cabinet Agency and academia	Conduct an economic impact analysis for OSW energy development in NC that includes quantifiable impacts on health, environment, emissions, direct and indirect jobs, local and regional tax bases, etc.	Short Term

H-4. Develop pathways to expand renewable natural gas recovery and usage.

The agricultural community sees RNG production as a new "home-grown" industry with the potential to increase employment and revenue generation potential for rural and agricultural communities, create more advanced, sustainable waste management solutions and produce bioenergy that offsets GHG emissions. By 2030, emissions from the agriculture and waste management sectors are projected to be almost 50% of the total emissions from the electricity sector. RNG projects in the State have the potential to significantly reduce these emissions. Furthermore, RNG can reduce reliance on natural gas.

Stakeholders have expressed concerns over air and water pollution from swine operations' use of biogas technology that rely on lagoons and sprayfield waste management systems. Pollution to waterways, odors, and public health concerns for nearby and downstream communities, including those felt disproportionately by minority populations, are the reasons for opposition to biogas production.

The Research Triangle Institute (RTI), Duke University, and East Carolina University are conducting a study to determine the extent and location of available biogas resources in the state and the percentage of

NC's GHG reductions that can be met with biogas. The analysis will include determining the climate, environmental, societal, and economic effects of the use of biogas and will recommend policy measures to accelerate biogas development, and the best uses for the gas (i.e., transportation fuel, RNG/pipeline, on-site energy generation). Implementation pathways for policy measures identifies in this study should address the benefits of biogas as well as environmental and societal impacts.

Table H-4: Action for Recommendation H-4

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Duke University, RTI, East Carolina University	Develop implementation pathways, including strategies to address environmental and societal impacts, for policy measures identified in a study currently underway that will determine the extent and location of available biogas resources in the state and the percentage of NC's GHG reductions that can be met with biogas.	Short term
Energy Policy Council – Energy Infrastructure Subcommittee	Convene a study committee to explore ways to capture and utilize RNG in NC. Topics to study: Ways to increase options and educate producers/ consumers; Consider what policy barriers exist; Feasibility of micro-pipelines to attract economic development; Application of food waste digesters; Supporting disaster related fuel supply needs and resiliency operations, and RNG transport mechanisms to end users and buyers; and evaluation of environmental, societal, and health impacts of biogas development.	Medium term

Strategy Areas & Recommendations

4.5 Equitable Access & Just Transition

Equitable Access and Just Transition

- **I. Equitable access and energy affordability**
  - I-1: Include non-energy equity-focused costs and benefits in decisions regarding resource needs, program design, cost-benefit analyses, and facility siting.
  - I-2: Examine the feasibility and proper design of a low-income rate class and associated rate structures, including but not limited to the elimination or reduction of fixed charges for ratepayers with high energy burdens.
  - I-3: Expand energy efficiency and clean energy programs specifically targeted at underserved markets and low-income communities.
- **J. Just transition to clean energy economy**
  - J-1: Ensure inclusion and meaningful involvement of historically marginalized individuals (people of color and people living in poverty) in decision-making regarding siting electricity generation assets and implementing programs that would affect their energy bills, health, and access to clean energy and energy efficiency opportunities.
  - J-2: Launch an EE Apprenticeship program within Apprenticeship NC to expand access to clean energy careers.
  - J-3: Create long term jobs with family sustaining wages and benefits in renewables and grid infrastructure industries for low income communities and workers displaced by the transition to a clean energy economy.

Strategy Area		Recommendation	Legislature	Utilities Commission	Governor's Office	State Agencies	IOU	CO-Ops / Public Utilities	Local Government	Academia	Businesses
Equitable Access and Just Transition	I. Address equitable access and energy affordability	I-1		●		●	●	●	●		
		I-2		●						●	
		I-3	●			●	●				
	J. Foster a just transition to clean energy	J-1		●		●					
		J-2								●	
		J-3	●				●	●	●	●	●

SHORT TERM MEDIUM & LONG TERM

I. Address equitable access and energy affordability

Background and Rationale

Low income and energy-burdened residents often live in older, less efficient housing which requires more energy for heating and cooling than newer homes. In 2018, those living with incomes below 50% of the Federal Poverty level, spent 33% of their annual income on energy bills (includes electricity, gas and other utilities).[147] In NC, low income residents spent between 17% (homeowners) and 21% (renters) of their annual income on electricity bills.[148,149]

Low income households may not be able to take advantage of existing programs for clean energy due to up-front costs and financing, physical challenges related to the quality of the building or ownership status of their housing, or simply a lack of access to high-integrity service providers. Low-income customers may lack savings or access to financing. They often have lower credit scores that may disqualify them from financing or lock them into high interest rates that make the benefits of clean energy less attractive. Many of the tax credits for clean energy, such as the federal solar investment tax credit and the EV tax credit, are nonrefundable, which means that individuals cannot directly benefit from these incentives unless they have a tax liability.[150]

Low income households have fewer choices in regard to housing options, with many low income residents living in homes with structural deficiencies that can make EE upgrades inaccessible.[151] Low income households are less likely to own their own homes, especially in urban areas, which makes it more difficult to install clean energy like solar. These households are more likely to live in multifamily buildings without access to their own roof. They often live in housing stock that is older and may be of poor structural integrity. A roof that needs repair is unlikely to be suitable for solar PV.

Energy burdened households struggle to pay unaffordable energy bills. 1.4 million people in NC are paying a disproportionately high amount of their income on energy bills[152] which makes making any investment in things like EE more difficult. Many of the same communities are directly impacted by the health and pollution impacts of energy extraction, transportation and production. These compounding factors mean that these communities are the least able to reap benefits of investments in clean energy and EE while being most impacted by the legacy energy industry.

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[147] Ibid

[148] Office of Energy Efficiency and Renewable Energy. (2017). Low-Income Energy Affordability Data (LEAD) Tool – OpenEi DOE Open Data (K. Layman, Ed.). Accessed May 2019. https://openei.org/doe-opendata/dataset/celica-data

[149] For more information, see CEP Supporting Document – Part 3: Electricity Rates and Energy Burden

[150] The *Low-Income Solar Policy Guide* provides a compendium of options and reference materials for addressing financial barriers on its "Financing" page. The recommendation included in this report regarding the creation of a green bank focused on financing clean energy projects would also be a way to address some of these challenges.

[151] Drehobl, A., & Ross, L. (2016). *Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities.* Accessed April 2019. https://aceee.org/sites/default/files/publications/researchreports/u1602.pdf

[152] Equitable Access and Just Transition Stakeholder Memo

The recommendations in this section address some of the barriers that low income and energy burdened communities face when it comes to energy affordability and access to clean resources.

Recommendations

I-1. Include non-energy equity-focused costs and benefits in decisions regarding resource needs, program design, cost-benefit analyses, and facility siting.

While utilities currently have programs targeted at low income households and tracks participation, these programs can be improved using a deeper equity analysis. By including equity considerations in these types of decisions, utilities, local government and state agencies can better reflect broader societal costs and benefits of energy production and use, and of EE programs or solar investments..[153] For example, in resource planning the Utilities Commission could consider impacts to low-income, energy burdened or historically marginalized communities when deliberating around utilities' IRP filings. Such consideration could lead to future resource decisions that reduce burden and even provide a benefit to these communities.

