OFFICIAL COPY

Oct 12 2017

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E 100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
2017 Integrated Resource Plans and	)	NC WARN
Related 2017 REPS Compliance Plans	)	INITIAL COMMENTS

NOW COMES the North Carolina Waste Awareness and Reduction Network, Inc. ("NC WARN"), through the undersigned attorney, with its initial comments on the Integrated Resources Plans ("IRPs") filed by Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (together "Duke Energy"). The purpose of these comments is to assist the Commission and the Public Staff in their reviews of the IRPs.

GENERAL COMMENTS

1. The State policy as expressed in G.S.62-2(a)(3a) is

> To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the ***least cost mix*** of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills.

(emphasis added).

OFFICIAL COPY

Oct 12 2017

2. Each year, the North Carolina electric utilities submit IRPs with the Commission pursuant to Commission Rule R8-60.[1] The IRPs forecast growth in demand for electricity over a 15-year period and are designed to determine the "least cost mix" of meeting the expected growth. The purpose of the IRPs is to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. *State ex rel. Utilities Comm. v. Empire Power Co*., 112 N.C.App. 265, 278 (1993), disc, rev, denied, 335 NC 564 (1994); *State ex rel. Utilities Comm. v. High Rock Lake Ass'n*, 37 N.C.App. 138, 141, disc, rev, denied, 295 NC 646 (1978). The IRPs further assist the Commission in preparing its reports to the General Assembly and other agencies on the status of the electric utilities within the state.

3. The most significant change in both the DEP and DEC 2017 IRPs is the reduction in the expected growth over the 15-year planning horizon. In its 2016 IRP, page 16, DEC forecast annual growth as summer peak 1.2%; winter peak 1.3%; overall energy needs 1.0%. In 2017, this was reduced to summer peak 0.4%; winter peak 0.9%; and energy 0.4%. These forecasts considered the contribution to lowering demand through DEC's energy efficiency ("EE") programs. Similarly, in its 2016 IRP, page 16, DEP forecast its annual growth as summer peak 1.1%; winter peak 1.3%; and energy 0.9%. In 2017, this was reduced to summer peak 0.7%; winter peak 0.7%; energy 0.6%. The DEP growth forecast also considers the contribution of its EE programs.

[1] As amended by Commission Order on July 20, 2015 in Docket E-100, Sub 111.

OFFICIAL COPY

Oct 12 2017

4. Even the lower forecasts in the 2017 IRPs are still higher than historic trends bear out. Duke Energy's growth has been flat for the past decade, even with a substantial increase in wholesale sales and increased population growth in the Duke Energy service area. Moreover, Duke Energy has consistently overestimated its growth forecasts over the years, leading to overbuilding of generation, stranded assets, and excess reserve margins. The best analysis of actual growth compared to IRP forecasts was in the testimony of Dr. Vitolo in the current docket on the Lincoln County Combustion Turbines.[2] After reviewing the past 15 IRPs, Dr. Vitolo questioned Duke Energy's ability to plan for any new generating unit based on the IRPs because of the consistent failure of the models, especially in more distant forecasting.

5. Lower forecasts present a challenge to the Duke Energy business model of consistently building new power plants and infrastructure in order to increase its rate base. The lower forecasts in the current IRPs put off the need for some the new generation for several years, and as discussed below, take nuclear additions out of the planning horizon. Even with the lower forecasts, neither utility shows additional retirement of existing plants. In its 2017 IRP, DEC actually plans to add 2,190 MW of natural gas more than it did in its 2016 IRP, primarily natural gas units for peaking and baseload.

6. To meet the projected need, the 2017 IRPs look at capacity needs rather than energy needs. DEC is planning for capacity additions of 36% from

[2] Prefiled Testimony of Thomas Vitolo, PhD, on behalf of the Natural Resources Defense Council and the Sierra Club, Docket E-7, Sub 1134, pages 9 - 11. See also Transcript, Vol. 3, pp. 68-70.

EE, and renewable energy ("RE") by 2032. DEC IRP, page 7. DEP forecasts capacity additions of 28% from EE and RE. DEP IRP, page 7. Neither utility plans on utilizing demand-side management ("DSM") in any meaningful way.

7. Both DEC and DEP rely extensively on new natural gas additions to meet the rest of the demand primarily because both DEC and DEP are now claiming to be winter peaking utilities, i.e., the largest demand is during the winter peak. The purpose of the planned capacity additions presented in the IRPs is done to meet that fairly narrow need. This assumption limits the perceived role of solar energy in meeting peak demand during winter mornings, but highlights the need for the use of battery storage in conjunction with RE assets.

8. DEC expects to increase its installed solar capacity from 889 MW in 2018 to 2806 MW in 2032, most of this utility scale solar resulting from the new procurement policies in this year's energy bill.[3] DEC IRP, page 14. Likewise DEP expects installed solar capacity increase from 2440 MW in 2018 to 3847 MW in 2032. DEP IRP, page 13. While this is a significant increase over the 2016 IRPs, The presented growth in solar is misleading as actual capacity is much lower than name place capacity, in the 10 – 25% range, as solar varies during the day. During the early morning winter peak would only contribute less than 5% per day but reach its full potential in summer peaks.

9. It is important to note the 2017 IRPs only look at additional capacity (in MWs) rather than look at RE contributions to energy generation. In response to NC WARN's data request, DEC and DEP supplied their estimates of the annual

[3] House Bill 589, Session Law 2017-192. See also Docket E-100, Sub 150.

OFFICIAL COPY

Oct 12 2017

solar contribution to their energy generation and NC WARN calculated the percentage of solar for each year. ATTACHMENT A. DEC starts out a 1.76% solar contribution in 2018, with a maximum of 5.67% in 2025, with a decline to 5.41% in 2032. DEP starts out at 7.17% in 2018, with a maximum of 11.18% in 2025, with a decline to 10.29% in 2032. Together DEC and DEP, start at 3.94% in 2018, with maximum of 7.86% in 2025, declining to 7.41% in 2032. This growth and then diminishment of solar resources reflects the legislative mandate, the Renewable Energy and Energy Efficiency Portfolio Standards (known as "REPS") in Session Law 2007-397 (Senate Bill 3), rather than a commitment to meeting future need with least cost energy.

10. The IRPs show the installation of only 75 MW of battery storage in the 2019-21 time period for both utilities. DEC IRP, page 22; DEP IRP, page 15). As shown in the NC CLEAN PATH 2025 discussed below, the combination of distributed RE with battery storage can meet all energy needs throughout the year.

11. What is troublesome about the IRPs is both utilities continue to have extremely high reserve capacity, i.e., available capacity over and above the capacity needed to meet normal peak demand levels. Over the IRP planning period, DEC's winter reserve stays above 20%, and summer reserve increase from 20% - 32%. DEP's winter reserve increases to 25%, and summer reserve is in the 28% - 32% range. DEP IRP, page 45; DEC IRP, page 58. This contrasts to the North American Electric Reliability Corporation ("NERC"), delegated by the Federal Energy Regulatory Commission to establish electric reliability criteria,

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

that assumes a default planning reserve margin of 15 percent for most utilities.[4] The bottom line is costly overbuilding leads to excessive and unnecessary reserve margins.

12. Reflecting recent filings in the DEC rate case in Docket E-7 Sub 1146, DEC in its IRP is seeking Commission permission to cancel the Lee Nuclear Station in Cherokee County, South Carolina. This cancellation is reflected in the DEC IRP (although DEC still holds out for an undesignated 1,117 MW unit at the end of the 15-year planning horizon). The estimated cost of two nuclear units is now upwards of $25 billion and after Westinghouse's bankruptcy, only the Southern Company is considering the nuclear option at its Vogtle plant in Georgia. The construction of the two units at its Vogtle plant is heavily subsidized by Federal loan guarantees and ratepayer funding through the annual pass through of construction costs.

THE CLEAN PATH ALTERNATIVE

13. In August 2017, NC WARN released the NORTH CAROLINA CLEAN PATH 2025: ACHIEVING AN ECONOMICAL CLEAN ENERGY FUTURE. ATTACHMENT B.[5] This innovative report demonstrates that distributed RE, EE,

---

[4] NERC, "M-1Reserve Margin," www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx; NERC 2016 Long term Reliability Assessment, page 45, discusses reference margin levels. www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf

[5] The NC CLEAN PATH 2025 is written by Bill Powers, P.E., with technical review performed by utility industry veterans. See page ii for his qualifications. Powers is a registered professional mechanical engineer trained at Duke University with over 30 years of experience in energy and environmental engineering. He has written numerous articles on the strategic cost and reliability advantages of local solar power over large-scale, remote, transmission-dependent renewable resources, and frequently appears as an expert witness on alternatives to conventional power

and battery storage can meet 57% of all demand by 2025 and meet all new demand and retire all fossil fuels by 2030. The transition can be economically accomplished using present technologies, providing additional reliability to the grid at a much lower cost. As discussed in the report, here are no technological or economic barriers to establishing a clean path.

14. Recent leaps in battery technology, combined with falling solar power prices and energy-saving advances, mean North Carolinians can avoid having at least 15 billion of their dollars spent by Duke Energy to build unneeded power plants, power lines and a fracked gas pipeline for the Carolinas. On top of the savings in infrastructure, the rate payers will save billions annually more in avoided purchase of fossil fuels. Solar power is now cheaper than average utility prices in many states including North Carolina. For commercial customers, solar plus battery storage for daily use is now far below the price of retail grid power and, according to government and industry data, cheaper than power from new natural gas-burning plants.

15. NC CLEAN PATH 2025 is an economic engine that will create more jobs than the expansion plans proposed by Duke Energy in the IRPs. The clean path will generate 16,000 jobs across the state.

16. This leads us to the foremost problem with the DEC and DEP IRPs; they are more of the same old 20th Century utility business model. NC WARN sees the critical need to start taking steps toward clean, affordable energy now.

---

generation infrastructure. Mr. Powers is the author of the 2012 strategic energy plan, Bay Area Smart Energy 2020, for the San Francisco Bay region. www.ncwarn.org/wp-content/uploads/NC-CLEAN-PATH-2025-FINAL-8-9-17.pdf

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

CONCLUSION

17. In light of the above, NC WARN urges the Commission to closely scrutinize Duke Energy's IRPs and their planned build out of natural gas generation and infrastructure so that ratepayers are not left with stranded costs, high rates, and a worsening climate crisis. Instead, NC WARN urges the Commission (and Duke Energy) to embrace the NC CLEAN PATH 2025 as an economic way forwards in reliably meeting our electricity needs.

Respectfully submitted, this the 11th day of October 2017.

/s/ *John D. Runkle*

John D. Runkle
Attorney at Law
2121 Damascus Church Rd.
Chapel Hill, N.C. 27516
919-942-0600
jrunkle@pricecreek.com

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing NC WARN'S INITIAL COMMENTS (E-100, Sub 147) upon each of the parties of record in this proceeding or their attorneys of record by deposit in the U.S. Mail, postage prepaid, or by email transmission.

This is the 11th day of October 2017.

/s/ *John D. Runkle*

____

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

ATTACHMENT A

NCWARN Calculations

DEC & DEP: Annual Renewable Energy contribution to total energy

	DEC total energy (GWH)	DEC Solar (GWH)	% solar in DEC	DEP total energy (GWH)	DEP Solar (GWH)	% solar in DEP	% solar DEP & DEC
2018	95739	1689	1.76	64592	4634	7.17	3.94
2019	95172	2306	2.42	65075	5128	7.88	4.64
2020	95864	2540	2.65	64794	5966	9.21	5.29
2021	96495	3245	3.36	64961	6300	9.70	5.91
2022	96761	3960	4.09	65284	6722	10.30	6.59
2023	97462	4686	4.81	65188	7047	10.81	7.21
2024	98234	5484	5.58	65933	7370	11.18	7.83
2025	98856	5604	5.67	66498	7390	11.11	7.86
2026	99513	5584	5.61	67110	7311	10.89	7.74
2027	100001	5565	5.56	67696	7295	10.78	7.67
2028	100405	5546	5.52	68323	7348	10.75	7.64
2029	100716	5518	5.48	68814	7258	10.55	7.54
2030	101032	5489	5.43	69317	7272	10.49	7.49
2031	101407	5487	5.41	69874	7279	10.42	7.45
2032	101840	5510	5.41	70483	7254	10.29	7.41

total energy: DEC IRP p.43 (w/ EE programs); DEP IRP, p. 48 (w/ EE programs)
solar contributions to total energy: DEC and DEP respones to data requests

NOTE: Data pulled from PROSYM output report, and energy shown is from solar resources located in DEC or DEP territory. It does not reflect any energy that may flow into, or out of, that territory through the Joint Dispatch Agreement.

ATTACHMENT B
E-100, Sub 147

OFFICIAL COPY

Oct 12 2017

NORTH CAROLINA
CLEAN PATH 2025:
Achieving an Economical Clean Energy Future

Prepared for NC WARN

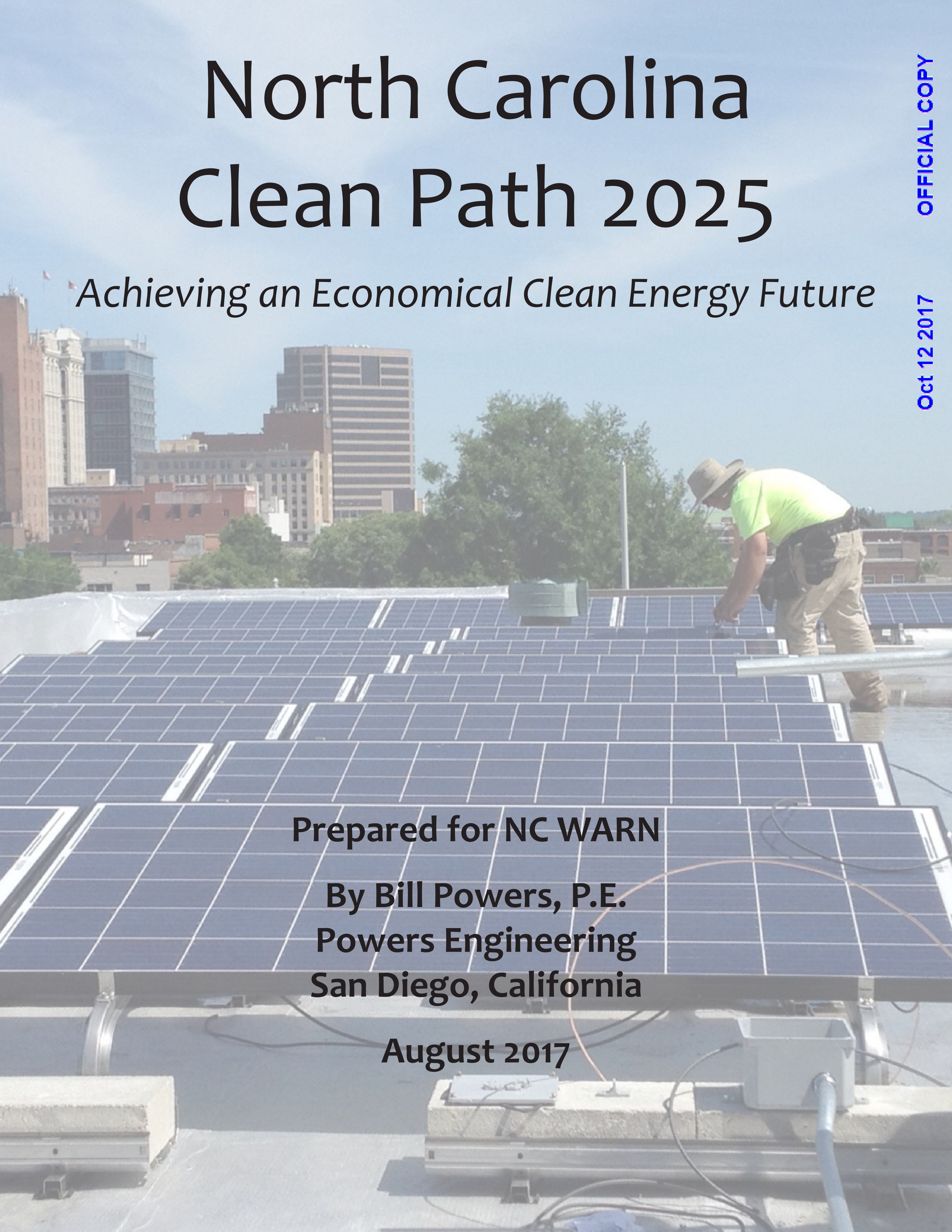
By Bill Powers, P.E.
Powers Engineering
San Diego, California

August 2017

Available on line at:
www.ncwarn.org/wp-content/uploads/NC-CLEAN-PATH-2025-FINAL-8-9-17.pdf

North Carolina Clean Path 2025

Achieving an Economical Clean Energy Future



Prepared for NC WARN

By Bill Powers, P.E.
Powers Engineering
San Diego, California

August 2017

OFFICIAL COPY
Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Acknowledgements

The author would like to thank Jaleh Firooz, P.E. and Christopher S. Hein, Ph.D. for their technical review of *NC CLEAN PATH 2025*.

A note on updates: *After this report was published, Duke Energy canceled plans for two new nuclear reactors at its Lee plant in Gaffney, SC. Thus, the $20 billion nuclear price tag cited in the report no longer applies. Even without the nuclear plants, the NC CLEAN PATH 2025 plan remains far cheaper than Duke Energy's long-term plan. Follow updates regarding NC CLEAN PATH 2025 at www.ncwarn.org/cp25-updates.*

Cover: Rooftop solar photovoltaic (PV) array, Faith Community Church, Greensboro, North Carolina. Photo by NC WARN.

For more information:

NC WARN
P.O. Box 61051
Durham, NC 27715

919-416-5077

ncwarn@ncwarn.org

Bill Powers, P.E., Biography

Mr. Powers is a registered professional mechanical engineer in California with over 30 years of experience in energy and environmental engineering. He has written numerous articles on the strategic cost and reliability advantages of local solar power over large-scale, remote, transmission-dependent renewable resources, and frequently appears as an expert witness on alternatives to conventional power generation infrastructure. Mr. Powers is the author of the 2012 strategic energy plan, *Bay Area Smart Energy 2020*, for the San Francisco Bay region. The plan relies on rooftop and parking lot solar power, combined with accelerated energy efficiency measures and battery storage, as the template to reduce greenhouse gas emissions from power consumption in the Bay Area region by 60 percent by 2020. Mr. Powers served as an expert witness in a landmark proceeding in 2009 where the California Energy Commission denied a new peaking gas turbine power plant while determining that urban solar power could potentially serve as a cost-effective alternative to the proposed gas plant.

Mr. Powers began his career converting Navy and Marine Corps shore installation power plants from oil-firing to domestic waste, including wood waste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo. He has permitted numerous peaking gas turbine, microturbine, and internal combustion engine power plants. His home currently serves as urban off-grid test bed, including rooftop solar, battery storage, backup generation, and an electric vehicle, to demonstrate the cost-effectiveness and reliability of this power delivery approach. Mr. Powers has a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from the University of North Carolina at Chapel Hill.

NC WARN

NC WARN is a 29 year-old, member-based nonprofit tackling the climate crisis – and other hazards posed by electricity generation – by watch-dogging Duke Energy practices and building people power for a swift North Carolina transition to clean, renewable and affordable power generation and increased energy efficiency.

In partnership with other organizations, and using sound scientific research, NC WARN informs and involves the public in key decisions regarding their health and economic well-being. Dedicated to climate and environmental justice, NC WARN seeks to address the needs of all of the public by intentionally including those often excluded from participation because of racism, sexism, classism, and other forms of oppression.

NC WARN commissioned this report in order to present a positive alternative to Duke Energy's long-term plan. See how NC WARN is working to implement NC CLEAN PATH 2025 at www.ncwarn.org/cp25/.

OFFICIAL COPY
Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Table of Contents

OFFICIAL COPY

Oct 12 2017

List of Tables

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

List of Figures

Page

OFFICIAL COPY
Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Acronyms

ACEEE	American Council for an Energy-Efficient Economy
CAISO	California Independent System Operator
CCA	Community Choice Aggregation
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
dc	direct current
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DNCP	Dominion North Carolina Power
DOE	U.S. Department of Energy
DR	demand response
EIA	U.S. Energy Information Administration
EE	energy efficiency
EMC	electric membership corporation (rural cooperatives)
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gases
GWh	gigawatt-hour
HVAC	heating, ventilation, and air conditioning
IRP	Integrated Resource Plan
kW	kilowatt
kWh	kilowatt-hour
IOU	investor-owned utility
LCOE	levelized cost of energy
MW	megawatt, equals 1,000 kilowatts, expressed as alternating current output
MW_{dc}	megawatt produced by solar panels in direct current prior to conversion to alternating current
MWh	megawatt-hour
NCEMC	North Carolina Electric Membership Corporation
NCEMPA	North Carolina Eastern Municipal Power Agency
NCMPA1	North Carolina Municipal Power Agency Number 1
NREL	National Renewable Energy Laboratory
NCUC	North Carolina Utilities Commission
PACE	property assessed clean energy
PJM	RTO for Mid-Atlantic states (excluding New York), Ohio, West Virginia, Virginia, and parts of Kentucky, Illinois, Indiana, and Michigan
PV	photovoltaic
RTO	Regional Transmission Operator
SCE	Southern California Edison
SEER	seasonal energy efficiency ratio
TOU	time-of-use
ZNE	zero net energy

OFFICIAL COPY

Oct 12 2017

Executive Summary

NC CLEAN PATH 2025 is an energy strategy focused on implementing local solar power,[i] battery storage, and energy efficiency measures to quickly replace fossil fuel-generated electricity and eliminate the resulting pollution, including greenhouse gases that are driving climate change.

This approach is cleaner, more reliable, and far less costly than the $40 billion-dollar expansion of fracked natural gas, nuclear power, and transmission infrastructure being planned by North Carolina's dominant investor-owned (private) utility, Duke Energy. NC CLEAN PATH 2025 is also an economic engine that will create more jobs than the expansion plans proposed by the utility, and is based on available technology and proven, successful programs.

North Carolina has twice as much local solar potential as needed to retire all fossil fuel plants, and existing distribution lines can handle large flows of local solar at little additional cost.

Smaller municipal and cooperative utilities have been leaders in advancing local solar and battery storage in the United States, and may be best adapted to implementing NC CLEAN PATH 2025. However, there are no economic or technical barriers to its adoption by the large investor-owned utilities.

NC CLEAN PATH 2025 is an opportunity for North Carolinians to provide national leadership in the urgent challenge to slow climate change. NC CLEAN PATH 2025 will:

- Reduce power generated by coal- and natural gas-fired plants 57 percent by 2025.
- Reduce greenhouse gas emissions from electricity generation 100 percent by 2030. All coal-fired plants will be closed and gas-fired plants will be used only for backup supply.
- Maintain the current growth rate, 1,000 megawatts per year, of large-scale solar in North Carolina, but build it on vacant urban and suburban land, and on brownfields.
- Add 2,000 megawatts of solar power each year at homes, businesses, schools, and other buildings – and back it up with cost-effective battery storage, capitalizing on rapid progress by Tesla and other companies.
- Create financing options for local solar power, battery storage, and efficiency upgrades that allow everyone to benefit without financial burden.
- Accelerate energy-saving programs to reduce electricity usage 20 percent by 2025.
- Expand demand response programs[ii] and energy efficiency upgrades to reduce peak summer cooling and peak winter heating loads 50 percent by 2025.
- Create 16,000 good jobs across the state in the first three years.

---

[i] Local solar can be on a residential, commercial, or institutional building's rooftop, covering parking areas, or ground-mounted next to the structure or on vacant urban land.
[ii] Demand response: Reducing or shifting consumers' electricity usage from peak demand periods to lower-demand periods by use of financial incentives.

OFFICIAL COPY

Oct 12 2017

NC CLEAN PATH 2025 will add 16,000 jobs spread across the state within three years of being adopted.

An approach that beats the obsolete, high-cost, high climate impact utility model

North Carolina's investor-owned electric utilities (IOUs) are focused on building large power plants and additional transmission and distribution projects. The predominant utility, Duke Energy, supplies about 90 percent of the electricity in the state. Its 15-year plan is to expand conventional power generation and grid investments, resulting in large rate increases for customers.

Duke Energy's plan for North and South Carolina is to spend \$5 billion on new natural gas-fired plants, \$2.5 billion building the Atlantic Coast Pipeline, and possibly upwards of \$20 billion to build two nuclear units. Just in North Carolina, Duke Energy plans \$13 billion in transmission and distribution additions. Meanwhile, it plans to do the minimum to advance renewable energy; by 2031, only six percent of Duke Energy's total Carolinas generation would be from renewables.

NC CLEAN PATH 2025, in contrast, will make local solar with battery storage the backbone of the statewide electricity system. The cost of electricity will be lower for all customers due to the lower cost of solar compared to utility retail rates. The massive utility investments in large power plants and infrastructure will be avoided under NC CLEAN PATH 2025. Power bills will become stable and predictable instead of rising relentlessly to pay for largely unnecessary conventional utility expansion.

Financing comes from utilities or competitive lenders

Investments in solar, batteries, and efficiency upgrades can be facilitated by utilities – and possibly local governments and private lenders – which provide upfront capital and allow customers to pay for the upgrades on their electric bills over time (known as

Several companies now have battery systems on the market for use with local solar.

Tesla's Powerwall is shown storing a home's solar power for use when the sun isn't shining.

Source: Utility Dive.

Grid Expenditure Comparison, NC CLEAN PATH 2025 vs. Duke Energy

Cost Category	NC CLEAN PATH 2025	Duke Energy
Cost of electricity	Less than utility retail rate	Utility retail rate
Energy efficiency and demand response	$450 million per year	$120 million per year
Smart meters	$0.5 billion	$0.5 billion
Grid operations & maintenance	$1 billion per year	$1 billion per year
Grid upgrades	Less than $1 billion (distribution grid upgrades)	$13 billion over ten years (NC only)
New gas-fired power plants	$0	$5 billion (NC & SC)*
New nuclear plants	$0	$20 billion (NC & SC)*
Atlantic Coast Pipeline	$0	$2.5 billion (NC & SC)**

* Duke Energy electricity sales in NC are about four times those in SC. However, much of the proposed new gas-fired and nuclear generation will be located in SC.

** Shale gas transported on this pipeline will serve Duke Energy gas-fired generation in NC and SC.

on-bill financing). Customers' monthly bills will remain the same or be reduced. Electricity savings under NC CLEAN PATH 2025 will exceed the monthly payment for the upgrades.

Only minor improvements to the electricity transmission and distribution system will be necessary to realize NC CLEAN PATH 2025 targets. The cost will be passed through to utility customers in the same manner as operations and maintenance costs. Customers installing solar power and batteries will receive available federal tax benefits.

Abundant, low-cost local solar as backbone of the state's power supply

The North Carolina solar resource potential on rooftops, parking lots, and urban vacant land is about 130 million megawatt-hours (MWh) per year. This is nearly double the approximately 77 million MWh per year needed to displace North Carolina's coal- and natural gas-fired power. This local solar resource is distributed across small towns, larger communities, and urban areas close to where electricity demand is located.

Customers unable to use solar at their home, business, or other building can participate in community-based solar programs.

Electricity generated at large-scale "solar farms" is sold at the wholesale price of electricity and does not increase customer rates. The cost of local solar power in North Carolina, at homes and businesses, has fallen below the utility retail rate for Duke Energy customers in 2017. (Typically, retail rates for the cooperative and municipal utilities are higher.) Meanwhile, solar prices keep declining as utility rates keep rising. This means that homeowners, businesses, nonprofits, and governments save money by offsetting the retail electricity they currently purchase from the grid with solar panels on their rooftops, parking lots, or next to the building.

When excess power is generated from these net metered solar systems, it flows to neighbors who then pay the utility for the kilowatts. This arrangement, known as net metering, is now more cost-effective than grid power and is ready to ramp up in North Carolina. Net metering is an economic benefit to all utility customers, even those

OFFICIAL COPY Oct 12 2017

without onsite solar, because it reduces the need to build large power plants and supporting transmission infrastructure, thus keeping rates from constantly rising.

Building on state success installing large amounts of solar

North Carolina is second in the nation in solar photovoltaic (PV) capacity, with approximately 3,000 MW now generating electricity. About 1,000 MW were installed in 2016 alone. Almost all of this was the result of large-scale projects greater than 1 MW in size on parcels of rural land.

NC CLEAN PATH 2025 will ramp up the solar installation rate to 3,000 MW per year by 2020, of which about 2,000 MW per year will be customer-sited rooftop, ground-mounted, or parking lot solar. The 1,000 MW annual installation rate of large-scale solar will be maintained, but with systems concentrated on vacant urban land and on brownfields (contaminated properties) closer to areas of electricity demand.

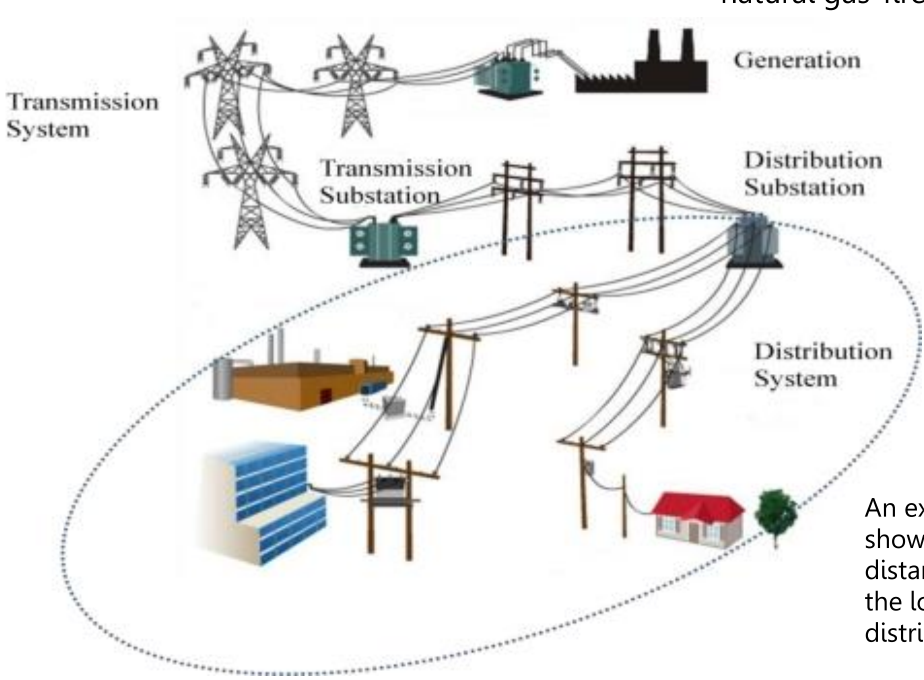
Local power lines can handle large flows of solar power at little additional cost

Low-cost distribution system upgrades carried out under NC CLEAN PATH 2025 will enable very high levels of solar power flow on existing distribution lines in local communities. Numerous studies by the U.S. Department of Energy and by utilities in states near North Carolina demonstrate that such upgrades should require a one-time cost of less than $1 billion – spread out over several years – for a state the size of North Carolina. This is approximately the amount Duke Energy spends annually on operations and maintenance for the electricity grid in its North Carolina service areas.

Utilizing some existing generation and storage resources while retiring others

All coal-burning power plants will be phased out quickly under NC CLEAN PATH 2025. Existing hydroelectric plants and solar projects will continue to operate as reliable renewable resources. Existing nuclear plants will continue operating until current licenses expire in 2030 and beyond. The existing natural gas-fired power plants and transmission grid become backup systems over time.

Duke Energy's existing 2,140 MW of pumped storage hydroelectric plants (Bad Creek and Jocassee) can be readily integrated into the NC CLEAN PATH 2025 framework. They will serve



An example of a power grid, showing the high-voltage, long-distance transmission system and the lower-voltage local distribution system.

Source: Lim et al.

OFFICIAL COPY
Oct 12 2017

as large-scale batteries by absorbing over 2,000 MW of solar power in daytime hours, then dispatching the energy as hydroelectricity at night when solar power is not available.

Solar, batteries, and energy-saving measures offset high-usage periods

A key to transitioning from the current utility model is to provide a clean energy alternative to construction of natural gas-fired "peaker" plants to meet demand during periods of high electricity usage. Along with energy efficiency and demand reduction programs, NC CLEAN PATH 2025 does this by combining local solar power with battery storage, and allowing utilities to tap the power stored in local batteries during times of peak demand.

NC CLEAN PATH 2025 includes the addition of 5,000 MW of battery storage connected to onsite solar systems by 2025. Onsite battery storage is cost-effective in 2017, even more so when customers are fairly compensated by utilities for making their batteries available during periods of high customer usage.

Implementing battery storage at the point where power is used will increase reliability for all communities. It is a more economical and effective solution than Duke Energy's existing proposal to build redundant backup transmission lines to meet vulnerable communities' reliability needs.

Heating, cooling, and other energy savings are key

Heating and cooling systems are key drivers of peak demand. Most antiquated, low-efficiency systems are beyond their useful design life and will be replaced over the next few years by far more efficient systems that will reduce electricity usage by substantial amounts.

Specifically, NC CLEAN PATH 2025 will achieve a 50 percent reduction in peak heating and cooling usage through comprehensive demand response programs and energy efficiency upgrades, and a 20 percent reduction in overall electricity consumption.

A statewide economic and employment engine

The new jobs necessary to fully develop this local solar and energy efficiency resource will be spread across the state in small towns and urban areas. New renewable investments will boost local economies through enhanced property value. NC CLEAN PATH 2025 will provide 50 percent more jobs than Duke Energy's proposed build-out, in much less time, as shown in the table on the next page.

Local solar power is now cheaper per kilowatt-hour than the retail rate customers are paying their utilities. On-bill financing helps customers benefit without upfront cost burden.

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Jobs Generated by NC CLEAN PATH 2025

	NC CLEAN PATH 2025	Duke Energy
Direct new jobs	Solar approx. 14,000 *(7,000 per 1,000 MW per year installed solar capacity, increased by 2,000 MW per year)* Energy efficiency approx. 2,000 *(7 per $1 million in annual output, increased by $330 million per year)*	approx. 10,000 (grid modernization and new gas-fired capacity)
Period over which direct new jobs are added	3 years	10 years
Additional indirect new jobs (in the community)	approx. 16,000 (Duke Energy direct:indirect ratio approx. 1:1)	approx. 10,000

A net 100% reduction in greenhouse gases from electricity generation by 2030

Through a combination of local solar and battery storage systems, energy efficiency, and demand response programs, NC CLEAN PATH 2025 will reduce power generated by fossil fuel plants and associated greenhouse gas emissions 57 percent by 2025, and 100 percent by 2030.

Some natural gas-fired generation will be necessary even after 100 percent net reduction in greenhouse gases is achieved, primarily during extended periods of inclement weather when solar, hydropower, and existing nuclear generation, along with batteries and pumped storage, are insufficient to meet demand. At other times, especially spring and fall when heating and cooling demand are low, renewable power will be generated in excess of what is needed to meet in-state demand and can be exported to neighboring states.

Public utilities are innovators in the clean energy transition – investor-owned utilities can join them

Public utilities (municipal utilities and cooperatives) have been in the vanguard of local solar and battery storage deployment in the United States. The typical utility business strategy has been resistant to implementing this innovative model. However, IOUs that commit to an explicit public benefit purpose – thus aligning shareholder interests with those of the public – can adopt a stable and profitable corporate structure that achieves a cleaner and less costly electricity supply for their customers.

At least one IOU, Green Mountain Power, has adopted the public benefit as an explicit corporate objective, balancing shareholder value with the public good. President and CEO Mary Powell expressed the nature of this public benefit obligation in the following terms:

> *Leveraging the latest innovations like battery storage, we are working with customers to move away from the antiquated bulk grid, to a cleaner and more reliable energy system, where power is generated closer to where it's used.*

OFFICIAL COPY

Oct 12 2017

1. Current Utility Structures and Growth Strategies in North Carolina

1.1 Electric Utility Structures

Three different utility structures exist in North Carolina: investor-owned utilities (IOUs), rural electric cooperatives, and municipal utilities. The North Carolina Utilities Commission (NCUC) is responsible for oversight of IOU rates and resources.[1] The IOU is provided a regulated monopoly franchise with a guaranteed rate of return in exchange for providing reliable service at reasonable rates to each customer in the territory.[2]

North Carolina's IOUs are Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP),[i] both subsidiaries of Duke Energy Corporation, and Dominion North Carolina Power (DNCP).[3] About two-thirds of North Carolina's five million utility customers are served by IOUs.

