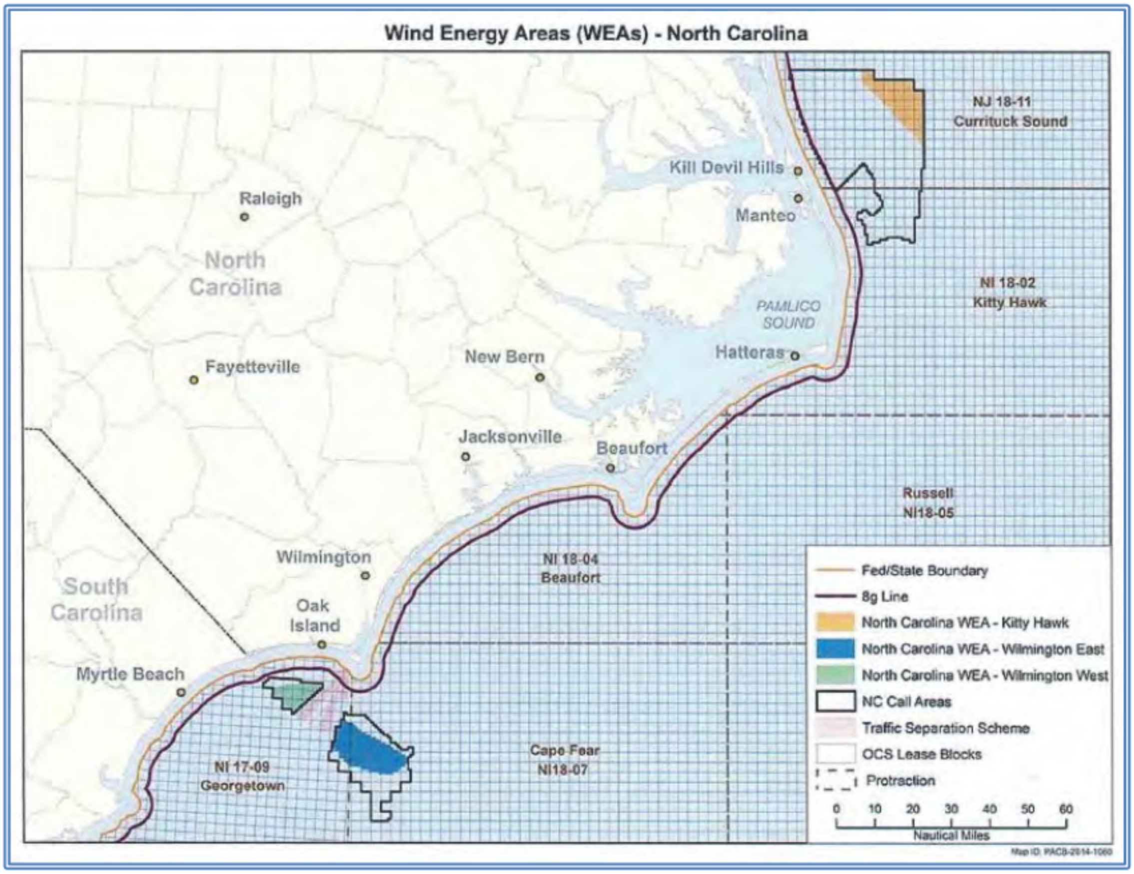
FIGURE G-3

NC WIND ENERGY AREAS (WEAS) (DEVELOPED IN JOINT VENTURE BY DUKE ENERGY AND NREL)



GENERATION FLEXIBILITY AND DUKE ENERGY CLIMATE PLAN

As more intermittent generation becomes associated with Duke's system there is a greater need for generation that has rapid load shifting and ancillary support capabilities. This generation would need to be dispatchable, possess desirable capacity, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or may do so in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of 'generic' plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions.