In crafting policy and regulatory responses to this recommendation, agreeing upon consistent language and definitions used to describe impacted communities and households will be important. The appropriate definitions for NC were not discussed in the CEP stakeholder process, however, the Nicholas Institute suggests the following terms and definitions for the purposes of crafting equity-focused policies and regulations:

- Household energy burden: the share of a household's income that is spent on specified utilities and heating fuels where the numerator reflects both the household's consumption as well as electricity rates, and the denominator reflects total household income or budget.
- Energy poor households - all those that spend on average more than 6% of their income on meeting energy costs.[154]

Utilities and state agencies could better incorporate equity into program design, such as EE program design, by adding metrics that track how many energy burdened households are enrolled or creating carve-outs designed to ensure certain percentages of program funds are dedicated to those households.

As discussed in recommendation C-2, cost-benefit testing, such as the analysis done to determine how much and what kinds of EE should be implemented, could be expanded to include an assessment of broader costs and benefits, often referred to as "non-energy" costs and benefits. Several states use a variety of methods to place values on societal public health and participant health benefits, and these methods could be explored in NC. Lastly, decisions about siting energy facilities could explicitly include an environmental justice or equity impact analysis.

[153] Note: elements of this recommendation were discussed in some detail in the section of this report that covers comprehensive system planning.

[154] The Nicholas Institute also suggests that a single threshold of energy burden as defined above does not capture the full story of energy burdened households in the state. The Institute is currently analyzing household income and energy bill data for NC in an effort to identify and characterize "tranches" of energy burden (by locations, home age and type, and demographics) tailored to NC.

Table I-1: Actions for Recommendation I-1

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Consider impacts to energy burdened households and communities in utility resource planning. In doing so, consider the appropriate definitions of household energy burden, energy poor households and other key terms as discussed above.	Medium term
State agencies, NCUC, utilities, Co-ops, public utilities, local governments	Add equity metrics and elements to program delivery, such as EE programs. In doing so, consider the appropriate definitions of household energy burden, energy poor households and other key terms as discussed above.	Short term
NCUC and DEQ	Consider and evaluate methodology to include broader non-energy equity-focused elements in cost-benefit testing. In doing so, consider the appropriate definitions of household energy burden, energy poor households and other key terms as discussed above. DEQ will provide technical assistance to NCUC regarding methods to assess public health and societal impacts, and siting decisions affecting environmental justice areas and high energy burden communities.	Medium term
NCUC and DEQ	Explore methodologies for including EJ impact analysis in siting decisions. In doing so, consider the appropriate definitions of household energy burden, energy poor households and other key terms as discussed above.	Short term

* It is assumed that the agencies named in this table have existing statutory authority to pursue this recommendation. DEQ did not conduct a thorough analysis of legal authority in conjunction with this plan. In the event that it is determined that entities do not have sufficient authority, legislation would be needed to provide the appropriate authority.

I-2. Examine the feasibility and proper design of a low-income rate class and associated rate structures, including but not limited to the elimination or reduction of fixed charges for ratepayers with high energy burdens.

Low-income customers face a more significant burden in paying their energy bills than other customers of the same "customer class" with higher incomes. Though "affordability" has been a core tenant of utility regulation and system planning, stakeholders in the CEP process identified that there are segments of customers for whom the cost of energy is not affordable and argued that there should be a more nuanced treatment of affordability in utility ratemaking and rate design. This could be accomplished in a number of different ways, such as through a bill discount, a percentage of income payment program, reduction or elimination of fixed charges, or other ways. The NC Utilities Commission could also consider creating a differentiated service classification for multi-family housing, where costs for the utility to provide electric service could be lower. Affordability was not only raised as an issue for customers of IOUs. Rate structures of co-ops and municipal utilities that emphasize fixed charges place disproportionate burden on low-usage customers and low-income customers.

The details of this recommendation, including the proper design of a low-income rate class and the right strategy for addressing affordability for low-income customers, were not able to be tackled by CEP stakeholders in the limited time available. An entity such as a higher education institution could establish a follow-up process involving stakeholders to discuss equity issues within utility ratemaking and recommend actions for legislation and for the NCUC to pursue.

Table I-2: Actions for Recommendation I-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Academia, Non Profits, NCUC	Convene a stakeholder process to discuss equity issues within utility ratemaking and recommend actions for legislation and for the NCUC to pursue	Short term

I-3. Expand energy efficiency and clean energy programs specifically targeted at underserved markets and low-income communities.[155]

Many low-income homes suffer from health, structural or safety issues, such as mold, leaky roofs or faulty wiring, as low-income people tend to live in older buildings and have more limited income to invest in upgrades and repairs. These conditions may prevent the installation of solar or EE measures. Studies have found that a significant portion of low-income homes (more than 10% in one such study) have health and safety issues that prevent providers from delivering weatherization services.[156] Equity-focused policies and programs that address some of these challenges can help ensure that vulnerable communities will benefit from the growing clean energy economy.

There are many existing EE programs in NC, and yet some sectors – including agricultural and multi-family housing – are underserved by these programs. Some existing dynamic incentive programs, such as Duke Energy Design Assistance program, cannot serve multifamily developments due to metering eligibility requirements. Other programs have payback schedules that do not match a sector's situation, or application periods that do not align with complementary funding sources. And although Duke Energy has EE programs specific to low income customers, they do not have a specific target or carve out for how many low income communities get access to funds, so it can vary from year to year how well these programs reach these customers.

Some existing utility EE programs could be tailored to be a "better fit" to address the target markets of agriculture, multifamily, mobile homes, military populations, and houses of worship, and others including small businesses and some industrial customers that are unable to take advantage of utility-offered programs due to the high cost of opting-in to the EE Rider. Fifty percent of low-income populations in NC reside in multifamily residences. However, many developers may not be taking full advantage of existing EE incentive programs in this sector. Opportunities exist to better align multifamily utility EE incentives with new NC Housing Finance Agency projects and their refinancing cycles, and to seek out complementary funding such as US Department of Agriculture (USDA), state weatherization and other non-regulated sources.

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155 Many of the ideas and some of the text for this recommendation were taken from the EE Roadmap's Recommendation #13 and #16. They have been combined with other ideas and shortened for the purposes of this document. More information on these recommendations can be found in the Roadmap.

156 Refer, for example, to: (1) Carroll, D., Berger, J., Miller, C., and Driscoll, C. (2014). *National weatherization assistance program impact evaluation: Baseline occupant survey; Assessment of client status and needs.* Oak Ridge, TN: Oak Ridge National Laboratory. ORNL/TM-2015/22. Retrieved from: https://weatherization.ornl.gov/wp-content/uploads/pdf/WAPRetroEvalFinalReports/ORNL_TM-2015_22.pdf; (2) Rose, E., Hawkins, B., Ashcraft, L., and Miller, C. (2014). *Exploratory review of grantee, subgrantee and client experiences with deferred services under the Weatherization Assistance Program.* Oak Ridge, TN: Oak Ridge National Laboratory. ORNL/TM-2014/364. Retrieved from: https://weatherization.ornl.gov/wp-content/uploads/pdf/WAPRecoveryActEvalFinalReports/ORNL_TM-2014_364.pdf; and (3) Green & Healthy Homes Initiative (2010, October). *Identified barriers and opportunities to make housing green and healthy through weatherization.* Prepared by the Coalition to End Childhood Lead Poisoning. Baltimore, MD: Green & Healthy Homes Initiative. Retrieved from: https://www.greenandhealthyhomes.org/wp-content/uploads/GHHI-Weatherization-Health-and-Safety-Report1.pdf. The latter report notes (on page 5) that "Health and safety issues render homes ineligible for weatherization work though the degree may vary between [programs]. Overall, the average number of homes deemed ineligible in the pre-auditing or auditing phase was 12.88%; however, there is a wide variance in why programs find those homes ineligible."