Thirty-one electric membership corporations (EMCs or rural cooperatives) provide electric service in specific localities instead of the IOU, and about 75 municipal governments and university campuses in the state retain local control of electricity service.[4] The distribution of customers among North Carolina electric utilities is shown in Table 1.[5]

Table 1. North Carolina Electric Utilities

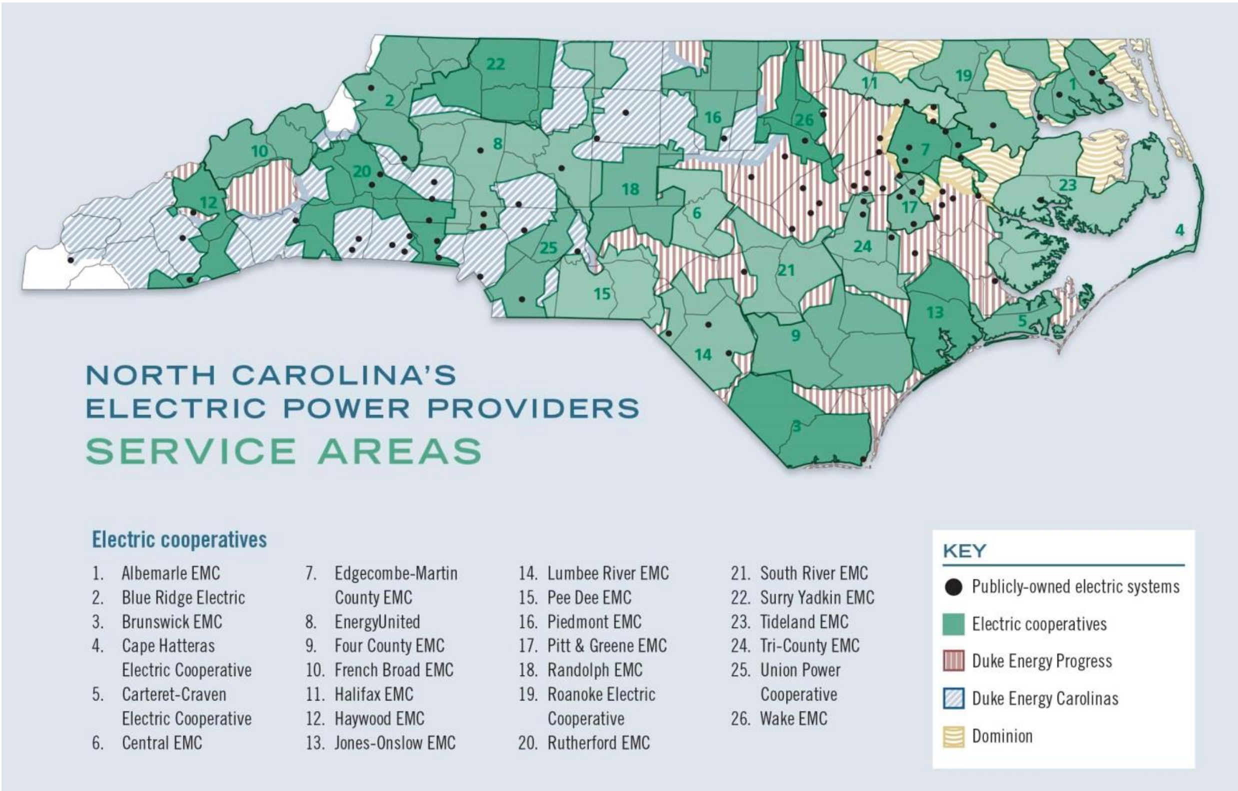
Entity	Number of Customers
Duke Energy Carolinas IOU	1,921,000
Duke Energy Progress IOU	1,339,000
Dominion NC Power IOU	120,000
Electric Membership Corporations (31)	1,071,000
Municipal- or university-owned utilities (approx. 75)	587,000

A map showing DEC, DEP, DNCP, EMC and municipal utility service territories in North Carolina is provided in Figure 1.

The 31 EMCs have a total of 1,071,000 customers interspersed among the IOU service territories.

[i] DEC and DEP operate in both North Carolina and South Carolina, and have power generation facilities in both states that serve customers in both states.

Figure 1. Map of Utility Service Territories in North Carolina
(source: North Carolina Electric Cooperatives, NCEMC, May 2016)



The approximately 75 municipal- and university-owned electric distribution systems have 587,000 customers.[6] Two agencies provide management services to some of these municipal utilities: 1) the North Carolina Eastern Municipal Power Agency (NCEMPA), consisting of 32 cities and towns in eastern North Carolina, and 2) the North Carolina Municipal Power Agency Number 1 (NCMPA1), consisting of 19 cities and towns in western North Carolina. The locations of these municipal and university utilities are shown in Figure 2.

OFFICIAL COPY
Oct 12 2017

Figure 2. Location of North Carolina Municipal Utilities

(source: NC Public Power website)[7]

1.1.1 IOU Business Model: Guaranteed Profit on Steel-in-the-Ground Infrastructure

North Carolina's principal IOUs are currently authorized to recover from customers a guaranteed rate of return in the range of 10 percent on capital investments.[8] The IOU guaranteed rate of return is earned on power plants, transmission lines, distribution infrastructure, and "grid modernization" projects such as smart meters. These investments are generally predicated on electricity demand forecasts that project steady growth in peak demand and annual electricity consumption, and serve as the basis for more infrastructure development. Until about a decade ago, such steady growth in demand was actually occurring.

In reality, over the last decade, there has been no increase in peak demand or annual electricity consumption on a statewide level, primarily due to mandatory federal efficiency standards for appliances and the widespread use of more efficient lighting.[i] The IOUs acknowledge that per capita demand has been on the decline but assert that population increases in the state will drive an increase in sales.[9] Both DEC and DEP continue to forecast peak load growth of 200 to 300 megawatts (MW) per year over the next decade.[10] The actual trends over the last ten years are shown for DEC and DEP in Figures 3 and 4.

Winter peak loads in DEC and DEP service territories have historically been lower than summer peak loads. DEC and DEP actual winter peak loads were flat or declining in the 2006-2012 period. DEC continues to forecast lower winter peak loads over the next decade in its 2016

[i] See detailed discussion of this issue in Chapter 8.

OFFICIAL COPY

Oct 12 2017

Integrated Resource Plan (IRP).[11] DEP forecasts that the winter peak load will be approximately the same as the summer peak load over the next decade.[12]

Figure 3. DEC and DEP Summer Peak Demand Trends for North Carolina, 2007-2015[13,i]

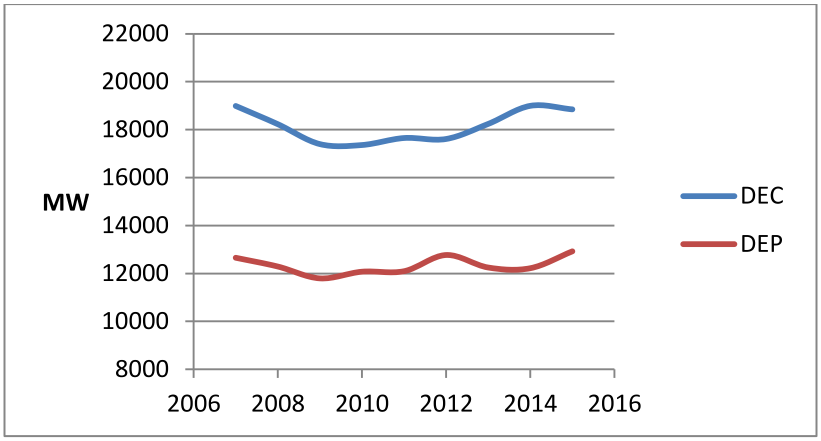
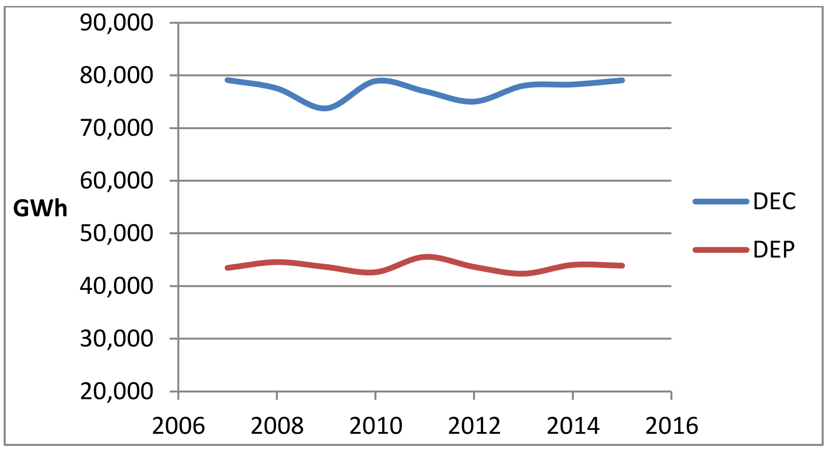


Figure 4. DEC and DEP Annual Retail Sales for North Carolina, 2007-2015[14]



However, DEC and DEP experienced high winter peak load events in 2013, 2014, and 2015, reaching substantially higher peak levels than forecast in the IRPs prepared by each utility. The DEC and DEP 2015 and 2016 IRPs indicate these higher-than-forecast winter peaks were due to

[i] NCUC revised its historic summer and winter peak load reporting methodology in its December 22, 2016 Electricity Report for the years 2010 through 2015. Reference: e-mail communication between B. Powers, Powers Engineering, and J. Lucas, NCUC Public Staff Electric Division, June 22, 2017. The revised methodology results in revised historical peak loads that, in some cases, are substantially higher than those previously reported by NCUC. For this reason, only historical peak loads reported in the 2015 NCUC Electricity Report, and earlier versions of the NCUC Electricity Report, are relied on in this document. It is important to note that the all-time DEC summer peak record reported by Duke Energy of 20,671 MW on July 27, 2016 is about the same as the previous record identified by Duke Energy of 20,628 MW registered on August 8, 2007. Therefore there has been no increase in DEC summer peak load between 2007 and 2016. Duke Energy, "Duke Energy Carolinas customers set summertime record for electricity use," news release, August 1, 2016, https://news.duke-energy.com/releases/releases-20160801.

OFFICIAL COPY

Oct 12 2017

anomalous weather events, specifically polar vortex events.[i,ii] These short-term winter peak loads were driven by reliance on electric space heating in DEC and DEP service territories beyond forecast levels.[iii] Electric heat pumps and electric baseboard heating are in common use in North Carolina. Electric heat pumps are least efficient at subfreezing ambient conditions. Under these conditions, high-demand electric strip heaters in the ductwork supplement and then gradually replace the heat pump output, resulting in a substantial increase in heating load.[15]

Effective, high-participation demand response (DR) programs that cycle these space heaters off and on during peaking conditions, while maintaining comfortable temperature levels, represent a straightforward, off-the-shelf tool that could prevent polar vortex events from driving winter peak demand upward. DR programs are discussed in detail in Chapter 8.

1.1.2 IOU Demand Forecasts Overestimate Growth, Resulting in Overbuilding of Reserves

The NCUC projects high IOU energy usage and summer peak load growth rates for the next fifteen years despite no significant growth over the last decade. The growth rate projections are shown in Table 2.

Table 2. IOU 15-Year Demand Growth Projections[16]

IOU	Avg. Annual Energy Consumption Growth (percent)	Avg. Annual Peak Demand Growth (percent)
DEC	1.2	1.3
DEP	1.2	1.4
DNCP	1.3	1.5

---

[i] For the first time in the 2016 IRP, DEC and DEP are now developing resource plans that also include new resource additions driven by winter peak demand projections inclusive of winter reserve requirements. The completion of a comprehensive reliability study demonstrated the need to include winter peak planning in the IRP process. The study recognized the growing volatility associated with winter morning peak demand conditions such as those observed during recent polar vortex events. Duke Energy Carolinas 2016 Integrated Resource Plan (DEC 2016 IRP), NCUC Docket E-100 Sub 147, September 1, 2016, p. 30-31.

[ii] "DEC's system peaked at 19,151 MW on January 30, 2014, at the hour ending 8:00 a.m. at a system-wide temperature of 12 degrees. The 12 degrees is significantly colder than the 18 degrees assumed in the winter peak load forecast. . . At this time, the Company did not activate any of its DSM [demand response] programs. However, during its second highest peak, which occurred on January 7, 2014, the Company did activate its DSM programs, reducing load by 478 MW." NCUC 2015 Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina (NCUC 2015 Annual Report), pdf p. 51.

[iii] "DEP's 2014 annual system peak of 14,159 MW occurred on January 7, 2014, at the hour ending 8:00 a.m., at a system-wide temperature of 11 degrees. The 11 degrees is significantly colder than the 18 degrees assumed in the winter peak load forecast. DEP's 2013 and 2012 peaks were 12,166 MW in August 2013 and 12,770 MW in July 2012." NCUC 2015 Annual Report, pdf p. 50.

OFFICIAL COPY

Oct 12 2017

North Carolina utilities and utilities in neighboring regions maintain ample reserves of generating capacity. The planning reserve margin represents the total amount of generation capacity utilities have available above what is needed to meet expected peak demand. Duke Energy has in the past planned to achieve a 15 percent planning reserve margin.[i] It recently increased that margin to 17 percent.[17]

DEC and DEP IRPs call for significant additional increases in planning reserve margins as shown in Table 3. Since the planning reserve margin is a percentage of an already overestimated peak load growth, this translates into thousands of MW of generation beyond what is needed to assure reliability.

Table 3. Duke Energy Forecasted Planning Reserve Margin Range, 2016-2031[18]

IOU	Winter Peak Reserve Range (percent)	Summer Peak Reserve Range (percent)
DEC	17 - 22	18 - 25
DEP	17 - 27	17 - 26

Regional reserve margins in and around North Carolina are also projected to be high. The SERC East (Carolinas) region has projected reserve margins ranging from between 16 and 24 percent over the next ten years.[19] Neighboring PJM (Mid-Atlantic region) has forecast reserve margins from 24.5 percent to 52 percent.[20] What these high regional reserve margins mean in practical terms is that there are more than ample resources in the region available to meet peak demand.

1.2 Duke Energy Integrated Resource Plans

The Duke Energy IRPs outline planned resource additions for both DEC and DEP. Each utility plans to add large amounts of new natural gas capacity. DEC proposes to build two 1,117 MW nuclear units at the Lee Nuclear Station, with projected operation in 2027 and 2029. DEC plans to construct as much as 2,481 MW of new natural gas capacity by 2031. DEP proposes to construct 5,409 MW of new natural gas capacity in the same period. DEC and DEP's potential proposed natural gas additions are outlined in Tables 4 and 5 below.

[i] The North American Reliability Council (NERC), delegated by the Federal Energy Regulatory Commission (FERC) to establish electric reliability criteria, assumes a default planning reserve margin of 15 percent. NERC, "M-1Reserve Margin," accessed July 9, 2017, http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Table 4. DEC Proposed Natural Gas Additions[21]

Gas Resource	Capacity (MW)
Combined Cycle	1,904
Combustion Turbine	468
Combined Heat and Power	109
Total Proposed Capacity	2,481

Table 5. DEP Proposed Natural Gas Additions[22]

Gas Resource	Capacity (MW)
Combined Cycle	1,781
Combustion Turbine	3,562
Combined Heat and Power	66
Total Proposed Capacity	5,409

Meanwhile, DEC plans to retire 604 MW of coal capacity in 2024 and 557 MW in 2028.[23] DEP projects closure of 76 MW of natural gas and oil capacity in 2017, 645 MW of natural gas and oil capacity in 2020, 68 MW of oil capacity in 2027, 164 MW of natural gas and oil capacity in 2027, and 384 MW of coal capacity (Asheville units) in 2019.[24]

Table 6 shows the combined company's projected energy mix for 2031.

Table 6. DEC and DEP Combined Energy Production, 2031[25]

Source	Energy Mix (%)
Nuclear	47
Natural Gas	21
Coal	20
Renewable Energy	6
Energy Efficiency	3
Hydro	3

1.3 Municipal Utilities and Cooperatives Resource Planning

Municipal and cooperative utilities are not required to submit formal IRPs to the NCUC for approval.[26] Therefore, projected annual growth, resource additions and wholesale purchasing plans are not formally reported by these power providers. However, the electric membership cooperatives website reports annual growth projections that actually exceed that of the IOUs at

1.5 percent from 2014-2023. An average annual growth of 1.6 percent over the past ten years is cited as the basis for the projection.[27]

1.4 Military Renewable Energy Goals

There are five military bases located in North Carolina – three Marine Corps bases, one Army base, and one Air Force base.[28] While military bases still obtain electricity from the designated provider in their areas, the military has additional resources at its disposal and incentives to pursue onsite energy projects. The Department of Defense has set a department-wide goal of acquiring 20 percent of energy demand from renewable energy by 2020.[29] Each military branch has separate goals in addition to the Defense Department target as shown in Table 7.

Table 7. Military Division Renewable Energy Goals

Branch	Goal
Navy and Marine Corps	50 percent energy consumption from alternative sources by 2020
Air Force	25 percent of total electricity use from renewable/alternative energy by 2025
Army	25 percent of energy consumption from renewable energy by 2025

The only North Carolina military base to pursue a renewable energy project to date is Camp Lejeune. The base installed a 247 kW solar PV array and a solar thermal system in 2016[30] and also served as the site for a 13 MW Duke Energy solar farm installed in 2015.[31] Other North Carolina bases have the potential to be leaders in moving toward NC CLEAN PATH 2025 as they consider solar and storage as avenues to meet renewable energy goals and reduce reliance on the electric grid to improve resiliency.

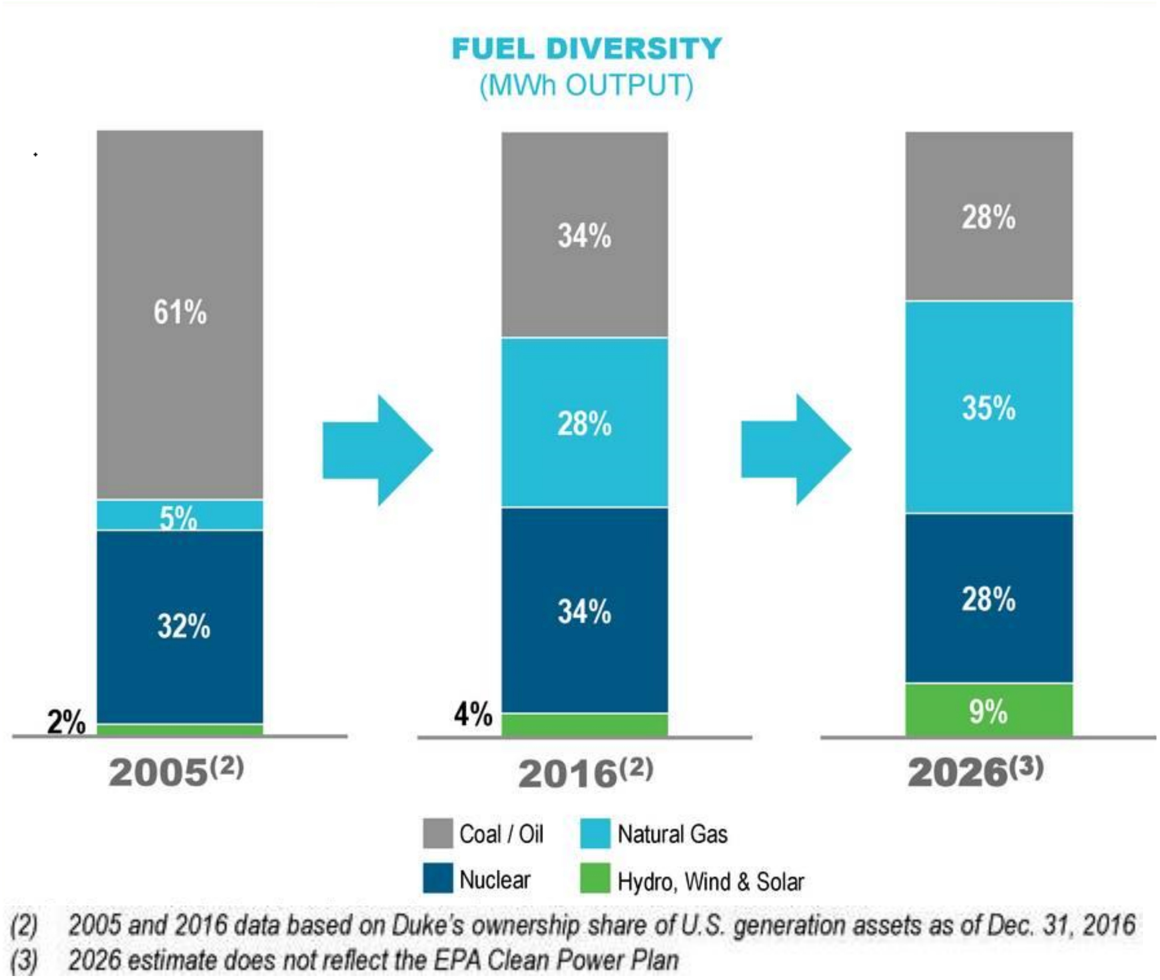
1.5 Greenhouse Gas Implications of North Carolina Utility Planning Strategies

1.5.1 Carbon dioxide

The carbon dioxide (CO_2) reductions projected over the next decade by the IOUs are primarily achieved by producing an incrementally larger share of electricity from gas-fired generation instead of coal-fired generation, though the percentage shares of coal- and gas-fired output remain roughly similar to those achieved at the end of the 2005–2016 timeframe. However, the total amount of power generated by fossil fuel resources actually increases slightly from 2016 to 2026, from 62 percent to 63 percent. This trend is shown in Figure 5 for all Duke Energy generation investments (including regulated generation assets in North Carolina, South Carolina, Indiana, Florida, Kentucky, and Ohio and commercial renewable generation across the country). Duke Energy's strategy appears to be to maintain maximum flexibility to use coal- or gas-fired generation depending on the relative cost-of-production of these two alternatives.

OFFICIAL COPY Oct 12 2017

Figure 5. Duke Energy Coal and Gas "All Options Available" Economic Strategy
(source: Duke Energy)[32]



The CO_2 emissions trend for the combined DEC and DEP is shown in Figure 6. Duke Energy is projecting about a 10 percent reduction in CO_2 emissions from 2017 to 2026, followed by a CO_2 increase of at least 10 percent due to nuclear plant retirements after 2029.

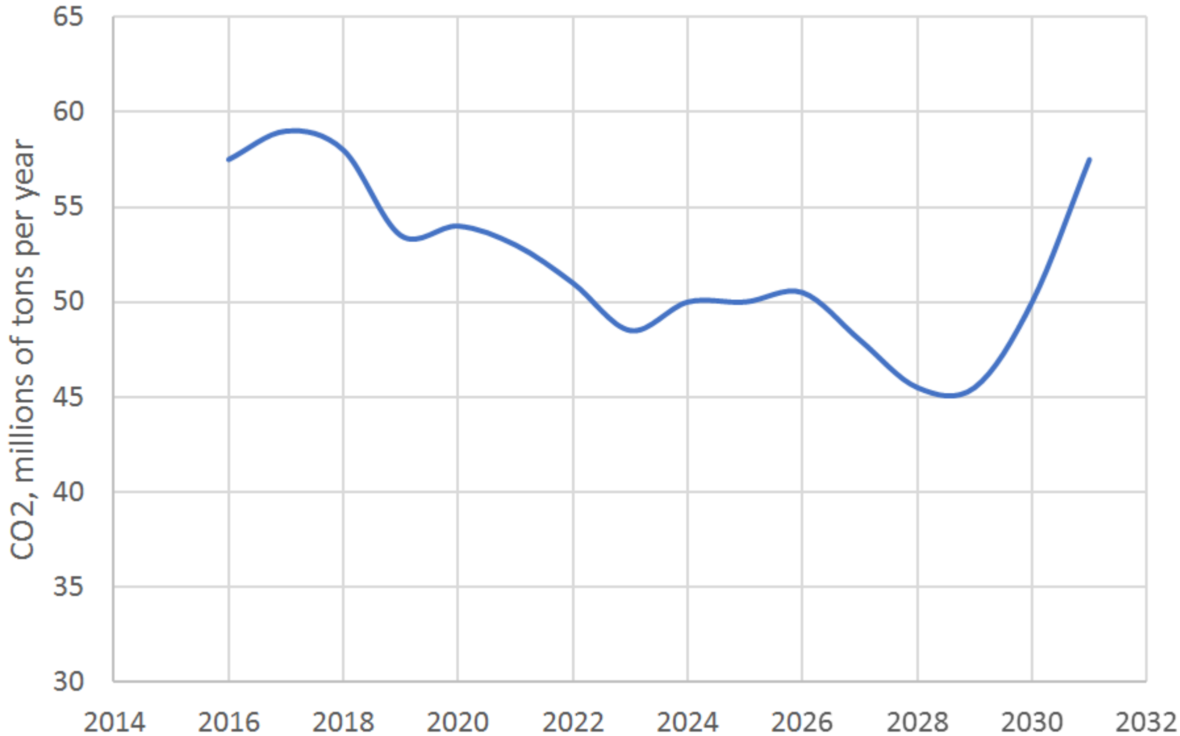
1.5.2 Methane

The Duke Energy greenhouse gas (GHG) calculations do not account for the associated supply-chain methane emissions from either coal mining or natural gas development and transport (wells, processing, pipelines, and compressor stations). When these associated methane emissions are accounted for, the total GHG emissions from coal and natural gas combustion increase significantly, as shown in Figure 7. Methane emissions from conventional natural gas production, and especially from shale gas production, are substantially higher than those associated with coal mining.[33]

OFFICIAL COPY
Oct 12 2017

OFFICIAL COPY Oct 12 2017

Figure 6. DEC & DEP Long-Term CO_2 Emissions Projections – Rising CO_2 in the 2030s[34]



An increasing amount of natural gas used in North Carolina will be shale gas from Pennsylvania when Transco completes its Atlantic Sunrise pipeline project in that state in 2018.[35] The main natural gas trunkline serving North Carolina is the Transco pipeline that has historically transported natural gas from the Gulf of Mexico region to states along the Eastern Seaboard. However, the Atlantic Sunrise project will provide Transco with the capability of moving gas bidirectionally, sending shale gas south from Pennsylvania or conventional and shale gas north from the Gulf.[36] In addition, a major infrastructure development proposed by Duke Energy and partners to facilitate greater use of shale gas in North Carolina is the $5.6 billion Atlantic Coast Pipeline.[i]

The mean methane emissions rate from the lifecycle of shale gas wells is about 4 percent greater than lifecycle emissions of conventional natural gas.[37] As shown in Figure 7, when methane emissions from shale gas production are accounted for, shale gas has median GHG emissions about 50 percent higher than the median GHG from coal (per unit of equivalent heating value).[ii]

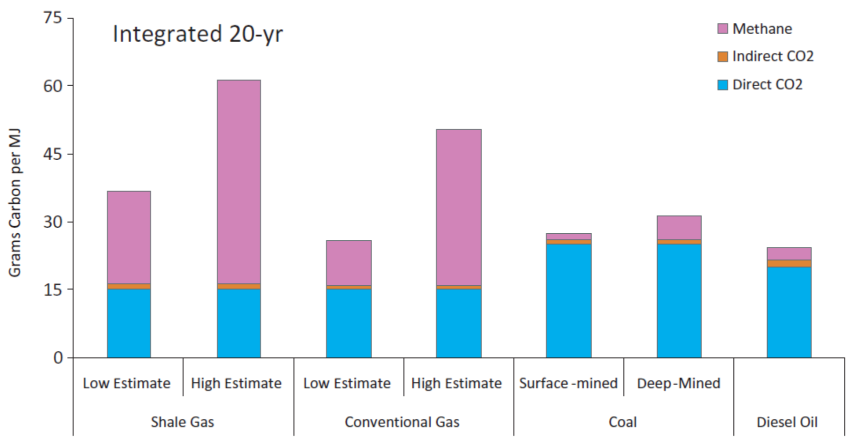
The new high-efficiency natural gas-fired power plants that form the core of the conventional energy strategy being carried out by North Carolina utilities are about 50 percent more efficient

[i] Duke Energy will have a 47 percent ownership stake in the Atlantic Coast Pipeline. DE Q4 2016, PPT, p. 64.
[ii] Shale gas median carbon equivalent GHG emissions = ~45 grams carbon per mega-joule (unit of heat content). Coal median carbon equivalent GHG emissions = ~30 grams carbon per mega-joule.

than the coal plants they are replacing.[i] The 50 percent higher GHG emissions from shale gas compared to coal cancel out the 50 percent efficiency gain of combined cycle technology. In common language, this means that the utility strategy of relying on natural gas-fired power plants as a principal GHG reduction strategy, using regional shale gas as the primary fuel, is flawed. The new combined cycle units, when methane emissions in the supply chain are accounted for, add as much GHG emissions to the atmosphere as the coal plants.

Figure 7. Cumulative GHG Impacts of Fossil Fuel Sources

(source: Howarth)[38]



[i] Typical thermal efficiency of a conventional coal-fired power plant is about 10,000 British thermal units (Btu) per kilowatt-hour (kWh). Typical thermal efficiency of a combined cycle power plant is about 6,500 to 7,000 Btu per kWh (both values are based on high heating value – HHV – of the fuel).

OFFICIAL COPY
Oct 12 2017

OFFICIAL COPY

Oct 12 2017

2. Electricity Demand and Supply in North Carolina

2.1 Meeting Electricity Demand

2.1.1 Investor-Owned Utilities

The 2014 and 2015 North Carolina retail sales of the state's IOUs are summarized in Table 8 below. The combined retail sales of DEC and DEP to their customers represented about 71 percent of North Carolina electricity demand in 2015.[i] The combined retail sales of all three North Carolina IOUs, DEC, DEP, and DNCP, to their customers represented about 74 percent of North Carolina electricity demand in 2015.[ii]

Table 8. IOU North Carolina Retail Sales, 2014 and 2015[39]

IOU	2014 NC Retail Sales (GWh)	2015 NC Retail Sales (GWh)
DEC	56,738	57,685
DEP	37,506	37,217
DNCP	4,447	4,378
Total	98,691	99,280

2.1.2 Municipal Utilities and Rural Cooperatives

Most of the municipal and cooperative utilities' customer demand is met through wholesale contracts with IOUs and generation owned by the municipal utilities and cooperatives. Wholesale electricity sales of IOUs in North Carolina in 2014 and 2015 are listed in Table 9.

Table 9. NC Wholesale Electricity Sales of IOUs[40]

IOU	2014 NC Wholesale Sales (GWh)	2015 NC Wholesale Sales (GWh)
DEC	7,826	6,025
DEP	16,650	18,787
DNCP	1,220	1,355
Total	25,696	26,167

The specific generating facilities owned by the municipal utilities and cooperatives are described in 3.2.2.

---

[i] Total retail sales = 133,847,523 MWh (133,848 GWh). (57,685 GWh + 37,217 GWh) ÷ 133,848 GWh = 0.709 (70.9 percent). EIA, State Electricity Profiles - North Carolina Electricity Profile 2015, January 17, 2017, https://www.eia.gov/electricity/state/northcarolina/.
[ii] (57,685 GWh + 37,217 GWh + 4,378 GWh) ÷ 133,848 GWh = 0.742 (74.2 percent)

2.1.3 Total North Carolina Electricity Demand Met by IOUs

The IOUs supply electricity to their own customers as well as municipal utilities and cooperatives in North Carolina, as shown in Tables 8 and 9. The IOUs total share of electricity supplied in North Carolina in 2015 was 94 percent.[i] Duke Energy's share of electricity supplied in North Carolina in 2015 was 89 percent.[ii]

2.2 Existing North Carolina Generation Resources

2.2.1 North Carolina IOUs

Duke Energy's energy mix, as reported in annual IRP filings and Utilities Commission annual reports, is predominantly reliant on nuclear and fossil-fuel generation with only minor contributions from renewable energy and energy efficiency. Tables 10 and 11 summarize the energy and capacity mixes of DEC and DEP reported in the 2016 IRPs of these IOUs.

DEC owns and operates the 780 MW Jocassee and 1,360 MW Bad Creek pumped storage hydroelectric facilities in northern South Carolina.[41] These facilities were built to help Duke Energy balance power production and load when Duke built its nuclear plants.[42] The Bad Creek pumped hydro facility can readily be adapted to "absorb" solar power during the day, when water would be pumped from the lower reservoir to the upper reservoir, and power would be generated by the facility at night or during weather not optimal for solar production.

Pumped storage can provide energy-balancing, stability, storage capacity, and ancillary grid services such as frequency control and reserves. This is due to the capability of pumped storage plants to respond to potentially large load changes within seconds. Pumped storage historically has been used to balance load on a system, enabling large nuclear or thermal generating sources to operate at peak efficiencies. Pumped storage projects also provide ancillary benefits including capacity and reserves, reactive power, black start capability, and spinning reserve. A pumped storage project would typically be designed to have 6 to 20 hours of reservoir storage for operation at rated capacity.[43]

2.2.2 Municipal Utilities and Rural Cooperatives

Municipal and cooperative electric utilities have ownership shares of some generating facilities in the state, in addition to procuring power through wholesale purchase contracts.

The Catawba Nuclear Station located in York County, SC, and operated by DEC has divided ownership. The North Carolina Electric Membership Corporation (NCEMC), which is responsible for purchase contracts and transmission for North Carolina's electric cooperatives,

[i] (99,280 GWh + 26,167 GWh) ÷ 133,848 GWh = 0.937 (94 percent). Assumes all IOU wholesale power sales are sold to NC wholesale customers.
[ii] (94,902 GWh + 24,812 GWh) ÷ 133,848 GWh = 0.894 (89 percent).

OFFICIAL COPY Oct 12 2017

has ownership of 61.5 percent of Catawba Nuclear Station Unit 1.[44] North Carolina Municipal Power Agency Number 1 (NCMPA1), responsible for purchase contracts and transmission for municipal utilities in the foothills region, has a 75 percent ownership interest in Catawba Nuclear Station Unit 2.[45]

Table 10. Duke Energy 2015 Capacity Mix[46,i]

Resource	DEC 2015 Energy (percent)	DEP 2015 Energy (percent)
Nuclear	61	44
Coal	27	34
Natural Gas	11	21
Hydro	<1	<1
Renewable Energy	<1	<1
Purchases	<1	<1

Table 11. Duke Energy Generating Capacity Resources[47]

Resource	DEC Capacity (MW)	DEP Capacity (MW)
Nuclear	3,698	3,698
Coal	6,859	3,592
Natural Gas Combined Cycle	1,403	2,991
Natural Gas Combustion Turbine	3,204	3,464
Natural Gas Boiler	170	---
Hydroelectric	1,096	227
Pumped Storage	2,140	---
Solar	3.87	44.4

[i] Note that the NCUC Annual Report provides different numbers than the DEC and DEP IRPs for the utilities' energy mix in 2015. DEC energy resources in 2015 were reported as 28 percent coal, 49 percent nuclear, 1 percent hydroelectric (net), 12 percent natural gas and oil, 1 percent non-hydro renewable, 9 percent purchased power. DEP energy resources in 2015 were reported as 19 percent coal, 39 percent nuclear, 1 percent hydroelectric (net), 33 percent natural gas and oil, 3 percent non-hydro renewable, 5 percent purchased power. And Dominion NC energy resources in 2015 were 26 percent coal, 30 percent nuclear, 1 percent hydroelectric (net), 25 percent natural gas and oil, 1 percent non-hydro renewable, 17 percent purchased power. NCUC 2016 Annual Report, Table 5.

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

NCEMC also owns and operates its own resources, including peaking diesel generators in Buxton (15 MW) and Ocracoke (3 MW),[i] and two natural gas peak-load power plants in Anson and Richmond counties, with a combined capacity of 600 MW. [48]

2.2.3 Independent Renewable Energy Resources

Table 12 lists the capacity of independent (non-utility) renewable energy resources in North Carolina. The state is second in the nation in solar capacity due to favorable policies toward independent solar power producers.[49] However, some members of the North Carolina General Assembly and Duke Energy are pushing back. For example, the General Assembly allowed the state renewable energy tax credit to expire on December 31, 2015.