Additionally, in 2020 Duke Energy released a revision to its previous Climate Report with aggressive goals to reduce output from its generating facilities by 2030 and even deeper reductions by 2050. Duke Energy concluded that it would need new technologies that have not yet reached commercialization status that performed as Zero-Emitting Load-Following Resources (ZELFR). The load-following requirement comes from the flexibility need described above, and the zero-emission portion is to help Duke Energy meet its future climate goals.

Duke Energy is evaluating several generation technologies that are considered pre-commercial to meet the ZELFR need. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and sequestration, fuel cells, hydrogen, long duration energy storage, and supercritical CO2 Brayton Cycle. All of these technologies are expected to help Duke Energy meet future carbon reduction goals if they reach commercial status and are economically competitive.

Duke Energy expects multiple technologies to be required to meet its carbon reduction goals, and therefore Duke Energy is considering potential paths to help move these technologies towards commercialization. One such effort Duke Energy is pursing is the recently announced partnership with two advanced reactor developers on DOE's Advanced Reactor Deployment Program to deploy one of the first two advanced nuclear reactors. Another effort underway is the collaborative work with Siemens as part of DOE's Energy Storage for Fossil Generation Program to evaluate the possibility of hydrogen co-firing at the Combined Heat and Power Plant on Clemson's campus. Duke Energy recognizes the potentially long commercialization timeframe for some of these technologies and will continue to pursue efforts to move these important technologies forward.

Although these technologies all screen out in the process due to their commercial status, Duke Energy will continue to follow a wider range of technologies to meet these future generation needs.

ECONOMIC SCREENING

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves, also referred to as *busbar* curves. By definition, the *Busbar* curve estimates the revenue requirement (i.e. life-cycle cost) of power from a supply option at the "busbar," the point at which electricity leaves the plant (i.e. the high side of the step-up transformer). Duke Energy provides some additional evaluation of a generic transmission and/or interconnection cost adder associated with each technology.

The screening within each general class of busbar (Baseload, Peaking/Intermediate, Renewables and Storage), as well as the final screening across the general classes, uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy. Again, for the 2020 IRP year, Duke Energy has provided an additional set of busbar curves to represent Storage technology comparisons. As Storage technologies are not traditional generating resource options, they should be compared independently from generating resources. In addition, there has been no *charging* cost associated with the storage busbar buildup. This charging cost is excluded as it is dependent upon what the next marginal unit is in the dispatch stack as to what would be utilized to "charge" the storage resource. For resource options inclusive of or coupled with storage, it is assumed that the storage resource is being directly charged by the generating resource (i.e. Solar PV plus Battery Storage option).

This screening (busbar) curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors. The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs. Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