Other unique opportunities exist for targeted sectors, such as a Heat Pump Water Heater (HPWH) rental program for low-income households. The reduction in the upfront cost of the equipment would dramatically increase the adoption of HPWH in low and moderate income communities helping each household significantly reduce energy use for heating water resulting in savings to the resident. In addition, by using HPWH as deployable demand-side management to shift loads off peak through thermal storage, additional utility cost savings and/or funding for programs could be realized.

The NC Weatherization Assistance Program (NC WAP) in partnership with multiple NC utilities is developing a limited community solar pilot for low income households. As discussed in the previous section, community solar allows customers that cannot install solar on their property to benefit from solar energy. Low income households have historically had little or no direct access to solar in NC. This new community solar pilot will give low income households an option to use solar energy to further reduce energy burdens for 15 years or more in addition to having their homes weatherized. The community solar measure is designed to provide each participating low income household an additional $365 in savings per year credited directly to their utility bills. NC WAP is working with its agencies and partner utilities to find approximately 40 eligible low income households within the service territory of the participating utilities. NC WAP plans to expand this low income community solar opportunity to other areas in future years through additional partnerships.

There are existing venues in the state for discussing changes to existing programs in order to better serve low-income and underserved communities. To the extent that new funding is needed to accomplish some of these actions, the legislature or philanthropies could be a source of financial support.

Table I-3: Actions for Recommendation I-3

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Legislature	Direct utilities to work with stakeholders to identify ways to better serve low-income and underserved communities through existing programs or by creating new program elements, such as a low-income carve out using the improved cost benefit analysis under Recommendation I-1	Short term
DEQ	Evaluate outcomes from NC WAP community solar program and determine ways to expand the program to reach more low income customers	Medium and long term
Duke Energy EE Collaborative	Discuss new program ideas, how better to serve underserved markets, and ways to administer new offerings	Short term
Energy Policy Council EE Committee	Discuss new program ideas, how better to serve underserved markets, and ways to administer new offerings and make recommendations for actions through collaborative partnerships	Medium and long term
Low income advocates	Work with utilities to design and implement programs. In the case of IOUs, these programs would need to be approved by the NCUC.	Medium and long term

J. Foster a just transition to clean energy

Background and Rationale

Throughout history as the economy has changed due to varying factors from trade policy to technological innovation, workers have often suffered disproportionately from these changes. The loss of manufacturing in the textile, tobacco, and furniture industries across NC are prime examples. As NC's energy system shifts toward one focused on clean resources, workers currently employed in traditional energy industries that will be transitioning stand to be impacted. Counties with fossil fuel facilities could lose millions of dollars from their tax base as fossil fuel facilities ramp down, for example. NC should anticipate and manage this transition, by putting worker protections and oversight by those most affected into the state's plans from the beginning..[157]

These concerns are not unique to NC. The Paris Climate Agreement recognized "the imperatives of a just transition of the workforce and the creation of decent work and quality jobs.".[158] The International Labour Organization (ILO), a specialized agency of the United Nations, was charged with developing a framework for implementing this principle. In its 2018 Policy brief on the subject, the ILO states that:

> "[t]he idea of just transition should not be an 'add-on' to climate policy; it needs to be an integral part of the sustainable development policy framework. From a functional point of view, just transition has two main dimensions: in terms of 'outcomes' (the new employment and social landscape in a decarbonized economy) and of 'process' (how we get there). The 'outcome' should be decent work for all in an inclusive society with the eradication of poverty. The 'process,' how we get there, should be based on a managed transition with meaningful social dialogue at all levels to make sure that burden sharing is just and nobody is left behind.".[159]

Recommendations

J-1. Ensure inclusion and meaningful involvement of historically marginalized individuals (people of color and people living in poverty) in decision-making regarding siting electricity generation assets and implementing programs that would affect their energy bills, health, and access to clean energy and energy efficiency opportunities.

Historically marginalized individuals and communities have largely been left out of decisions that often affect their economic opportunities, environmental quality, health, and wellness. This has led to a cycle of increasing hardship and impacts for these communities, relative to individuals and communities that have greater access and ability to influence decisions. The US EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations,

[157] AFL-CIO comments
[158] UNFCCC "Paris Agreement." https://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf
[159] ILO Just Transition Guidelines. https://www.ilo.org/wcmsp5/groups/public/---ed_dialogue/---actrav/documents/publication/wcms_647648.pdf

and policies. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.".[160]

In NC, as in other states, people of color and low-income people are disproportionately impacted by decisions about siting and operating energy facilities, what types of clean energy and EE programs will be available and how those programs will be structured, what utility costs are approved and how utility costs will be recovered from ratepayers, among others. NC must continue to strive for the achievement of environmental justice goals around inclusion and meaningful involvement in decisions like these. Inclusive decision-making processes and meaningful involvement of historically marginalized individuals means seeking input and ideas from the beginning of any given decision process, before options are being developed. It requires concerted effort to reach out to community members, grassroots organizations, and tribal governments to understand how different options will impact them. DEQ will report to the Governor's Office how it is implementing actions that ensure meaningful participation and inclusion of historically marginalized communities and considering impacts on those communities in agency decision making related to energy.

Table J-1: Actions for Recommendation J-1

Entity Responsible	Action	Timing (Short, Medium, or Long term)
DEQ	Report to the Governor's Office how it is implementing actions that ensure meaningful participation and inclusion of historically marginalized communities and considering impacts on those communities in agency decision making.	Short term
NCUC	Consult with stakeholders and explore ways to incorporate environmental justice into decisions and make Commission processes more inclusive. Consider adding a required section in future IRPs and other relevant filings that demonstrates inclusion and meaningful involvements of historically marginalized communities.	Short term
DEQ	Support the Environmental Justice and Equity Advisory Board on energy issues by informing the Board of relevant energy issues and supporting their evaluation of those issues.	Short term

[160] https://www.epa.gov/environmentaljustice

J-2. Launch an EE Apprenticeship program within Apprenticeship NC to expand access to clean energy careers.[161]

Apprenticeships and pre-apprenticeships provide opportunities for experiential learning through paid "on the job" training with real companies in the industry. Allowing for both apprenticeships and pre-apprenticeships would ensure that anyone could participate in the program regardless of education level or background. Part of a just transition to the clean energy economy of the future is ensuring that NC residents of all racial and socioeconomic backgrounds have opportunities to find and keep jobs that pay family-sustaining wages. Apprenticeship programs can help create a pipeline of skilled workers for businesses in need of good employees, reduce operational costs by establishing a streamlined channel to bring on new workers and advance existing workers, build employee loyalty and reduce attrition, and foster new leaders.

NC is home to a successful state apprenticeship program. Apprenticeship NC is an economic development-focused organization housed within the NC Community Colleges System. The U.S. Department of Labor has described Apprenticeship NC as an agency that works "to ensure NC has an innovative, relevant, effective, and efficient workforce development system that develops adaptable, work ready, skilled talent to meet the current and future needs of workers and businesses to achieve and sustain economic prosperity." However, currently, Apprenticeship NC does not focus on EE as a career path.