Table 12. Independent Renewable Power Generation Capacity

Resource	Statewide Capacity (MW)
Wholesale solar[ii]	3,016
Net metered solar[50]	32
Utility-scale wind[51]	208 [this wind power is sold to an out-of-state customer]
Biomass – poultry waste[iii]	41
Biomass – landfill gas[52]	40
Biomass – swine waste[53]	10
Small-scale hydro[54]	5

Duke Energy also worked with members of the General Assembly to draft HB589, signed by Governor Roy Cooper in July 2017, which reduces the size limit for installations eligible for standard contracts and introduces a competitive bidding process for new utility-scale independent solar projects.[55] The contract terms previously in effect served as the financial engine for rapid solar development in North Carolina. The payments were at Duke Energy's electricity production "avoided cost," or the cost that Duke would be paying for a conventional mix of wholesale power. This means these solar contracts imposed no cost burden on North Carolina ratepayers while offsetting the need for conventional coal- or gas-fired generation to

[i] The Ocracoke generator is in the process of being paired with solar and batteries to create a microgrid: https://ocracokeobserver.com/2016/12/12/ocracoke-is-first-in-the-state-for-a-microgrid/.
[ii] Solar installed as of December 31, 2016: 3,016 MW. Solar Energy Industries Association, "Top 10 Solar States," http://www.seia.org/sites/default/files/Top_10_Solar_States_Infographic_Full.png.
[iii] The capacity of wood waste biomass facilities in North Carolina is not included in Table 12. There is approximately 249 MW of wood waste biomass capacity in the state. North Carolina Utilities Commission, "Renewable Energy and Energy Efficiency Portfolio Standard (REPS)," http://www.ncuc.commerce.state.nc.us/reps/reps.htm, Renewable Energy Facility Registrations Accepted by the NC Utilities Commission: NEW Renewable Energy Facility Registrations Accepted by the North Carolina Utilities Commission 2008-2017.

provide the same power. Under the new competitive bidding process, payments to solar projects will be based on rates negotiated with the utilities.

2.2.4 Merchant Power Plants in the Carolinas and Virginia

In addition to IOU and cooperative owned-and-operated generating capacity, numerous merchant generating facilities operate in North Carolina and nearby. Merchant facilities generally sell power via firm wholesale contracts to IOUs, municipalities, cooperatives, or regional transmission organizations (RTOs). While some of these facilities are currently contracted to operate at full capacity, others have spare capacity or are largely idle. These merchant plants include:

- 380 MW Brookfield Smoky Mountain hydroelectric facility, North Carolina-Tennessee border[56]
- 523 MW Columbia Energy combined cycle plant, Columbia, SC[57]
- 475 MW combined cycle at Kings Mountain Energy Center owned by NTE in Cleveland County, NC (operational in 2018)[58]
- 500 MW combined cycle at Reidsville Energy Center owned by NTE in Rockingham County, NC (operational in 2021)

OFFICIAL COPY Oct 12 2017

OFFICIAL COPY

Oct 12 2017

3. Governance Structure Necessary to Realize NC CLEAN PATH 2025

3.1 Utility Business Strategies in North Carolina

3.1.1 Corporate Objectives

Investor-owned utilities (IOUs), public municipal utilities, and rural electric cooperatives all operate in North Carolina. IOU customer demand, including DEC, DEP, and DNCP, accounts for about 74 percent of electricity sales.[i] The IOUs, along with NCEMC and NCMPA1, also provide another 20 percent of statewide electricity sales to municipal utilities and rural cooperatives.[59] Independent power producers, including manufacturers, military installations, wholesale solar power generators, and some universities, provide the remainder.[60]

A fundamental objective of IOUs is increasing the value of company stock for shareholders. For the last century, IOUs have received a fixed rate of return (gross profit) on steel-in-the-ground construction, including transmission and distribution lines, power plants, meters, and pipelines. The IOUs are granted monopoly control in exchange for regulation of rates and profit by a state utilities commission.

An example of this IOU focus on steel-in-the-ground construction is Duke Energy's ten-year strategic grid expansion plan, Power/Forward Carolinas[ii] and its broader, 15-year Integrated Resource Plan. Duke Energy is the predominant electric IOU provider in the state, supplying about 90 percent of the electricity consumed.

Duke Energy plans to spend $13 billion on grid upgrades in North Carolina alone.[61] In addition, it plans to spend $2.5 billion on the Atlantic Coast natural gas pipeline,[62] $5 billion on new gas-fired plants,[63,iii] and at least $20 billion for new nuclear,[64] all of which would serve both Carolinas. Meanwhile, it plans to do the minimum in renewable energy development. Duke Energy owns and operates one of the largest battery storage facilities (36 MW) at its 153 MW Notrees wind power plant in Texas, but has no plans to invest substantial resources in battery technology (or wind energy) in the Carolinas.[iv] The strategic focus on gas-fired power is a

---

[i] See Table 8.

[ii] See Tables 4 through 6.

[iii] Herman K. Trabish, "Utilities in hot water: Realizing the benefits of grid-integrated water heaters," *Utility Dive*, June 20, 2017, http://www.utilitydive.com/news/utilities-in-hot-water-realizing-the-benefits-of-grid-integrated-water-hea/445241/. "DR and storage can result in the very real benefit of helping utilities avoid the $1,000 per kW cost of a peaker plant." 5,000 MW x 1,000 kW/MW x $1,000/kW = $5 billion.

[iv] Duke Energy has proposed to build a 5 MW battery storage facility in Asheville as an adjunct to the Asheville Grid Modernization Project, a 550 MW combined cycle power plant. Energy Storage Association, *Improving Grid Stability and Integrating Wind Energy: Younicos Battery Park,* accessed June 11, 2017: http://energystorage.org/energy-storage/case-studies/improving-grid-stability-and-integrating-wind-energy-younicos-battery.

OFFICIAL COPY

Oct 12 2017

primary reason that Duke Energy is forecasting higher GHG emissions in the 2030s than in the 2010s (see Figure 6).

The major investments proposed by Duke Energy in "grid modernization" infrastructure, presented as necessary to support a green energy future, include undergrounding some transmission lines, building redundant transmission lines to vulnerable communities, transformer and cable upgrades, cybersecurity, and substation automation.[65] This is in addition to the $1 billion per year that Duke Energy spends on operations and maintenance of its transmission and distribution system.[66] These types of major grid modernization building programs being proposed by other IOUs around the country are controversial.[67]

Not-for-profit public utilities have a local or regional focus and are not shareholder driven. They are directed by a local elected board or the political leadership of the jurisdiction. Public utilities have traditionally tended to concentrate on customer service and minimizing the cost of electricity. There are about 70 municipal utilities in North Carolina, such as the cities of Apex, Wake Forest, High Point, New Bern, and Lumberton.[68] Independent university electric utilities include North Carolina State University, University of North Carolina at Chapel Hill, Appalachian State University, Elizabeth City State University, and Western Carolina University.[69]

3.1.2 Independent Solar Power Generation

North Carolina had over 3,000 MW of installed solar power at the end of 2016, ranking the state second in the nation after California in solar capacity.[70] Solar development in North Carolina has primarily been occurring outside of utility procurement strategies. The primary reasons large-scale solar power has thrived in North Carolina in recent years are federal and state law regarding treatment of independent power projects, a state renewable portfolio standard, and the rapidly declining price of solar power.[71] The federal Public Utility Regulatory Policies Act, passed in the 1970s, authorizes independent power production of alternative energy sources and requires IOUs to purchase power from those independent producers at a reasonable price and with standard contract terms set by state regulators. A reasonable standard contract price, and assurance of a long-term income stream for independent projects, have been critical building blocks supporting the growth of solar power in North Carolina.[72]

The rapid rise of independent solar producers in North Carolina resulted in the dominant IOU in the state, Duke Energy, offering a competing alternative known as the "Green Source Rider." Green Source Rider is a program in which large commercial customers can purchase from Duke Energy renewable electricity produced by a third-party solar generator.[73]

A state tax incentive for renewable energy played a role in the rapid development of North Carolina's solar industry through 2015.[74] However, the North Carolina General Assembly allowed the state renewable energy incentive payment to sunset on December 31, 2015.[75]

North Carolina utility regulation allows retail "net metering" of solar power produced at homes and businesses.[76] Net metering is the placement of solar systems behind the customer's meter, generally on a rooftop or parking lot, to offset retail electricity purchases by the customers and feed excess power produced by the system onto the grid. There is no cap on the number of customers in the state that can participate in net metering.[77] However the economics of solar net metering have not been favorable enough to result in mass rooftop solar deployment in North Carolina.

The North Carolina solar market has been primarily focused on multi-MW wholesale power projects that receive payments at the utility's avoided cost. As a result, relatively little net metered solar had been installed in the state as of the end of 2016. The recent precipitous drop in the cost of solar has, in 2017, created favorable economic conditions for net metered solar in the state. North Carolina homeowners and businesses can now save money by offsetting grid power electricity purchases with net metered solar. As a result, net metered solar power is ready to ramp up in North Carolina.[i]

3.2 Models Best Adapted to Addressing Changing Power Priorities

3.2.1 Nonprofit Public Utility

Nationally, public utilities as a category have demonstrated greater flexibility in responding to the changing needs of customers in their jurisdictions than have IOUs. This is one apparent advantage to local control and the lack of shareholders expecting profits. A number of smaller public utilities in the U.S. have been at the vanguard of the transition to renewable energy, and especially solar power. This phenomenon is evident in the list shown in Table 13 of the ten U.S. utilities with the highest density of solar power per customer in 2016. Eight of the top ten performers are public utilities.[ii]

Kauai Island Utility Cooperative (KIUC), a public utility with 30,000 customers and peak load and annual energy demand of 78 MW and 430 million MWh, respectively,[78,79] has taken the lead in transitioning from a fossil fuel-based grid to a model built on solar combined with battery storage. KIUC will replace about 40 percent of overall demand provided by fossil fuels with renewables in the 2015 to 2025 timeframe, increasing the percentage of renewables to 76 percent in 2025. KIUC has two major projects combining solar and battery storage: the SolarCity project consisting of 20 MW of solar and 52 MWh of battery storage (operational as of April 2017) and the AES project consisting of 28 MW of solar and 100 MWh of battery storage (under construction as of June 2017).

[i] This assumes that revised net metering tariffs to be proposed by North Carolina utilities under HB 589 do not result in unfavorable economics for net metered systems. See North Carolina House Bill 589, signed into law on July 27, 2017, which establishes at § 62-126.4 that "each electric public utility shall file for Commission approval revised net metering rates for electric customers,"http://www.ncleg.net/Sessions/2017/Bills/House/PDF/H589v6.pdf.
[ii] The two IOUs are Dominion North Carolina Power (DNCP) and Rocky Mountain Power.

OFFICIAL COPY Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Table 13. Top Ten Utilities – Solar Watts per Customer in 2016[i]

Solar Watts per Customer			
Utility Name	State	Rank	Watts per Customer
City of Palo Alto Utilities	California	1	2753
Dominion North Carolina Power	North Carolina	2	1718
Farmers Electric Coop - Kalona	Iowa	3	1564
Ouachita Electric Cooperative Corporation	Arkansas	4	1282
Brunswick Electric Membership Corporation	North Carolina	5	1183
Rocky Mountain Power	Utah	6	847
City of Colton	California	7	800
Cobb EMC	Georgia	8	639
Roseville Electric	California	9	632
Pasadena Water and Power	California	10	545

A 2012 presentation on the Duke University electrical system shows that the university's peak load and annual demand are nearly identical to those of KIUC,[ii] suggesting that large consumers of electricity in North Carolina such as major research universities will be particularly good candidates for implementing NC CLEAN PATH 2025.

Minster, Ohio, is another example of innovation by a small municipal utility. Minster's normal load is about 16 MW, and its peak load is about 24 MW. The Minster municipal utility contracted for a 3 MW solar array and a 3 MWh battery energy storage system with 7 MW peak output that became operational in December 2015 under a power purchase agreement (PPA).[80]

The PPA sets the Minster utility's price for solar energy-generated electricity at $0.07 per kWh. The resulting all-in price with storage of $0.095 per kWh matches the utility's average retail electricity rate.

The economic benefit to the Minster utility is achieved through three specific services provided by the energy storage system. The project was bid into the regional market (PJM) for frequency regulation. The batteries also provide the utility with both 1) peak-shaving capability and 2) power quality stabilization and voltage regulation.

[i] It is important to note that the solar capacity located in Dominion North Carolina Power service territory, the second utility listed in Table 13, was either 1) not developed by DNCP for use by DNCP customers or 2) was developed by DNCP but contracted to third parties and not for use by DNCP customers. Joseph Bebon, "Top utilities of 2016 for solar and battery storage," *Solar Industry Magazine*, April 26, 2017, http://solarindustrymag.com/top-utilities-2016-solar-energy-storage.

[ii] A. Selezeanu (Duke University Utilities & Engineering), *Electrical System Capital Renewal and Preventive Maintenance*, PowerPoint, February 2012, p. 6 and p. 9. Campus peak load = 76 MW, annual electricity consumption = ~450,000 MWh.

OFFICIAL COPY

Oct 12 2017

According to the Minster city administrator, the utility exercised the unique ability of small independent utilities to act quickly, stating, “When we see an advantage for the community’s citizens, we don’t have to worry about what is best for shareholders.”[81]

Brunswick Electric Membership Cooperative, a North Carolina nonprofit rural cooperative, is following the Minster model. Brunswick EMC is developing twelve separate solar with storage projects that will have a combined storage capacity of 12 MWh. The projects are expected to be online by October 2017. The contracts will utilize a new power purchase agreement structure that allows the cooperative to purchase solar energy at its avoided cost while realizing the economic benefits of the battery storage.[82]

3.2.2 Community Choice Aggregation

Community Choice Aggregation (CCA) allows local governments and some special districts to pool their electricity load in order to purchase and develop power on behalf of their residents, businesses, and municipal accounts. CCA is an energy supply model that works in conjunction with the region’s existing utility. The existing utility continues to deliver the electric power over its transmission and distribution (T&D) system, maintain the grid, and provide billing and other customer services. Local governments can choose to enact CCA on an opt-in basis, where individual customers must choose to obtain their power from the CCA rather than from the traditional utility, or an opt-out basis, where all customers are initially included in the CCA but can opt out to continue receiving energy supply service from the IOU at any time. Opt-out programs are typically more successful, with higher customer participation rates.[83]

California, Illinois, Massachusetts, New Jersey, New York, Ohio, and Rhode Island, a total of seven states, have enacted CCA legislation that empowers local governments to supply electric power to the combined electricity loads of the customer accounts within their jurisdictional boundaries.[84]

CCA programs reflect the values of their governing boards and the communities they serve. Most emphasize reducing the cost of electricity. Some also focus on reducing GHG emissions, establishing new revenue streams to support local energy programs, or creating local jobs. Some CCA programs are designed to accomplish several of these goals concurrently.

California CCA legislation, Assembly Bill 117,[85] was passed into law in 2002 in the wake of the California energy crisis. California is one CCA state where the emphasis is on both reducing GHG emissions and reducing the cost of electricity. CCAs are expanding rapidly in the state. The California Public Utilities Commission is projecting that over 80 percent of California’s IOU customers may shift to CCAs or some other non-IOU electricity supplier by 2025.[86]

OFFICIAL COPY

Oct 12 2017

3.2.3 Investor-Owned Utility as B Corporation

It is rational from a short-term financial standpoint for a conventional IOU to resist the loosening of its monopoly status and potential threats to income. This IOU corporate perspective has been summarized by the Institute for Local Self-Reliance in the following manner:[87]

> Most of today's investor-owned electric utilities retain their century-old monopoly, but insufficient regulation has often left the public good by the wayside. Instead, investor-owned electric utilities (IOUs) have kept a laser focus on shareholders' returns. They have built large, unnecessary fossil-fueled power plants when more energy-efficient approaches would cut consumers' costs. They try to change electric rates in ways that harm the poor and elderly, then use public funds to help the indigent pay their bills. They spurn rooftop solar and customer-owned power generation.
>
> In some sense, this behavior is no surprise. The regulatory scheme Insull (developer of IOU business model) imagined shaped two key profit motives for utility companies: selling more power and building more infrastructure. But neither makes sense any longer. Electricity demand has leveled off, and distributed, non-utility power generation is often less expensive than relying on utility shareholder capital.
>
> Adding insult to the injury of the public good, investor-owned utilities frequently lobby against legislation in the public interest, from renewable energy to energy efficiency standards to community solar programs. They use their publicly-granted monopoly profits to oppose the public interest.

IOUs do not have to operate in opposition to proactive pursuit of clean energy in favor of more conventional gas-fired and nuclear options, or in opposition to allowing more customer participation in clean energy generation. Green Mountain Power in Vermont is one example of an IOU with a public benefit obligation.

Green Mountain Power transformed itself into a B Corporation in 2014.[88] The B Corporation designation formalizes the company's commitment to sustainability, transparency, and accountability.[i] The certification is administered by the nonprofit organization B Lab.[89] It reflects legislation in most states allowing businesses to become "benefit corporations" that uphold similar goals. Green Mountain Power President and CEO Mary Powell spoke on the company's vision of its role in September 2016:

> We will empower our customers to control their energy use, keep costs low and increase reliability all year long.

---

[i] B Corps are for-profit companies certified by the nonprofit B Lab to meet rigorous standards of social and environmental performance, accountability, and transparency. B Lab website, "What Are B Corps?" https://www.bcorporation.net/what-are-b-corps.

> Leveraging the latest innovations like battery storage, we are working with customers to move away from the antiquated bulk grid, to a cleaner and more reliable energy system, where power is generated closer to where it's used. [90]

A benefit corporation is an alternative corporate structure. It changes the for-profit corporation, which may consider the public interest, into one that legally must pursue greater social goods and regularly report to shareholders on its progress. Failure to do so could trigger a shareholder lawsuit.[91]

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

4. NC CLEAN PATH 2025 – An Economical Clean Energy Future

4.1 Principal Concepts

NC CLEAN PATH 2025 utilizes solar power, the one form of clean energy available to most customers at the point of use, combined with battery storage and maximum energy efficiency and demand response, as the primary electricity supply resources for North Carolinians. The fundamental building block of NC CLEAN PATH 2025 is rooftop, parking lot, and local ground-mounted solar combined with onsite battery storage to allow homes and businesses to auto-supply clean energy and have the capability of autonomous operation for limited periods of time, especially during weather-related grid outages. This framework provides a maximum degree of resiliency compared to the inherent vulnerabilities of the existing grid.[i] The NC CLEAN PATH 2025 target is one million onsite solar systems by 2025.[ii]

Tesla is among the several companies that are rapidly advancing battery storage technology for daily home and business use. Shown are two Tesla Powerwall battery units storing residential solar power. Source: Utility Dive.

Under NC CLEAN PATH 2025, the utility's existing transmission and distribution system will be maintained to assure reliable operation, but not expanded. An expansion of the grid is not necessary to implement NC CLEAN PATH 2025.[iii]

---

[i] These weaknesses include overhead transmission and distribution lines subject to outages due to falling branches, ice, and high winds, and communities served by a single transmission line where an outage can interrupt service to the entire community.

[ii] Onsite solar panels could be on the rooftop, covering the parking lot, or ground-mounted adjacent to the structure. These solar systems are on the customer's side of the customer's electric meter, not on the utility side.

[iii] NC CLEAN PATH 2025 does not concur with the generalized utility viewpoint in the Carolinas that major modernization of the existing transmission and distribution system is necessary to integrate solar and battery storage, as stated in a 2016 report: "A modernization and hardening of the existing infrastructure will allow the integration of new technologies, such as battery storage and microgrids. To participate in the innovation coming to fruition in the electric sector (e.g., solar panels, wind turbines, electric vehicles, battery storage, and microgrids), the Carolinas will require an advanced, integrated grid to manage and optimize the increasingly dynamic flow of electricity." South Carolina Energy Office (SCEO), *Carolinas Energy Planning for the Future*, December 2016, p. 21, https://www.advancedenergy.org/wp-content/uploads/2016/12/SCEO_Carolina_Energy_Report_FINAL-WEB-Copy.pdf.

OFFICIAL COPY

Oct 12 2017

Electric supply reliability will be reinforced by enabling homes and businesses to function autonomously when necessary, especially at times when the transmission or distribution grids are unavailable, and not by expending billions of dollars to harden and expand the existing grid as a presumptive precursor to enabling homes and businesses to function autonomously. There will be a decline in the demand for grid power as point-of-use solar and battery storage substitute for grid power.

As NC CLEAN PATH 2025 is implemented, existing coal-fired power plants will be phased out quickly and natural gas-fired plants will transition to being a backup power supply and be gradually retired. North Carolina nuclear plants will continue to operate through their current operating license terms. No new fossil fuel generators, gas-fired or coal-fired, or new nuclear plants, will be constructed.

Wind power was not included as a component of NC CLEAN PATH 2025 due to siting challenges for utility-scale onshore wind power, the uncertainty that any offshore wind power development will occur by 2025, and the fact that solar power is now cost-competitive with wind power. There is only one utility-scale wind development in North Carolina[i] and the state's Ridge Law effectively prohibits wind power in its mountains.[92] Planning processes are underway that may lead to offshore wind projects, but development of offshore wind power will not be within 24 nautical miles of the North Carolina coastline.[93] This means that major undersea transmission infrastructure will have to be in place before a substantial amount of the offshore North Carolina wind resource can be developed. Furthermore, recent legislation passed by the North Carolina General Assembly has established an 18-month moratorium on new wind projects or expansion of existing projects in the state.[94]

The state of California proposed a similar strategic energy plan almost a decade ago, built around point-of-use rooftop solar and energy efficiency, known as the "*California Energy Efficiency Strategic Plan"* ("California Plan").[95] NC CLEAN PATH 2025 incorporates several key elements of the California Plan. California's implementation of the Plan has only been partially successful because the state continues to build utility-scale, remote solar power at a faster rate than point-of-use rooftop solar.[ii]

[i] Amazon Wind Farm U.S. East in northeastern North Carolina became operational at end of 2016. Ibid.

[ii] A concrete result of the rapid expansion of renewable power in California has been the premature retirement of gas-fired and nuclear plants in the state with no reduction in grid reliability. Two state-of-the-art combined cycle units, 500 MW Sutter and 1,100 MW La Paloma, were mothballed in 2016 due to lack of demand. The state had two nuclear plants, 2,200 MW San Onofre and 2,200 MW Diablo Canyon. San Onofre shut down in 2012 due to a mechanical problem and was never restarted but had no impact on grid reliability. Diablo Canyon will be retired in 2024 by owner Pacific Gas & Electric and any residual need will be met with clean energy resources.

One positive legacy of the California Plan is the state's ongoing commitment to net metered rooftop solar.[i,ii] The state had more than 5,000 MW of net metered solar power at the end of 2016, with 1,266 MW installed in 2016 alone.[96] Another positive legacy of the California Plan is a state building code that requires many state-of-the-art energy efficiency measures in new structures and in retrofits to existing buildings. It also requires that all new buildings be "zero net energy" (ZNE) by 2020.[97] The primary measure used to achieve ZNE is rooftop solar. Both the commitment to net metering and the building code modifications have been incorporated in NC CLEAN PATH 2025.

The current North Carolina strategic energy outlook provided by Duke Energy is "more of the same." DEC and DEP provide about 90 percent of the electricity sold in North Carolina, with DNCP, public municipal utilities, and rural electric cooperatives providing the remainder. Duke Energy is proposing to build a number of new gas-fired units, totaling about 8,000 MW, to meet North Carolina's energy needs over the next fifteen years. The company also proposes to build over 2,000 MW of nuclear capacity, with only a small increase in renewable power, over the same period.[98] As a result, Duke Energy forecasts only a modest GHG emissions improvement over the next decade, followed by increasing GHG emissions as its older nuclear units begin to retire.[99] This is without taking into consideration the substantial GHG impacts of methane leakage from shale and conventional natural gas production and transport.[iii]

Concurrently, Duke Energy is working to dampen the growth of independent solar power in North Carolina. HB589, enacted in July 2017 and reportedly written with significant input from Duke Energy, reduces the size of solar installations eligible for standard contract terms and establishes a process for competitive bidding on new independent utility-scale solar projects. This creates uncertainty for solar developers that have made the growth in NC solar possible. HB 589 also threatens to undercut the favorable net metering policies available to North Carolina by requiring utilities to submit revised net metering rates to the NCUC.[100] These changes could slow the pace of implementing NC CLEAN PATH 2025.

NC CLEAN PATH 2025 will position North Carolina to comprehensively implement the energy strategy proposed but only partially implemented in California nearly a decade ago. North Carolina has already demonstrated it can add solar power at a rapid rate, nearly 1,000 MW per year, and has an established solar industry that can rapidly expand solar capacity in the state.

The solar power that third-party developers in North Carolina have been so successful in installing, typically 1 MW to 5 MW projects covering 6 to 30 acres of land, is financed at the

[i] In California, rooftop solar behind the customer utility meter, known as "behind the meter" solar power, is treated as functionally equivalent to an energy efficiency measure as it reduces the user's demand for grid power.
[ii] Net metered solar power is generated on the customer side of the utility meter and is compensated at the retail electricity rate. It is also known as "behind the meter" solar power.
[iii] See Figure 7.

OFFICIAL COPY

Oct 12 2017

avoided cost of wholesale electricity. This means that Duke Energy customers in North Carolina pay no additional cost for this wholesale solar power above what they pay on average for conventional sources of electricity supply.

Net metered solar systems are paid for by the solar customer. The customer then offsets his/her own energy use at the retail electric rate with this solar power. Despite utility claims to the contrary, net metering imposes no additional costs on utility customers that do not have net metered solar systems. Solar power from these net metered systems benefits non-solar customers by reducing the overall consumption and price of grid-supplied electricity, especially during periods of peak summer demand.

Battery storage can now be added to commercial solar installations in North Carolina at a rate that is cost-competitive and reduces the commercial customer's annual electricity cost by substantially reducing demand charges.[101,i] Residential battery storage is also cost-competitive. Green Mountain Power, an investor-owned utility in Vermont, is offering retail customers 14 kWh battery storage units for $15 per month in 2017.[102,ii] Green Mountain Power is also aggregating the output of these battery storage systems to serve as a virtual peaking power plant.[iii] With reasonable load management, 14 kWh of storage can last on the order of 24 hours in a typical home, depending on the season, with no battery recharge. Utility-scale battery storage was determined by one of California's largest electric utilities, Southern California Edison, to be more cost-effective than a conventional peaking gas turbine in 2014.[103]

Battery storage can be deployed very rapidly. In 2016, 70 MW of utility-scale battery storage was installed in Southern California in six months, from project concept to operation, in response to a potential natural gas supply constraint.[iv]

NC CLEAN PATH 2025 will impose no increased costs on North Carolina electricity consumers for clean energy supply. Net metered solar is now lower cost than retail grid power in North Carolina. The on-bill financing envisioned by NC CLEAN PATH 2025 will allow customers to

---

[i] Demand charge: Charge based on the highest demand, during any 15 to 30 minute interval that is measured in a billing period. Demand charge is typically a fixed charge per kilowatt of demand.

[ii] NC CLEAN PATH 2025 anticipates that all deployed solar inverters will be "battery-ready" to facilitate the addition of battery storage. An example of this type of inverter is the StorEdge™ inverter: https://www.solaredge.com/us/products/storedge#/.

[iii] Green Mountain Power (GMP) was the first utility in the U.S. to offer (Tesla) Powerwalls to customers with a 'no money down' option in a business model that depended on the customer then making some of the batteries' capacity available to the utility to use for grid-balancing or peak demand reduction. Andy Colthorpe, "Tesla launches first aggregated 'virtual power plant' in US," *Energy Storage News*, May 16, 2017, https://www.energy-storage.news/news/tesla-launches-first-aggregated-virtual-power-plant-offering-in-us.

[iv] The companies collectively brought on-line more than 70 MW of energy storage in less than six months. Julia Pyper, "Tesla, Greensmith, AES Deploy Aliso Canyon Battery Storage in Record Time," *GreenTech Media,* January 31, 2017, https://www.greentechmedia.com/articles/read/aliso-canyon-emergency-batteries-officially-up-and-running-from-tesla-green.

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

take advantage of the lower solar cost with no out-of-pocket expense. Less than $1 billion in additional costs for upgrades to distribution grid hardware and distribution substation transformers will be incurred over several years, enabling high levels of distributed solar to flow on the distribution grid.[i] These costs will be a small fraction of the roughly $40 billion that Duke Energy is proposing to spend in the Carolinas over the next decade on new generation and grid projects.[ii,iii]

A key to the success of NC CLEAN PATH 2025 is setting aggressive zero net energy (ZNE) targets and achieving them through a combination of solar, energy efficiency (EE), and demand response (DR). The current North Carolina net metered solar program has no cap and is therefore adequate to enable achievement of aggressive ZNE targets. A rebate program should be implemented if net metered solar capacity additions lag below target levels. Issuing rebates is an available regulatory tool to keep a net metered solar program on track to meet established targets.[iv]

The NC CLEAN PATH 2025 targets, timelines, and clean energy production are shown in Table 14. Twenty-five percent of North Carolina residential and commercial customers achieve ZNE by 2025 under NC CLEAN PATH 2025. This is equivalent to approximately 1 million customer solar systems by 2025.[v] This increases to 50 percent of residential and commercial customers by 2030. Industrial customers reduce energy usage by 25 percent by 2025. Residential and commercial building net metered solar installations average about 2,000 MW per year from 2018 through 2025, and increase to an average of about 3,000 MW per year from 2026 through 2030.

NC CLEAN PATH 2025 includes battery systems with all residential and commercial customer solar systems. The average amount of battery storage capacity is assumed to be the residential battery storage "standard" in 2017, the 14 kWh Tesla Powerwall™ battery storage system.[vi] Assuming 25 percent of North Carolina residential and commercial customers achieve ZNE in 2025 with an average of 14 kWh of battery storage each, that total amount of battery-stored

---

[i] See Chapter 7 for a complete discussion of this issue.

[ii] Total North Carolina energy grid investment over 10 years, $13 billion. Duke Energy, *Power/Forward Carolinas Fact Sheet - Building a Smarter Energy Future*, April 2017.

[iii] Herman K. Trabish, "Utilities in hot water: Realizing the benefits of grid-integrated water heaters," *Utility Dive*, June 20, 2017, http://www.utilitydive.com/news/utilities-in-hot-water-realizing-the-benefits-of-grid-integrated-water-hea/445241/. "DR and storage can result in the very real benefit of helping utilities avoid the $1,000 per kW cost of a peaker plant." 5,000 MW x $1,000/kW x 1,000 kW/MW = $5 billion.

[iv] The South Carolina net metered solar program includes an incentive payment of $1 per watt of residential net metered solar capacity. Duke Energy press release, *Duke Energy solar rebate program exceeding expectations in South Carolina one year after launch*, September 22, 2016, https://news.duke-energy.com/releases/duke-energy-solar-rebate-program-exceeding-expectations-in-south-carolina-one-year-after-launch.

[v] See Chapter 8, Table 32.

[vi] In addition to Tesla, there are several other companies providing lithium battery storage systems for homes and businesses, including 1) Tabuchi (http://www.tabuchiamerica.com/news/what%E2%80%99s-included-price-your-home-battery-system), 2) Sonnen (https://www.sonnen-batterie.com/en-us/start), and 3) LG (http://www.lgchem.com/global/ess/ess/product-detail-PDEC0001).

electricity in North Carolina homes and businesses would be about 17.6 million kWh,[i] or about 17,600 MWh. This amount of storage would have the potential to discharge 5,000 MW of electricity to meet peaking power demand.

Table 14. NC CLEAN PATH 2025: Targets, Timelines, and Clean Energy Production

Category	**Targets**	**Target date**	**2025 reduction** **in GWh per year**	**2030 reduction** **in GWh per year**
Residential	New: all zero net energy (ZNE)	2018	14,476 (9,200 MW)	28,952 (18,400 MW)
	Existing: • 25 percent ZNE • 50 percent ZNE	 2025 2030		
Commercial	New: all ZNE	2018	12,059 (7,600 MW)	24,118 (15,300 MW)
	Existing: • 25 percent ZNE • 50 percent ZNE	 2025 2030		
Industrial	Reduce energy intensity by 25 percent	2025	6,925	6,925
Total			33,460	59,995

An important additional component of NC CLEAN PATH 2025 is a 50 percent reduction in the electricity demand of heating, ventilation, and air conditioning (HVAC) systems within 10 years of plan implementation. The steps necessary to achieve this HVAC reduction target are described in Chapter 8.

NC CLEAN PATH 2025 allocates 30 percent of total installed solar capacity to urban utility-scale and brownfield solar in the 1 MW to 5 MW size range. This is an extension of the current successful North Carolina wholesale solar development program, with focus on locating these projects in urban settings and contaminated brownfields. This translates into approximately 6,300 MW (10,000 GWh) of new urban utility-scale and brownfield solar by 2025, and 11,400 MW (18,000 GWh) by 2030. This is an average installation rate of 1,000 MW per year, consistent with the actual North Carolina installation rate for 1 MW to 5 MW solar projects of 923 MW in 2016.[104]

There has been minimal electricity demand growth in NC over the last decade, despite a steady population growth rate of 1.2 percent over the same time period.[i] Total North Carolina electricity

[i] Chapter 8, Table 32, total residential and commercial customers in North Carolina in 2015 = 5,030,229. Twenty-five percent of this customer base = 5,030,229 customers x 0.25 = 1,257,557 customers. 1,257,557 customers x 14 kWh/customer = 17,605,802 kWh (17,605 MWh).

OFFICIAL COPY
Oct 12 2017

consumption in 2007 was 131,880 GWh.[105] Total consumption in 2015 was 133,847 GWh.[106] This represents an average electricity demand growth rate of less than 0.2 percent.[ii] It is reasonable to assume little real growth in electricity demand by 2025 or 2030, based on the actual trend over the last decade and continued development of energy efficiency technologies and practices. In any case, under NC CLEAN PATH 2025 all new construction will be ZNE and will not add incremental demand for grid power.[iii] New residential construction that cannot add solar due to shading or other constraints can co-own an off-site community solar array, while commercial developments can build larger, wholly-owned, off-site solar arrays on suitable nearby vacant land to achieve ZNE.

NC CLEAN PATH 2025 will reduce reported GHG emissions from electricity consumption in North Carolina by approximately 57 percent by 2025, as shown in Table 15. GHG emissions from grid power will be 100 percent offset by 2030, at least on a net basis.[iv] It is expected that electric vehicle use will steadily expand in North Carolina. The definition of ZNE used in this report includes electric vehicle loads at homes and businesses. Onsite solar systems combined with energy efficiency measures at the point of use will accommodate electric vehicle loads and maintain the ZNE balance.

North Carolina electricity demand in 2015 was 133,847 GWh.[107] Of this total, 76,900 GWh was produced by GHG-emitting coal-, natural gas-, and oil-fired power plants.[108] As shown in Table 15, NC CLEAN PATH 2025 will displace about 57 percent of this coal- and gas-fired power by 2025 and 100 percent by 2030.

---

[i] Population July 1, 2015 = 10,042,802 (See U.S. Census Quick Facts North Carolina: https://www.census.gov/quickfacts/table/PST045215/37. Population July 1, 2007 = 9,090,572 (See NC Budget and Management, Facts & Figures: https://ncosbm.s3.amazonaws.com/s3fs-public/demog/nctrend14.html). Population growth rate between 2007 and 2015 = 9,090,572 x $(1 + 0.012)^8$ = 10,000,813 [1.2 percent annual population growth, 2007 – 2015].

[ii] 131,880 GWh × $(1 + 0.002)^8$ = 134,005 GWh.

[iii] The most expeditious way to achieve this objective would be to update the North Carolina Building Code to include this requirement for new construction built in 2020 or later. See: https://www.energycodes.gov/adoption/states/north-carolina. As an example, beginning in 2020, new residential construction in California must be zero net energy: http://www.title24express.com/what-is-title-24/.

[iv] Some fossil fuel generation will be necessary when 100 percent GHG reduction is achieved, primarily during extended periods of inclement weather when solar, hydro and existing nuclear generation, along with battery and pumped storage, are insufficient to meet demand. At other times, especially spring and fall when heating and cooling demand is low, excess renewable power will be generated beyond what is needed to meet in-state demand. This excess generation will be exported to neighboring states or curtailed.