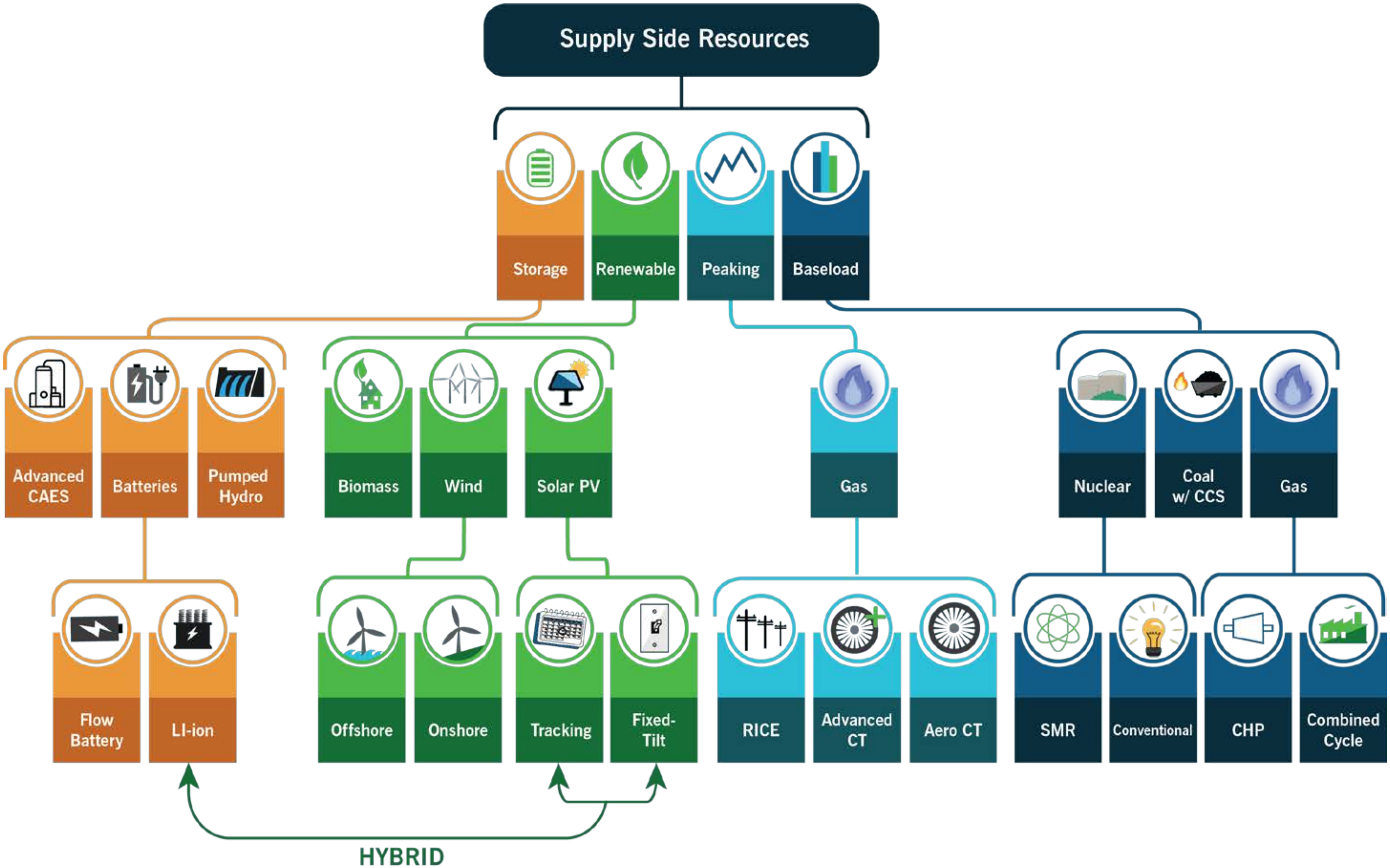
The Company selected the technologies listed below for the screening curve analysis. While future carbon emission constraints may effectively preclude new coal-fired generation, Duke Energy has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for baseload analysis. 2020 additions include Offshore wind, additional Lithium Ion Battery Storage options, Flow Battery Storage, and Advanced Compressed Air Energy Storage.

DISPATCHABLE (WINTER RATINGS)

BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE
601 MW, 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	18 MW, 2 x Reciprocating Engine Plant	10 MW / 10 MWh Lithium-ion Battery	75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
1,224 MW, 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	15 MW Industrial Frame Combustion Turbine (CT)	10 MW / 20 MWh Lithium-ion Battery	5 MW Landfill Gas
782 MW Ultra-Supercritical Pulverized Coal with CCS	192 MW, 4 x LM6000 Combustion Turbines (CTs)	10 MW / 40 MWh Lithium-ion Battery	**NON- DISPATCHABLE (WINTER RATINGS)**
557 MW, 2x1 IGCC with CCS	201 MW, 12 x Reciprocating Engine Plant	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
720 MW, 12 Small Modular Reactor Nuclear Units (NuScale)	752 MW, 2 x J-Class Combustion Turbines (CTs)	50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
2,234 MW, 2 Nuclear Units (AP1000)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	20 MW / 160 MWh Redox Flow Battery	75 MW Fixed-Tilt (FT) Solar PV
9 MW Combined Heat & Power (Reciprocating Engine)		250 MW / 4,000 MWh Advanced Compressed Air Energy Storage	75 MW Single Axis Tracking (SAT) Solar PV
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

FIGURE G-4

DUKE ENERGY, SCREENED-IN SUPPLY SIDE RESOURCE ALTERNATIVES



INFORMATION SOURCES

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include a variety of internal departments at Duke Energy. In additional to the internal expertise, the following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, operating and maintenance costs (O&M), fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No CO_2, With CO_2) in the four major categories defined (Baseload, Peaking/Intermediate, Renewables, Storage).