Apprenticeship NC already works in collaboration with the NC Community Colleges System, the NC Department of Commerce, and the US Department of Labor's Bureau of Apprenticeship and Training and currently recognizes building trades and energy industries as part of their apprenticeship programs. This partnership could easily expand to include various EE trades. In order for this to happen, specific EE careers would need to be identified and companies would need to be contacted and asked to participate in the program. To ensure equitable outcomes, specific focus should be made to include small businesses, Historically Underutilized Businesses, and Historically Black Colleges and Universities in this program.

[161] This recommendation is part of the Energy Efficiency Roadmap recommendations and the text in this document was largely copied from the Roadmap. More detail on this recommendation is available in the Roadmap.

Table J-2: Actions for Recommendation J-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Community Colleges System - Apprenticeship NC	Work with the following stakeholders to coordinate and implement EE apprenticeship programs: • Technical and community colleges • Traditional colleges and universities • EE industry employers • K-12 institutions • NC Department of Commerce/NCWorks • Workforce Development Boards • NC Business Committee for Education Navigator Tool • Training institutions • Credentialing organizations such as Building Performance Institute (BPI) • Local businesses • Municipalities • Utilities	Medium term

J-3. Create long term jobs with family sustaining wages and benefits in renewables and grid infrastructure industries for low income communities and workers displaced by the transition to a clean energy economy.

Focusing job training and creation is minority and low-income communities and those where workers are being (or likely to be) displaced by a transition away from fossil fuels will help ensure that all parts of NC can thrive in a clean energy future. This focus is important because these communities are at the greatest risk of suffering economic hardship and growing wealth inequality relative to the wealthier parts of the state. A concerted effort must be made by multiple entities to ensure that these communities are made better off with the transition to clean energy.

Stakeholders in the clean energy plan process identified a few key actions to realize this recommendation, including creating more accessibility to the Registered Apprenticeship Programs by establishing pre-apprenticeship programs in partnership with high schools and community colleges. Various entities could help drive up labor standards by prioritizing contractors that provide good wages, benefits and career pathways. Best practices from around the state and the country for displaced workers from the fossil fuel industry could be collected by government and shared in order to encourage private sector action.

Under direction from EO 80, the Department of Commerce completed its Clean Energy and Clean Transportation Workforce Assessment. This assessment identified occupations, number of jobs for each occupation, and the five-year growth rate for jobs related to the clean energy industries, EE industries, and clean transportation industries. The assessment also provided four recommendations for action to develop a future workforce by bringing together employers, workers, and education and training providers to meet changing needs. The assessment recognizes that the importance of job placement and training need of communities and workers to ensure a just transition.

Table J-3: Actions for Recommendation J-3

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Utilities and clean energy developers	Work with "High road" contractors or those that provide living wages and benefits and career pathways for workers.	Medium term
Legislature	Consider tax incentives to encourage targeted investment in certain communities, and labor standards	Medium term
Local and Tribal Governments	Use economic development agencies to direct and prioritize investment, use existing powers to direct use of incentives for development	Medium term
Higher Education	Train contractors and workers in clean energy and EE professions, create pre-apprenticeship programs in partnership with the Registered Apprenticeship Programs	Medium and long term

Strategy Areas & Recommendations

4.6 Energy Efficiency & Beneficial Electrification

Energy Efficiency and Beneficial Electrification

- **K. Energy efficiency and demand side management programs**
  - K-1: Establish an Energy Efficiency Advisory Council (EEAC) to oversee implementation of the EE Roadmap recommendations.
  - K-2: Enable customers to have greater access to their energy data through new functionalities, such as those available through Green Button "Download My Data" Button.
  - K-3: Establish minimum EE goals within existing REPS or establish an energy efficiency resource standard (EERS).
  - K-4: Enhance education and awareness around energy efficiency opportunities in K-12 schools and community colleges through an "Energy Efficiency Everywhere (E3)" project.
  - K-5: Require utilities to develop innovative rate design pilots to encourage customer behavior that helps achieve clean energy goals, such as peak demand reduction, better utilization of renewable resources, and strategic storage deployment.
  - K-6: Increase EE awareness on the North Carolina Building Code Council.
- **L. Electrification Strategies**
  - L-1: Require utilities to develop innovative rate design pilots for electric vehicles to encourage off-peak charging of vehicles and to test effectiveness of different rate structures at shifting customer usage of the grid and encourage the adoption of electric vehicles.
  - L-2: Conduct an analysis of the costs and benefits of using electrification to reduce energy burden and GHG emissions in end-use sectors in NC, such as in homes, buildings, transportation, industrial, and agricultural operations.

Strategy Area		Recommendation	Legislature	Utilities Commission	Governor's Office	State Agencies	IOU	CO-Ops / Public Utilities	Local Government	Academia	Businesses
Energy Efficiency and Beneficial Electrification	K. Increase use of energy efficiency and demand side management programs	K-1			•						
		K-2	•	•			•	•			
		K-3	•	•							
		K-4								•	
		K-5		•				•			
		K-6	•			•					
	L. Create strategies for electrification	L-1		•				•			
		L-2								•	

SHORT TERM MEDIUM & LONG TERM

K. Increase use of energy efficiency and demand side management programs.[162]

Background and Rationale

EE is widely considered a least cost option for meeting energy demand, while reducing energy costs and carbon emissions. While EE has experienced slow and steady growth in NC, much more can be done to maximize the full potential of this least cost resource. Total retail electricity sales to NC consumers in 2017 was just over 131,000 GWh. Although the state has realized increasing annual incremental EE savings – exceeding 1,220 GWh in 2017 – annual incremental EE savings from utility programs as a percentage of retail sales is still under 1.0%.[163,164] Each incremental investment in EE accrues multiple benefits to consumers, including lower energy bills, increased grid reliability and the deferral or elimination of expensive new generation, transmission and distribution infrastructure investments – costs that would otherwise be borne by ratepayers.

Despite bipartisan support for the economic and environmental benefits of EE and an increasing focus by advocates, utilities and big energy users, barriers remain to fully realizing EE's potential. To discuss and start to address these barriers, the Nicholas Institute at Duke University, in partnership with NC's Department of Environmental Quality initiated a process to develop a comprehensive state EE roadmap. This initiative, launched in August 2018, convened stakeholders from separate EE working group discussions to think collectively about this issue.[165] Some of the barriers that the EE roadmap stakeholders identified include:

End-user Barriers

- Lack of reliable information about EE opportunities (particularly in rural and agricultural communities)
- EE is often confused with renewable energy

[162] Much of the background and recommendations discussion in this section is taken from the EE Roadmap, with slight modifications and editorial changes made by DEQ.
[163] NC State Electricity Data, Energy Information Administration, Form EIA-861,"Annual Electric Power Industry Report" for the years 2013-2017. https://www.eia.gov/electricity/data/eia861/
[164] Annual incremental energy efficiency is defined as "The annual changes in energy use (measured in MW hours) and peak load (measured in kilowatts) caused by new participants in existing DSM (Demand-Side Management) programs and all participants in new DSM programs during a given year. Reported Incremental Effects are annualized to indicate the program effects that would have occurred had these participants been initiated into the program on January 1 of the given year. Incremental effects are not simply the Annual Effects of a given year minus the Annual Effects of the prior year, since these net effects would fail to account for program attrition, equipment degradation, building demolition, and participant dropouts. Please note that Incremental Effects are not a monthly disaggregate of the Annual Effects, but are the total year's effects of only the new participants and programs for that year." US Energy Information Administration Glossary, accessed 7/3/19. https://www.eia.gov/tools/glossary/index.php?id=I
[165] The EE Roadmap strives to include diverse voices from across the state and identify a variety of paths forward to help all stakeholders seize the EE opportunities in the state. Some of the discussions generated substantial debate and disagreement among various parties that could be impacted by a new paradigm for EE. Much more information about the EE Roadmap collaboration and outcomes, including detailed discussion of the full list of outcomes, can be found in the EE Roadmap document. The recommendations included in the Clean Energy Plan are those that were prioritized as most important by the Clean Energy Plan participating stakeholders.