OFFICIAL COPY

Oct 12 2017

Table 15. Rate of Displacement of North Carolina Coal- and Gas-Fired Power under NC CLEAN PATH 2025

Year	Coal-& gas-fired power (GWh)	Residential ZNE (GWh)	Commercial ZNE (GWh)	Industrial EE (GWh)	Urban/ brownfield large solar (GWh)	Total ZNE, EE, large solar (GWh)	Reduction coal/gas power (percent)
2015	76,900	base case	base case	base case	base case	base case	0
2025	33,440	14,476	12,059	6,925	10,000	43,460	57
2030	0	28,952	24,118	6,925	18,000	77,995	100+

4.2 Cost of NC CLEAN PATH 2025

NC CLEAN PATH 2025 is less costly than the conventional utility alternative, as shown in Table 16. The lower cost of electricity under NC CLEAN PATH 2025 is described in detail in Chapter 6. The retail cost of electricity will be lower for customers, due to the lower cost of solar and EE measures relative to current retail utility electricity rates. As noted, on-bill financing will be utilized to allow customers to add solar and EE with no upfront expense and no increase in electricity charges.[i]

Going forward, NC CLEAN PATH 2025 will avoid $40 billion in grid additions and power plant construction proposed over the next decade by Duke Energy, at least the portion that would serve customers in the North Carolina part of the two-state service areas (NC has approximately 70 percent of the DEC and DEP customers). This in turn will keep rates, which would otherwise relentlessly rise to pay for the transmission and generation infrastructure, stable and predictable. More investment will be made in EE and DR programs than under current utility practice in North Carolina. These investments are described in detail in Chapter 9.

The Duke Energy costs shown in Table 16 include the construction of two new 1,117 MW nuclear units proposed by the company for 2027 and 2029, which constitute more than half of the new capital expenditures Duke Energy is proposing over its 15-year planning horizon.[109] It should be noted that the investments in power plants and pipelines in the Duke Energy column are shared between North and South Carolina, whereas grid investments are for North Carolina only. NC CLEAN PATH 2025 addresses only North Carolina costs.

[i] See Chapter 9 for a more detailed discussion of on-bill financing.

OFFICIAL COPY Oct 12 2017

Smart meter data will enable the most effective EE and DR strategies by identifying the least efficient users of electricity and concentrating upgrade programs on these customers.[i] Investments in grid operations and maintenance will remain unchanged.[110]

Nominal distribution grid upgrades will be necessary under NC CLEAN PATH 2025 to maximize the development of local solar resources. Local solar and battery storage resources will become the backbone of the electricity supply system. For this reason, no transmission and distribution system investments will be needed beyond those required to maximize local solar power flows on the distribution systems and to maintain the existing North Carolina transmission and distribution grids in reliable condition. No new natural gas-fired power plants will be constructed under NC CLEAN PATH 2025.[ii] Existing natural gas- and coal-fired units will be steadily displaced by solar power, battery storage, EE, and DR.

Table 16. Comparison of Cost: NC CLEAN PATH 2025 and Duke Energy Alternative[iii]

Cost Category	NC CLEAN PATH 2025	Duke Energy
Cost of electricity	Less than utility retail rate	Utility retail rate
EE & DR	$450 million per year	$120 million per year
Smart meters	$0.5 billion	$0.5 billion
Grid maintenance	$1 billion per year	$1 billion per year
Grid upgrades	Less than $1 billion (distribution grid upgrades)	$13 billion over ten years (NC only)
New gas-fired power plants	$0	$5 billion (NC & SC)*
New nuclear plants	$0	$20 billion (NC & SC)*
Atlantic Coast Pipeline	$0	$2.5 billion (NC & SC)**

* Duke Energy electricity sales in NC are about four times those in SC. However, much of the proposed new gas-fired and nuclear generation will be located in SC.

** Shale gas transported on this pipeline will serve Duke Energy gas-fired generation in NC and SC.

[i] Total North Carolina energy grid investment over 10 years, $13 billion. Smart meter component, $549 million. Duke Energy, *Power/Forward Carolinas Fact Sheet - Building a Smarter Energy Future*, April 2017.

[ii] Duke Energy investment in new natural gas-fired generation, 2017-2026, will be approximately $5 billion. DEC, 2016 IRP, Table 8-G, p. 49 and Table 8-I, p. 51 (new DEC gas turbine capacity by 2021, and joint DEC+DEP capacity by 2026 = 4,187 MW); DEP, 2016 IRP, Table 8-G, p. 49 (new DEP gas turbine capacity by 2021 = 726 MW).

[iii] Note that the Duke Energy column of this table includes maintenance and upgrade for the Duke-owned grid only, not grid expenditures by municipal and cooperative utilities. The corresponding NC CLEAN PATH 2025 figures include coop and muni territories (see Chapter 7 for more on grid upgrades).

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

4.3 Job Creation and Other Economic Benefits of NC CLEAN PATH 2025

NC CLEAN PATH 2025 will add substantially more jobs, spread across the state, and add them in less time than Duke Energy's plans.

NC CLEAN PATH 2025 will create at least 50 percent more jobs, in more parts of the state and in less time, than the conventional utility alternative advanced by Duke Energy. The solar installation rate under NC CLEAN PATH 2025 will increase from the current level of approximately 1,000 MW per year to 3,000 MW per year in 2020. This represents an increase in direct solar jobs in the state of about 14,000 by 2020.[i] Investments in EE and DR will increase from about $120 million per year to about $450 million per year. This represents an increase in direct EE jobs of about 2,000 per year.[ii] A total of approximately 16,000 new direct solar and EE jobs will be created. Total jobs created, including direct and indirect jobs, would be about double the quantity of direct jobs, or about 32,000 jobs.[iii] The total economic investment will be on the order of $3.3 billion per year.[iv]

In contrast, the proposed $13 billion Duke Energy Power/Forward Carolinas ten-year energy grid modernization program would add 7,000 direct jobs.[111] Duke Energy's proposed natural gas-fired gas turbine construction program over the next ten years would add approximately 5,000 MW of capacity at an estimated cost of about $5 billion.[112] The natural gas-fired power plant construction program represents about 2,800 direct new jobs, based on an interpolation of the Power/Forward Carolinas investment-to-direct jobs ratio.[v] Duke Energy's grid modernization and power plant construction programs would create about 10,000 new direct jobs. Total direct

---

[i] Solar installed in 2016 = 994.8 MW. Solar jobs in 2016 = 7,112. Approximate ratio of direct jobs to installed solar capacity = 7,000 direct jobs per 1,000 MW. Solar Energy Industries Association, "State Solar Policy – North Carolina Solar," accessed May 2, 2017, http://www.seia.org/state-solar-policy/north-carolina.

[ii] Direct job creation per $1 million in output = 7.0. Therefore, assuming $330 million per year increase in EE spending in North Carolina, 7.0 direct jobs per $1 million x $330 million/yr = 2,310 direct jobs. Center for American Progress, *The Economic Benefits of Investing in Clean Energy*, June 2009, Table 4 – building retrofits, p. 28.

[iii] Powers Engineering assumes the ratio of direct-to-indirect new jobs will be approximately one-to-one, consistent with the assumption in the Duke Energy, *Fact Sheet Power/Forward Carolinas - Investing in North Carolina's Energy and Economic Future*, March 2017.

[iv] Average cost of solar capacity is $1.50/watt. See Chapter 6. Installed capital cost of the added 2,000 MW per year of solar is: $1.50/W x 2,000 MW/yr x 10^6 W/MW = $3 x 10^9/yr ($3 billion/yr). The increase in EE spending will be: $450 million/yr - $120 million/yr = $330 million/yr ($0.3 billion/yr).

[v] ($5 billion ÷ $13 billion) x 7,272 direct jobs = 2,797 direct jobs.

and indirect jobs would be about double the quantity of direct jobs, or approximately 20,000 jobs.[i]

Duke Energy assumes that the number of indirect new jobs created by its Power/Forward Carolinas grid modernization spending will be roughly equivalent to the number of direct new jobs created. That same one-to-one ratio of indirect to direct new jobs is assumed for NC CLEAN PATH 2025 in Table 17.

In addition to jobs created by the installation, maintenance, and manufacturing of solar and battery systems, there are direct benefits to landowners who lease their property to solar developers. Solar installations are seen as a "cash crop" for family farmers. Local governments also benefit from an increased tax base. The solar and EE jobs will be distributed around the state instead of being concentrated around a few central power stations.

Table 17. Comparison of Jobs Created: NC CLEAN PATH 2025 and Duke Energy[113,114,115]

	NC CLEAN PATH 2025	**Duke Energy**
Direct new jobs	Solar approx. 14,000 *(7,000 per 1,000 MW per year installed solar capacity, increased by 2,000 MW per year)* Energy Efficiency approx. 2,000 *(7 per $1 million in annual output, increased by $330 million per year)*	approx. 10,000 (grid modernization and new gas-fired capacity)
Period over which direct new jobs are added	3 years	10 years
Additional indirect new jobs (in the community)	approx. 16,000 (Duke Energy direct:indirect ratio approx. 1:1)	approx. 10,000

4.4 Conditions and Policies Most Conducive to Implementation of NC CLEAN PATH 2025

The establishment of solar and battery storage targets is an essential framework for NC CLEAN ENERGY 2025. In 2007 California established a ten-year target of 3,000 MW of net metered solar and achieved that target in 2014, three years early. The program is no longer supported by state incentives, and it reached an installation rate of ~1,000 MW per year in 2016.

[i] Powers Engineering assumes the ratio of direct-to-indirect new jobs will be approximately one-to-one.

OFFICIAL COPY
Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Numerous states have also established targets for energy storage systems. Massachusetts must procure 200 MWh of energy storage by January 1, 2020, to meet the target set by the state Department of Energy Resources.[116] California set the largest storage target in 2013 at 1,300 MW by 2020. Nevada passed legislation in June 2017 for an energy storage incentive. Maryland has a 30 percent tax incentive for storage facilities. New York has passed legislation mandating state agencies to develop an Energy Storage Deployment Program and include a storage procurement target for 2030.[117]

NC CLEAN PATH 2025 assumes the following: 1) customers will own their onsite solar and battery storage, 2) on-bill financing programs will be established to allow customers to add solar, storage, DR, and EE at no upfront cost and with a net reduction in monthly bills, and 3) DR and EE must be opt-out programs to assure maximum customer participation.

The following market conditions that already exist will promote the success of NC CLEAN PATH 2025: 1) rooftop solar generation is less costly than the retail price of electricity and the cost of solar continues to decline, 2) large-scale solar generation is no more costly than the wholesale price of electricity and the cost continues to decline, and 3) onsite battery storage is cost-effective now if customers receive fair market value for the grid reliability attributes of storage, and battery storage costs continue to decline.

A utility's structure will be critical to the success of NC CLEAN PATH 2025. Three utility structures could be used to implement NC CLEAN PATH 2025, in the following order of likely effectiveness: 1) municipal utility or rural cooperative, 2) community choice aggregation (CCA), and 3) IOU with B Corporation certification.

OFFICIAL COPY

Oct 12 2017

5. Cost of Solar Power and Gas-Fired Generation

Residential and commercial rooftop solar is cost-competitive in 2017 with North Carolina retail electricity rates. Commercial solar with batteries, by allowing customers to shift demand to off-peak hours and by reducing utility demand charges, is also economical in North Carolina in 2017. Residential solar with batteries, by allowing customers to shift demand to off-peak hours and by displacing combustion turbines as sources of reserve grid power, is economical in North Carolina in 2017. Consumers in 2017 can select from among multiple battery storage providers for commercial and residential solar systems. Large-scale solar with batteries is already more cost-effective than all forms of new gas-fired generation. Net metered solar projects with energy storage have the added benefit of providing onsite reserve power to assure supply reliability during grid power interruptions.

5.1 Solar Power Cost of Energy

Residential and commercial solar photovoltaic (PV) systems qualify for a maximum 30 percent federal tax credit through 2021.[i] Commercial PV systems also qualify for accelerated depreciation of the capital invested in the PV system. Each of these financial benefits has a substantial impact on lowering the cost of the produced solar energy.

5.1.1 Commercial Onsite Solar

The 100 kW commercial rooftop system example shown in Tables 18a and 18b, for cash purchase and financed PV systems, respectively, demonstrates the financial impact of tax credits and accelerated depreciation on the net cost of a commercial PV system. Assuming 4th quarter 2017 best-in-class North Carolina pricing of $1.80 per watt direct current (dc), the levelized cost of electricity from the system as a cash purchase would be $0.037 per kilowatt-hour (kWh), and $0.050/kWh for the system financed over 20 years at 5 percent annual interest. This commercial net metered solar production cost range of $0.037/kWh to $0.050/kWh is substantially below the 2015 average retail commercial electricity cost in North Carolina of $0.0873/kWh.[118] It is also below the Energy Information Administration projected production cost of electricity of $0.059/kWh from a new combined cycle natural gas-fired power plant.[ii]

[i] The solar investment tax credit is 30 percent through 2019, 26 percent in 2020, and 22 percent in 2021. The investment tax credit drops to 10 percent for commercial solar systems after 2021, and is eliminated for residential systems after 2021. Solar Energy Industries Association, "Impacts of Solar Investment Tax Credit Extension," http://www.seia.org/research-resources/impacts-solar-investment-tax-credit-extension.
[ii] See Table 22.

Table 18a. Cost of Electricity for 100 kW Commercial Rooftop PV System, Cash Purchase

Cost or (Credit), $	Cost Element
$180,000	Gross cost of 100 kW_{dc} rooftop solar system @ $1.80/watt (dc)
--	State incentive payment expired December 31, 2015
($54,000)	30 percent federal tax credit on gross cost
($62,424)	Federal tax depreciation on gross cost less 1/2 tax credit: ($180,000 - $27,000) × 35% marginal tax rate = $53,550 + State tax depreciation on gross cost less 1/2 tax credit: ($180,000 - $27,000) × 5.8% marginal tax rate = $8,874
$63,576	Net cost of PV system
$3,179/yr	Annual cost of system, cash transaction, 20-year financial life: $63,576 ÷ 20 years = $3,179/yr
$2,000/yr	Annual fixed O&M, $20/kW-year[119]
141,516 kWh/yr	Annual electricity production, fixed solar array, Raleigh, NC (source: NREL PV Watts calculator)
$0.037/kWh	Cost of solar electricity: ($5,179/yr ÷ 141,516 kWh/yr = $0.037/kWh
$0.0873/kWh	Average NC utility commercial cost of electricity, 2015

Table 18b. Cost of Electricity for 100 kW Commercial PV System, Financed at 5 Percent, 20-Year Term

Cost or (Credit), $	Cost Element
$180,000	Gross cost of 100 kW_{dc} rooftop solar system @ $1.80/watt (dc)
--	State incentive payment expired December 31, 2015
($54,000)	30 percent federal tax credit on gross cost
($62,424)	Federal tax depreciation on gross cost less 1/2 tax credit: ($180,000 - $27,000) × 35% marginal tax rate = $53,550 + State tax depreciation on gross cost less 1/2 tax credit: ($180,000 - $27,000) × 5.8% marginal tax rate = $8,874
$63,576	Net cost of PV system
$5,099/yr	Annual cost of system, 20-year, 5 percent financing, capital recovery factor = 0.0802 per year: $63,576 x 0.0802/yr = $5,099/yr
$2,000/yr	Annual fixed O&M, $20/kW-year
141,516 kWh/yr	Annual electricity production, fixed solar array, Raleigh, NC (source: NREL PV Watts calculator)
$0.050/kWh	Cost of solar electricity: $7,099/yr ÷ 141,516 kWh/yr = $0.050/kWh
$0.0873/kWh	Average NC utility commercial cost of electricity, 2015

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

5.1.2 Residential Solar

Accelerated depreciation is not available for customer-owned residential solar systems. Assuming 4th quarter 2017 best-in-class North Carolina pricing of \$2.50 per watt dc,[i] the cost of electricity from the system assuming a cash purchase would be \$0.076/kWh, as shown in Table 19a. It would be \$0.113/kWh for the same system financed over 20 years at 5 percent annual interest, as shown in Table 19b. This residential solar system production cost range, \$0.076/kWh to \$0.113/kWh, is at or below the average retail residential electricity cost for IOUs in North Carolina in 2015 of \$0.113/kWh.[120] Note that retail rates for the cooperative and municipal utilities are typically higher than IOU retail rates.[121]

Table 19a. Cost of Electricity for 6 kW Residential Rooftop PV System, Cash Purchase

Cost or (Credit), $	Cost Element
\$15,000	Gross cost of 6 kW_{dc} rooftop solar system @ \$2.50/watt (dc)
--	State incentive payment expired December 31, 2015
(\$4,500)	30 percent federal tax credit on gross cost
\$10,500	Net cost of PV system
\$525/yr	Annual cost of system, cash transaction, 20-year financial life: \$10,500 ÷ 20 years = \$525/yr
\$120/yr	Annual fixed O&M, \$20/kW-year[122]
8,491 kWh/yr	Annual electricity production, fixed solar array, Raleigh, NC (source: NREL PV Watts calculator)
\$0.076/kWh	Cost of solar electricity: \$645/yr ÷ 8,491 kWh/yr = \$0.076/kWh
\$0.113/kWh	Average NC utility residential cost of electricity, 2015

[i] Solar panels produce direct current electricity. The electric grid, and all standard appliances, are designed for alternating current electricity (alternating current is produced by spinning electric generators at conventional power plants). For this reason, power from solar panels is modified from direct current to alternating current in an inverter. This process involves some losses. As a result, the alternating current capacity rating of solar PV system is somewhat lower, on the order of 10 percent, than the direct current capacity of the system.

Table 19b. Cost of Electricity for 6 kW Residential PV System, Financed at 5 Percent, 20-Year Term

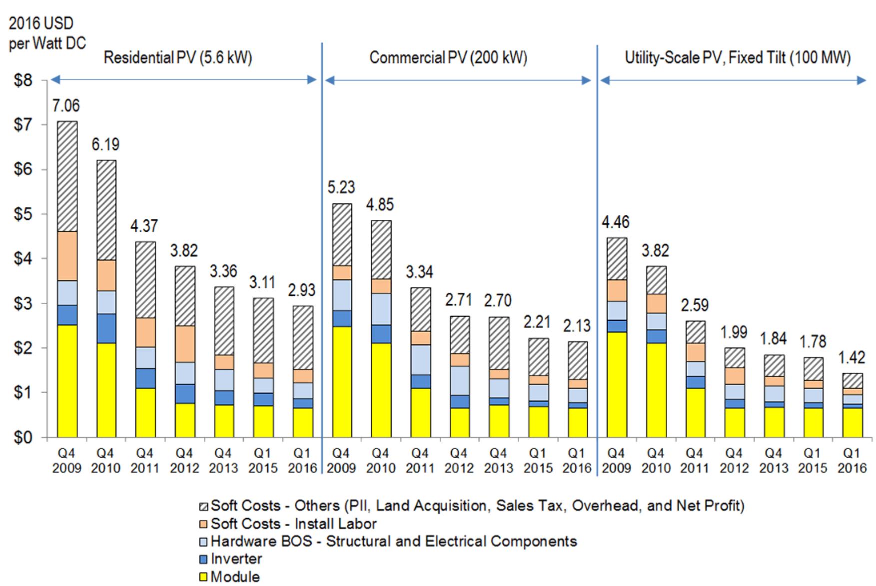
Cost or (Credit), $	Cost Element
$15,000	Gross cost of 6 kW_{dc} rooftop solar system @ $2.50/watt (dc)
--	State incentive payment expired December 31, 2015
($4,500)	30 percent federal tax credit on gross cost
$10,500	Net cost of PV system
$842/yr	Annual cost of system, 20-year, 5 percent financing, capital recovery factor = 0.0802 per year: $10,500 × 0.0802/yr = $842/yr
$120/yr	Annual fixed O&M, $20/kW-year
8,491 kWh/yr	Annual electricity production, fixed solar array, Raleigh, NC (source: NREL PV Watts calculator)
$0.113/kWh	Cost of solar electricity: $962/yr ÷ 8,491 kWh/yr = $0.113/kWh
$0.113/kWh	Average NC utility residential cost of electricity, 2015

5.1.3 Rapid Decline Rate of Solar Pricing

The costs of solar systems have continued to decline at an average rate of approximately 5 to 10 percent per year in all solar categories, as shown in Figure 8 through the first three months of 2016.

Figure 8. NREL Modeled Solar PV Cost Decline, 4th Quarter 2009 through 1st Quarter 2016

(source: NREL)[123]



OFFICIAL COPY
Oct 12 2017

OFFICIAL COPY

Oct 12 2017

The costs per watt shown in Figure 8 are a "bottom up" modeled cost based on expected current costs for each of the elements contributing to the overall cost. Regional pricing varies from the National Renewable Energy Laboratory (NREL) modeled cost forecast, and "best-in-class" pricing can be lower than indicated in Figure 8 for a variety of reasons. The projected 4th quarter 2017 modeled solar costs (rounded to nearest 10 cents per watt) are shown in Table 20, and are based on 1) the most recent two-year average cost decline shown in Figure 8 for each solar category and 2) confirmation by a North Carolina solar industry representative. The commercial solar projected pricing assumes an approximate 50/50 split between rooftop and parking lot installations. Parking lot installations are assumed to average $0.50 per watt (dc) more than rooftop installations.[124]

Table 20. Projected 4th Quarter 2017 Modeled Solar Pricing, Based on Most Recent Two Years of NREL Modeled Pricing Data

Solar category	Projected Q4 2017 pricing ($/$W_{dc}$)
Residential	2.50
Commercial	1.80
Utility-scale	1.20

5.1.4 Utility-Scale Solar Farms Meet Wholesale Grid Power Cost

Large solar projects that interconnect directly to the Duke Energy transmission system are compensated at the avoided cost of wholesale electric power. "Avoided cost" means the cost to the utility to generate the same amount of power. The current avoided cost in North Carolina ranges from $0.055/kWh to $0.08/kWh.[125] This avoided cost payment level has been sufficient, due to sharply declining solar costs, to spur a rapid increase in North Carolina wholesale solar projects in the 1 MW to 5 MW range over the last few years. However, the state enacted legislation in July 2017 that will replace the standard avoided cost payment contract to solar developers and establish a competitive bidding process under which payments to solar projects will be based on rates negotiated with the utilities.[126] This legislation, HB589, also will require that each electric public utility propose revised net metering rates for its customers.[127]

5.2 New Gas-Fired Generation Costs

The capital cost of natural gas-fired generation, both simple cycle combustion turbines and combined cycle power plants, has been relatively unchanged over the last eight years. As shown in Table 21, there was almost no change between 2009 and 2014, which is to be expected since these are mature technologies.

OFFICIAL COPY

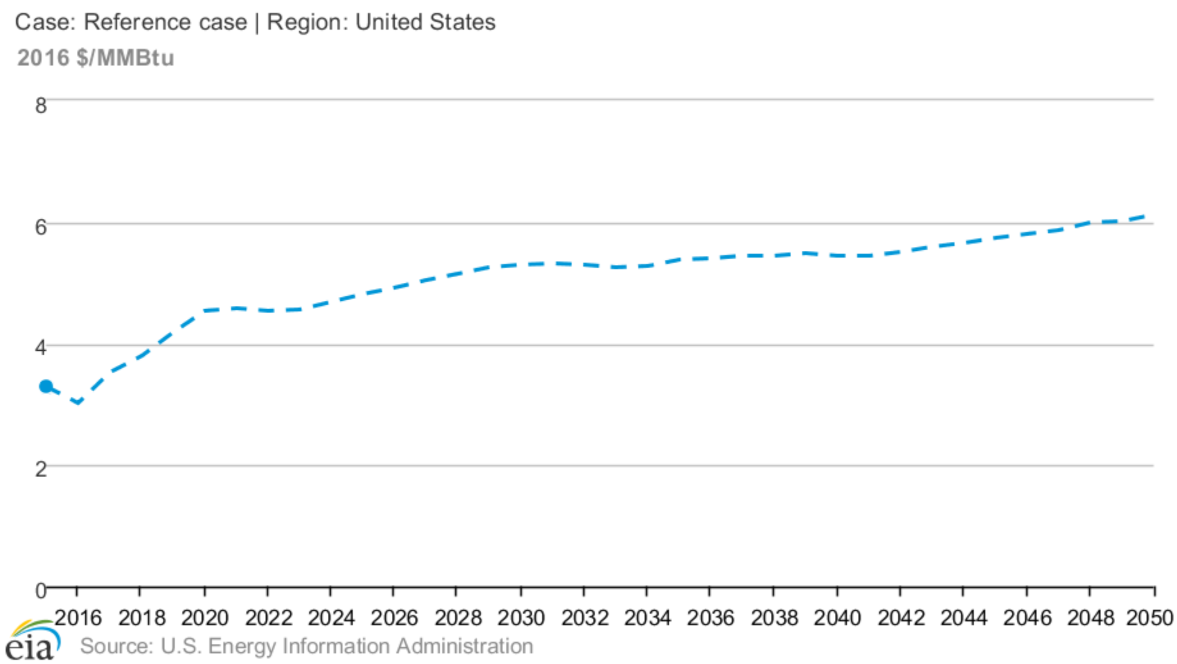
Oct 12 2017

Table 21. Capital Cost of Simple Cycle Combustion Turbines and Combined Cycle Power Plants, 2009 and 2014

Gas turbine technology	2009[128] ($/kW)	2014[129] ($/kW)
Simple cycle – aeroderivative, 100 MW	1,231	1,200
Combined cycle – conventional, 500 MW	1,095	1,125

The primary cost associated with gas turbine power plants is fuel.[130] Natural gas costs reached historic low levels in the U.S. in recent years, driven by shale gas production, resulting in low production costs for the baseload combined cycle power plants. However, current projections are that natural gas prices will steadily increase over the next two decades, as shown in Figure 9.

Figure 9. Forecast Cost of Natural Gas for Electric Power Generation, 2016 – 2036
(source: EIA)[131]



The Energy Information Administration (EIA) has forecast the levelized cost of electricity from both conventional combined cycle and combustion turbine power plants entering service in 2022, based on natural gas price projections for 2022.[132] EIA projects that the cost of natural gas for electric power generation will increase from approximately $3 per million British thermal units (MMBtu) in 2016 to approximately $5/MMBtu in 2022 as shown in Figure 9. The gas turbine levelized cost projections are shown in Table 22.

OFFICIAL COPY

Oct 12 2017

Table 22. EIA Levelized Cost of Energy from New Combined Cycle and Combustion Turbine Power Plants in 2022[133]

Gas turbine technology	Levelized cost of energy, $/kWh
Combined cycle	0.059
Combustion turbine	0.101

The levelized cost of generation from a new combined cycle unit in 2022 of $0.059/kWh is significantly greater than the levelized cost of generation of $0.055/kWh from a new North Carolina commercial rooftop solar array financed by the system owner in 2017, as shown in Table 18b. The levelized cost of generation from a new combustion turbine in 2022 of $0.101/kWh is double the levelized cost of generation from a commercial rooftop solar array of $0.055/kWh in 2017.

5.3 Solar Power with Battery Storage Cost of Energy

Battery storage has value to the grid as reserve power available for use at times of peak need or in emergencies. This role has been filled by combustion turbines in recent decades. The same charges assessed to utility customers to maintain a fleet of combustion turbines available when needed are directly applicable to battery storage systems. Battery storage has advantages over combustion turbines, including very fast response to a dispatch command, the ability to store renewable energy, and the ability to operate completely on solar power for supply when operated behind the meter of a solar-powered residence or commercial building.

Utility customers pay substantial charges to assure that peaking combustion turbines are available when needed. Duke Energy is proposing to build approximately 4,000 MW of new peaking combustion turbine capacity in North Carolina over the next fifteen years.[i] These units typically operate only during periods of peak demand or when more efficient generators are offline for planned or unplanned outages. Utility customers pay a capacity charge to cover the cost of building and maintaining these peaking/backup units. A representative charge for new peaking combustion turbine capacity in North Carolina is $100 per kW per year.[134]

It is assumed below that battery storage associated with a commercial solar project will be used only to shift the individual customer's load on a continuous basis to reduce time-of-use (TOU) charges and minimize peak load (to reduce standby charges) and not as reserve capacity for utility dispatch.[ii] Therefore, no capacity credit is included in the commercial solar with batteries

[i] See Tables 4 and 5.

[ii] TOU tariffs have different rates at different times of the day, week, and season that reflect higher and lower demand periods. Standby charges (also called demand charges) are additional monthly fees typically assessed based on the peak 15-minute usage rate each month, intended to compensate the utility for maintaining enough

cost-of-production calculations in Tables 23a and 23b as these systems may not be available to provide peaking power to the grid. This same approach may be used with residential solar with batteries, as TOU rates with standby charges are also available to residential customers.[135]

However, for simplicity in this analysis, it is assumed that the residential customer is on a flat rate residential service tariff and that battery storage associated with residential solar systems will be used as reserve capacity for dispatch by the utility when needed. A storage capacity credit of $100 per kW is applied to the "residential solar with battery storage" cost of production calculations in Tables 24a and 24b.

In reality, both the commercial and residential solar with battery rates could include TOU, standby charge, and capacity payments for some or all of the battery storage capacity. For this type of contract to be equitable, the determination of the monthly standby charge and TOU charges would not include any periods when the utility was exercising its option to utilize the battery storage system to absorb or discharge electricity.[i]

The commercial example assumes 50 kW of battery storage for 5 hours (250 kWh) at an installed cost of $58,000.[ii] This is equivalent to a battery storage cost of approximately $230/kWh.[iii] The residential example assumes 14 kWh of battery storage with peak battery output of 3 kW at an installed cost of $7,000.[iv,v]

---

capacity to supply customers with power under a maximum demand scenario. Only customers on TOU billing incur standby charges. Most NC residential customers are currently on flat-rate billing instead.

[i] For example, the utility exercises its option to absorb power during a hot summer afternoon using the residential customer's battery storage system, when the solar-powered residence would normally be drawing no power from the grid. The utility action creates a substantial spike in demand, higher than the customer would see when the system is being used only to balance the demand of the residence. That spike in demand would normally serve as the basis for the utility setting the customer's monthly standby charge. However it was utility action, and not the decision of the customer, that caused the spike in demand to occur. Therefore the customer should not be penalized for the utility's action.

[ii] "The battery cost numbers used for the cost benefit analysis are based on recently quoted prices to the utility for 250 kWhr and 500 kWhr sized storage systems which were $58k and $128k respectively." $58,000 ÷ 250 kWh = $232/kWh. PEPCO Holdings, Inc. et al, *Model-Based Integrated High Penetration Renewables Planning and Control Analysis Final Report*, DOE Award Number: DE-EE0006328, December 10, 2015, p. 16: https://www.osti.gov/scitech/servlets/purl/1229729.

[iii] The battery storage cost of $230/kWh was corroborated by McKinsey & Company in June 2017. David Frankel and Amy Wagner, McKinsey & Company, "Battery storage: The next disruptive technology in the power sector," June 2017, http://www.mckinsey.com/business-functions/sustainability-and-resource-productivity/our-insights/battery-storage-the-next-disruptive-technology-in-the-power-sector.

[iv] Tesla Powerwall webpage, accessed June 11, 2017: https://www.tesla.com/powerwall#design. Battery capacity = 14 kWh, installed cost of single residential unit = $7,000.

[v] DEP 2016 IRP, p. 114. DEP demand response activation period, to offset peak demand, is 4 hours. A 4-hour duration is assumed in this report as the design duration for battery storage operating as peaking power capacity. The Tesla Powerwall can maintain an output of approximately 3 kW over a 4-hour period.

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

5.3.1 Commercial Solar Power with Battery Power

Commercial utility customers can select a TOU rate with a monthly standby charge. An onsite battery pays for itself under such a rate structure by shifting load at hours of peak charges to hours of lower rates, and by reducing the peak demand reached during the month, which reduces the standby charge. There is no need for an incentive payment for a battery system to be an economic benefit when integrated with a commercial PV system.

The National Renewable Energy Laboratory (NREL) in 2015 evaluated the cost-effectiveness of battery systems at commercial buildings in Knoxville, TN, and Los Angeles, CA, to determine if they provided a net cost benefit by shifting load to off-peak hours and reducing the monthly standby charge by reducing peak demand for grid power at the facility.[136]

The NREL study found that a commercial solar PV with battery system was cost-effective in Los Angeles compared to retail grid power, and that a battery system by itself was cost-effective in Knoxville. However, the analysis assumed an obsolete solar cost of $3.52 per watt (dc), about double the projected 4thquarter 2017 North Carolina commercial solar pricing of $1.80 per watt (dc) used in this report. Solar prices have continued to fall rapidly since the NREL study was published. A commercial solar with battery system would also be cost-effective in Knoxville at 4th quarter 2017 North Carolina commercial solar pricing.

The cost range for North Carolina commercial solar with battery storage would be $0.044/kWh to $0.062/kWh, as shown in Tables 23a and 23b. These costs are well below the 2015 average North Carolina commercial retail cost of electricity of $0.087/kWh.

5.3.2 Residential Solar with Battery Power

The primary functions of battery storage in a residential application would be 1) absorbing and discharging solar power, 2) shifting demand to hours of lower-cost power under TOU rates, 3) supplying peak power to the grid, and 4) onsite backup power source available when the grid goes down.[i]

[i] Onsite direct usage and batteries absorbing electricity occur at the same time. If there is a lot of sunshine and those first two demands are fully met, excess solar will flow from the home/business to the closest neighbors that can use it. If that sunny afternoon is a peak demand period where the utility wants to discharge supplemental power from the batteries (which are at that point 100% full), that can also occur. That last action might pull the batteries fairly low over 3-4 hours, but they will then be recharged later when the peak demand has passed and there is no stress on the grid.

OFFICIAL COPY

Oct 12 2017

Table 23a. Cost of Electricity for 100 kW Commercial Rooftop PV System with 250 kWh of Battery Storage Capacity, Cash Purchase

Cost or (Credit), $	Cost Element
$180,000	Gross cost of 100 kW_{dc} rooftop solar system @ $1.80/watt (dc)
$58,000	Cost of 250 kWh battery storage[137]
--	State incentive payment
($71,400)	30 percent federal tax credit on gross cost
($82,538)	Depreciation on gross cost less ½ tax credit: ($238,000 - $35,700) × 35% marginal tax rate) = $70,805 + State tax depreciation on gross cost less 1/2 tax credit: ($238,000 - $35,700) × 5.8% marginal tax rate = $11,733
$84,062	Net cost of PV system
$4,203/yr	Annual cost of system, cash transaction, 20-year financial life: $84,062 ÷ 20 years = $4,203/yr
$2,000/yr	Annual fixed O&M, $20/kW-year[138]
141,516 kWh/yr	Annual electricity production, fixed solar array, Raleigh, NC[139]
$0.044/kWh	Cost of electricity: $6,203/yr ÷ 141,516 kWh/yr = $0.044/kWh
$0.087/kWh	Average NC utility commercial cost of electricity, 2015

Table 23b. Cost of Electricity for 100 kW Commercial PV System with 250 kWh of Battery Storage Capacity, Financed at 5 Percent, 20-Year Term

Cost or (Credit), $	Cost Element
$180,000	Gross cost of 100 kW_{dc} rooftop solar system @ $1.80/watt (dc)
$58,000	Cost of 250 kWh battery storage
--	State incentive payment
($71,400)	30 percent federal tax credit on gross cost
($82,538)	Depreciation on gross cost less ½ tax credit: ($238,000 - $35,700) × 35% marginal tax rate) = $70,805 + State tax depreciation on gross cost less 1/2 tax credit: ($238,000 - $35,700) × 5.8% marginal tax rate = $11,733
$84,062	Net cost of PV system
$8,017/yr	Annual cost of system, 20-year, 5 percent financing, capital recovery factor = 0.0802 per year: $84,602 x 0.0802/yr = $6,785/yr
$2,000/yr	Annual fixed O&M, $20/kW-year
141,516 kWh/yr	Annual electricity production, fixed solar array, Raleigh, NC (source: NREL PV Watts calculator)
$0.062/kWh	Cost of electricity: $8,785/yr ÷ 141,516 kWh/yr = $0.062/kWh
$0.087/kWh	Average NC utility commercial cost of electricity, 2015

Using the 4th quarter 2017 best-in-class North Carolina solar pricing of $2.50 per watt (dc) and battery storage installed pricing of $7,000 for 14 kWh, the cost of electricity from the system, assuming a cash purchase, would be $0.081/kWh, as shown in Table 24a. The key to this net cost of production is the residential customer receiving a bill credit equivalent to the capacity value of the energy storage system (assumed capacity value for 3 kW = $300/yr). This is the value to the utility of having the battery storage available to serve peak demand needs instead of relying on gas turbine capacity to serve the same purpose.