CAPITAL COST FORECAST

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs but the costs of all resource technologies technically screened in. The Technology Forecast Factors were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides cost projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2020 as a base year, an " annual cost factor is calculated based on the change from a base year for the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2018, April 2019)

From *NEMS Model Documentation 2018, April 2019*:

> *"Uncertainty about investment costs for new technologies is captured in the ECP [Electricity Planning Submodule] using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*
>
> *Learning factors represent reductions in capital costs as a result of learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."*

The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table G-1.

TABLE G-1

SNAPSHOT FROM FORECAST FACTOR TABLE BY TECHNOLOGY (EIA - AEO 2020)

YEAR	FRAME CT	AERO CT	NUCLEAR	BATTERY STORAGE	1X1 COMBINED CYCLE	ONSHORE WIND
2020	1.000	1.000	1.000	1.000	1.000	1.000
2021	0.985	0.987	0.984	0.812	0.987	0.987
2022	0.970	0.973	0.967	0.718	0.973	0.973
2023	0.950	0.961	0.950	0.640	0.961	0.961
2024	0.901	0.953	0.920	0.625	0.953	0.953
2025	0.873	0.945	0.909	0.609	0.945	0.945
2026	0.852	0.937	0.898	0.594	0.937	0.937
2027	0.831	0.928	0.886	0.579	0.927	0.928
2028	0.815	0.918	0.874	0.563	0.918	0.918
2029	0.803	0.907	0.861	0.546	0.907	0.907
2030	0.789	0.896	0.847	0.530	0.896	0.896

SCREENING RESULTS

The results of the screening within each category are shown in the figures below. Results of the baseload screening show that natural gas combined cycle generation is the least-cost baseload resource. With lower gas prices, larger capacities and increased efficiency, natural gas combined cycle units have become more cost-effective at higher capacity factors in all carbon scenario screening cases (i.e. No CO_2 and With CO_2). Although CHP can be competitive with CC, it is site specific and requires a local steam and electrical load. Carbon capture systems have been demonstrated to reduce coal-fired CO_2 emissions to levels similar to natural gas and will continue to be monitored as they mature; however, their current cost and uncertainty of safe, reliable storage options has limited the technical viability of this technology in Duke Energy territories.

The peaking technology screening included F-frame and J-Frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. Simple cycle aeroderivative gas turbines remain in close contention with reciprocating engines. Should a need be identified for one of these two types of resources, a more in-depth analysis would be performed.