- Longer payback period for some EE investments as the opportunities for shorter payback investments for "low hanging fruit" (like efficient lighting) have already been realized
- Lack of inclusive financing options

Building Sector Barriers[166]

- NC building code cycle is six years for residential homes, twice as long as best practice in other states, and the state's energy conservation code is falling behind national standards
- Lack of energy managers / EE champions in commercial and small business
- Quantitative analysis (energy audit) of EE opportunities can be expensive

State Regulatory and Policy Barriers

- Federal weatherization funding is limited
- Lack of efficiency mandate for all utilities
- Industrial and large commercial customers are allowed to opt out of utility programs provided they implement EE on their own, making tracking and creating incentives for EE difficult for these customers

Utility Barriers

- Perception that the cost per kilowatt hour (kWh) may increase with additional EE utility investment
- Absent incentives or mandates, the current cost-of-service utility business model is not aligned with EE; investments in EE undercut revenue to the utility in the Near term and deferred or avoided generation, transmission, or distribution investments—while good for ratepayers—limit opportunities for profits to shareholders in the long term.
- Lower avoided costs and advancement of codes/standards create barriers to utility programs under traditional cost-effectiveness tests
- Failure to recognize all energy and non-energy benefits of efficiency in cost-effectiveness tests

Some of the identified barriers, including those related to the cost-of-service utility business model, cost-effectiveness tests, addressing energy burdened communities and hard to reach sectors, and financing options, have been addressed elsewhere in this report through recommendations related to EE and other topics. Additional recommendations included in this section relate to ensuring implementation of EE recommendations are overseen by an advisory committee, giving customers access to their energy usage data, increasing education and awareness of EE opportunities, increasing the EE targets within the existing REPS, better utilization of load flexibility to meet clean energy goals, and building codes. These recommendations come primarily from the EE Roadmap process.

[166] According to NCDEQ's 2018 Greenhouse Gas Emissions Inventory Report, commercial buildings sector was the only sector with increased energy usage between 2005 and 2017 compared to residential and industrial sectors.

Recommendations

K-1. Establish an Energy Efficiency Advisory Council (EEAC) to oversee implementation of the EE Roadmap recommendations

Currently, there is no established body that is diverse and inclusive of all the many EE interests in NC that could oversee and guarantee the implementation of the NC Clean Power Plan EE recommendations. The EEAC would fill this gap and track implementation of the approved recommendations as well as the emissions reductions, economic development benefits and other metrics from EE measures. With a diverse make-up, the EEAC would ensure that balanced, consensus-driven recommendations are made, and that new EE policies are implemented as quickly and effectively as possible. The EEAC would help establish better communication between the EE stakeholders, and improve the sharing of best practices to boost adoption of EE measures within the state.

The NC EEAC could be created within the Executive Branch of NC's government, with a state-wide purview for broadening EE programming.

- The EEAC would target the residential and commercial sectors, but occasionally, could provide oversight to and recommendations for industrial EE initiatives.
- The EEAC would align with the activities of the Energy Policy Council (EPC) to the extent possible.

The EEAC should be comprised of representatives from utilities, state agencies, higher education, industry, advocates and other EE experts. The EEAC would be responsible for sharing information and best practices between stakeholders in order to increase state-wide EE measures for residential and commercial programs across the state in support of the Governor's Executive Order 80. In the near-to-medium term, the EEAC would oversee the implementation of the recommendations selected for inclusion into the state's Clean Energy Plan and help to monitor and report on the progress of the EE recommendations. Long-term, the Energy Policy Council would be responsible for tracking broad EE efficacy in NC and undertake studies and analyses that can inform future EE recommendations.

Table K-1: Actions for Recommendation K-1

Entity Responsible	Action	Timing (Short, Medium, or Long-term)
Governor's office	Establish an Energy Efficiency Advisory Council, appoint a person or entity to chair the council, and align with the activities of the Energy Policy Council to the extent possible.	Short term

K-2. Enable customers to have greater access to their energy data through new functionalities, such as those available through Green Button "Download My Data" Button

The ability for customers to easily access their own energy usage data and authorize that data to be provided to third parties is an essential enabling step for identifying energy-saving opportunities. Making customer data readily available is often viewed as one of the key customer benefits of advanced metering infrastructure investments. While utilities in the state are currently providing access to some electricity consumption data from smart meters, it is being provided in a variety of formats. Standardizing this data statewide to be consistent with a nationally recognized standard like Green Button "Download My Data" would allow for a more efficient analysis for EE and demand reduction opportunities by customers and any consultants or third parties they choose to work with. According to MissionData, a nonprofit dedicated to advocating for energy data access, over 55 utilities across the country have adopted the Green Button Download my Data standard..[167] Duke Energy has committed to start implementing a data access program equivalent to Green Button beginning in the third quarter of 2019. The NCUC has opened a docket to seek information and establish rules related to electric customer billing data, which is an opportunity for utilities, stakeholders and the Commission to have discussions about the desired functionality of a tool like Green Button.

In addition to the Download My Data standard, the Green Button initiative has established the Green Button "Connect My Data" program that allows customers to provide their chosen service providers with automatic access to their data. While Green Button "Connect My Data" has been proposed in NC, utilities have continued to express concerns related to customer protections, liability, regulatory cost recovery issues, and implementation cost. Utilities and interested stakeholders should continue to pursue ways to address those issues in addition to exploring other methods for providing automatic energy data transfers to trusted third parties such as Energy Star portfolio manager.

[167] Murray, Michael and Jim Hawley, "Got Data? The Value of Energy Data Access to Consumers," MissionData and More Than Smart, January 2016. Pg 8.
https://static1.squarespace.com/static/52d5c817e4b062861277ea97/t/56b2ba9e356fb0b4c8sb7d/1454553838241/Got+Data+-+value+of+energy+data+access+to+consumers.pdf

Table K-2: Actions for Recommendation K-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)
IOUs, municipal, and co-op utilities	Standardize existing data availability and provide easy access to 24 months of incremental usage data	Short term
NCUC	Ensure streamlined easy access to energy usage data for customers	Medium term
Legislature / NCUC	Review municipal and co-op utility implementation of Green Button Download My Data standard and determine if legislation is needed to ensure compliance	Medium term

K-3. Establish minimum EE goals within the existing REPS or establish an energy efficiency resource standard (EERS)

NC REPS allows energy efficiency measures to be used for meeting a portion of the purchase requirements. The ability to use EE measures varies by year and by utility type:

- Investor-owned utilities: 12.5% renewable energy (as % of retail sales) by 2021. EE measures can be used to meet up to 25% of this requirement, and up to 40% after 2021
- Electric cooperatives, municipal utilities: 10% renewable energy by 2018, and there is no limit on the amount that may be met through EE.