The net cost of production would be $0.124/kWh for the same system financed over 20 years at 5 percent annual interest, as shown in Table 24b. This net residential solar system cost range, $0.069/kWh to $0.124/kWh, is generally below the average 2015 retail residential electricity cost in North Carolina of $0.113/kWh.[140] This example does not assume a TOU residential rate structure or standby charge. A TOU residential rate structure, with a standby charge as applied to commercial customers, would increase the economic benefit of the battery system to the residential customer.[141]

Providing bill credits for remote dispatch of residential load is already a routine utility function. Many residential customers are involved in utility air conditioner cycling programs, where the utility provides incentive payments to residential customers to enable the utility to remotely cycle the air conditioner and thereby reduce load across its system on peak demand days. The credit for reserve capacity paid to residential energy storage providers would work the same way. The bill credit would equal the charge that would otherwise be paid by utility customers for the construction of new combustion turbine capacity. As an example, 50,000 residential 3 kW energy storage systems would be automatically dispatched to provide 150 MW of peaking capacity instead of one new 150 MW combustion turbine built to provide the same peaking capacity.

Some utilities are moving ahead proactively in deploying residential and commercial net metered energy storage systems. For example, investor-owned utility Green Mountain Power in Vermont is currently offering residential customers a lease on 14 kWh of lithium battery storage for $15 per month.[142] A primary motivator for the program according to Green Mountain Power is to enable customers to ride through relatively frequent seasonal short-duration blackouts. Green Mountain Power also asserts that deploying batteries and grid software, combined with use of smart thermostats, smart water heaters, solar panels, and other distributed resources it is integrating in pilot projects, will be cheaper than more typical capital improvements on the distribution system.[143]

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Table 24a. Cost of Electricity for 6 kW Residential Rooftop PV System with 14 kWh Battery Storage Capacity, Cash Purchase

Cost or (Credit), $	Cost Element
$15,000	Gross cost of 6 kW_{dc} rooftop solar system @ $2.50/watt (dc)
$7,000	Installed cost of battery system, Tesla Powerwall, 14 kWh.[144] Assumed peak demand export capacity of battery storage system = 3 kW
($6,600)	30 percent federal tax credit on gross cost
$15,400	Net cost of PV + battery system
770/yr	Annual cost of system, cash transaction, 20-year financial life: $15,400 ÷ 20 years = $770/yr
120/yr	Annual fixed O&M, $20/kW-year[145]
(300/yr)	Peaking power capacity payment, from utility to energy storage provider: $100/kW-yr × 3 kW = $300/yr (credit)
8,491 kWh/yr	Annual electricity production, fixed solar array, Raleigh, NC (source: NREL PV Watts calculator)
$0.069/kWh	Net cost of electricity: $590/yr ÷ 8,491 kWh/yr = $0.069/kWh
$0.113/kWh	Average NC utility residential cost of electricity, 2015

Table 24b. Cost of Electricity for 6 kW Residential PV System with 14 kWh Battery Storage Capacity, Financed at 5 Percent, 20-Year Term

Cost or (Credit), $	Cost Element
$15,000	Gross cost of 6 kW_{dc} rooftop solar system @ $2.50/watt (dc)
$7,000	Installed cost of battery system, Tesla Powerwall, 14 kWh.[146] Assumed peak demand export capacity of battery storage system = 3 kW
($6,600)	30 percent federal tax credit on gross cost
$15,400	Net cost of PV + battery system
1,235/yr	Annual cost of system, 20-year, 5 percent financing,[i] capital recovery factor = 0.0802 per year: $15,400 x 0.0802/yr = $1,235/yr
120/yr	Annual fixed O&M, $20/kW-year
(300/yr)	Peaking power capacity payment, from utility to energy storage provider, $100/kW-yr × 3 kW = $300/yr (credit)
8,491 kWh/yr	Annual electricity production, fixed solar array, Raleigh, NC
$0.124/kWh	Cost of electricity: $1,055/yr ÷ 8,491 kWh/yr = $0.124/kWh
$0.113/kWh	Average NC utility residential cost of electricity, 2015

[i] As of September 2016, a leading PV + battery system provider, Tabuchi America, offers financing in North Carolina for its residential 5.5 kW, 10 kWh battery storage system at 4.99 percent interest over 20 years, http://www.tabuchiamerica.com/news/tabuchi-announces-300m-solar-plus-storage-financing.

5.3.3 Urban Utility-Scale Solar with Battery Storage

Utility-scale battery storage has been identified by investor-owned utilities as cost-competitive with combustion turbines for peaking power since 2014. Southern California Edison (SCE), in its November 2014 procurement application to the California Public Utilities Commission (CPUC), stated that its least-cost, best-fit resource modeling indicated the acquisition of utility-scale battery storage would be the most economic scenario relative to combustion turbines or other non-fossil resources.[i] The CPUC ultimately approved 100 MW of utility-scale battery storage and 130 MW of behind-the-meter battery storage in response to SCE's November 2014 application.[147,ii]

Separate from the SCE authorization described above, over 100 MW of battery storage (with 400 MWh of storage capacity) was added in Southern California in only nine months from the time the CPUC notified the Southern California utilities to seek additional storage capacity in June 2016. That capacity reached operational status in late 2016 and early 2017.[148] This large-scale, fast-track battery deployment process demonstrated that the long lead time procurement cycles typical of conventional gas-fired generation, based on long-term utility growth forecasts that may never become reality, are not necessary for battery storage procurement.

The lowest published cost for large-scale solar PV with batteries, less than $0.045/kWh, is from Tucson Electric in May 2017.[149] This production cost is substantially below the production cost of $0.059/kWh estimated by EIA for a new gas-fired combined cycle power plant.[iii] The solar component of the project is 100 MW. The battery component is 30 MW rated capacity and 120 MWh of energy storage.[150] Prior to the Tucson Electric announcement, the lowest published cost figures had been for two Kauai Island Utility Cooperative (KIUC) solar with battery projects, by AES and SolarCity. The contract power cost for the 28 MW solar with 20 MW battery facility by AES, contracted in December 2016 at $0.11/kilowatt-hr (kWh),[151] is comparable to that of new peaking gas-fired power plants.[iv] In 2015, KIUC signed a similar contract with Solar City for $0.145/kWh. The Solar City project became operational in March 2017.[152]

The current cost of generation for new peaking gas turbines in North Carolina is in the range of $0.10/kWh (see Table 22). Utility-scale solar with batteries can compete with new peaking

---

[i] SCE's least-cost best-fit modeling indicated the acquisition of 900 MW of in-front-of-meter (IFOM, signifying "utility-scale") energy storage would be the most economic scenario from among all resources, including simple cycle gas-fired generation: "[When SCE imposed a 100 MW] IFOM ES constraint [cap], the [least-cost best-fit] optimization selected a higher amount of GFG (gas-fired generation). This was largely due to the limitation on IFOM ES and GFG being the next economic resource in terms of NPV." Southern California Edison, Application A.14-11-012, *SCE-1: Testimony of Southern California Edison Company on the Results of Its 2013 Local Capacity Requirements Request for Offers (LCR RFO) for the Western Los Angeles Basin*, November 21, 2014, pp. 57-58.

[ii] Behind-the-meter battery storage is located on a customer's premises, either home or business, on the customer's side of the electric meter.

[iii] See Table 22.

[iv] See Table 22, combustion turbine, 2022 start date = $0.101/kWh.

OFFICIAL COPY

Oct 12 2017

combustion turbines or new combined cycle units now. The cost of generation from solar with battery projects is declining rapidly. In contrast, the cost of generation from gas-fired power plants is projected to rise along with fuel prices and other operating costs (see Table 22 and Figure 9).

5.4 Value of Distributed Solar

An April 2017 report prepared for the Office of the People's Counsel for the District of Columbia[i] calculates the utility system levelized value of distributed solar over the 2017 to 2040 time period in Washington DC as \$133/MWh (\$0.133/kWh).[153,ii] The value of solar represents comprehensive monetization of all the attributes of distributed solar relative to conventional utility-scale electric power generation by central station coal- or gas-fired power plants. This value of solar calculated for net metered solar in the Washington DC area in 2017 is consistent with the value of net metered solar calculated for North Carolina, in the range of \$120/MWh to \$130/MWh, in 2013.[154]

A breakdown of the components of the value of solar in Washington DC is shown in Figure 10. It is significant that the energy value of solar, usually the only metric addressed by a utility when comparing the value of solar compared to conventional fossil-fired utility generation alternatives, is only about 40 percent of the overall value of solar.[iii]

The fundamental point highlighted in Figure 10 is that the distributed solar has substantially more value as a resource than just the cost of electricity production from the solar project itself.

5.5 Net Metering Does Not Impose Additional Costs on Non-Participating Customers

By the end of 2015, regulators in at least ten states had conducted studies to develop methodologies to value distributed generation and net metering, while other states conducted less formal inquiries ranging from direct rate design or net metering policy changes to general education of decision makers and the public. There is a degree of consensus. A growing number of these studies show that net metering benefits all utility customers.[155]

---

[i] The Office of the People's Counsel is a body within the DC Public Service Commission charged with representing the interests of consumers.

[ii] The electric utility serving Washington, DC is PEPCO.

[iii] \$53/MWh ÷ \$133/MWh = 0.398 (39.8 percent). Other values of distributed solar, including the reduced need for conventional generation investment, reduced need for new or upgraded transmission and distribution capacity, RPS (renewable portfolio) compliance, reduced losses, and reduced electricity supply risk, actually exceed the energy value of solar.

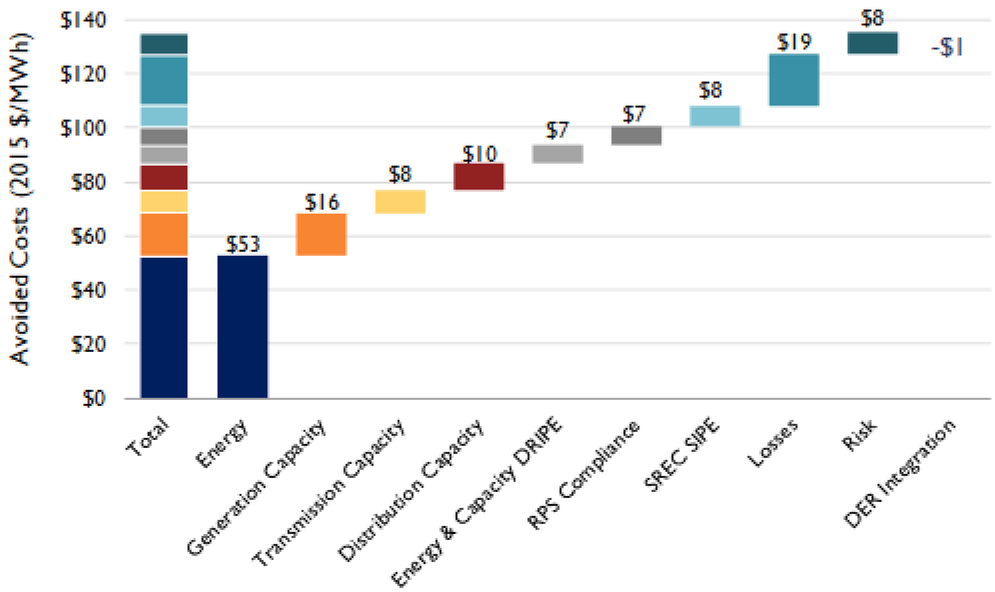
OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Figure 10. Components of Value of Distributed Solar Avoided Cost for Washington DC
(source: Synapse)[156]



5.6 Economic Benefit of Locating Large-Scale Solar on the Local Distribution Grid to Avoid Transmission Expansion

The movement of power that is not generated and utilized locally requires transport, known as "wheeling," over the high-voltage transmission system. Utilities pass on to customers the cost to operate, maintain, and expand the high-voltage transmission system, and third parties then must use the transmission system to move power. However, locally generated and utilized solar power that is delivered at distribution voltage does not require use of the transmission system.[i]

The estimated avoided transmission value of local solar in North Carolina is estimated at $10 per MWh[ii]. This is $10 per MWh that would otherwise be spent to expand the transmission system to accommodate solar development in remote parts of the state that must be transported to major demand centers such as Charlotte and Raleigh-Durham.

Large-scale solar projects that interconnect at the distribution voltage of urban and suburban substations allow utilities to avoid expanding the transmission network. Therefore, an "avoided transmission cost" payment of approximately $10 per MWh should be credited to these local large-scale projects as a financial incentive to assure they are built in or near the demand centers.

[i] Transmission is the movement of electricity from a generating site, such as a power plant, to an electrical substation. Distribution is the movement of electricity from the substation to customers. The combined transmission and distribution network is typically referred to as the power grid.

[ii] DEC transmission avoided cost of $0.010/kWh ($10/MWh) is assumed applicable statewide. Crossborder Energy, *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*, October 18, 2013, Table 7, p. 12.

OFFICIAL COPY Oct 12 2017

6. North Carolina PV Technical Potential

6.1 Potential of Rooftops, Parking Lots, Urban Land, Brownfields

There is about 86,000 MW (136,000 GWh per year) of PV potential in North Carolina on rooftops, commercial parking lots, undeveloped larger-size urban parcels, and brownfield (contaminated land) sites. This is about four times the PV capacity needed to meet the 2025 solar energy targets of NC CLEAN PATH 2025.[i]

Rooftop of Faith Community Church in Greensboro, NC. Source: NC WARN

Of this total, about 38,000 MW (60,000 GWh per year) is rooftop and commercial parking lot PV potential.

Open parcels at least six acres in size without restrictive uses in urbanized areas of North Carolina can provide up to 43,000 MW (68,000 GWh per year) of solar capacity. There is also approximately 5,000 MW (8,000 GWh per year) of additional PV that could be developed on contaminated land, known as brownfield sites, in North Carolina. The quantity and distribution of these solar resources are shown in Table 25.

Table 25. Estimate of North Carolina Local Solar and Brownfield PV Potential

Unit	Residential rooftop	Commercial/ industrial rooftop	Commercial parking lot	Undeveloped urban commercial-size parcels	Brownfields	Total
MW	19,400	9,300	9,300	43,000	5,000	86,000
GWh/yr	30,600	14,700	14,700	68,000	8,000	136,000

Table 26. Estimate of North Carolina Rooftop Solar Potential[157]

Unit	Residential rooftop	Commercial/ Industrial rooftop	Total
MW	19,400	9,300	28,700
GWh/yr	30,600	14,700	45,300

[i] See Table 15.

OFFICIAL COPY
Oct 12 2017

6.1.1 North Carolina Rooftop Solar Potential

The National Renewable Energy Laboratory (NREL) published an updated rooftop solar potential estimate for North Carolina in 2016 that is based on geospatial data and statistical analysis.[158] NREL divides roof categories into "small buildings" and "medium to large buildings." This report equates small buildings to residential rooftops, and medium to large buildings to commercial rooftops. NREL estimates approximately 29,000 MW (45,300 GWh per year) of rooftop solar technical potential in North Carolina,[i] as shown in Table 26.

6.1.2 North Carolina Commercial Parking Lot Solar Potential

An estimate of the PV potential of parking areas and parking structures is necessary to develop a complete understanding of the distributed PV potential of North Carolina. An April 2017 assessment of the solar potential of Washington DC included an estimate of the solar potential of commercial and industrial parking lots,[159] and found it to be similar to the rooftop solar potential of the commercial and industrial buildings.[160] This estimate is provided in Table 27.


North Carolina has a large solar potential on parking lots and parking decks. Source: Dovetail Solar

Table 27. Estimate of Rooftop and Parking Lot Solar Potential in Washington DC, Reference Case

Small rooftop (MW)	Government, commercial, and industrial (GC&I) rooftop (MW)	GC&I parking lot solar (MW)
360	1,320	1,400

[i] NREL reports direct current MW capacity, prior to conversion to alternating current, and annual electricity production (alternating current). This report assumes the direct current-to-alternating current ratio is 0.86 for all solar categories, including residential, commercial, and utility-scale. This is the default direct current-to-alternating current ratio assumed in NREL's PVWatts™ Calculator (http://pvwatts.nrel.gov/) for fixed residential systems, and results in a MW-to-MWh/year capacity factor for North Carolina fixed solar systems of 0.18. NREL, *Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment*, January 2016, p. 35, http://www.nrel.gov/docs/fy16osti/65298.pdf.

The estimated commercial parking lot solar technical potential in North Carolina is 9,300 MW (14,700 GWh per year), equivalent to the North Carolina commercial rooftop potential. As an independent check on the accuracy of the parking lot solar estimate for Washington DC, a commercial parking space calculation methodology has been utilized to estimate North Carolina commercial parking lot solar potential. The calculation methodology used is shown in Table 28.

A core Powers Engineering assumption in the methodology is that only 25 percent of total estimated parking surface is sufficiently open, meaning largely unshaded, for its full solar potential to be realized. The estimated ground-level parking lot and parking structure PV potential in North Carolina, assuming 25 percent of the total parking surface area is utilized for PV, is 10,305 MW. This is similar to the 9,300 MW estimate derived from 1) the NREL commercial rooftop solar estimate and 2) the Synapse estimate of equivalency between commercial rooftop capacity and commercial parking lot capacity in Washington DC.

Table 28. Assumptions Used to Estimate PV Potential of Parking Lots – North Carolina

Assumption	Source
771 vehicles per 1,000 citizens	Dr. Donald Shoup, urban planning, UCLA[161]
At least 4 parking spaces per vehicle, one of which is residential space	Dr. Donald Shoup, urban planning, UCLA
10,000,000 people	Approximate NC population, 2015 U.S. Census: https://www.census.gov/quickfacts/table/PST045215/37.
162 square feet per parking space	Square footage of typical 9-foot by 18-foot parking space, Envision Solar, San Diego[162]
Approximately 23,130,000 non-residential parking spaces in North Carolina	Calculated value: 10,000,000 × (771/1,000) × 3 spaces [4 total spaces per car – 1 residential space per car]
11 W_{ac} per square foot PV capacity per square foot of parking area	Envision Solar, San Diego
41,218 MW parking lot PV theoretical potential without considering shading	Calculated value: 23,130,000 spaces × 162 square feet per space × 11 W_{ac} per square feet × 1 MW per million W_{ac}
10,305 MW actual potential	Rough estimate of actual PV potential - assumes 25 percent of non-residential parking spaces are unshaded throughout the day and full PV potential can be realized at these sites

OFFICIAL COPY Oct 12 2017

OFFICIAL COPY

Oct 12 2017

6.1.3 North Carolina Urban Utility-Scale (> 1 MW) Solar Potential

NREL has evaluated the potential of larger (> 1 MW) PV arrays located on unutilized lands within city limits around the country.[163] NREL defined urban utility-scale solar as large-scale solar PV deployed within urban boundaries on urban open space. The NREL assessment process excluded unsuitable areas deemed unlikely for development. These unsuitable areas included landmarks, parks, wetlands, and forests.[164] NREL identified 43,345 MW (68,346 GWh per year) of urban utility-scale solar potential in North Carolina.[165]

An example of large-scale solar. It can also be sited on vacant urban land and brownfields. Source: Charlotte Observer

6.1.4 North Carolina Brownfields Solar Potential

The U.S. Environmental Protection Agency (EPA) has developed a nationwide inventory of brownfield sites that are potentially suitable for renewable energy development. The EPA inventory includes hundreds of sites in North Carolina totaling approximately 350,000 acres.[166] This area is equivalent to a solar power potential of almost 60,000 MW.[i] About 90 percent of these brownfield sites are military bases. Many of these sites are suitable for the deployment of solar PV arrays. A list of major North Carolina brownfield sites, each with a potential of 100 MW or more of solar power, is provided in Table 29.

Much of the land on military bases is forested. It is also remote from major North Carolina load centers like Raleigh-Durham and Charlotte. For this reason, this analysis assumes that only about 5,000 MW of solar power is developed on North Carolina brownfields included in the EPA site list. This is equivalent to approximately 8,000 MWh per year of electricity generation.

6.1.5 Community Shared Solar for Customers with Shaded Property

North Carolina is heavily forested and many structures are partially or completely shaded by trees. Community shared solar programs allow customers who cannot generate solar power on their own property to acquire a share of a larger solar array constructed in the area by the

[i] EPA assumes a land area to solar potential of 6 acres = 1 MW. Therefore, 350,000 acres would have a solar power potential of: 350,000 acres ÷ 6 acres/MW = 58,333 MW.

Table 29. Major Brownfield Sites in North Carolina Potentially Available for Solar Development[167]

Site	Site size, acres	PV potential of site, MW [assuming 6 acres = 1 MW]
Camp Lejeune, USMC (Jacksonville)	151,040	25,173
Fort Bragg, Army (Fayetteville)	150,000	25,000
Cherry Point, USMC (Havelock)	13,164	2,194
Seymour Johnson AFB (Goldsboro)	3,216	536
E.I. Dupont Fayetteville Works (Fayetteville)	2,587	431
DAK Americas LLC (Leland)	2,077	346
Clariant Corporation (Mount Holly)	1,500	250
Neptco Incorporated (Lenoir)	1,027	171
Chemtronics, Inc. (Swannanoa)	1,027	171
Weyerhaeuser Corporation (Plymouth)	1,017	170
U.S. Coast Guard (Elizabeth City)	800	133
Carolina Stalite Company (Norwood)	689	115
FMC Corporation (Bessemer City)	650	108
DuPont (Kinston)	650	108
Mallinckrodt Pharmaceutical Plant (Raleigh)	600	100

OFFICIAL COPY

Oct 12 2017

utility.[i,ii] In this manner a customer with no onsite solar can become a solar customer by acquiring a portion of a community shared array.

Brunswick EMC is an example of a North Carolina utility with a community solar program. It has two solar farms available for members who want to purchase solar energy.[168]

6.2 Rapid Local Solar Development Is Achievable

Internationally, "feed-in tariffs" have been utilized in some countries to achieve spectacular levels of local solar growth. A feed-in tariff is a fixed payment for solar power that is set high enough to assure a profit for the solar owner. Japan increased its installed solar capacity from about 3,000 MW at the beginning of 2012 to approximately 43,000 MW by the end of 2016 using a feed-in tariff.[169,170] This is an increase of 40,000 MW in five years. Feed-in tariffs have yet to be utilized at a significant scale anywhere in the U.S. to accelerate solar deployment. However, use of a standard contract, with avoided cost payments to independent wholesale solar developers in North Carolina is, in effect, a de facto feed-in tariff for large-scale projects.

Net metering is the standard framework in the U.S. and North Carolina to finance behind-the-meter rooftop and parking lot solar projects. California added 1,266 MW of net metered rooftop solar power in 2016 alone, and had about 5,000 MW of installed rooftop capacity by the end of 2016.[171] The accelerating growth of net metered solar capacity in California is shown in Figure 11. The structure of the North Carolina net metering program is favorable to rapid growth,[172,iii] and the low and declining solar system prices make such growth possible. If North Carolina averaged the same 1,266 MW of net metered solar capacity additions achieved by California in 2016 over the next eight years, North Carolina would add about 10,000 MW (15,768 GWh per year) of new net metered solar capacity by 2025. This is equivalent to the approximate annual electricity output of three Duke Energy baseload gas-fired combined cycle power plants.[iv]

---

[i] Duke Energy already offers this option to customers in South Carolina. Duke Energy, "Duke Energy proposes innovative solar programs for South Carolina," news release, February 10, 2015, https://news.duke-energy.com/releases/duke-energy-proposes-innovative-solar-programs-for-south-carolina.

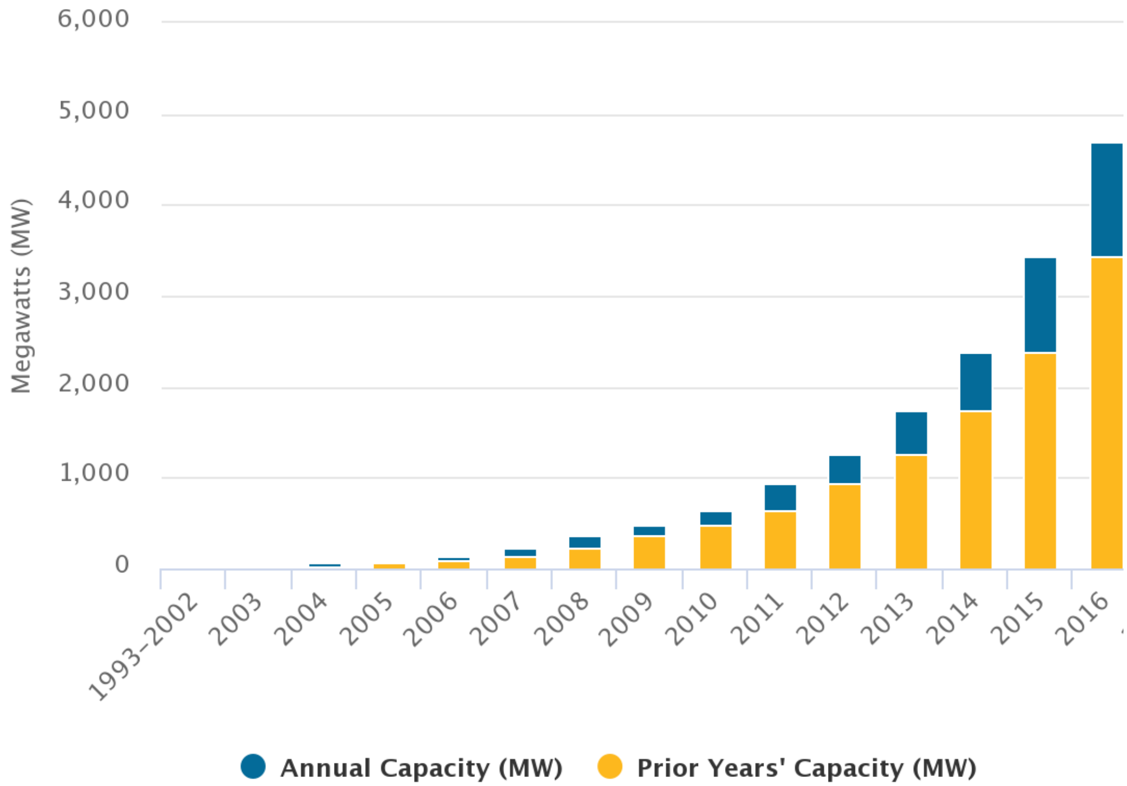
[ii] HB589, signed into law on July 27, 2017, requires that North Carolina utilities file a community solar program for the North Carolina Utilities Commission to approve, modify, or deny within 180 days, http://www.ncleg.net/Sessions/2017/Bills/House/PDF/H589v6.pdf.

[iii] The net metering program in North Carolina could become less favorable in the future. HB589 was signed into law on July 27, 2017 and establishes, at § 62-126.4 that "each electric public utility shall file for Commission approval revised net metering rates for electric customers," http://www.ncleg.net/Sessions/2017/Bills/House/PDF/H589v6.pdf.

[iv] One baseload gas-fired combined cycle power plant = 620 MW × 0.90 (capacity factor) × 8,760 hr/yr = 4,888,080 MWh per year (4,888 GWh per year) x 3 plants = 14,664 GWh per year.

OFFICIAL COPY
Oct 12 2017

Figure 11. Growth of California Net Metered Solar Capacity, 2008-2016
(source: California Distributed Generation Statistics)[173]



OFFICIAL COPY
Oct 12 2017

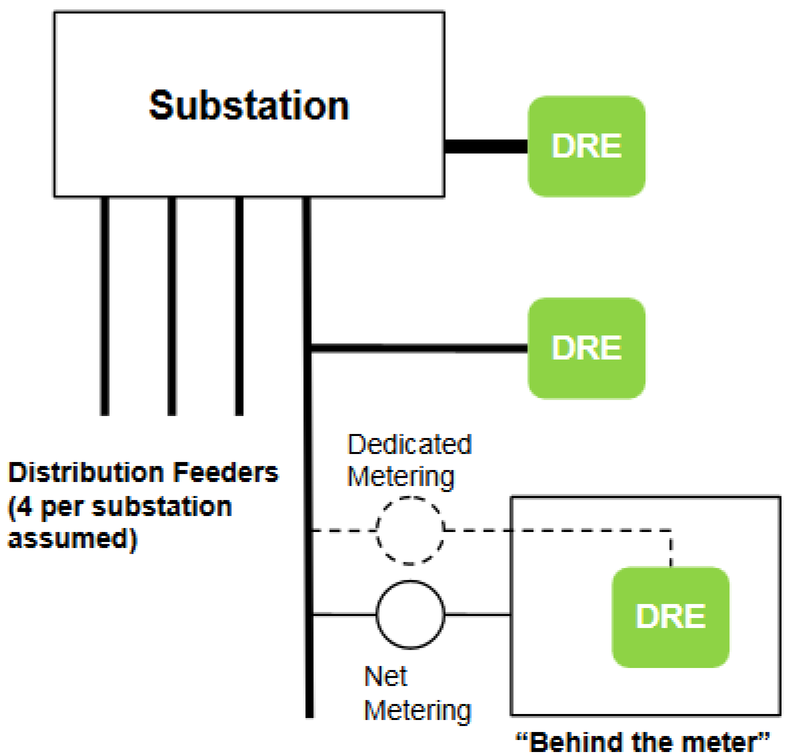
OFFICIAL COPY

Oct 12 2017

7. Integrating Distributed Generation (DG) into the Grid

A clean energy strategy with a primary focus on local distributed solar resources as the backbone of electricity supply requires a transmission and distribution (T&D) system that can reliably transport this resource. The existing T&D system has changed little over the last century, and is configured to transmit electricity generated at large power plants over high-voltage transmission lines to distribution substations. The voltage is reduced via transformers at the distribution substation and flows from there along conductors, known as “feeders,” to customers. Two-way energy delivery was not envisioned when this system was originally designed. A local clean energy path prioritizing the generation of large amounts of distributed solar power will require a two-way delivery system. The relationship between distribution substations, feeders, and distributed solar sources is shown in Figure 12.

Figure 12. Distribution Substation, Feeders, and DG Sources
(source: Navigant)[174]



DRE = distributed renewable energy (typically rooftop or parking lot solar arrays connected to individual feeders, and larger ground-mounted solar arrays connected directly to the substation)

Recent government-funded evaluations of the ability of existing utility distribution systems to host distributed solar power indicate these systems can transport large amounts of solar power when upgraded with simple and low-cost modifications. Therefore, long-running utility claims

OFFICIAL COPY

Oct 12 2017

that the distribution grid can accept only minimal levels of rooftop solar power without major and expensive upgrades are incorrect.[i]

Voltage regulation equipment, such as voltage regulators and capacitors, maintain voltage within allowable tolerances along the feeder. Safety devices are also utilized, such as circuit breakers at distribution substations and reclosers[ii] on the feeders. The purpose of these safety devices is to protect the feeder or substation equipment in case of a fault condition. Typical feeder safety equipment is not directionally sensitive, but has historically been coordinated assuming power flowing from the substation. This two-way flow pattern is known as "bidirectional flow" or "reverse flow." Reverse flow occurs when the amount of solar power generated on a feeder exceeds the customer demand for power on that feeder. This additional solar power will reach the substation. If this is happening on all the feeders connected to the substation, the solar power will continue moving in reverse direction through the substation, will be transformed to transmission voltage, and will flow onto the subtransmission or transmission system.

The capability of the existing distribution system to accept high levels of distributed solar power inflows is critical if distributed solar resources are to fill a substantial amount of customer electricity demand. The need to carry out substantial and expensive upgrades to distribution circuits in order to accommodate more than nominal levels of onsite solar would be a major bottleneck to rapid deployment of distributed solar. Analysis of real-world utility distribution circuits demonstrates that, in most cases, high levels of distributed solar inflows sufficient to meet the NC CLEAN PATH 2025 solar energy targets can already be achieved on the existing utility distribution circuits with relatively minor modification and cost.

In recent years the issue of distribution circuit capacity to handle high levels of distributed solar penetration has been the focus of considerable study by government laboratories in cooperation with electric utilities. A number of utilities have received substantial Department of Energy funding to evaluate the readiness of their distribution circuits to accept high levels of distributed solar power inflows.

Among the most notable of these studies are the PEPCO Holdings, Inc. (PEPCO) high-penetration PV study completed in December 2015 and the Dominion Virginia Power (DVP) "Virginia Solar Highways" study completed in June 2016.[175,176] Both of these studies indicate that, on most existing distribution circuits, high levels of distributed solar penetration can be

---

[i] SDG&E identified one of the biggest problems as a 15 percent solar penetration on the distribution grid, meaning about 15 percent of the peak capability on that load could be served by solar. "When it gets to that stage, the intermittent issues associated with solar can create havoc on our system," Avery warned. "Now, keep in mind, a lot of our system is antiquated analog equipment." Julia Pyper, "SDG&E's James Avery on the Promise of EVs and the Pitfalls of Solar," *GreenTech Media*, February 27, 2015, https://www.greentechmedia.com/articles/read/Jim-Avery-on-the-Promise-of-EVs-and-the-Pitfalls-of-Solar.

[ii] Definition of recloser: A circuit breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault.

achieved with low-cost/no-cost actions including 1) simple adjustment of set points on transformers, regulators, and phase shifting[177] and 2) requiring the use of advanced "smart" inverters[178] on distributed solar projects to maintain optimum voltage levels along the distribution feeder. Major additional gains in distributed solar penetration can generally be achieved by the relocation or addition of relatively low-cost capacitor banks and dynamic voltage control.[179,180]

The advantages of requiring the use of smart inverters on distributed solar systems cannot be overstated. As NREL points out when addressing mitigation techniques for high-penetration PV impacts:[181]

> An advanced PV inverter, at near-zero marginal cost, could have the ability to virtually eliminate voltage variation on a distribution feeder resulting from variations in the real power output of a PV plant. A PV inverter could even mitigate the effects of load-induced voltage variations elsewhere on the feeder. An advanced PV inverter could also mitigate the effects of its own variable real power output on the grid voltage by correcting changes while they are happening and maintaining dynamic VAR reserve in a similar way as is done in modern transmission-system VAR compensators.[i]

Smart inverters are becoming standard equipment for residential, commercial, and utility-scale solar arrays. There is little cost differential between a conventional inverter and a smart inverter. That is the reason NREL states that an advanced smart inverter has "near-zero marginal cost." NC CLEAN PATH 2025 assumes that all new solar inverters will be smart inverters capable of enhancing grid reliability.

A two-way distribution system that is optimized for high levels of distributed solar is shown in Figure 13.

---

[i] Volt-Amp Reactive "VAR" is reactive power, an induced resistance to real power flow on alternating current conductors. Reactive power exists in an alternating current circuit when the current and voltage are not in phase. A VAR setting less than unity (1.0) reduces resistance to power flow and has the effect of reducing voltage on the conductor. A VAR setting greater than unity generates resistance to power flow and has the effect of increasing voltage on the conductor.

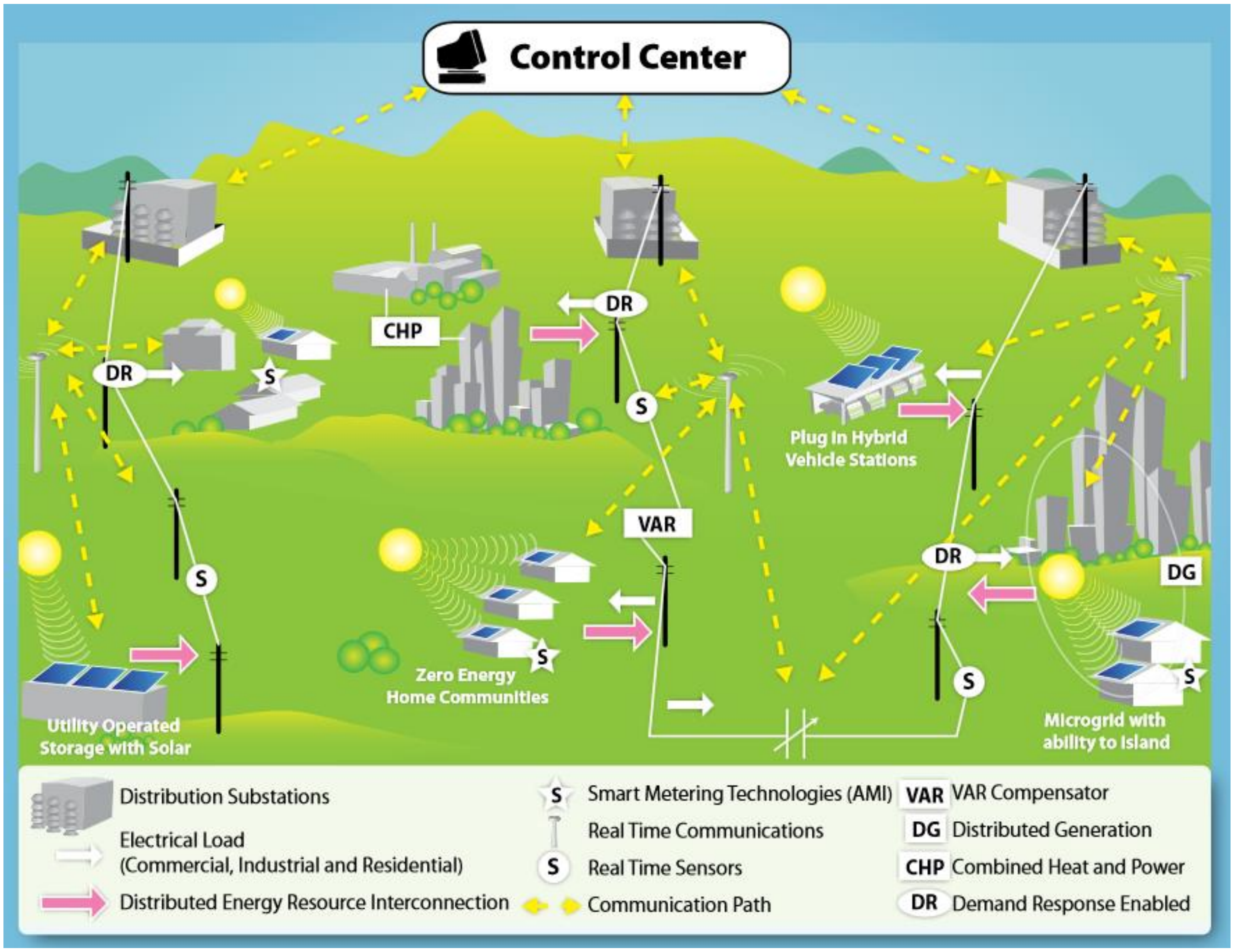
OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Figure 13. Two-Way Distribution System
(source: California Energy Commission)[182]



7.1 PV Capacity of Existing Distribution System

7.1.1 No modifications to existing distribution system

Existing distribution feeders can typically accept 25 to 40 percent of peak load without generating any reverse flow on the feeder.[183] For this reason, a "25 percent of peak load" limit on distributed solar is assumed to be the upper limit for solar additions to an "as is" feeder with no utility evaluation necessary.