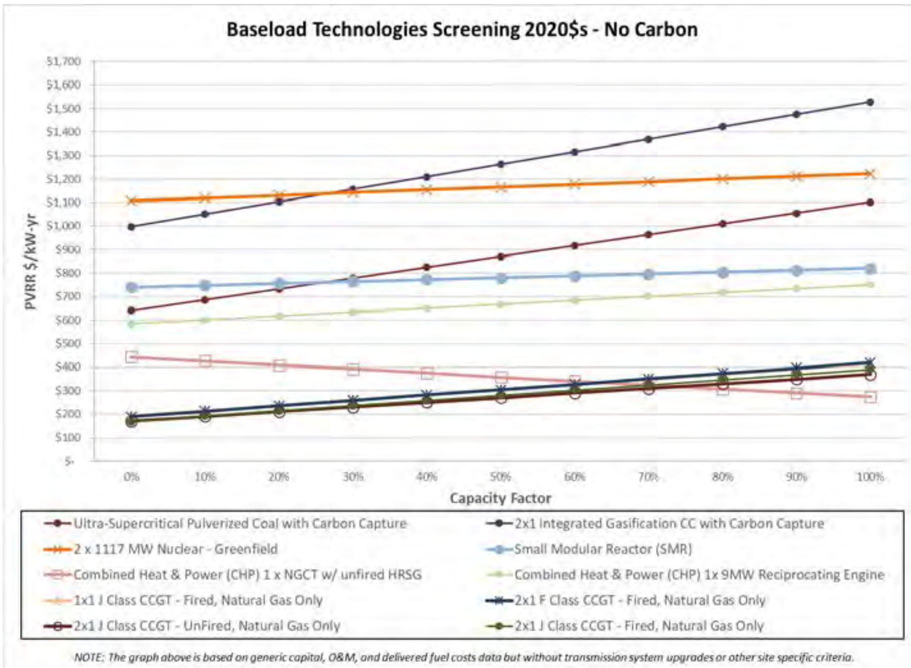
The renewable screening curves show solar continues to be a more economical alternative than other renewable resource options. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas and biomass projects are limited based on site availability but are dispatchable. Landfill gas is not shown in the busbar curve for renewables as the options are limited since most sites have already been transacted with. Although solar PV prices have become competitive with conventional generators, the lack of dispatchability and low capacity factor does not allow it to be a baseload resource.

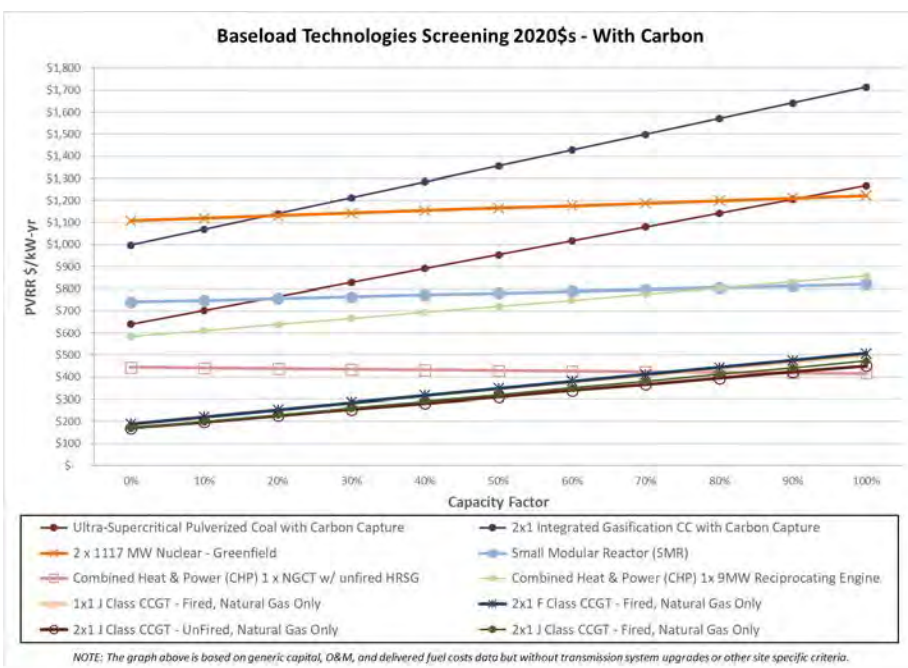
Energy storage has become an increasingly important asset as companies add more variable resources to their portfolio. Energy storage can provide a variety of benefits to the grid and overall resource portfolio. Additional information on energy storage can be found in Appendix H. For the screening results, the lowest $/kW option for energy storage was 1-hour duration Li-Ion storage as expected. However, batteries have a variety of use cases and longer duration storage can be more useful than shorter duration storage in certain cases. Additionally, the $/kWh decreases as the duration of the storage increases. So, although the 1-hour duration Li-Ion battery storage asset had the lowest screening cost, the specific application of the storage option will determine which storage option is the best fit for its use case.