REPS defines "Energy efficiency measure" as an equipment, physical, or program change implemented after January 1, 2007, that results in less energy used to perform the same function. "Energy efficiency measure" includes energy produced from a combined heat and power system that uses nonrenewable energy resources; the term does not include demand-side management. Energy efficiency resource standards (EERS) refer to policies that require utilities and other covered entities to achieve quantitative goals for reducing energy use by a certain year. An EERS is similar in concept to a renewable enery portfolio standard. While the later requires that electric utilities generate a certain percentage of their electricity from renewable sources, in EERS requires that they achieve a certain amount of energy savings from energy efficiency measures.

The current REPS Program EE component is voluntary – it allows utilities to voluntarily meet part of their renewable energy targets through use of implemented EE Measures. This could be made more stringent by the creation of mandatory minimums for IOUs for their REPS target to be met with cost-effective EE measures beginning in 2021. A conservative target is preferred by utilities due to concern that EE opportunities that utilities can influence are declining as more mainstream efficient equipment becomes available to customers outside of utility EE programs. Requiring a minimum EE target ensures that EE remains a valued resource despite the gains in renewable energy and avoided cost comparisons that tend to make EE a less attractive component of the REPS program. Duke Energy Carolinas and Duke Energy Progress are currently meeting a 25% target and this recommendation would ensure their continued compliance. Dominion is not currently meeting a 25% minimum.

Table K-3: Actions for Recommendation K-3

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Legislature	Modify existing REPS statute to require IOUs to meet mandatory minimum of their REPS obligations with EE measures or establish an energy efficiency resource standard (EERS) by 2021.	Short term

K-4. Enhance education and awareness around energy efficiency opportunities in K-12 schools and community colleges through an "Energy Efficiency Everywhere (E3)" project

Although every student in NC is directly impacted by our electricity generation and consumption, many students do not understand the basics of how our electricity is produced, the real environmental costs, and what actions can be taken at home and at school to reduce electricity consumption. Students and young adults are often well-versed in everyday technology but unaware of the technologies that produce the electricity that their devices depend upon. An understanding of NC's energy landscape and how consumers influence future decisions will help our students become more environmentally and scientifically literate and thus better prepare them for the careers and jobs of the future. The best way to bring this and similar topics into the classroom is to equip and train teachers through professional development workshops to ensure they are able and willing to teach our students these important topics.

The NC public school curricula for K-12 do not include an EE component. Nor do schools provide "career awareness" programming for students to learn about careers in EE. Teachers are left to learn about these issues on their own, should they want to bring EE into the classroom. Several NC institutions offer energy-focused trainings and certificate programs, including UNC Chapel Hill's Institute for the Environment and NC's Office of Environmental Education (training here earns state teachers Environmental Education Certification credit). DEQ and the U.S. Department of Energy (DOE) also offer a rich selection of energy-related materials and activities. In addition, broader science and technology curricula and training opportunities have been created in science-based centers.[168] and community colleges..[169] However, these opportunities are too scattered and varied for most teachers to look through and evaluate on their own.

The primary goal of the Energy Efficiency Everywhere (E3) project is to support the implementation of EE curriculum programs within the existing educational systems of NC to include K-12 public school

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[168] The NC Museum of Natural Sciences created the Educators of Excellence Institutes to support continued learning for educators: https://naturalsciences.org/learn/educators-of-excellence-institutes

[169] For example, Wake Technical Community College currently offers a Building Automation Certificate Program: https://www.waketech.edu/programs-courses/credit/credit-programs/air-conditioning-heating-refrigeration-technology/degrees-1

systems and county-based community colleges. Ideally, education programs would be developed and used within existing curriculums appropriate for each grade level. E3 would foster excitement about EE, educate students on the electricity consumption and generation in our state, encourage specific actions by individuals and communities to reduce energy usage, and raise public awareness to the benefits of pursuing EE skilled trade careers. The project would launch a professional development training program for teachers as well as other educators in NC, create a statewide EE certification certificate, and establish an online sharing platform for EE related activities and lessons for teachers to use in their classroom.

Table K-4: Actions for Recommendation K-4

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Academia or non-profit	Collaborate with the following entities to stand up a program to support implementation of EE curriculum programs within the existing educational systems in NC: • NC Community College Systems Office (NCCCSO) • NC Department of Public Instruction (DPI) • NC DEQ • NC Community Colleges • NC K-12 County School Systems • National Energy Education Development Project (NEED) • NC's EE industry organizations and corporate leaders • Accreditation organizations that oversee curriculum programs in K-12 & Community Colleges • School groups, science educators, state education public information officers, science-based centers and museums, superintendent offices and universities that are already involved in energy education, nonprofits that support this type of work and others. • Utility outreach and education programs	Medium term

K-5. Require utilities to develop innovative rate design pilots to encourage customer behavior that helps achieve clean energy goals, such as peak demand reduction, better utilization of renewable resources, and strategic storage deployment.[170]

Two trends underway in the electricity sector make better utilization of flexible loads essential: increasing amounts of low-cost, variable generation resources on the grid, and expanding technology options for customer control of energy use. By encouraging or enabling customers to use power at times when clean, cheap energy is available on the grid and avoid using it when the system is under stress, it is possible to reduce overall costs and increase the utilization of low cost renewable resources. Technologies such as programmable thermostats, water heaters, and electric vehicle chargers, and smart appliances that can automatically adjust usage by following a utility or aggregator signal, are giving customers and utilities new tools to easily manage customer energy usage to minimize system costs and save customers money on bills. Rate design, also known as the price that customers pay for electricity at various times of the day, season, and year, is an essential part of making this happen.

Utilities around the country are beginning to experiment with innovative rate structures and accompanying programs to reward customers for shifting their usage in a way that is beneficial to the grid. For example, in July 2019, Portland General Electric launched a Smart Grid Test Bed which will work with 20,000 customers to take advantage of demand-response signals and incentives for using smart-home technologies, helping customers control energy use and greenhouse gas emissions. In this pilot, the utility is automatically enrolling customers in a rate design that will reward them for shifting their energy use during times of grid stress. This approach of combining time-varying rates with technologies and programs that make it easy for customers to shift usage and utilize technologies like storage and smart devices, has proven effective elsewhere as well.[171]

In the general rate case in 2018, the NCUC directed Duke Energy Carolinas to implement innovative rate design pilots to allow customers to take advantage of peak and energy shifting opportunities from the roll-out of advanced meters. The conclusions of the Clean Energy Plan are supportive of the direction the Commission is taking in this instance.

[170] Note: this recommendation is not from the EE Roadmap. It was prioritized by stakeholders in the Clean Energy Plan workshop and is included in this strategy area because of its direct link to demand-side management.
[171] Other utilities with successful programs along these lines include Baltimore Gas and Electric, Oklahoma Gas and Electric, Pacific Gas and Electric, and Hawaiian Electric Companies.

Table K-5: Actions for Recommendation K-5

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Require utilities to work with stakeholders to develop proposals for innovative, equitable rate design pilots that encourage customers to shift their usage and utilize technologies like storage to help reduce peak demand and increase utilization of clean energy. Pilot sites, co-located with low-income neighborhoods that have participated in the Duke Energy Neighborhood Energy Saver program, should be considered to further reduce energy burden rate for those residents	Short term
Co-ops and Municipal utilities	Work with stakeholders, customers, and member-owners to develop proposals for innovative, equitable rate design pilots that encourage customers to shift usage and utilize technologies like storage to help reduce peak demand and increase utilization of clean energy	Medium term

K-6. Increase EE awareness on the NC Building Code Council

The NC Building Code Council (NCBCC) was established to oversee the state's building codes, which include energy code. In addition, the state legislature may update building codes at any time. The Building Code Council is comprised of seventeen members, each representing a different area of expertise or constituent group as detailed in the state law..[172] Currently EE is not represented on the Building Code Council.