The forecast for DEC 2017 summer peak load is 18,776 MW,[184] 25 percent of which is 4,694 MW. The forecast for DEP 2017 summer peak load is 13,277,[185] 25 percent of which is 3,319 MW.

Together this represents 8,013 MW of available “no reliability impact” capacity on existing unmodified feeders.[i]

Aggregated individual feeder peak loads sum to more than the coincident summer system-wide peak load. For example, the aggregated total of individual feeder peak loads on the PEPCO system is about 25 percent greater than the coincident summer peak load.[186] Assuming this relationship is also applicable to the DEC and DEP systems, a total of 10,016 MW of distributed solar could be added to the DEC and DEP distribution feeders in North Carolina with no cost to upgrade the DEC and DEP distribution networks.[ii,iii]

The June 2016 Virginia Solar Highways report assumes that about 70 percent of total solar capacity is assigned to net metered distributed solar interconnected at the feeder level, and 30 percent is large distributed solar (> 1 MW) connected directly to the substation.[187] Using this same solar partitioning metric in this evaluation, about 4,300 MW of large distributed solar would be connected directly to the DEC and DEP distribution substations in addition to the 10,016 MW connected at the feeder level. This is a total of about 14,300 MW of solar. At an assumed annual capacity factor of 18 percent,[iv] 14,300 MW of distributed solar generation in North Carolina would produce approximately 22,500,000 MWh of electricity per year or about 17 percent of electricity generated in the state with no additional cost to improve the grid.[v]

Currently DEC and DEP North Carolina own or have under contract about 3,000 MW of solar, almost all of it large-scale solar greater than 1 MW connected at the substation level. There was only 32 MW of net metered solar in DEC and DEP North Carolina systems as of December 2015.[188]

---

[i] Duke Energy contracted with the Pacific Northwest Laboratory to prepare “*Duke Energy Photovoltaic Integration Study: Carolinas Service Areas*,” March 2014. This study evaluated the integration of relatively limited amounts of solar, up to 6,800 MW or 20 percent of peak load, in its Carolinas service territories. The majority of the solar was assumed to be large-scale and utilizing the transmission system. The study determined that 1) storage and demand response are effective approaches to increase flexibility to integrate solar and minimize impacts on gas turbine operations and 2) integration of PV energy generally results in net reduction in total energy production cost measured by fuel, startup and O&M costs of the conventional (power generation) fleet, and also reduces the capacity required from conventional generation to meet peak demand.

[ii] 8,013 MW × 1.25 = 10,016 MW.

[iii] This presumes that the feeder peak loads sum to the coincident DEC and DEP summer peak system loads. If the sum of the non-coincident feeder peak loads is greater than the reported DEC and DEP summer peak loads, 25 percent should be multiplied by the sum of the non-coincident feeder peak loads to determine the presumptive distributed solar capacity of the DEC and DEP North Carolina systems.

[iv] NREL, PVWatts™ Calculator, Raleigh, NC, assumed dc-to-ac conversion = ~0.9, capacity factor = 0.18: http://pvwatts.nrel.gov/.

[v] 22,500,000 MWh ÷ 128,388,445 MWh (net 2015 statewide generation, EIA) = 0.175 (17.5 percent).

OFFICIAL COPY
Oct 12 2017

7.1.2 Existing feeders upgraded to maximize hosting capacity

The cost per feeder to upgrade the feeder distributed solar capacity, known as the "hosting capacity," was evaluated in both the December 2015 PEPCO study and the June 2016 DVP study. PEPCO service territory includes New Jersey, Delaware, Maryland, and Washington DC. DVP service territory includes Virginia and northeastern North Carolina. The PEPCO study provides more detail than the DVP study, as it documents the increase in solar hosting capacity relative to the unmodified feeder base case for each of twenty representative feeders for each incremental "hosting capacity increase" step evaluated by PEPCO. A limitation of the DVP analysis is that it only provides the relationship between hosting capacity increase and cost for three of the fourteen representative feeders evaluated.

7.1.2.1 PEPCO

The maximum increase in hosting capacity for each feeder evaluated in the PEPCO study, and the cost necessary to achieve that hosting capacity, is shown in Table 30a for the top 12 feeders of the 20 evaluated and in Table 30b for the bottom 8 of the 20. These 12 feeders accounted for 56 percent of the feeder peak load for the 20 feeders studied, yet accounted for about 80 percent of the hosting capacity gain, from just under 20 MW in the unmodified base case to over 121 MW with selected upgrades. The upgrades increased the average hosting capacity of individual feeders to nearly double, 184 percent, of the peak load on the feeders.

The upgrades evaluated included: phase balancing, optimal capacitor bank location, voltage regulator set-point reduction, dynamic voltage regulator control, inverter non-unity power factor operation, and battery storage.[189] Upgrade improvements were added in sequence to establish the relationship between the cost of upgrades and the hosting capacity improvement.

PEPCO found that the shorter, smaller feeders are capable of handling much higher PV penetrations than the longer feeders studied.[190] Shorter, smaller feeders are more characteristic of urban and suburban areas. The longer feeders were generally more limited by voltage flicker (momentary voltage fluctuation) at lower penetration levels. The short feeders were limited by steady-state, over-voltage issues. The shorter feeders responded better to these improvements evaluated by PEPCO to correct over-voltages.

PEPCO found that the upgrade costs to accommodate an increase of solar PV penetration on a feeder are very small compared to the capital cost of solar installed on the feeder. In most cases evaluated by PEPCO, the levelized cost of energy (LCOE) of feeder upgrade costs is less than 1 percent of the LCOE of the installed solar.[191]

OFFICIAL COPY

Oct 12 2017

Table 30a. Increase in Solar Hosting Capacity and Upgrade Cost for Top 12 of 20 PEPCO Feeders Evaluated

Feeder number	length, miles	feeder peak load, MW	basecase PV penetration level, MW	maximum strict PV penetration limit, MW	maximum strict PV penetration limit, % of peak load	cost to achieve max. strict PV limit, $
18	15	6.6	2.8	22.2	336.4	25,000
3	8	4.1	2.2	10.9	265.9	149,300
6	8	6.6	2.6	14.5	219.7	78,500
2	12	5.3	1.5	10.4	196.2	32,500
5	9	4.5	2.0	8.7	193.3	96,800
20	22	5.9	2.7	11.0	186.4	2,500
1	6	3.5	1.0	5.9	168.6	60,200
9	8	5.0	0.1	8.1	162.0	21,000
4	8	3.5	1.2	4.8	137.1	22,000
17	36	10.1	2.0	12.1	119.8	31,000
8	18	5.9	1.4	6.9	116.9	21,500
13	23	5.4	0.2	5.8	107.4	150,200
		66.4	19.7	121.3	184.1	690,500

Maximum strict penetration: maximum solar capacity that causes no reliability violations on the feeder.

Table 30b. Increase in Solar Hosting Capacity and Associated Cost for Bottom 8 of 20 PEPCO Feeders Evaluated

Feeder number	length, miles	feeder peak load, MW	basecase PV penetration level, MW	maximum strict PV penetration limit, MW	maximum strict PV penetration limit, % of peak load	cost to achieve max. strict PV limit, $
7	26	5.0	1.9	4.7	94.0	131,400
15	17	8.1	1.6	6.2	76.5	21,500
11	59	4.5	2.0	3.1	68.9	178,300
19	34	6.1	1.5	4.1	67.2	80,000
16	64	8.1	0.5	5.2	64.2	167,100
10	26	2.6	0.3	1.5	57.7	27,500
14	110	9.0	1.5	1.7	18.9	33,000
12	115	8.2	0.7	1.0	12.2	118,700
		51.6	10	27.5	57.5	757,500

PEPCO also found that reverse flow across the distribution substation transformer(s) could cause, under very rare circumstances, a voltage shift on the transmission side of the transformer if reverse power flow is occurring and a line-to-ground fault occurs on the transmission side of the transformer.[192] To address this possibility, PEPCO would require three single phase-to-ground potential transformers to be added to the bus section on the transmission side of the distribution transformers to mitigate the risk to the power system. Each potential transformer

OFFICIAL COPY

Oct 12 2017

costs about $150,000.[193] The cost of this retrofit, which would require three power transformers per substation, would be approximately $450,000 per substation.[i] The combined PEPCO system has 384 distribution substations.[ii] Assuming this retrofit was carried out at all 384 distribution substations, the total cost would be $173 million.[iii]

The PEPCO evaluation determined that the average minimum "as is" base case feeder hosting capacity of approximately 25 percent was increased to an average of 133 percent, a factor-of-five increase in solar hosting capacity, at an average cost of $71,400 per feeder.[194] Assuming four feeders per distribution substation, and 384 PEPCO distribution substations, the cost of feeder upgrades to enable a factor-of-five increase in distributed solar flow potential over the entire population of feeders in PEPCO's distribution system would be $110 million.[iv]

The complete cost to upgrade the PEPCO feeders and distribution transformers to maximize distributed solar generation would be: $110 million (feeders) + $173 million (substation transformer high side protection) = $283 million.

7.1.2.2 Dominion Virginia Power

DVP evaluated 14 representative feeders from an overall feeder population of 1,813 in its service territory.[195] The DVP summer peak load of 15,570 MW[196] is comparable to the DEC and DEP peak loads of 18,776 MW and 13,277 MW respectively. DVP took a different approach from PEPCO's, in that it evaluated the percentage of thermal rating of the feeder available for solar hosting as upgrades were added. This necessitates understanding the relationship between peak load on the feeder and the thermal rating of the feeder. As shown in the PEPCO results in Table 30a, some feeder hosting capacities improved to as much as 3 times the peak load of the feeder.

The feeder thermal rating, meaning the point at which overhead feeders sag excessively due to the high temperature of the conductor or at which underground feeders approach the temperature where the insulation could begin to melt, is typically 2 to 3 times the peak load on the feeder. Conversely, 100 percent of peak load is approximately 33 to 50 percent of the feeder thermal rating, depending on the individual feeder. This is an important relationship to understand to interpret the DVP results. The results shown in Figure 14 are for the three feeders selected by DVP for presentation, and assume that smart solar inverters are utilized to optimize voltage at the point of interconnection between the solar array and the feeder.

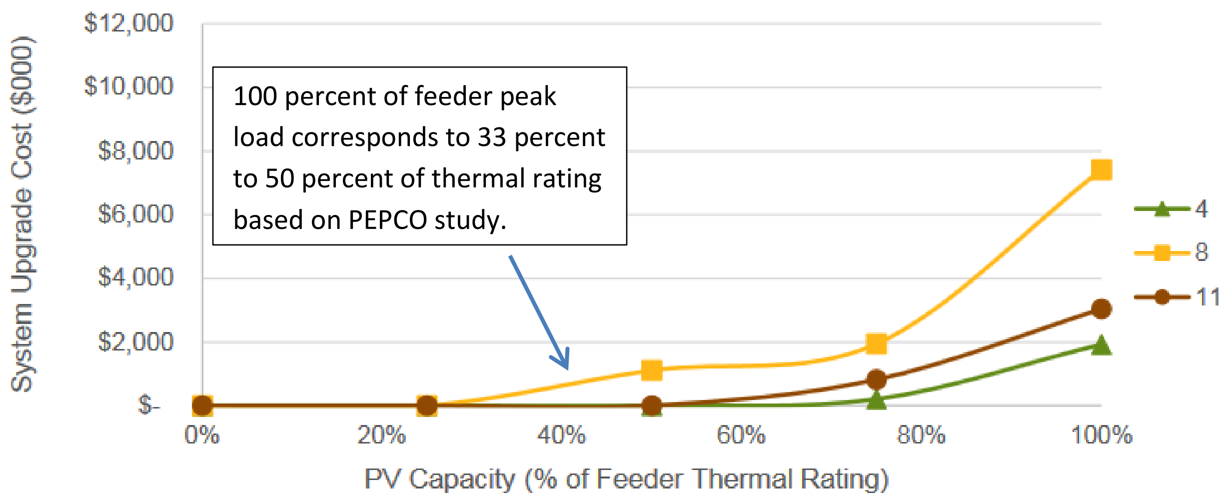
---

[i] $150,000/power transformer x 3 power transformers per substation = $450,000/substation.
[ii] PEPCO (MD and DC), 134 distribution substations: www.pepco.com/connect-with-us/about-us/; Atlantic City Electric (NJ), 90 distribution substations: http://www.atlanticcityelectric.com/connect-with-us/about-us/; Delmarva Power (DE and MD), 160 distribution substations: www.delmarva.com/connect-with-us/about-us/. Total combined distribution substations = 134 + 90 + 160 = 384 distribution substations.
[iii] 384 distribution substations x $450,000/substation = $172,800,000.
[iv] $71,400 per feeder x 4 feeders/substation x 384 substations =$109,670,400.

OFFICIAL COPY

Oct 12 2017

Figure 14. Cost Versus Improvement in Solar Hosting Capacity for Selected DVP Feeders Assuming Use of Advanced Solar Inverters
(source: Navigant)[197]



The most representative feeder among the three shown in Figure 14, in the opinion of Powers Engineering, is Feeder 11. This feeder serves a predominantly residential load, as do most of the 14 representative feeders included in the DVP study. In contrast, Feeder 8 serves a predominantly commercial load and is representative of only about 1 percent of the 1,813 feeders in the DVP service territory. Feeder 4 is somewhat of an outlier, representing low voltage (4.16 kilovolts) and very short (3 miles) feeders. No significant solar hosting upgrade costs are encountered on Feeder 11 until about 67 percent of the thermal rating is reached, which equates to 133 to 200 percent of feeder peak load based on the PEPCO feeder analysis. At least for Feeder 11, the DVP and PEPCO results are similar. The solar hosting capacity of most feeders can be greatly increased for relatively little cost.

7.1.3 Cost to Upgrade North Carolina Distribution Grid to Maximize Solar Capacity

Assuming a base case "as is" hosting capacity of the DEC and DEP North Carolina distribution feeders of 8,013 MW,[i] a factor-of-five increase in hosting capacity, from 25 percent of peak load in the "as is" base case to an average of approximately 125 percent following the application of

---

[i] 8,013 MW is approximately 25 percent of the non-coincident peak load on the total population of DEC and DEP feeders.

OFFICIAL COPY
Oct 12 2017

OFFICIAL COPY

Oct 12 2017

the mix of upgrades,[i] would expand available system-wide solar hosting capacity on the distribution feeders to over 40,000 MW.

DEC and DEP have approximately 866 distribution substations in North Carolina.[ii] Assuming four feeders per substation on average, there are about 3,464 feeders associated with these distribution substations.

The feeder and substation transformer protection upgrade costs developed by PEPCO are used here to estimate the cost to upgrade the DEC and DEP feeders and distribution substation transformers to allow a factor-of-five increase in distributed solar on the DEC and DEP systems. The feeder upgrade cost would be: 3,464 feeders x $71,400/feeder = $246 million. The substation transformer protection upgrade cost would be: 866 substations x $450,000/substation = $390 million. The total upgrade cost would be: $246 million + $390 million = $636 million.

DEC and DEP together supply about 71 percent of retail load served in North Carolina.[iii] Assuming the feeders and distribution transformers operated by other North Carolina utilities have similar hosting capacity upgrade costs to those developed by PEPCO, the total cost to upgrade all feeders and distribution substations in North Carolina to maximize distributed solar would be: $636 million ÷ 0.71 = $896 million. This would increase the hosting capacity of distribution feeders in North Carolina to: 40,000 MW ÷ 0.71 = ~56,000 MW.

NC CLEAN PATH 2025 assumes 70 percent of the local solar is net metered residential and commercial solar connected to the distribution feeders. The potential of this local solar resource flowing on distribution feeders is approximately 56,000 MW. NC CLEAN PATH 2025 also assumes that 30 percent of the local solar is larger distributed solar connected directly to the substation (and not a feeder). The capacity of this larger local solar resource is approximately 24,000 MW.[iv] Therefore, the total local solar potential of North Carolina feeders and distribution substations, for an upgrade investment of less than $1 billion,[v] is about 80,000 MW.

7.2 Use of Smart Inverters in All PV Systems

Traditionally, PV inverters were intentionally designed to feed into the grid as much active power as possible, in kW or MW, as is available from the solar array at unity power factor. It is

---

[i] Powers Engineering assumes that the level of upgrade cost identified by PEPCO to increase solar hosting capacity on PEPCO would be similar to the upgrade cost necessary on DEC and DEP feeders to achieve a similar increase in solar hosting capacity.
[ii] Total DEC and DEP distribution substations in North Carolina = 576 + 290 = 866 distribution substations. DEC, 2016 FERC Form 1, April 13, 2017, pdf p. 513 (576 distribution substations); DEP, 2016 FERC Form 1, April 13, 2017, pdf pp. 455-465 (290 distribution substations).
[iii] When the wholesale power produced by DEC and DEP for North Carolina municipal utilities and cooperatives is included, DEC and DEP provide approximately 89 percent of the electricity consumed in North Carolina.
[iv] (56,000 MW ÷ 0.70) – 56,000 MW = 24,000 MW.
[v] The estimate in this report is $896 million. See calculation above.

now possible for the solar inverter to also absorb and provide reactive power from and to the grid. This capability defines an advanced or smart solar inverter.[198]

The flow of active power and reactive power in the grid are somewhat independent from one another and largely require different control schemes. Absorbing and providing reactive power from and to the grid does reduce the inverter's active power capacity. Active power control is tied to controlling grid frequency, whereas reactive power control is linked with controlling the grid voltage.[199]

7.2.1 Control of Active Power and Frequency

In a transmission and distribution network it is necessary to keep the frequency as stable as possible because the biggest generating resources, all of which historically have been large synchronous electric generators,[i] work at their most efficient point when spinning at exactly 60 cycles per second. Also, the speed governors on these machines must operate in lock-step so the generators can share the load to meet demand. For the frequency to remain stable, the generated active power must match the power demand at all times.

However, many electricity-consuming devices operate out of phase with a standard alternating current waveform and the current waveform leads or lags the voltage waveform. The degree to which the current waveform is in phase with the voltage waveform is called the "power factor." When current and voltage are not in phase, for example because an electricity-consuming device creates induction, this out-of-phase effect must be countered with reactive power. Some loads requiring offsetting reactive power are shown in Table 31.

Table 31. Typical Reactive Power-Consuming Loads[200]

Load	Power factor
Fluorescent lighting	0.90
Heat pump and air conditioning	0.83
Washer	0.65
Industrial motor	0.85

7.2.2 Control of Reactive Power and Alternating Current Voltage

Although reactive power can be controlled in large generation stations, it is necessary to control voltage by injecting and absorbing reactive power at various points throughout the transmission and distribution network. Excessive voltage can adversely affect equipment and loads. Reactive power control also enhances grid stability and reduces line transmission losses.

[i] The electric generators are connected to gas turbines or steam turbines.

OFFICIAL COPY Oct 12 2017

Transmission lines can, depending on load and length, either absorb or provide reactive power. The resistive power loss component, heat loss, is often insignificant in comparison to the reactive power component at very high voltage levels.

The reactive power capacity of a smart PV inverter can be used as a fast-acting static reactive power compensator. A major benefit of this approach is that it comes at very little additional component cost. There is a corresponding incremental reduction in useful power output.

At the distribution line level, smart PV inverters can be used to correct the power factor by providing reactive power close to where they are being used, rather than importing the reactive power from far away. Transformers and most electrical loads are inductive in nature and therefore consume reactive power.[201]

Traditionally, power factor correction is done by connecting large, paralleled capacitor banks to many of the voltage levels of the distribution system. These capacitors are strategically placed to adjust voltage along the feeder. Power factor correction and alternating current voltage regulation can be performed much more economically by distributed smart PV inverters along the feeder. This regulation will also be done in a continuous and smooth fashion, without any step changes or noticeable switching events.[202]

OFFICIAL COPY

Oct 12 2017

OFFICIAL COPY

Oct 12 2017

8. Achieving Rapid Load Reductions with Demand Response & Energy Efficiency

Energy efficiency (EE) and demand response (DR) measures are the two primary tools available to reduce peak load and annual energy consumption at the point of use, in a home, apartment, commercial building, or industrial facility.

EE consists of replacing existing lighting and appliances such as refrigerators, dishwashers, clothes washers and dryers, and stove/oven with higher-efficiency replacements. EE also includes upgrading the building envelope with improved insulation, tighter windows, and tighter doors. All utilities offer some degree of incentives to promote EE upgrades. For example, Duke Energy Carolinas has an appliance recycling program; energy-efficient appliances and devices program; heating, ventilation, and air conditioning (HVAC) energy efficiency program; multi-family energy efficiency program; and income-qualified energy efficiency and weatherization program.[203]

Under NC CLEAN PATH 2025 the EE savings rate would increase from 0.62 percent in 2015 to approximately 2 percent each year through 2025. The EE savings target would be 20 percent compared to a 2015 baseline. This would reduce North Carolina electricity consumption from 130 million megawatt-hours (MWh) per year in 2015 to approximately 104 million MWh per year in 2025.

DR programs focus primarily on reducing peak demand by temporarily turning down or shutting off high-demand heating and cooling systems. A typical example of a DR program would be the automatic cycling of a large number of residential central air conditioning units during periods of high demand.[204] "Cycling" means turning them off and on every 15 or 30 minutes to substantially reduce the average load of the units being cycled while maintaining a comfortable temperature range. A DR program of this type would have the potential to reduce load from the participating air conditioning units by at least 50 percent, as half or more of the units would be offline at any given moment.[i] This same procedure would be used to reduce the demand of heat pumps and electric resistance heaters in cold weather conditions. DR programs can be very effective at reducing peak demand on the grid if implemented at sufficient scale. DR programs

[i] For example, the air conditioner cycling schedule could be: one-third of the participating units online for 10 minutes while the other two-thirds are offline. In this scenario, one-third of the population is online in any given moment, and no unit is offline more than 20 minutes. The automatic cycling function would be overridden at any individual location if the temperature increased above 78°F or some other upper limit temperature, to assure that participants are not subject to uncomfortable conditions.

OFFICIAL COPY

Oct 12 2017

can also be implemented very quickly, as all that is needed is the installation of a relatively inexpensive controller that responds to a utility signal.[i]

DR would increase under NC CLEAN ENERGY 2025 from a 2015 deployed level of DR of approximately 500 MW to a 2025 deployed level of about 5,700 MW.[ii] These levels assume a projected 2025 North Carolina system-wide peak load of 33,000 MW.[205] Much of the DR peak load reduction in winter would be achieved by automatically cycling heat pumps that provide space heating. In summer, much of the load reduction would be achieved by automatically cycling central air conditioning units.

NC CLEAN PATH 2025 would target a 50 percent reduction in peak summer and winter heating and cooling loads using DR and EE. This DR target is based on 1) a Federal Energy Regulatory Commission (FERC) analysis of North Carolina DR potential based on customer participation achievable using an opt-out program structure,[206] which will reduce peak load 15 to 20 percent (about one-third of the 50 percent reduction,) and 2) accelerated replacement of obsolete high-demand heating and cooling units with high-efficiency state-of-the-art upgrades, an EE measure that will reduce peak load 30 to 35 percent (about two-thirds of the 50 percent reduction).

8.1 Overview of Current Trends

Federal minimum appliance efficiency standards covering air conditioning, heat pumps, refrigerators, and a host of other devices in common use in homes and commercial buildings, as well as the cost-competitiveness of LED lighting, are primary reasons for the national trend toward declining electricity demand in the U.S. This trend is shown in Figure 15. To a significant extent, energy efficiency measures are now “built in” to the economy and are not primarily dependent on actions taken by the utilities commissions or individual utilities.

This trend can be accelerated by incentivizing ratepayers to change out older, high-use appliances more quickly than they would have done without an economic incentive to do so. Incentives also serve the purpose of enabling ratepayers to select new appliances that reflect the maximum efficiency currently available and not default to the model meeting the minimum federal standard to save what may be a relatively small additional expense.

Properly focused EE expenditures result in lower electricity costs for all ratepayers. A case in point is California. The state leads the nation in utility-scale and local distributed solar, with 13,000 MW and 5,000 MW, respectively, at the end of 2016.[207,208] Rapid expansion of solar development and EE measures has led to a steep decline in the price of wholesale power.

---

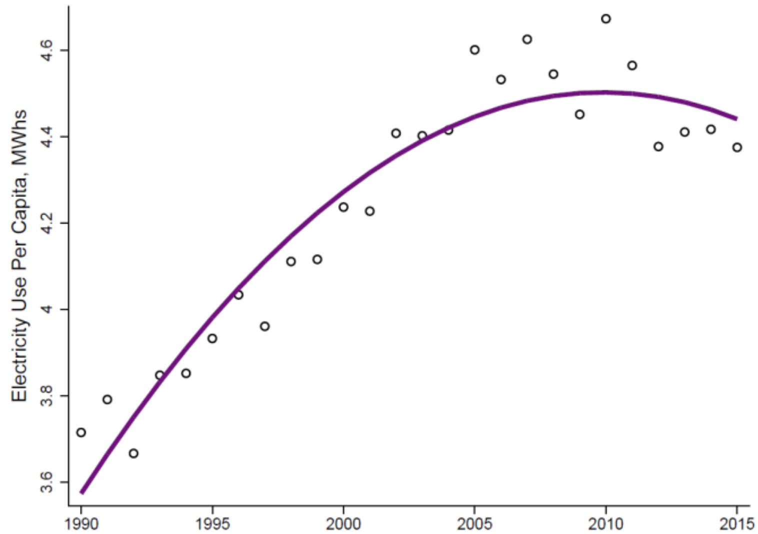
[i] Because cooling system cycling programs are generally very cost-effective, some utilities give the air conditioner cycling controllers to customers free of charge to encourage participation.

[ii] FERC “Active Participation” scenario for North Carolina, increasing achievable DR to 17.4 percent (over 10 years), equivalent to 5,680 MW. FERC, *A National Assessment of Demand Response Potential*, October 2009, p. 150, https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

OFFICIAL COPY

Oct 12 2017

Figure 15. U.S. Grid Electricity Per Capita Consumption Trend
(source: Haas School of Business, UC Berkeley)[209]

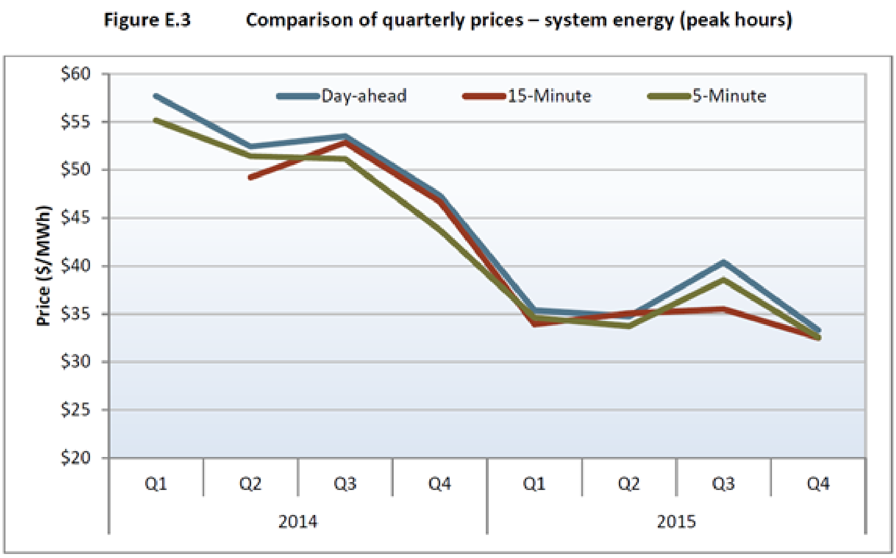


California serves as a harbinger of the effect of rapidly expanding solar and EE on wholesale power prices in North Carolina. This trend is shown in Figure 16. As EE and solar power displace conventional power sources, the value of conventional wholesale power also declines due to less demand for the product. All utility customers benefit from lower wholesale power costs, to the extent a utility relies on wholesale power purchases to meet customer demand. The "problem" that California is addressing in an ongoing proceeding is the premature retirement of relatively new state-of-the-art gas-fired combined cycle power plants due to low wholesale power prices caused by reduced demand for conventional sources of power.

EE programs also typically are expected to have a reasonable payback period for customers. For example, the investment in the wholesale replacement of incandescent bulbs with LED bulbs in a home may be recovered quickly by the homeowner due to the much lower electricity demand of LED lighting compared to incandescent lighting.

A companion issue is the accelerating demand for grid power caused by the expanded use of electric vehicles. California is again the harbinger for other states. California utilities argue that the rapid increase in EVs will lead to a reversal in static or downward trends in grid power demand. The California policy target for electric vehicles is that they comprise approximately 15 percent of the auto population in the state by 2025.[210] There were approximately 14.5 million registered automobiles in California in 2015.[211,i] Therefore, if the target is reached, there will be approximately 2 million EVs on the road in 2025.

Figure 16. Rapid 2-Year Decline in Wholesale Power Cost in California Due to Displacement of Fossil Fuel Generation, 2014-2015
(source: CAISO)[212]



There were about 3.5 million automobiles registered in North Carolina in 2013, as well as 4.1 million trucks of all types.[213] The vehicle population in North Carolina is about one-quarter that of California. Therefore, if California EV targets were adopted in North Carolina, there would be about 500,000 EVs in the state by 2025.

A primary objective of the EE targets in NC CLEAN PATH 2025 is to at least keep pace with the growth of EV electricity demand so that the phase-out of coal- and natural gas-fired generation in North Carolina is not delayed by rising EV electricity demand.

8.2 Distribution of North Carolina Electricity Demand

There are approximately 5 million North Carolina electricity meters, or "customers," as shown in Table 32. Annual electricity demand is approximately 130 million MWh, split between residential, commercial, and industrial customers as shown in Figure 17.

---

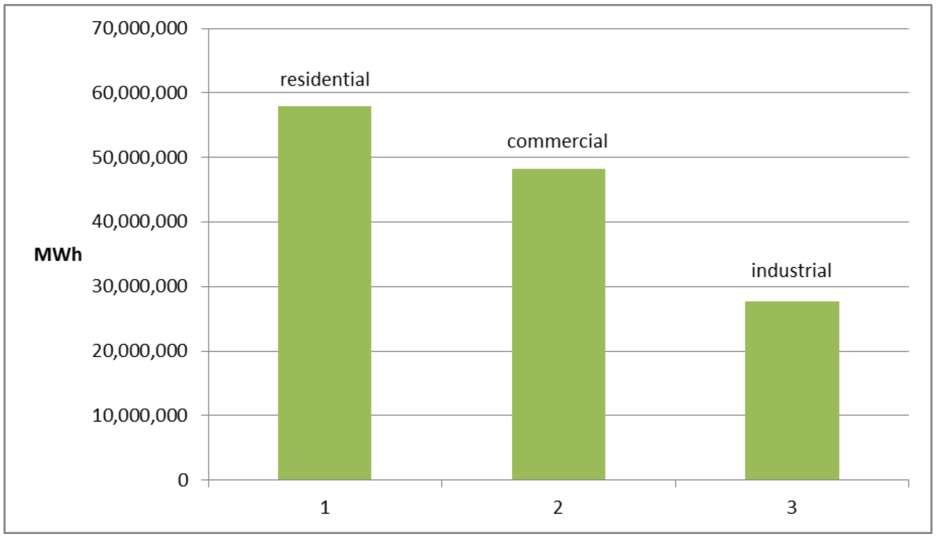
[i] There are approximately the same number of trucks as automobiles registered in California. In 2012, there were 13.2 million automobiles registered and 13.6 million trucks registered. See: https://www.reference.com/vehicles/many-registered-vehicles-california-52c20f61bcb10e9d#.

OFFICIAL COPY
Oct 12 2017

Table 32. Number of Residential, Commercial, and Industrial Electricity Customers in North Carolina, 2015[214]

Customer category	Number of customers
Residential	4,388,390
Commercial	641,839
Industrial	14,832
Total:	5,045,061

Figure 17. Distribution of 2015 North Carolina Electricity Demand Among Customer Categories[215]



Some of this demand is being met by net metered rooftop and parking lot solar in North Carolina. The number and capacity of net metered solar installations in North Carolina at the end of 2015 is shown in Table 33. There are no caps on net metered solar installations in the state.

Table 33. Net Metered Solar Residential, Commercial, and Industrial Customers in North Carolina, 2015[216]

Customer category	Number of customers	Solar capacity (MW)
Residential	3,782	18.04
Commercial	268	11.99
Industrial	4	1.73
Total:	4,054	31.76

OFFICIAL COPY Oct 12 2017

OFFICIAL COPY
Oct 12 2017

It is most cost-effective to match the annual electricity demand profile of the state with the annual solar electricity production profile for the state. The North Carolina solar output profile is shown in Figure 18.

Figure 18. North Carolina Month-to-Month Solar Production Profile, 4 kW Fixed Rooftop System, Raleigh, NC

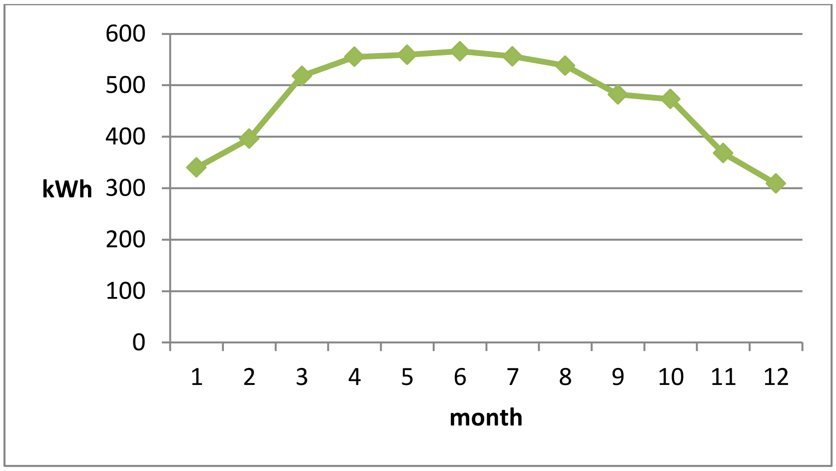
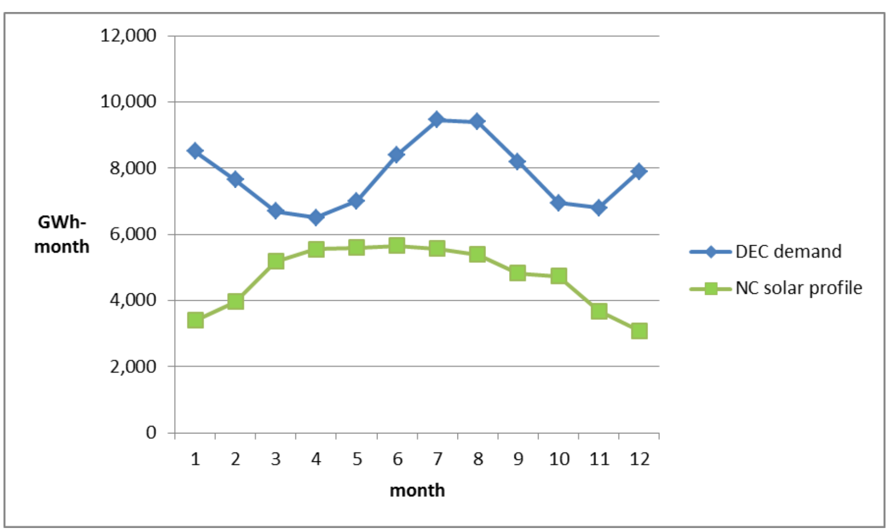


Figure 18 shows that output of a North Carolina solar power system in December and January is about 60 percent of its output from March through October.[217] This roughly follows the month-to-month retail demand of North Carolina utilities – except for the substantial electric space heating loads in the winter months.