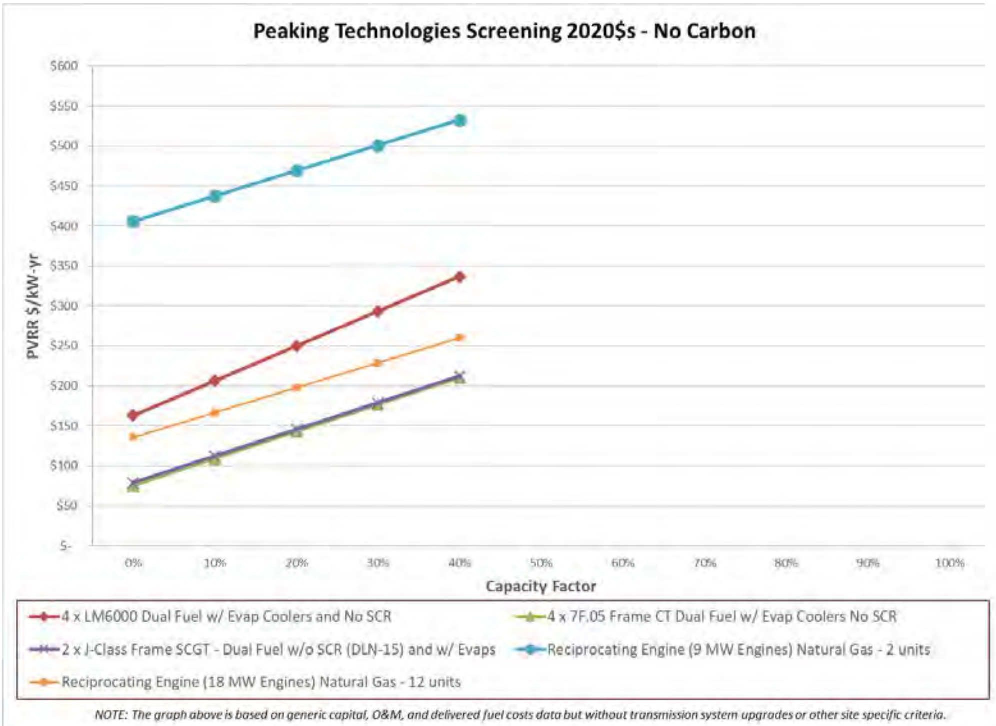
The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