The NCBCC has regulatory control over the sources – buildings – of more than 50% of NC's energy consumption. This control is authorized by law and enacted by setting and managing the minimum energy code standards and voluntary measures for all new and existing residential, commercial and industrial buildings. For the past several years, the 17-member council, whose positions are established via the Legislature and appointed by the Governor, have supported weak increases in EE minimum code requirements and approved roll-backs of moderate, yet cost-effective, energy code increases. This action has led to NC's energy codes becoming less stringent when compared to other Southeastern states, national and international standards.

State-authorized energy codes play a major role in how a state acts on EE and, because NC is a Dillon Rule state, local jurisdictions are limited in how they can implement increased stringency (above state code) in local codes to support their own climate change and energy goals. To improve local and state support for EE, establishing greater support, understanding and action of the NCBCC is a fundamental starting point.

Responsible, cost-effective increases to minimum EE requirements in the NC building code would economically benefit the owners of residential and commercial building and reduce air pollution. Prudent, cost-effective energy code improvements could save up to $10 Billion (NCBPA, 2018) in direct avoided energy costs over the next ten years, offer significant environmental and health impacts to the state, and provide strong economic impacts through improved housing and property affordability, local economic development improvement and workforce development.

Florida is one of the few Southeastern states that has an EE, clean energy or green building seat on its code council. The Florida Building Commission includes a representative of the "green building industry" as well as from the Florida Office of Energy.

The EE Roadmap stakeholders identified the following actions as important to pursue: Improve the NC Building Code Council (NCBCC)'s support of EE by updating the energy conservation code to increase the EE requirements for buildings, modernizing the building code to ensure new buildings are ready for the installation of vehicle charging infrastructure and clean energy resources (e.g., rooftop solar and battery storage), and adding an Energy seat to the Council's makeup, and establishing new actionable goals that prioritize EE in NC's current and future building codes.

[172] See the relevant NC Statutes here:
https://www.ncleg.gov/EnactedLegislation/Statutes/PDF/BySection/Chapter_143/GS_143-136.pdf

Table K-6: Actions for Recommendation K-6

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Legislature	Add Energy efficiency seat to the NCBCC	Short term
Building Code Council	Update the energy conservation code to increase the energy efficiency requirements for buildings	Short term
Building Code Council	Modernize the building code to ensure new buildings are ready for the installation of vehicle charging infrastructure and clean energy resources	Short term

L. Create strategies for electrification

Background and Rationale

Electrification is the conversion to electricity of end uses of energy that are currently fueled with fossil fuels. Beneficial electrification considers whether, in electrifying, consumers are able to save money on their total energy bills, environmental benefits are achieved, and benefits to the grid are maximized. Beneficial electrification is included in the same strategy area as EE because, despite resulting in a net increase in *electricity* use, measures that constitute beneficial electrification will result in a net decrease in total *energy* use (in British thermal units, or some other measure of total energy). Participants in the clean energy plan process identified beneficial electrification, particularly of the transportation sector, as a key opportunity for NC to meet its GHG emission reduction goals, provide North Carolinians with cleaner and cheaper transportation options, and give utilities the ability to manage new flexible loads for the benefit of the electric grid.

As the electricity sector has been becoming less carbon-intensive over the last decade, the transportation sector has become the second largest source of greenhouse gas emissions in the state. In 2017, the sector accounted for 32.5% and emitted 48.7 million metric tons of GHG emissions. Electrification of transportation presents a significant opportunity to reduce energy use and emissions from the sector due to the superior fuel efficiency of electrified transportation..[173] As the electricity sector becomes cleaner, electrification will result in greater emission reductions over time. In addition to reducing GHG emissions, electrifying transportation can result in reductions in local air pollutants such as particulate matter and NOx. This can make an especially big difference for communities that are most directly impacted by motor vehicle pollution, such as those in urban areas with diesel bus traffic or those located close to freeway corridors.

Electrifying transportation also presents new opportunities for communities and individuals to save money on fuel and operating costs of vehicles. Although the upfront cost of a new EV is still higher than comparable gasoline cars, this is changing quickly as battery technology continues to improve. This trend is occurring in the passenger vehicle market as well as for larger vehicles such as buses and fleet vehicles.

Under Executive Order 80, the state's Department of Transportation is developing a NC Zero Emission Vehicle (ZEV) Plan, designed to increase the number of registered ZEVs in the state to at least 80,000 by 2025 and plan for the charging infrastructure needed support this growth..[174] In April 2019, Duke Energy filed a plan with the NCUC for a $76 million investment in electric transportation infrastructure, including a statewide fast-charging station network. That plan is currently under review at the Commission. The recommendations described in this section are focused on how the utility sector can best integrate and encourage the adoption of electric vehicles and how the state can play a leadership role in accelerating transportation electrification.

[173] For example, the average electric vehicle has a fuel efficiency of roughly 30 kWh per 100 miles, which translates to a "miles-per-gallon equivalent" of about 112. This means that the average electric vehicle is 3-4 times more fuel efficient on an energy basis than a typical gasoline-powered vehicle. Note, this only considers the fuel efficiency of the vehicle itself, and not any energy used upstream of the vehicle.

[174] NC now allows retail resale of electricity for EV charging stations per House Bill 329 which signed into law by Governor Cooper on July 19, 2019.

Recommendations

L-1. Require utilities to develop innovative rate design pilots for electric vehicles to encourage off-peak charging of vehicles and to test effectiveness of different rate structures at shifting customer usage of the grid and encourage the adoption of electric vehicles.

Rate design, particularly when paired with smart chargers.[175] or the programmable charging feature of an EV, can be very effective at encouraging drivers to charge their vehicles at times of the day when it is advantageous to the electric grid to do so. For example, a super-off-peak rate during the overnight hours will entice drivers to program their vehicles to wait to charge until that time period starts, avoiding the early evening hours that might otherwise exacerbate system peak demand. On a utility system that is solar-rich, such as the one in NC, it may be helpful for rate design to encourage workplace charging of EVs.

Not only can rate design help encourage the off-peak charging of vehicles, it can impact the economics of driving an EV as compared to a gasoline-powered vehicle. This is particularly true for charging stations located at commercial sites, such as workplaces, shopping centers, truck stops, etc. The typical rate design structure that utilities use for these kinds of customers can be a major inhibitor to the adoption and usage of charging infrastructure. Utilities are beginning to experiment with new structures that will recover costs from charging stations in a way that is more advantageous to the economics of EV charging.

State public utility commissions have begun to require utilities to employ the kinds of rate designs described above as a condition of approval for rate recovery of electric vehicle charging infrastructure..[176] In reviewing proposals from utilities regarding EV charging infrastructure, the NCUC could ensure that utilities plan to deploy rate designs that will encourage off peak charging and assist with EV adoption. As EV adoption increases in NC, innovative rate design programs can assist in broader clean transportation deployment as described in DOT's NC ZEV Plan..[177] The ZEV Plan outlines 4 key action areas that will support ZEV adoption: education, convenience, affordability, and policy.

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[175] The Washington State Utilities and Transportation Commission describes smart chargers as follows:

> Smart chargers provide enhanced capabilities that allow for data acquisition, network communication, and demand response, which will allow the Company to determine baseline charging profiles and to ultimately enable demand response programs.