The DEC month-to-month electricity demand (blue) is shown in Figure 19 as representative for North Carolina.[218] The month-to-month solar production profile for North Carolina (green) is also shown in Figure 19.[219]

Figure 19. Month-to-Month DEC Demand Profile Compared to North Carolina Solar Production Profile

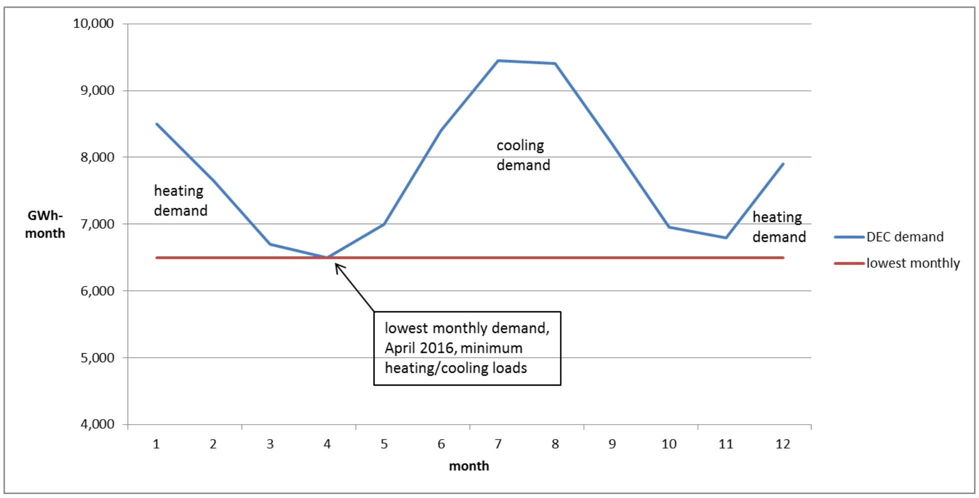


OFFICIAL COPY

Oct 12 2017

It is electric heating loads in winter and air conditioning loads in summer that give the blue demand curve in Figure 19 its shape. These heating and cooling loads are identified in Figure 20. The 2016 DEC month-to-month load profile is compared in Figure 20 to the minimum heating and cooling load month, April 2016, to demonstrate the impact of winter heating and summer cooling loads on the profile. The ratio of the minimum monthly DEC load in April to the maximum monthly load in July is about 68 percent. This is comparable to the ratio of minimum monthly rooftop solar system output in December to maximum monthly output in June of about 55 percent.[i]

Figure 20. DEC Heating and Cooling Demand



Wintertime monthly electricity demand in North Carolina would be relatively low compared to summer demand without the electric heating loads in winter. Space heating with electricity is common in the South, where nearly two-thirds of households heat primarily with electricity.[220] Use of electric heat pumps for winter heating (and summer air conditioning) is rapidly increasing in North Carolina.[221]

These heat pump units are least efficient for home heating during periods of cold ambient temperatures. The outside air contains little heat under these conditions and the heat pump struggles to produce enough warmth. As a result, these systems generally also include heat strips inside the ductwork to generate additional heat when the outside air falls into the thirties. The heat strips warm the air by electrical resistance, the same technology found in high energy usage electric baseboard heaters.[ii] Baseboard heaters are also heavily used in North Carolina, in part due to utility programs that have promoted "all-electric" houses. Under cold temperature

---

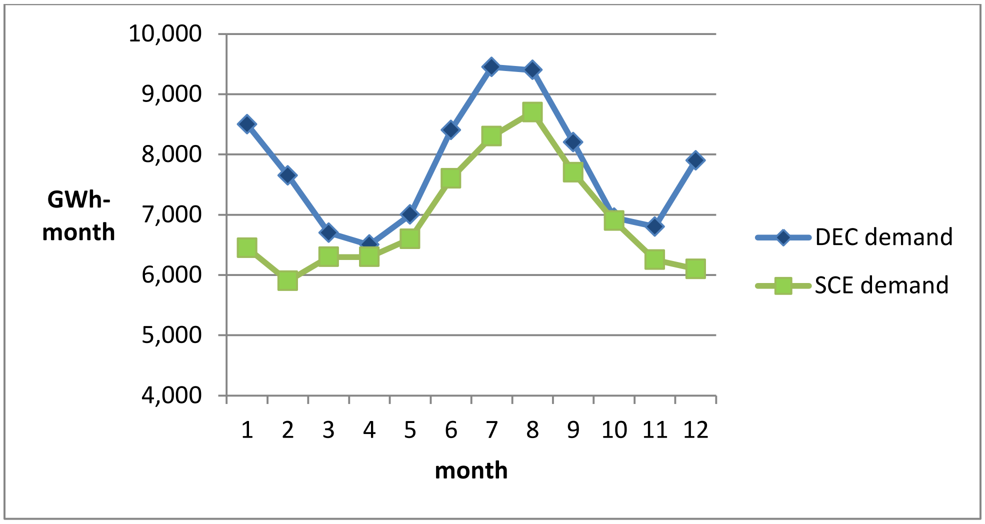
[i] NREL PVWatts™ Calculator, Raleigh, NC: http://pvwatts.nrel.gov/. December production = 309 kWh. June production = 566 kWh. 309 kWh/month ÷ 566 kWh/month = 0.55.

[ii] Electric baseboard heater: A heating system in which the heating elements are housed in special panels placed horizontally along the baseboard of a wall.

conditions when the need for heat is greatest, electric heat pumps are at their least efficient and use the most power.[222]

The expected month-to-month demand curve for a utility, Southern California Edison (SCE), without the winter electric heating demand of DEC is shown in Figure 21. The demand served by SCE is comparable to that of DEC. The space heating demand of SCE customers is met almost exclusively by natural gas. For this reason, the winter months in SCE territory are consistently the lowest demand months of the year. The SCE month-to-month demand profile is a good match for the month-to-month production profile of solar power.

Figure 21. Comparison of DEC and SCE Month-to-Month Demand Curves



A utility month-to-month demand curve that is lowest in winter and highest in summer is the best "fit" for a system that will rely on large amounts of solar power. Therefore, the primary focus of EE and DR investments under NC CLEAN PATH 2025 will initially be directed at minimizing the demand of electric space heaters in North Carolina homes and businesses.

8.3 Demand Response

8.3.1 Current North Carolina Demand Response Programs

A challenge with the current management of utility demand response (DR) programs is that only a portion of the available DR capacity under contract is deployed, or none at all, during system peaks. There were large increases in demand for electricity at the 2014 system peaks that occurred in January 2014 at abnormally low temperatures for all three North Carolina IOUs.[223] For example, North Carolina experienced two severe cold spells on January 7 and 8, 2014 and January 29 and 30, 2014.

DEC did not activate any DR when it experienced its 2014 peak load of 19,151 MW on the morning of January 30, 2014. DEC did activate its DR programs to address the second-highest

OFFICIAL COPY Oct 12 2017

OFFICIAL COPY

Oct 12 2017

peak hour of 2014, which occurred on January 7, 2014, reducing load by 478 MW. DEC's 2013 IRP projected 561 MW of available DR capacity. Only 478 MW, or 85 percent, of the 2013 projection was available when needed.[224] This represents a reduction in winter peak load due to DR of approximately 2.5 percent.[i]

DEP activated all of its available DR resources, 383 MW, to address its 2014 peak hour load on January 7, 2014, of 14,159 MW.[ii] However, DEP had only 76 percent of its projected DR capacity actually available at the system peak on that date.[225] The 383 MW of DR represents a reduction in DEP winter peak load of approximately 2.6 percent.[iii] DEP's activation of its "EnergyWise" DR program in the summer of 2014 resulted in 107 MW of capacity reduction out of the 230 MW forecasted to be available.

Each North Carolina utility has a summer air conditioning load control program, customer-owned standby generation, and load curtailment programs. Standby generation and load curtailment resources are available to each utility in the winter season. Some utilities also have a winter season dispatchable DR program. For example, DEC and DEP include emergency heat strips associated with electric heat pump space heaters in the commercial EnergyWise demand response program.[226] DEC has no residential winter emergency heat strip DR program.[227] DEP does have a residential winter emergency heat strip and electric water heater DR program. However, participation in the DEP residential winter DR program is low, approximately 10 MW.[228] This is a voluntary "opt in" program where residential participants receive a $25 per year bill credit.[229] The emergency heat strip and electric water heater DR program applies only to the DEP Western Region (Asheville area).[230]

A description of how Duke Energy controls these DR resources is provided in DEC's 2016 IRP:

> Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEC will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a $50 annual bill credit for each unit at the 30% cycling level, $85 for 50% cycling, or $135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/back up heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional $25 annual bill credit. Participants will also be allowed to override two conservation periods per year.[231]

---

[i] 478 MW ÷ 19,151 MW = 0.025 (2.5 percent).

[ii] NCUC 2015 Annual Report, pdf p. 50. The DR resources deployed included: EnergyWise Home for 9 MW, Commercial, Industrial, and Government (CIG) Demand Response Automation for 6 MW, Distribution Service Demand Response (DSDR) for 157 MW, and Curtailable Rate programs for 211 MW.

[iii] 383 MW ÷ (383 MW +14,159 MW) = 0.026 (2.6 percent).

OFFICIAL COPY

Oct 12 2017

The quantity of residential DR that can be remotely controlled by the utility is shown in Table 34 for DEC and DEP. Over 320,000 residential customers were enrolled in the DEC and DEP air conditioner cycling programs by the end of 2015.

Table 34. Quantity of Residential DR that Can Be Remotely Controlled by DEC and DEP[232,233]

Utility	Total customers enrolled	Summer (MW)	Winter (MW)
DEC	179,017	487	0
DEP	143,186	281	10.3

The IOUs in North Carolina tend to use DR only in near-emergency situations to maintain grid reliability.[234] The North Carolina Utilities Commission reviewed the DR activations at the time of the fifteen highest hourly peaks for each utility in 2014 when system operations called on DR as a resource. It found a substantial difference between the DR load reduction actually realized on the fifteen days when peak demand was highest for all three utilities and the amount of DR load reduction forecasted by the utilities.[235] The total amount of DR available to DEC and DEP in 2015, and the total amount utilized on summer and winter peak days, is shown in Table 35.

Table 35. Total DEC and DEP DR Available and Utilized on Peak Days in 2015[236]

Utility	Date	Residential DR		Non-Residential DR	
		available	actually utilized	available	actually utilized
DEC	1/9/15	0	0	608	469
DEC	6/16/15	487	228	608	0
DEP	1/8/15	10.3	9.4	331	248
DEP	7/10/15	281	227.9	331	0

The Commission indicates the utilities could take greater advantage of their DR programs by activating them on a more frequent basis, both for reliability and for reduction in fuel costs.[237] The use of DR only to address near-emergency conditions underutilizes the available DR resource.

Another challenge to achieving large reductions in heating and cooling demand with DR is the condition of the building stock and the capabilities of the existing heating and cooling systems. To meet the current North Carolina building code, new structures must be well-insulated and well-sealed against leaks. However, using DEP Western Region as an example, nearly half of the Asheville area (Buncombe County) housing stock was built before 1980. A significant number of those homes are occupied by low-income residents who face high winter heating bills and often

OFFICIAL COPY

Oct 12 2017

do not have money to invest in weatherization or insulation upgrades that would make their homes more energy-efficient.[238]

North Carolina utilities do have low-income assistance programs. For example, the DEC Refrigerator Replacement Program includes replacement of inefficient operable refrigerators in low-income households.[i] The program is available to homeowners, renters, and landlords who own a qualified appliance in properties rented to low-income tenants. The income eligibility requirements for the Refrigerator Replacement Program are the same as the income eligibility standards for the North Carolina Weatherization Assistance Program. DEP has a comparable program.[ii] These low-income programs serve only about 2 percent of the combined DEC and CEP customer base.[iii]

8.3.2 NC CLEAN PATH 2025 Achievable Demand Response

North Carolina can achieve much higher levels of DR than are currently being realized. FERC evaluated North Carolina's potential and determined that an order of magnitude (10 times) more DR could be achieved cost-effectively in the state, from actual maximum DR deployment of about 500 MW of DR during peak events to about 5,700 MW by 2025.[iv] This would increase the DR load reduction achieved on average on peak event days from about 1.5 percent to approximately 17 percent.

In summer, much of the load reduction would be achieved by automatically cycling central air conditioning units. In winter, heating load reduction would be achieved by automatically cycling the emergency heat strips utilized with earlier models of electric heat pumps, and electric water heaters, to minimize loads during peak conditions.

One underutilized DR opportunity, electric water heaters, currently included only in DEP's Western Region DR program, would serve a major role in absorbing solar power under NC CLEAN PATH 2025. A number of utilities have pilot projects underway to evaluate grid-integrated water heating (GIWH) as a path to system flexibility at a fraction of the cost of battery energy storage. Each electric water heater could act as a battery for load-shifting or peak-shaving, or to integrate renewables.[239]

Hot water is used largely by residential utility customers in morning and evening hours. However it can be heated when power is most available. The stored hot water can then be used during the morning and evening without increasing system demand. It could be heated at midday

---

[i] DEC, 2016 IRP, p. 111 (32,122 low-income customers).
[ii] DEP, 2016 IRP, p. 102 (27,993 low-income customers).
[iii] (32,122 customers + 27,993 customers) ÷ 3,260,000 retail customers = 0.0184 (1.84 percent).
[iv] FERC "Active Participation" scenario for North Carolina, increasing achievable DR to 17.4 percent (over 10 years), equivalent to 5,680 MW. FERC, *A National Assessment of Demand Response Potential*, October 2009, p. 150, https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

to take advantage of abundant midday solar production throughout the state, and additionally at midday in winter to avoid the morning peak electric demand period during winter cold spells.[240]

Green Mountain Power has a pilot program with up to 540 customers using a water heater controller and intelligent thermostat. Customers will pay $0.99 per month to participate. Other utilities, including Portland General Electric and Arizona Public Service, also have grid-integrated water heater pilot programs.[241]

The key elements necessary to achieve a major increase in DR under NC CLEAN PATH 2025 are 1) that it be an opt-out program and 2) that it rely on incentive payments that are comparable to the cost of new combustion turbine capacity that will not be built as a result of dispatching the DR. As stated by Kansas City Power & Light regarding its state-of-the-art air conditioner cycling program, the program is "*cheaper than if we had to go out and build a natural gas peaking plant . . . Everybody benefits*."[242]

This report assumes new combustion turbine capacity has a cost of $100 per kW-yr.[243] This means the value to the grid of a customer that can reduce load 5 kW when called by the utility would be $500 per year,[i] and not the current utility practice of a $25 per year bill credit. In exchange for the incentive payment, customer DR resources could be dispatched up to 100 hours per year.

An opt-out program is a program where all customers are enrolled in the program initially. Any customer that does not want to be in the program for any reason can opt out. Examples of populations that may want or need to opt out are the elderly, chronically ill, and any others who are negatively impacted by even slight variations in interior temperature.

Opt-in programs require that customers affirmatively choose to enroll, with no obligation to do so. Opt-in DR programs typically do not exceed a participation rate of more than approximately 5 percent of the customer base.[244] In contrast, opt-out DR programs generally retain at least 75 percent of the customer base. For the DR programs to maximize their potential, they must be opt-out programs that include a substantial public education component so customers understand and support the programs.

Charging high prices for electricity to reduce load on the very hottest peak days is another tool available to North Carolina utilities.[245] This is known as “critical peak pricing” (CPP). The intent is to encourage customers to find ways to minimize usage during these periods to avoid high payments. NC CLEAN PATH 2025 would rely instead mostly on robust incentive payments that reflect the avoided cost of new combustion turbine capacity to assure high levels of customer participation in DR programs. These incentives would provide a predictable payment to customers and achieve the same objective as CPP rates.

[i] $100/kW-yr x 5 kW = $500/yr.

OFFICIAL COPY Oct 12 2017

OFFICIAL COPY

Oct 12 2017

8.4 NC CLEAN PATH 2025 Energy Efficiency Target

North Carolina utilities spent $113.7 million in 2015 on energy efficiency (EE) programs.[246] These investments reduced energy usage in 2015 by 0.62 percent, compared to a base case that assumes no incremental EE measures being applied in 2015.[247] The American Council for an Energy-Efficient Economy ranks North Carolina 30th among states on its 2016 Energy Efficiency Scorecard.[248] Large commercial and industrial customers are authorized to opt out of utility EE programs if they choose to do so. About 40 percent of large commercial and industrial utility customers have chosen to opt out.[249]

NC CLEAN PATH 2025 EE measures would address the highest energy users first. Customers in the top 25 percent energy-use level in each customer category would be the primary focus of EE measures through 2022. The focus would expand to the second 25 percent in each customer category through 2025. The objective of the EE program under NC CLEAN PATH 2025 would be to reduce annual energy consumption by 20 percent relative to a 2015 base case by 2025.

The 2015 EE savings rate must be tripled under NC CLEAN PATH 2025, from 0.62 percent in 2015 to approximately 2 percent each year through 2025. The objective of this target is to assure that a rapid increase in EVs in the state does not result in a net increase in demand for grid power.

The top state in EE savings in 2015 was Rhode Island, allocating 6.34 percent of statewide utility revenue to achieve a 2015 EE savings rate of 2.91 percent.[250] California allocated 3.43 percent of statewide utility revenue to achieve incremental EE savings of 1.95 percent.[251] Powers Engineering estimates that North Carolina utilities would need to quadruple spending on EE programs, from 0.91 percent of total revenue to approximately 4 percent, from $113.7 million per year to approximately $450 million per year, to achieve the NC CLEAN PATH 2025 target of 2 percent per year in EE savings year-after-year through 2025.[i] This increased investment in energy efficiency measures would be offset by lower wholesale energy prices,[ii] resulting in a net reduction in overall consumer spending on electricity in North Carolina.

8.5 Achieving Energy Efficiency Reductions

8.5.1 Lighting

No other household technology is as disruptive as lighting, from the standpoint of electricity demand reduction, when incandescent bulbs are replaced with LED or fluorescent bulbs. The reduction in electricity usage is as much as 80 percent or more. Incandescent bulbs do not last

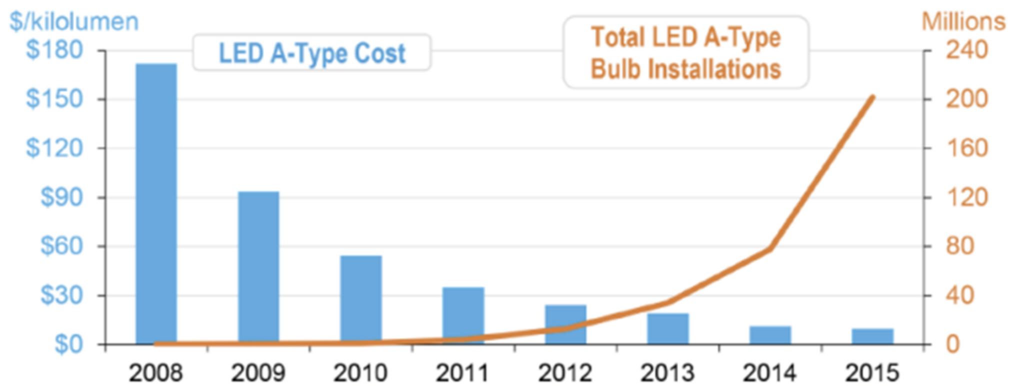
---

[i] The one large (population) state achieving an EE savings of just under 2 percent in 2015, California, spent 3.43 percent of statewide utility revenue on EE programs. ACEEE 2016 Scorecard, EE spending and savings table – all states: http://database.aceee.org/sites/default/files/docs/spending-savings-tables.pdf.

[ii] See Figure 16.

long, so the installed stock turns over quickly. Air conditioners, refrigerators, dishwashers, and other appliances, in contrast, all have useful lifetimes in the range of 10 years or more. These technologies have become more energy-efficient and are contributing to the per capita decline in electricity use. The mainstream acceptance of LED bulbs has been a driving force in the decline in per capita electricity consumption around the country. The rapid acceleration of LED bulb sales is shown in Figure 22.[252] The trend in Figure 22 is expected to continue over the next several years until the dominant bulb in use is the LED bulb.[253] No special utility incentive program is required to make this happen. The LED bulb is now a smart consumer choice with no incentives.

Figure 22. Relationship of Cost of LED Bulbs to Market Share
(source: Haas School of Business, UC Berkeley)[254]



8.5.2 Refrigerator/Freezer

Refrigerator energy efficiency is regulated by federal government standards. Refrigerators have become much more efficient over the past 20 years. Current refrigerators use 60 percent less electricity on average than 20-year-old models.[255]

8.5.3 Heating and Air Conditioning (HVAC)

Most homes and small businesses in North Carolina are equipped with central air conditioning units.[256] The remaining homes that are equipped with air conditioning use window-mounted room air conditioners. The most efficient commercially available residential and small commercial central air conditioning units achieve about double the efficiency level of units meeting the minimum standard. The highest efficiency units are more expensive, but this additional upfront expense is more than made up for by electricity cost savings over the useful life of the system. An automatic upgrade to the highest level of efficiency would be paid for using utility EE funds under NC CLEAN PATH 2025 for any application where an older, central air conditioning unit with a relatively low seasonal energy efficiency ratio (SEER) is being replaced.

OFFICIAL COPY Oct 12 2017

Another HVAC alternative that is now mainstream technology is the mini-split air conditioner and heat pump.[i] These units have no ductwork and are intended to heat and cool individual rooms or multiple adjacent rooms. Mini-split units can achieve exceptionally high levels of efficiency.

8.5.3.1 Heating

Space heating can be provided by natural gas or oil-fired furnaces, central electric heat pump, mini-split heat pump, baseboard electric resistance heating, portable electric resistance heating, passive solar heating, and geothermal heat pumps.[257] Electric heat pumps are well-suited to the relatively mild winters in hot-humid areas and some mixed-humid areas, and they are in common use in North Carolina. The state is defined as both mixed-humid and hot-humid.[258] Of the 12.1 million households that use electric heat pumps in the U.S., 9.3 million are in mixed-humid and hot-humid regions, which cover much of the Southeast.[259]

Contemporary electric heat pumps are also a high-efficiency replacement for baseboard and portable electric resistance heating, reducing electricity consumption by as much as two-thirds or more.[ii]

8.5.3.2 Air Conditioning

The SEER of air conditioning units is a standard measure of cooling efficiency. It is a linear measurement, meaning that a SEER 20 air conditioning unit uses one-half the electricity used by a SEER 10 unit to produce the same amount of cooling. The current minimum federal SEER rating for new central air conditioning units is SEER 14.[260] However, the average SEER rating for in-use central air conditioning units is approximately SEER 10,[261] below even the 2006 federal minimum standard of SEER 13 for new units.[262] Competitively-priced central air conditioning units with ratings as high as SEER 26 are commercially available.[263] Central air conditioner electricity consumption is reduced by more than 60 percent when a SEER 26 central air conditioner replaces a SEER 10 unit.[iii]

---

[i] Definition: Mini-splits have two main components – outdoor compressor/condenser and an indoor air-handling unit. A conduit, which houses the power cable, refrigerant tubing, suction tubing, and a condensate drain, links the outdoor and indoor units.

[ii] "With electric resistance, each kilowatt-hour consumed generates 1 kWh of heat (3,412 Btu). A minisplit heat pump (MSHP) can collect, move, and release 1.5 to 4 kWh of heat for each kWh of electricity consumed, depending upon the unit's efficiency and the outdoor and indoor temperatures." Mini-split heat pumps are also capable of maintaining rated heat output at 5°F ambient temperature without supplemental electric resistance strip heaters. Vaughan Woodruff, "Mini-split: Efficient Home Heating with Mini-split Heat Pumps," *Home Power Magazine*, Issue 180, July/August 2017, pp. 50-56, https://www.homepower.com/articles/home-efficiency/equipment-products/efficient-heating-minisplit-heat-pumps.

[iii] [1 – (10 ÷ 26)] = 0.615 (61.5 percent)

OFFICIAL COPY Oct 12 2017

OFFICIAL COPY

Oct 12 2017

Energy efficiency upgrades to central air conditioning units will pay for themselves. For example, the installed cost differential between the highest efficiency central air conditioning unit and one meeting the minimum federal standard is about $3,000.[i,ii] The electricity savings with the highest efficiency unit over ten years, a reasonable minimum useful lifetime assumption for the unit, would be approximately $5,000.[iii] In addition to the individual customer economic benefit, all customers would collectively benefit economically from lower demand during the summer peak, which in turn would reduce the usage of expensive backup gas turbine peaking.

8.5.3.3 Combined Heating and Cooling

Mini-split heat pumps offer a highly efficient, cost-competitive alternative for room-to-room heating and cooling. Ducted whole-house central air conditioning units are the standard in the U.S. and North Carolina. However, 15 to 20 percent of North Carolina homes and small businesses use low-efficiency wall-mounted air conditioners for cooling.[264] The mini-split option is a good candidate for these residences.

The mini-split heat pump is also a good candidate for homes with central heating and cooling systems where only one or two rooms in the structure are typically occupied and require heating and cooling. In this case the mini-split unit(s) would become the day-to-day heating and cooling system, and the existing central air unit would become a backup system that is rarely used. An example mini-split residential application is shown in Figure 23.

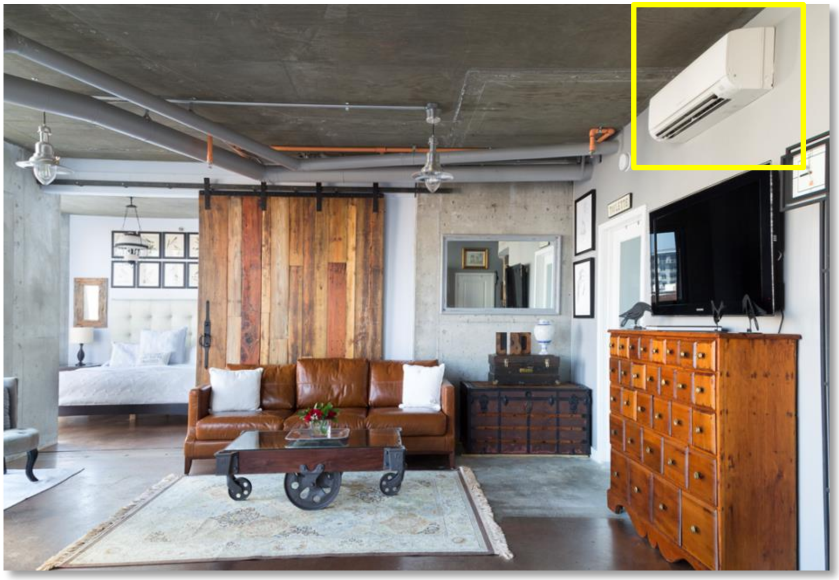
Central heating and air conditioning units have an average service life of 10 to 14 years.[265] About half of the heating and cooling systems in North Carolina would be replaced by 2025 by natural attrition based on this expected average service life. Therefore, more than half the population of operational heating and cooling systems will be replaced by 2025. If the replacement heating and cooling systems reduce electricity consumption by two-thirds on average, the overall electricity consumption of heating and cooling systems in the state will decline by about one-third, or 33 percent, by 2025.

---

[i] Installed cost average, 2.5 ton cooling, SEER 15 = $4,270. PickHVAC, Central Air Conditioner Prices, Reviews, and Final Buyer's Guide – 2017, June 7, 2017, http://www.pickhvac.com/central-air-conditioner/.
[ii] Installed cost, 2.5 ton cooling Lennox XC25, SEER 26 = $7,300. PickHVAC, Lennox Air Conditioner Buying Guide – Reviews, Prices and Tax Credits – 2017, June 7, 2017, http://www.pickhvac.com/central-air-conditioner/lennox/.
[iii] Five-year savings of $2,425 expected from a 26 SEER air conditioner vs. existing equipment with a 10 SEER rating. Cooling costs based on 3-ton capacity specifications, with 1,800 cooling hours per year and 12.29 cents per KWh. Lennox XC25 air conditioner brochure, 2017, p. 3, http://www.lennox.com/lib/legacy-res/pdfs/brochures/lennox_xc25_air_conditioner.pdf.

OFFICIAL COPY Oct 12 2017

Figure 23. Residential Application of a Mini-Split Heat Pump
(see yellow box in upper right; source: Contractor Magazine)[266]



8.5.3.4 Commercial and Industrial Building Cooling

Substantial summer peak load reduction can also be achieved by upgrading existing commercial and industrial cooling systems. Many commercial buildings use electric motor-driven centrifugal chillers to provide cooling. Centrifugal chillers typically consume more electricity than any other single device in a commercial building.[267] Evaluations of the energy efficiency of hundreds of chiller systems indicate that over 90 percent of these systems operate with relatively low efficiency, in the range of 1.0 to 1.2 kW/ton of cooling, using oversized pumps, constant speed equipment, and controls that do not work well.[i,ii]

A current trend in these commercial and industrial chiller cooling systems is converting all devices to variable speed operation and a simplified control system. One example of conversion to this ultra-efficient operating format resulted in an average energy-use reduction of 54 percent over a three-year period.[268] The results indicate that ultra-efficient all-variable-speed systems are reliable and can be installed for the same cost as standard central plant chiller systems.

An example of effective application of all-variable-speed operation to an existing chiller plant is a regional county government center in California with 610,000 square feet of air-conditioned space, including a courthouse, offices, and a jail. The retrofit was completed and commissioned

[i] The term "kW per ton of cooling" is a measure of the electric energy necessary to operate a commercial or institutional chiller plant.
[ii] One ton of cooling load is the amount of heat absorbed to melt one ton of ice in one day, which is equivalent to 12,000 Btu per hour.

OFFICIAL COPY

Oct 12 2017

at a cost of $423,700. Two years later the county was saving more than $175,000 a year on chiller plant electricity demand. The simple payback for this upgrade was less than two-and-a-half years.[269]

This is an example of a commonsense, non-residential efficiency improvement retrofit that would be an element of an opt-out commercial efficiency upgrade program under NC CLEAN PATH 2025.

8.5.3.5 Renewable Non-Electric HVAC and Hot Water Alternatives

Homes and businesses using solar and battery storage to meet 100 percent of their onsite needs are using only green energy to power electric appliances, devices, HVAC systems and hot water heaters.

Solar thermal and geothermal alternatives are also available to provide space heating and cooling and hot water. Solar hot water heaters are a cost-effective option to supplement a conventional hot water heater, and can typically reduce by about 60 percent the annual electricity demand of residential or commercial electric hot water heating systems.[270] Geothermal heat pumps can be utilized where soil conditions are appropriate. Such systems have substantial upfront costs that are balanced by low operating costs and good longevity.[271]

8.5.4 HVAC NC CLEAN PATH 2025 Target – 50 Percent Peak Demand Reduction

The NC CLEAN PATH 2025 target for HVAC systems is a 50 percent reduction in peak electricity demand by 2025. This will be accomplished primarily by 1) maximizing use of DR cycling programs to minimize heating and cooling loads during peak demand events and 2) opt-out upgrade programs directed at equipping high-usage heating and cooling customers with high-efficiency, state-of-the-art heating and cooling units.

8.6 Financing Energy Efficiency, Demand Response, and Distributed Generation

Property Assessed Clean Energy (PACE) and on-bill financing are two proven and effective alternatives for funding EE and DR. PACE programs offer a financially manageable mechanism for home and business owners to achieve zero net energy in existing residential and commercial buildings by paying for improvements over time on their property tax bills. PACE is independent of utility-funded energy efficiency programs. North Carolina does allow PACE financing, but it does not have any active PACE programs.[272]

On-bill financing allows customers to overcome cost barriers by providing financing for energy efficiency and onsite solar upgrades, which are then paid over time via charges on their utility bill. A standard test of “bill neutrality” will be applied to all opt-out energy efficiency upgrades carried out under NC CLEAN PATH 2025. This means that energy efficiency savings on monthly bills must be greater than or equal to a customer's loan payments.[273] Solar, battery storage, or EE projects considered priorities that cannot meet a bill neutrality test would be supplemented by incentive payments to achieve bill neutrality for the customer.

On-bill financing with bill neutrality provides customers with upgrades at no added cost, since the expected monthly energy savings from improvements are greater than the monthly on-bill repayment. Default rates are lower than with other loans, making them lower-risk for lenders, probably because customers are more accustomed to regular payment of utility bills.[i] Some utilities in North Carolina, including Roanoke Electric Cooperative, are developing on-bill financing.[274]

8.7 Targeting Obsolete, High-Demand Appliances and HVAC Systems

An important element of a comprehensive EE program under NC CLEAN PATH 2025 will be rapid retirement of obsolete, low-efficiency appliances, especially obsolete HVAC systems and refrigerators. The benefits of rapidly retiring high-demand appliances include savings to the individual customer that will help achieve bill neutrality and collective savings to the entire customer base in the form of lower electricity costs. It is not uncommon that the least efficient appliances are used by customers who are least able to afford to replace them with new, high-efficiency appliances. Replacement programs with no added cost burden on the low-income customer serve an important social justice function by reducing the electric bills for those needing it most.

A fundamental objective of the EE program under NC CLEAN PATH 2025 will be to assure that obsolete, high-demand appliances do not continue operating indefinitely solely because the owners of those appliances do not have the economic ability to replace the appliance, much less replace the appliance with a high-efficiency upgrade. This will be accomplished using a two-step process: 1) the customer will receive an annual incentive payment equivalent to the peak load reduction that will be achieved by the upgrade[ii] and 2) on-bill financing will be utilized to avoid the need for an upfront payment by the customer for the upgrade. The target net cost of the upgrade to the customer will be 10 percent less than the customer currently pays for electricity using the existing inefficient appliance. If the incentive payment and ongoing energy savings are

---

[i] Funds for on-bill financing programs can come from local government, utilities, or private lenders. In the latter case, the term "on-bill repayment" is used. The National Conference of State Legislatures describes it this way: "On-bill repayment programs leverage private, third-party capital for financing. Banks, credit unions or financial institutions provide the loan capital and loan payments are displayed on utility bills. This approach allows third-party institutions to take care of administrative functions, while utilities only need to process payments… On-bill repayment can also be sole sourced or open sourced—programs in New York and Oregon use a single source of capital while Hawaii is currently developing an open source model where banks and investors compete for customers." National Conference of State Legislatures, April 7, 2015: http://www.ncsl.org/research/energy/on-bill-financing-cost-free-energy-efficiency-improvements.aspx.

[ii] Assume peak load reduction is 5 kW and the incentive payment is \$100/kW-yr. The annual incentive payment, in the form of a bill credit, would be: 5 kW x \$100/kW-yr = \$500/yr.

OFFICIAL COPY

Oct 12 2017

not sufficient to achieve a 10 percent monthly cost reduction, an additional incentive payment will be provided to achieve this cost reduction target.