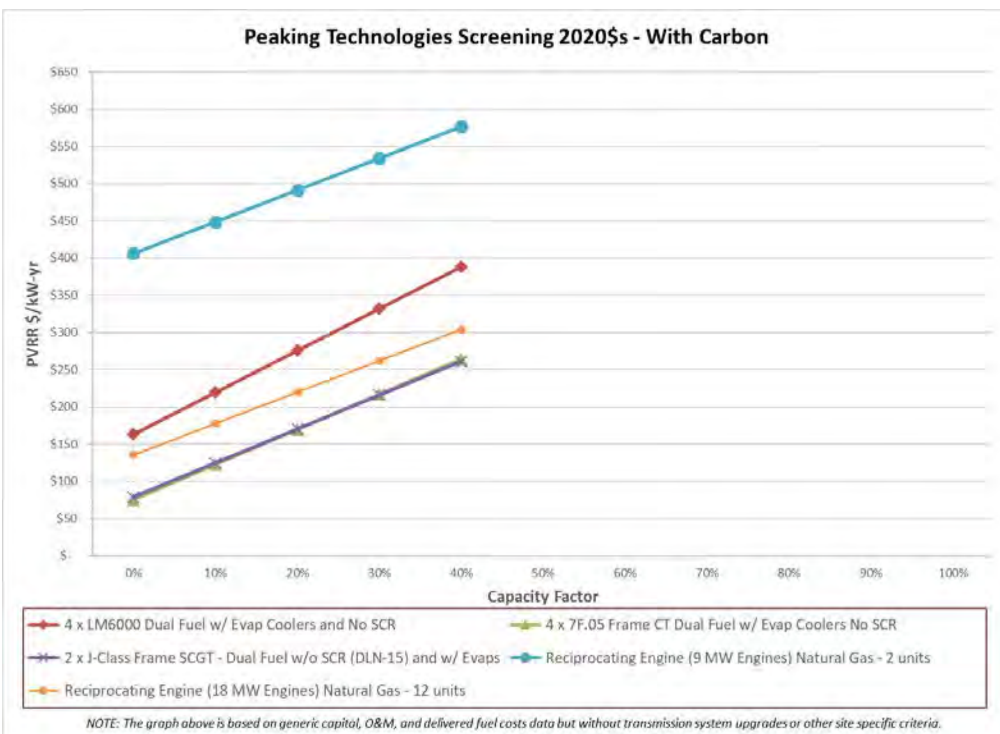
SCREENING CURVES

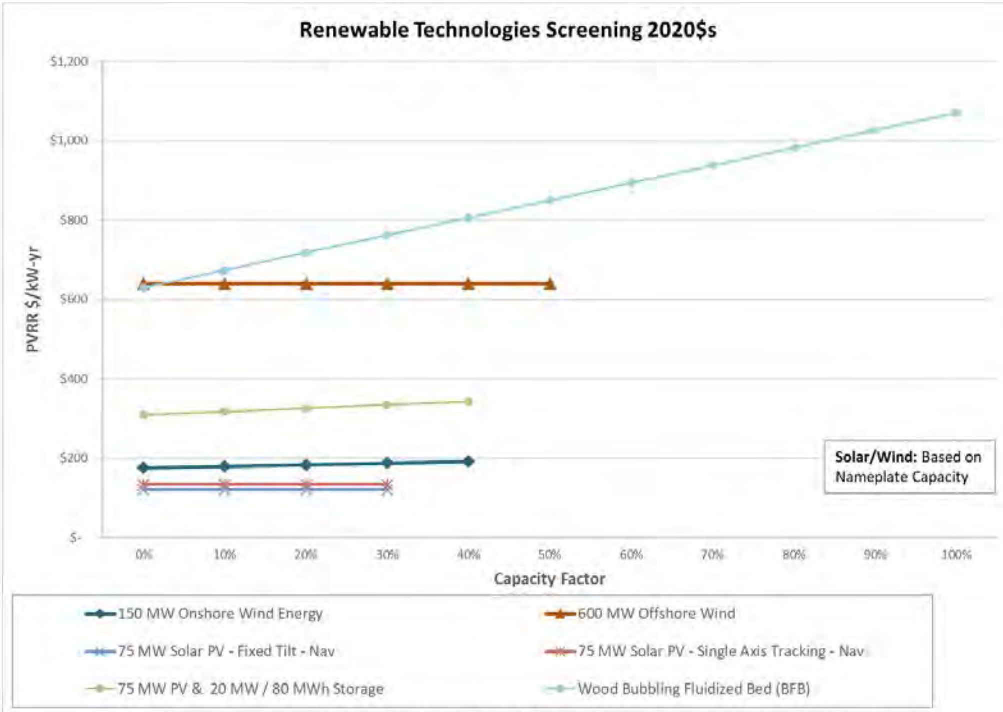
The following pages contains the technology screening curves for baseload, peaking/intermediate, renewable and storage technologies.