See UTC, Docket UE-160799, Staff investigation regarding policy issues related to the implementation of RCW 80.28.360, electric vehicle supply equipment, Notice of Open Meeting, June 24, 2016. https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=4&year=2016&docketNumber=160799.

[176] Maryland, California, Nevada, and Michigan are some of the states that have recently issued orders requiring innovative EV rate designs.

[177] The NC ZEV Plan, another directive of EO 80, can be viewed at https://www.ncdot.gov/initiatives-policies/environmental/climate-change/Pages/electric-vehicles.aspx

Table L-1: Actions for Recommendation L-1

Entity Responsible	Action	Timing (Short, Medium, or Long term)
NCUC	Ensure that utility proposals for EV charging infrastructure deployment are accompanied by pilots designed to test innovative rate design that encourages off peak charging and EV adoption	Short term
Co-ops and Municipal Utilities	Implement EV rate designs that encourage off peak charging and EV adoption	Medium term

L-2. Conduct an analysis of the costs and benefits of using electrification to reduce energy burden and GHG emissions in end-use sectors in NC, such as in homes, buildings, transportation, industrial, and agricultural operations.

Clean Energy Plan stakeholders identified the electrification of transportation as a key strategy for reducing emissions from that sector, as more fully discussed in the final section. They also acknowledged that an economy-wide strategy to meet the state's GHG reduction goals would require emission reductions from other sectors in addition to electricity and transportation, such as fuel use in buildings, homes, industrial processes, and agricultural operations. Many studies have identified electrification of those energy end uses as potentially the most technologically feasible and least-cost strategy to reduce emissions from those sectors. Such a study has not been conducted for NC, and thus this clean energy plan process did not focus specifically on electrification as a GHG reduction strategy. However, given the importance of getting started on emission reductions from all sectors, stakeholders identified such a study as an important next step for the state.

Beneficial electrification has the potential to provide significant financial relief to 30% of NC residents living in poverty. Low income households spend a disproportionate percentage of their household income on energy costs relative to their higher income counterparts..[178] For those living with incomes below 50% of the Federal Poverty level, 33% of their annual income is spent on energy bills. Of this amount, about 20% is spent on electric bills while over 60% is spent on natural gas or bottled gas (see Supporting Document-Part 3 for more information). Examples of residential beneficial electrification include switching from electrical resistance space or water heating to using heat pump technologies for

[178] Fisher, Sheehan, & Colton (2019). Home Energy Affordability Gap. Accessed May 2019. www.homeenergyaffordabilitygap.com/.

heating. Heat pumps can provide 1.5 to 3 times more heat energy than the electrical energy they use, a big improvement from electrical resistance heating..[179]

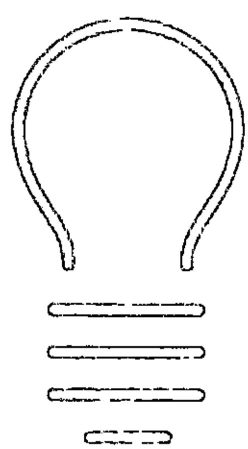
The industrial sector also offers potential electrification benefits. Industries using thermal processes can shift to electrical process heating. Industrial induction heating offers more temperature precision, reduced start-up times and faster product throughput, and more flexible control strategy. These factors result in better quality products. In addition to process improvements, electrical induction heating can also improve site air quality and reduce noise levels in industrial operations..[180]

A NC study could identify beneficial electrification opportunities in different sectors, noting technologies offering the most benefits in terms of economics and environmental improvement.

Table L-2: Actions for Recommendation L-2

Entity Responsible	Action	Timing (Short, Medium, or Long term)
Academia	Initiate an analysis of the costs and benefits of electrification of end-use sectors such as homes, buildings, industrial processes, and agricultural operations	Medium term

[179] Farnsworth, Shipley, Lazar, & Colton (2018). Beneficial Electrification: Ensuring electrification in the public interest. Regulatory Assistance Project. Accessed at https://www.raponline.org/wp-content/uploads/2018/06/6-19-2018-RAP-BE-Principles2.pdf
[180] Deason, Wei, Leventis, Smith, & Schwartz (2018). Electrification of Buildings and Industry in the United States. Lawrence Berkeley National Laboratory. Accessed at http://eta-publications.lbl.gov/sites/default/files/electrification_of_buildings_and_industry_final_0.pdf



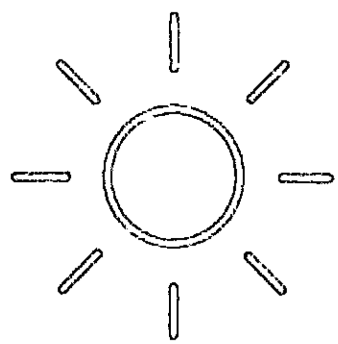
Next Steps

5. Conclusions and Next Steps

An ongoing transformation of North Carolina's electricity system requires ambitious actions at the state and local levels, with active participation from the private sector. To achieve the goals and performance measurement targets laid out in the CEP, a framework is needed that centers on strategic investments that provide long-term energy, economic, and environmental benefits. **Developing modern regulatory tools, market structures and processes to achieve state goals can set us on a path to lower risk, lower-cost and lower-impact energy future.**

In the coming months and years, the entities identified in this plan are called upon to lead this effort by carrying out the stated recommendations or make adjustments within their normal business and operational practices to achieve the collective vision. We recognize that certain strategies and actions will require additional deeper dives and detailed analysis when considering new legislation or amending existing policies/practices. Many experts from within the state and across the country are ready to work with North Carolina leaders to continue transforming our state into a national leader in clean energy economy.

nc.deq.gov/cleanenergyplan

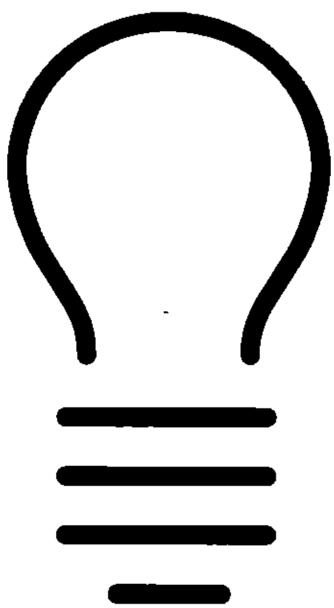


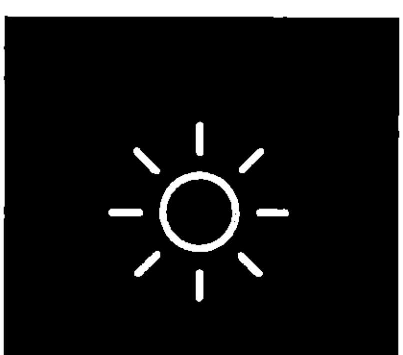
North Carolina

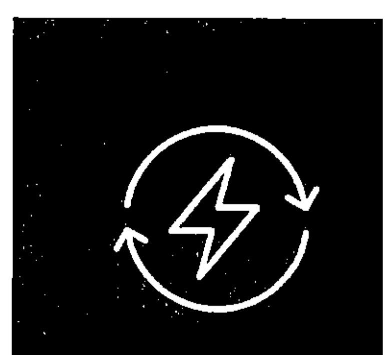
Clean Energy Plan

All North Carolina Clean Energy Plan documents and supporting documents can be found at:

deq.nc.gov/cleanenergyplan







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