The advent of smart electric meters in North Carolina enables convenient analysis of large volumes of meter data to identify efficient and inefficient users of electricity in each customer category and region. Customers with clearly elevated seasonal and year-round electricity usage patterns will be identified through methodical analysis of customer meter data. Free EE assessments will then be conducted under NC CLEAN PATH 2025 to identify cost-effective upgrades for the home or business.[i]

8.8 Job Growth from Increased Energy Efficiency Spending

As noted above, investments in EE will increase from about $120 million per year to about $450 million per year under NC CLEAN PATH 2025. The total new employment generated by a $330 million per year increase in EE spending in the state will be about 4,000 direct and indirect jobs.[ii]

Energy efficiency retrofits are labor intensive and local, and they will occur throughout the state under NC CLEAN PATH 2025. Examples of EE measures include caulking to plug air leaks, adding insulation to attics and basements, replacing windows that have air leaks, and installing energy-efficient appliances including HVAC systems, refrigerators, water heaters, and lighting. Increased EE investment will create expanded employment opportunities for electricians, heating/air conditioning installers, carpenters, construction equipment operators, roofers, insulation workers, industrial truck drivers, construction managers, and building inspectors.[275]

The 4,000 jobs created by EE retrofits and the 28,000 jobs created by solar expansion in a period of just 3 years (see Table 17) make NC CLEAN PATH 2025 a major economic driver for the state.

[i] These types of assessments are already conducted by North Carolina utilities. "Residential Energy Assessments Program provides eligible customers with a free in-home energy assessment performed by a Building Performance Institute (BPI) certified energy specialist designed to help customers reduce energy usage and save money," DEC, 2016 IRP, p. 106.

[ii] Total new direct and indirect jobs per $1 million in output = 11.9. Therefore, $330 million x 11.9 jobs/$1 million output = 3,927 total jobs. Center for American Progress, *The Economic Benefits of Investing in Clean Energy*, June 2009, Table 4 – building retrofits, p. 28.

OFFICIAL COPY
Oct 12 2017

NOTES

[1] NC General Statutes § 62-110.2
[2] North Carolina Utilities Commission (NCUC), *North Carolina's Public Utility Infrastructure & Regulatory Climate*, July 2016, Slide 4: http://www.ncuc.commerce.state.nc.us/overview/overview.pdf
[3] Ibid., Slide 16.
[4] Ibid., Slide 17.
[5] Ibid., Slides 16-17.
[6] NC Public Power website: http://www.ncpublicpower.com/AboutUs.aspx.
[7] Ibid.
[8] Effective in Duke Energy Carolinas Application to Adjust and Increase Retail Electric Rates, NCUC Docket E-7 Sub 1026 and Progress Energy Carolinas Application to Adjust and Increase Retail Electric Rates, NCUC Docket E-2 Sub 1023.
[9] Duke Energy Carolinas 2016 Integrated Resource Plan (DEC 2016 IRP), NCUC Docket E-100 Sub 147, September 1, 2016, p. 16; Duke Energy Progress 2016 Integrated Resource Plan (DEP 2016 IRP), NCUC Docket E-100 Sub 147, September 1, 2016, p. 16.
[10] DEC 2016 IRP, pp. 40-41; DEP 2016 IRP, pp. 41-42.
[11] DEC 2016 IRP, Table C-6, p. 100.
[12] DEP 2016 IRP, Table C-6, p. 95.
[13] NCUC 2011 Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina (NCUC 2011 Annual Report), p. 12; NCUC 2015 Annual Report, p. 11; DEC 2014 IRP, Table 3-A; DEP 2014 IRP, Table 3-A.
[14] DEC 2016 IRP, Table C-2, p. 95; DEP 2016 IRP, Table C-2, p. 91.
[15] Virginia Daffron, "Heat pumps drive rapid growth in WNC's peak electricity demand," *Mountain Xpress*, January 21, 2017, https://mountainx.com/news/heat-pumps-drive-rapid-growth-in-wncs-peak-electricity-demand/.
[16] NCUC 2016 Annual Report, Table 2, p. 11.
[17] DEC 2016 IRP, p. 31; DEP 2016 IRP, p. 32.
[18] DEC 2016 IRP, pp. 40-41; DEP 2016 IRP, pp. 41-42.
[19] North American Electric Reliability Corporation, 2016 Long-Term Reliability Assessment, December 2016, p. 130, http://www.nerc.com/pa/RAPA/ra/Reliability percent20Assessments percent20DL/2016 percent20Long-Term percent20Reliability percent20Assessment.pdf.
[20] Ibid., p. 124.
[21] DEC 2016 IRP, pp. 45-46.
[22] DEP 2016 IRP, p. 46.
[23] DEC 2016 IRP, p. 89.
[24] DEP 2016 IRP, p. 86.
[25] DEC 2016 IRP, p. 48; DEP 2016 IRP, p. 48.
[26] NCUC Rule R19-1: http://www.ncuc.commerce.state.nc.us/ncrules/Chapter19.pdf.
[27] NCEMC website: http://www.ncemcs.com/co-ops/stats.htm.
[28] My Military Base website, http://mymilitarybase.com/north-carolina/.
[29] American Council on Renewable Energy website: http://www.acore.org/dod-energy-goals.
[30] Environmental and Energy Study Institute, DoD's Energy Efficiency and Renewable Energy Initiatives, July 2011: http://www.eesi.org/files/dod_eere_factsheet_072711.pdf.
[31] Naomi Whidden, "Camp Lejeune lights up with solar farm," *New Bern Sun Journal*, July 21, 2016, http://www.newbernsj.com/business/20160721/camp-lejeune-lights-up-with-solar-farm.
[32] Duke Energy, *Q4 2016 Earnings Review and Business Update*, PowerPoint, February 16, 2017, p. 10.
[33] Dr. Robert W. Howarth (Cornell University), "A Bridge to Nowhere: Methane Emissions and the Greenhouse Gas Footprint of Natural Gas," *Energy Science & Engineering*, accepted April 22, 2014, p. 2, http://www.eeb.cornell.edu/howarth/publications/Howarth_2014_ESE_methane_emissions.pdf.
[34] DEC 2016 IRP, pp. 74-77.

OFFICIAL COPY

Oct 12 2017

[35] Transco Pipeline Atlantic Sunrise expansion project description (shale gas from Pennsylvania to North Carolina and other southeastern states), http://atlanticsunriseexpansion.com/about-the-project/overview/.
[36] Ibid. Also Virginia Daffron, "Duke Energy's planned power plant tied to fracking," *Mountain Xpress*, June 30, 2016, https://mountainx.com/news/duke-energys-planned-power-plant-tied-to-fracking/.
[37] Supra note 33, p. 3.
[38] Supra note 33, p. 2.
[39] Supra note 16, Table ES-1.
[40] Ibid.
[41] DEC 2016 FERC Form 1, April 13, 2017, pdf pp. 428-429.
[42] John Downey, "Duke Energy spending $15 million on its hydro plant upgrades," *Charlotte Business Journal*, September 17, 2010.
[43] Energy Storage Association, "Pumped Hydroelectric Storage," accessed July 9, 2017, http://energystorage.org/energy-storage/technologies/pumped-hydroelectric-storage.
[44] NCEMC website http://www.ncemcs.com/electricity/powerPlants.htm.
[45] Supra note 6.
[46] DEC 2016 IRP, p. 80; DEP 2016 IRP, p. 80.
[47] DEC 2016 IRP, pp. 80-86; DEP 2016 IRP, pp. 80-83 (all capacities are winter rating).
[48] Supra note 27.
[49] Christopher Gergen and Stephen Martin, "N.C. solar is bright, but for how long?" *Charlotte Observer*, March 14, 2015, http://www.charlotteobserver.com/opinion/op-ed/article14059787.html.
[50] U.S. Energy Information Administration, North Carolina Electricity Profile 2015, January 17, 2017, "Full 2015 data Tables 1-12," Table 11 "Net Metering," https://www.eia.gov/electricity/state/northcarolina/.
[51] American Wind Energy Association, "U.S. Wind Energy State Facts," http://www.awea.org/state-fact-sheets, North Carolina.
[52] North Carolina Utilities Commission, "Renewable Energy and Energy Efficiency Portfolio Standard (REPS)," http://www.ncuc.commerce.state.nc.us/reps/reps.htm, Renewable Energy Facility Registrations Accepted by the NC Utilities Commission: NEW Renewable Energy Facility Registrations Accepted by the North Carolina Utilities Commission 2008-2017.
[53] Ibid.
[54] Ibid.
[55] Robert Walton, "North Carolina solar reform bill easily clears House, moves to Senate," *Utility Dive*, June 8, 2017, http://www.utilitydive.com/news/north-carolina-solar-reform-bill-easily-clears-house-moves-to-senate/444511/.
[56] Brookfield website: https://www.brookfield.com/en/Businesses/Renewable-Power/Sectors.
[57] Petition to Intervene of Columbia Energy LLC, February 2, 2016, NCUC Docket E-2 Sub 1089, p. 2.
[58] Kings Mountain Energy Center website: http://www.kmenergycenter.com/#project-overview.
[59] Supra note 50, Table 5.
[60] Ibid.
[61] Duke Energy, *Power/Forward Carolinas Fact Sheet - Building a Smarter Energy Future*, April 2017.
[62] Duke Energy, *Q4 2016 Earnings Review and Business Update*, PowerPoint, February 16, 2017, p. 64.
[63] DEC, 2016 IRP, Table 8-G, p. 49 and Table 8-I, p. 51 (new DEC gas turbine capacity by 2021, and joint DEC+DEP capacity by 2026 = 4,187 MW); DEP, 2016 IRP, Table 8-G, p. 49 (new DEP gas turbine capacity by 2021 = 726 MW).
[64] John Downey, "Report says abandoning Summer nuclear project could save S.C. customers billions," *Charlotte Business Journal*, July 19, 2017, https://www.bizjournals.com/charlotte/news/2017/07/19/report-gives-preview-of-case-against-s-c-nuclear.html. Also Russell Gold, "Tab Swells to $25 Billion for Nuclear-Power Plant in Georgia," *Wall Street Journal*, August 2, 2017, https://www.wsj.com/articles/tab-swells-to-25-billion-for-nuclear-power-plant-in-georgia-1501691212.
[65] Supra note 61.
[66] John Downey, "Duke Energy: $13 billion spend would create 14,000 jobs over 10 years," *Charlotte Business Journal*, April 12, 2017, https://www.bizjournals.com/charlotte/news/2017/04/12/duke-energy-plans-13b-in-new-infrastructure.html. "The planned spending would be in addition to the $1 billion Charlotte-based Duke (NYSE:DUK) already spends annually on grid maintenance and upgrades."

OFFICIAL COPY

Oct 12 2017

[67] Southern California Edison, Application A.16-09-001 of Southern California Edison Company (U 338-E) for Authority to Increase Its Authorized Revenues for Electric Service In 2018, Among Other Things, and to Reflect that Increase in Rates, Direct Testimony of Curt Volkmann on Behalf of the Solar Energy Industries Association and Vote Solar, May 2, 2017, p. 6 and p. 10. "*My testimony serves two objectives. First, I will explain why the grid modernization investments proposed by Southern California Edison ("SCE" or "Company") are premature, excessive, and fail to provide net benefits to ratepayers. Second, I will explain how SCE is not taking full advantage of DER (distributed energy resources) and third-party capabilities to minimize costs. . . The total cost to modernize SCE's grid using its proposed approach could exceed $7.5 billion*."
[68] Supra note 6.
[69] Ibid.
[70] Solar Energy Industries Association, "Top 10 Solar States," accessed May 1, 2017, http://www.seia.org/research-resources/top-10-solar-states. North Carolina = 3,016 MW at end of 2016.
[71] Owen Smith and Christa Owens (Rocky Mountain Institute), "5 Reasons For North Carolina's Rapid Emergence As A Solar Energy Leader," *CleanTechnica*, April 29, 2015, https://cleantechnica.com/2015/04/29/5-reasons-for-north-carolinas-rapid-emergence-as-a-solar-energy-leader/.
[72] Ibid.
[73] Ibid.
[74] Herman K. Trabish, "Nearly $1B in applications for North Carolina renewable tax credits under Safe Harbor amendment," *Utility Dive*, January 7, 2016, http://www.utilitydive.com/news/nearly-1b-in-applications-for-north-carolina-renewable-tax-credits-under-s/411676/.
[75] Ibid.
[76] NC Clean Energy Technology Center DSIRE website, "Net Metering: North Carolina Program Overview," http://programs.dsireusa.org/system/program/detail/1246.
[77] Ibid.
[78] Peter Fairley, "Hawaii's Solar Push Strains the Grid: Kauai's utility takes a second stab at battery storage as solar heads toward 80 percent of peak power," *MIT Technology Review*, January 20, 2015, https://www.technologyreview.com/s/534266/hawaiis-solar-push-strains-the-grid/.
[79] KIUC, "HRS [§269-16.4] Annual Fuel Mix Disclosure," http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/rates/FuelMixDisclosure_2016.pdf. 2015 sales = 432,084 MWh.
[80] Herman K. Trabish, "Inside the first municipal solar-plus-storage project in the US," *Utility Dive*, July 5, 2016: http://www.utilitydive.com/news/inside-the-first-municipal-solar-plus-storage-project-in-the-us/421470/.
[81] Ibid.
[82] Peter Maloney, "Cypress Creek to develop 12 solar + storage projects for North Carolina co-op," *Utility Dive*, July 5, 2017: http://www.utilitydive.com/news/cypress-creek-to-develop-12-solar-storage-projects-for-north-carolina-co-/446290/.
[83] Local Energy Aggregation Network, "What Is CCA?," accessed July 14, 2017: http://www.leanenergyus.org/what-is-cca/.
[84] Local Energy Aggregation Network, "CCA by State," accessed July 14, 2017: http://www.leanenergyus.org/cca-by-state/.
[85] California Assembly Bill 117 (2002), http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_bill_20020924_chaptered.pdf.
[86] California Public Utilities Commission press release, *CPUC and California Energy Commission to Hold En Banc on Customer Choice in Electricity in California*, April 11, 2017, http://www.energy.ca.gov/releases/2017_releases/2017-04-11_Retail_Choice_En_Banc_ma.pdf.
[87] John Farrell, "What if…Your Electric Utility Was a Benefit Corporation?," *Renewable Energy World*, February 14, 2015, http://www.renewableenergyworld.com/ugc/articles/2017/02/13/what-ifyour-electric-utility-was-a-benefit-corporation.html.
[88] B Lab website, "Green Mountain Power," https://www.bcorporation.net/community/green-mountain-power.
[89] B Lab website, "About B Lab," https://www.bcorporation.net/what-are-b-corps/about-b-lab.
[90] Green Mountain Power, "Green Mountain Power and SunCommon Launch First Vermont Solar Storage Partnership," news release, September 14, 2016, http://www.greenmountainpower.com/press/green-mountain-power-suncommon-launch-first-vermont-solar-storage-partnership/.
[91] Supra note 87.

OFFICIAL COPY

Oct 12 2017

[92] South Carolina Energy Office (SCEO) *Carolinas Energy Planning for the Future*, December 2016, p. 21, https://www.advancedenergy.org/wp-content/uploads/2016/12/SCEO_Carolina_Energy_Report_FINAL-WEB.pdf.
[93] Ibid., p. 21.
[94] North Carolina House Bill 589, signed into law on July 27, 2017, http://www.ncleg.net/Sessions/2017/Bills/House/PDF/H589v6.pdf.
[95] California Public Utilities Commission, "Energy Efficiency Strategic Plan," April 29, 2017, http://www.cpuc.ca.gov/General.aspx?id=4125.
[96] California Solar Initiative, "California Distributed Generation Statistics," http://www.californiadgstats.ca.gov/.
[97] California Public Utilities Commission, *California Energy Efficiency Strategic Plan: January 2011 Update*, January 2011, p. 11, http://www.cpuc.ca.gov/General.aspx?id=4125.
[98] DEC 2016 IRP, p. 45-46; DEP 2016 IRP, p. 46. Also see Tables 7 and 8.
[99] DEC, 2016 IRP, p. 75 (#1, base case scenario).
[100] Supra note 94.
[101] National Renewable Energy Laboratory (NREL), *Economic Analysis Case Studies of Battery Energy Storage with SAM*, November 2015, p. 1, http://www.nrel.gov/docs/fy16osti/64987.pdf.
[102] Jeff St. John, "Tesla and Green Mountain Power: Get Your Behind-the-Meter Battery for $15 a Month," *GreenTech Media*, May 12, 2017, https://www.greentechmedia.com/articles/read/tesla-and-green-mountain-power-get-your-behind-the-meter-battery-for-15-a-m.
[103] Southern California Edison, Application A.14-11-012, *SCE-1: Testimony of Southern California Edison Company on the Results of Its 2013 Local Capacity Requirements Request for Offers (LCR RFO) for the Western Los Angeles Basin*, November 21, 2014, pp. 57-58.
[104] Solar Energy Industries Association, "State Solar Policy – North Carolina Solar," accessed May 2, 2017, http://www.seia.org/state-solar-policy/north-carolina.
[105] U.S. Energy Information Administration, *Sales to Ultimate Customers (Megawatthours) by State by Sector by Provider, 1990-2015*, October 12, 2016: https://www.eia.gov/electricity/data.cfm#sales.
[106] Ibid.
[107] Ibid.
[108] Ibid., Table 5. Electric power industry generation by primary energy source, 1990 through 2015.
[109] Supra note 64.
[110] Supra note 66.
[111] Supra note 61.
[112] Herman K. Trabish, "Utilities in hot water: Realizing the benefits of grid-integrated water heaters," *Utility Dive*, June 20, 2017, http://www.utilitydive.com/news/utilities-in-hot-water-realizing-the-benefits-of-grid-integrated-water-hea/445241/. "DR and storage can result in the very real benefit of helping utilities avoid the $1,000 per kW cost of a peaker plant, [Portland General Electric Director of Retail Technology Strategy Conrad Eustis] said."
[113] Supra note 104.
[114] Center for American Progress, *The Economic Benefits of Investing in Clean Energy*, June 2009, Table 4 – building retrofits, p. 28.
[115] Supra note 61.
[116] Krysti Shallenberger, "Massachusetts targets 200 MWh of energy storage by 2020," *Utility Dive*, June 30, 2017, http://www.utilitydive.com/news/massachusetts-targets-200-mwh-of-energy-storage-by-2020/446281/.
[117] Ibid.
[118] Supra note 105, Table 8. Retail sales, revenue, and average retail price by sector, 1990 through 2015.
[119] NREL, "Distributed Generation Renewable Energy Estimate of Costs," updated February 2016 (webpage), http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html.
[120] Supra note 105, Table 8. Retail sales, revenue, and average retail price by sector, 1990 through 2015.
[121] David Tucker and Jennifer Weiss, *Residential Electricity Rates and Pricing in North Carolina 2014*, Environmental Finance Center (University of North Carolina), July 2014, p. 14, https://efc.sog.unc.edu/sites/www.efc.sog.unc.edu/files/Residential%20Electricity%20Rates%20and%20Pricing%20in%20North%20Carolina%202014_FINAL.pdf.
[122] Supra note 119.
[123] NREL, "NREL Report Shows U.S. Solar Photovoltaic Costs Continuing to Fall in 2016," September 28, 2016: http://www.nrel.gov/news/press/2016/37745.

OFFICIAL COPY
Oct 12 2017

[124] S. Miller, Yes Solar Solutions, e-mail to A. Henry, NC WARN, April 26, 2017.
[125] Bruce Henderson, "Duke Energy says solar power will cost N.C. customers $1 billion too much," *Charlotte Observer*, February 24, 2017: http://www.charlotteobserver.com/news/local/article134736169.html.
[126] Supra note 94.
[127] Ibid.
[128] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation*, January 2010, Table 14, p. 54, http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.
[129] Energy & Environmental Economics (E3), *Capital Cost Review of Power Generation Technologies*, March 2014, p. 16, https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.
[130] U.S. Energy Information Administration, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017*, April 2017, Table 1a: Estimated LCOE (weighted average of regional values based on projected capacity additions) for new generation resources, plants entering service in 2022, p. 7, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.
[131] U.S. Energy Information Administration, *Annual Energy Outlook 2017*, January 5, 2017, Table A1: Total Energy Supply, Disposition, and Price Summary Case: Reference Case, Total Energy: Real Prices: Henry Hub, https://www.eia.gov/outlooks/aeo/.
[132] Ibid.
[133] Ibid.
[134] Crossborder Energy, *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*, October 18, 2013, Table 5, p. 9.
[135] Duke Energy, DEC residential TOU with demand charge tariff, July 1, 2015, https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/ncschedulert.pdf?la=en, and DEP residential TOU tariff, July 1, 2016, https://www.progress-energy.com/assets/www/docs/home/R-TOUD.pdf.
[136] Supra note 101, pp. 7-9.
[137] PEPCO Holdings, Inc. et al, *Model-Based Integrated High Penetration Renewables Planning and Control Analysis Final Report*, DOE Award Number: DE-EE0006328, December 10, 2015, p. 16, https://www.osti.gov/scitech/servlets/purl/1229729.
[138] Supra note 119.
[139] NREL PV Watts calculator: http://pvwatts.nrel.gov/.
[140] Supra note 105, Table 8. Retail sales, revenue, and average retail price by sector, 1990 through 2015.
[141] Ryan Randazzo, "Battery surge: The technology is here, but 'demand rates' might be key to promoting them," *Arizona Republic*, June 13, 2016, http://www.azcentral.com/story/money/business/energy/2016/06/13/battery-surge-technology-here-but-demand-rates-might-key-promoting-them/85573366/.
[142] Supra note 102.
[143] Ibid.
[144] Tesla, Powerwall webpage, accessed June 11, 2017, https://www.tesla.com/powerwall#design.
[145] Supra note 119.
[146] Supra note 144.
[147] Supra note 103, p. 71.
[148] Julia Pyper, "Tesla, Greensmith, AES Deploy Aliso Canyon Battery Storage in Record Time," *GreenTech Media*, January 31, 2017, https://www.greentechmedia.com/articles/read/aliso-canyon-emergency-batteries-officially-up-and-running-from-tesla-green.
[149] Peter Maloney, "How can Tucson Electric get solar + storage for 4.5¢/kWh?," *Utility Dive*, May 30, 2017, http://www.utilitydive.com/news/how-can-tucson-electric-get-solar-storage-for-45kwh/443715/.
[150] Ibid.
[151] Gavin Bade, "Hawaii co-op signs deal for solar + storage at 11cents/kWh," *Utility Dive*, January 10, 2017, http://www.utilitydive.com/news/hawaii-co-op-signs-deal-for-solarstorage-project-at-11kwh/433744/.
[152] KIUC, "Hawaii's First Utility Scale Solar-Plus-Battery Storage System Is Energized on Kauai," news release, March 8, 2017, http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/pr/pr2017-0308-KIUC%20Tesla%20plant%20energized.pdf.
[153] Synapse Energy Economics, Inc., *Distributed Solar in the District of Columbia - Policy Options, Potential, Value of Solar, and Cost-Shifting*, April 12, 2017, pp. 10-11, http://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf.

OFFICIAL COPY
Oct 12 2017

[154] Supra note 134, Tables 2 and 3, p. 3.
[155] Brookings Institution, *Rooftop solar: Net metering is a net benefit*, May 23, 2016, p. 4, https://www.brookings.edu/research/rooftop-solar-net-metering-is-a-net-benefit/.
[156] Supra note 153, Figure ES-3, p. 11.
[157] NREL, *Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment*, January 2016, Table 3, p. 26 and Table 5, p. 32, http://www.nrel.gov/docs/fy16osti/65298.pdf.
[158] Ibid., p. v.
[159] Supra note 153, p. 99.
[160] Supra note 153, p. 95.
[161] Dr. Donald Shoup, *The High Cost of Free Parking*, March 2005, published by American Planning Association, Chapter 1.
[162] Jim Trauth, Envision Solar, estimate of solar parking lot potential in San Diego County, e-mail to B. Powers, Powers Engineering, June 13, 2007.
[163] NREL, *U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis*, July 2012, Figure 2, p. 10.
[164] Ibid., Appendix A, Table A-1, p. 24.
[165] Ibid., Figure 2, p. 10.
[166] Environmental Protection Agency, "RE-Powering Mapping and Screening Tools," RE–Powering Screening Dataset, updated May 9, 2017, https://www.epa.gov/re-powering/re-powering-mapping-and-screening-tools/.
[167] Ibid.
[168] Brunswick Electric Membership Corporation, "Community Solar," accessed June 20, 2017, http://www.bemc.org/content/community-solar.
[169] SolarPlaza, *The Revised Feed-In Tariff: A New Chapter for Solar in Japan*, March 17, 2017, http://solarassetmanagement.asia/news/2017/3/13/the-revised-feed-in-tariff-a-new-chapter-for-solar-in-japan.
[170] SolarPlaza, *Whitepaper - Insights Into Japan's FIT Regulation*, February 2, 2017, p. 1. "By the end of 2016, around 43 GW of solar PV capacity had cumulatively been installed in Japan."
[171] Supra note 96.
[172] Supra note 76.
[173] Supra note 96.
[174] Navigant, *Distributed Renewable Energy Assessment Final Report*, prepared for PIER Program, California Energy Commission, August 11, 2009, p. 21.
[175] PEPCO Holdings, Inc. et al., *Model-Based Integrated High Penetration Renewables Planning and Control Analysis Final Report*, DOE Award Number: DE-EE0006328, December 10, 2015, https://www.osti.gov/scitech/servlets/purl/1229729.
[176] Navigant, *Virginia Solar Pathways Project , Study 1: Distributed Solar Generation Integration and Best Practices Review - Final Report*, prepared for Dominion Virginia Power (DVP), April 30, 2016.
[177] Supra note 175, p. 13. "Similar to the capacitor design improvement, the utility estimates that this improvement would cost $500 per voltage regulator on the feeder. This included the cost of rolling a service truck and the labor of the line crew to change the load tap changer or voltage regulator setting."
[178] Ibid., pp. 14-15.
[179] Ibid., p. 13. "Utility cost estimates for this feeder improvement are $3,000 to remove an existing capacitor bank, $10,000 to move a capacitor bank (including the removal) and $25,500 to purchase and install a new capacitor bank."
[180] Ibid., p. 14. "The utility estimates the cost of this control system at $20,000 per voltage regulator and load tap changer on the feeder."
[181] NREL, *High-Penetration PV Integration Handbook for Distribution Engineers*, January 2016, p. 71: http://www.nrel.gov/docs/fy16osti/63114.pdf.
[182] California Energy Commission, *2007 Integrated Energy Policy Report*, December 5, 2007, p. 155: http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF.
[183] Supra note 175, Appendix A – individual performance profiles for 20 feeder profiles, December 2015.
[184] DEC 2016 IRP, Table 8-D, p. 41.
[185] DEP 2016 IRP, Table 8-D, p. 42.
[186] Telephone communication between A. Acharya-Menon – PEPCO Holdings, Inc. and B. Powers, Powers Engineering, April 27, 2017.

OFFICIAL COPY

Oct 12 2017

[187] Supra note 176, p. 26.
[188] Supra note 50.
[189] Supra note 175, pp. 12-16.
[190] Ibid., p. 35.
[191] Ibid., p. 40.
[192] S. Steffel – PEPCO Holdings, Inc., e-mail communication (including attached PEPCO memo titled "The Problem with Reverse Power on Substation Distribution Power Transformers") with B. Powers, Powers Engineering, April 24, 2017.
[193] A. Acharya-Menon – PEPCO Holdings, Inc., e-mail communication with B. Powers, Powers Engineering, April 25, 2017.
[194] S. Steffel, A. Acharya-Menon – PEPCO Holdings, Inc., *Model-Based Integrated High Penetration Renewables Planning and Control Analysis*, PowerPoint presentation, October 22, 2015, p. 20, http://ceeep.rutgers.edu/wp-content/uploads/2013/11/NrelWorkshopPres.pdf.
[195] Supra note 176, Table 3-1, p. 14.
[196] Ibid.
[197] Supra note 176, Figure 3-18, p. 39.
[198] Engerati, "Smart Inverters To Connect Distributed Generation in California," January 21, 2015, https://www.engerati.com/article/smart-inverters-connect-distributed-generation-california. "Georgia Power requires that small solar generators use advanced inverters to provision reactive power."
[199] M. Zuercher-Martinson (Solectria Renewables, LLC), "Smart PV inverter benefits for utilities," *Photovoltaics World*, November/December 2011, p. 18.
[200] Ibid.
[201] Ibid.
[202] Ibid.
[203] DEC 2016 IRP, p. 104.
[204] Supra note 92, p. 9. "Demand response is a strategy by which customers can opt into a utility program and agree to curtail their energy use during high-demand periods. In return, the utility will compensate the customer at an agreed-upon rate. DEC has established programs called 'PowerManager' for residential and 'PowerShare' for non-residential customers. An additional demand response program is EnergyWise, which allows utilities to cycle customers' air conditioners during peak events."
[205] FERC, *A National Assessment of Demand Response Potential*, October 2009, p. 150: https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.
[206] Ibid.
[207] Solar Energy Industries Association, "State Solar Policy – California Solar," accessed June 5, 2017, http://www.seia.org/state-solar-policy/california.
[208] Supra note 96.
[209] L. Davis (Haas School of Business, University California Berkeley), "Evidence of a Decline in Electricity Use by U.S. Households," *Berkeley Blog*, May 8, 2017, http://blogs.berkeley.edu/2017/05/08/evidence-of-a-decline-in-electricity-use-by-u-s-households/.
[210] Russ Mitchell, "Bolt EV helps boost electric car sales by 91% in California," *Los Angeles Times*, May 20, 2017, http://www.latimes.com/business/autos/la-fi-hy-ev-sales-california-20170519-story.html.
[211] Statista, "Number of registered automobiles in California 2015, by type," https://www.statista.com/statistics/196024/number-of-registered-automobiles-in-california/.
[212] N. Millar (CAISO), *Economic Early Retirement of Gas Fired Generation – Managing the Risk*, April 24, 2017, p. 3.
[213] Statista, "Number of registered motor vehicles in North Carolina in 2013, by vehicle type," https://www.statista.com/statistics/196804/registered-motor-vehicles-in-north-carolina-in-2010-by-vehicle-type/.
[214] Supra note 50, Table 12: Advanced metering, 2007 through 2015, "All meters – 2015."
[215] Supra note 50, Table 8: Retail sales, revenue, and average retail price by sector, 1990 through 2015, "Retail sales – 2015."
[216] Ibid., p. 95.
[217] NREL PVWatts™ Calculator, Raleigh, North Carolina, 4 kW (dc) fixed rooftop system, http://pvwatts.nrel.gov/.
[218] DEC, *FERC FINANCIAL REPORT, 2016 FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report*, April 13, 2017, pdf p. 402.

OFFICIAL COPY

Oct 12 2017

[219] NREL, PVWatts™ Calculator, Raleigh, NC: http://pvwatts.nrel.gov/.
[220] U.S. Energy Information Administration, "Winter residential electricity consumption expected to increase from last winter," December 12, 2016, https://www.eia.gov/todayinenergy/detail.php?id=29112#.
[221] Supra note 15.
[222] Ibid.
[223] NCUC 2015 Annual Report, pdf p. 50-52.
[224] Ibid., pdf p. 51.
[225] Ibid., pdf p. 52.
[226] Ibid.
[227] DEC 2016 IRP, pp. 115-116.
[228] DEP 2016 IRP, pp. 111-112.
[229] Ibid.
[230] Ibid.
[231] DEC, 2016 IRP, p. 121.
[232] Ibid., p. 116.
[233] DEP, 2016 IRP, p. 111.
[234] NCUC 2015 Annual Report, pdf p. 51: "DEC has indicated to the Public Staff that its Demand Side Management (equivalent to DR) resources are used in near emergency situations to maintain reliability and has pointed to its higher level of available operating reserves at the time of the peak and other near peak events that forestalled the need to use DSM."
[235] Ibid., pdf p. 52.
[236] DEC 2016 IRP, pp. 115-122; DEP 2016 IRP, pp. 110-116.
[237] Supra note 234, p. 51.
[238] Supra note 15.
[239] Supra note 112.
[240] Ibid.
[241] Ibid.
[242] Robert Walton, "KCP&L thermostat program shows how regulatory design can make or break DSM," *Utility Dive*, June 7, 2017, http://www.utilitydive.com/news/kcpl-thermostat-program-shows-how-regulatory-design-can-make-or-break-dsm/444397/.
[243] Supra note 134, Table 5, p. 9.
[244] FERC, *A National Assessment of Demand Response Potential*, October 2009, p. 25, https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.
[245] U.S. Department of Energy, *Project Description - Duke Energy Business Services, LLC, Smart Grid Deployment*, November 2015, p. 1, https://www.smartgrid.gov/files/Duke-Energy_Smart-Grid-Deployment_Final-Project-Description.pdf. "Duke also initiated pilot programs for electricity pricing, including time-of-use rates, peak-time rebates, and critical peak pricing. Customers in these pilot programs used smart thermostats, web portals, and direct load control devices to reduce their electricity consumption and peak demand."
[246] ACEEE 2016 Scorecard, EE spending and savings table – all states: http://database.aceee.org/sites/default/files/docs/spending-savings-tables.pdf.
[247] Ibid.
[248] ACEEE 2016 Scorecard, North Carolina: http://database.aceee.org/state/north-carolina.
[249] Ibid.
[250] ACEEE 2016 Scorecard, Rhode Island: http://database.aceee.org/state/rhode-island.
[251] Supra note 246.
[252] Supra note 209.
[253] Goldman Sacks Equity Research, *The Low Carbon Economy: GS SUSTAIN equity investor's guide to a low carbon world, 2015-25*, November 30, 2015.
[254] Supra note 209.
[255] F. John Hay and Lynn Chamberlin, "Home Efficiency: Refrigerators," Nebraska Energy Office, http://www.neo.ne.gov/publications/PDFs/NebGuideRefrigeratorEfficiency.pdf
[256] U.S. Energy Information Administration, *Residential Energy Consumption Survey (RECS) Air conditioning in nearly 100 million U.S. homes*, August 19, 2011.

OFFICIAL COPY
Oct 12 2017

[257] U.S. Department of Energy, "Energy Saver 101: Everything you need to know about home heating," December 16, 2013, https://energy.gov/articles/energy-saver-101-infographic-home-heating.
[258] U.S. Energy Information Administration, "U.S. households' heating equipment choices are diverse and vary by climate region," *Today in Energy*, April 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30672.
[259] Ibid.
[260] Code of Federal Regulations § 430.31 Subpart C – Energy and Water Conservation Standards, https://www.gpo.gov/fdsys/pkg/CFR-2012-title10-vol3/pdf/CFR-2012-title10-vol3-sec430-32.pdf.
[261] Lennox Industries, Inc. XC25 central air conditioner brochure, April, 2015, p. 3 ($2,425 savings calculation), http://www.lennox.com/lib/legacy-res/pdfs/brochures/lennox_xc25_air_conditioner.pdf.
[262] Supra note 260.
[263] 2017 Energy Star Central Air Conditioner Ratings (Lennox XC25), https://www.energystar.gov/index.cfm?c=most_efficient.me_cac_ashp
[264] Supra note 256.
[265] Sears Home Services, "Heating and Cooling Preventive Maintenance," July 15, 2017, https://www.searshomeservices.com/blog/heating-and-cooling-preventive-maintenance. "The average service life of a whole house HVAC unit is 10-14 years."
[266] Michelle Robb (Mitsubishi), "Residential mini-splits: the takeover," *Contractor*, February 14, 2017, http://www.contractormag.com/technology/residential-mini-splits-takeover.
[267] Platts Purchasing Advisor, *HVAC: Centrifugal Chillers*, 2004.
[268] B. Erpelding, P.E. (San Diego Regional Energy Office), "Ultra-efficient All-Variable Speed Chilled-Water Plants – Improving the energy efficiency of chilled-water plants through the utilization of variable speed and the optimization of entire systems," *HPAC Engineering*, March 2006, pp. 35-43.
[269] Ibid.
[270] Environment North Carolina, *Growing Solar in North Carolina: Solar Power's Role in a Clean Energy Future*, 2008, p. 14.
[271] Jim Pierobon, "Carolinas' different approaches on geothermal could provide lessons for Virginia," *Southeast Energy News*, February 6, 2017, http://southeastenergynews.com/2017/02/06/carolinas-different-approaches-on-geothermal-could-provide-lessons-for-virginia/.
[272] NC Clean Energy Technology Center DSIRE website, "North Carolina Profile, Property Assessed Clean Energy (PACE) Financing," September 19, 2015, http://programs.dsireusa.org/system/program/detail/3647.
[273] National Conference of State Legislatures, "On-Bill Financing: Cost-free Energy Efficiency Improvements," April 7, 2015, http://www.ncsl.org/research/energy/on-bill-financing-cost-free-energy-efficiency-improvements.aspx.
[274] Roanoke Electric Cooperative, "Upgrade to $ave," http://roanokeelectric.coopwebbuilder2.com/UpgradeToSave.
[275] Supra note 114, p. 16 and p. 31.

OFFICIAL COPY

Oct 12 2017