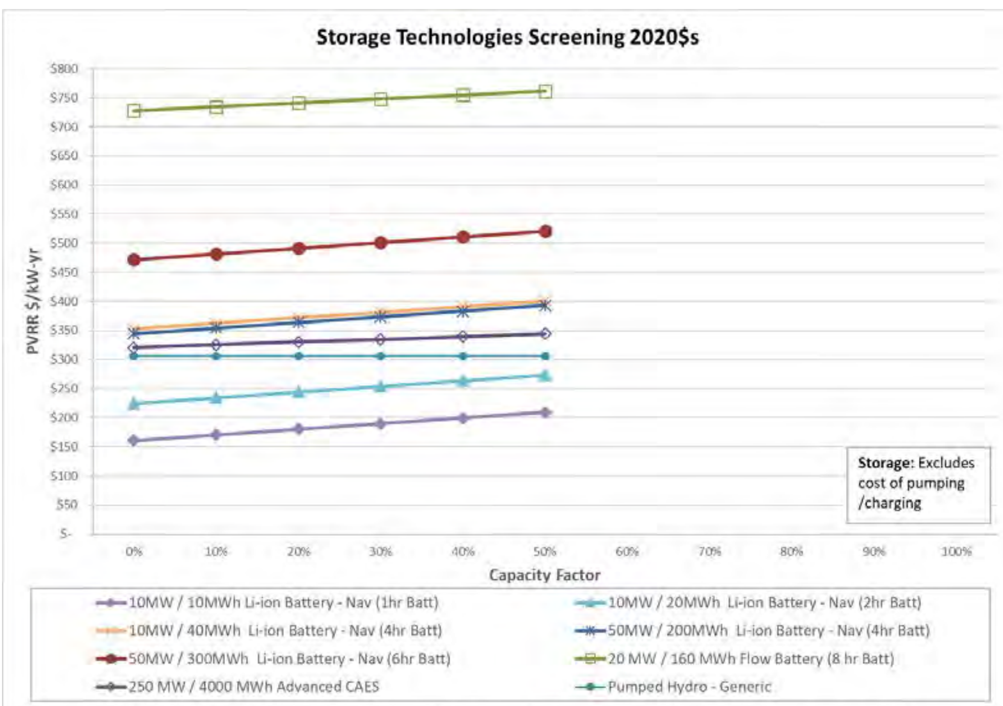



Peaking Technologies Screening 2020$s - No Carbon
PVRR $/kW-yr
$600
$550
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$-
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Capacity Factor
4 x LM6000 Dual Fuel w/ Evap Coolers and No SCR
4 x 7F.05 Frame CT Dual Fuel w/ Evap Coolers No SCR
2 x J-Class Frame SCGT - Dual Fuel w/o SCR (DLN-15) and w/ Evaps
Reciprocating Engine (9 MW Engines) Natural Gas - 2 units
Reciprocating Engine (18 MW Engines) Natural Gas - 12 units
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.


Peaking Technologies Screening 2020$s - With Carbon
PVRR $/kW-yr
$650
$600
$550
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$-
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Capacity Factor
4 x LM6000 Dual Fuel w/ Evap Coolers and No SCR
4 x 7F.05 Frame CT Dual Fuel w/ Evap Coolers No SCR
2 x J-Class Frame SCGT - Dual Fuel w/o SCR (DLN-15) and w/ Evaps
Reciprocating Engine (9 MW Engines) Natural Gas - 2 units
Reciprocating Engine (18 MW Engines) Natural Gas - 12 units
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.

H

ENERGY STORAGE

APPENDIX H: ENERGY STORAGE

Battery storage is expected to play an important role in meeting future needs on the DEP system. As discussed in Chapter 6, battery storage can provide multiple services. For purposes of the 2020 IRP, the Company considered capacity, energy arbitrage, and ancillary service benefits when valuing battery storage. Additionally, the Company conducted a thorough review of battery cost and operating assumptions modeled in the 2020 IRP. Benchmarking battery storage costs across publications is difficult, and oftentimes not possible, due to disparate definitions and incomplete documentation. Some publications do not include the full cost that would be needed to construct a battery storage system that would meet the requirements of a manufacturer's warranty and the needs of the Utility over the life of the asset. For this reason and to provide transparency of the cost estimating process, the Company is detailing the battery storage assumptions used in the 2020 IRP below.

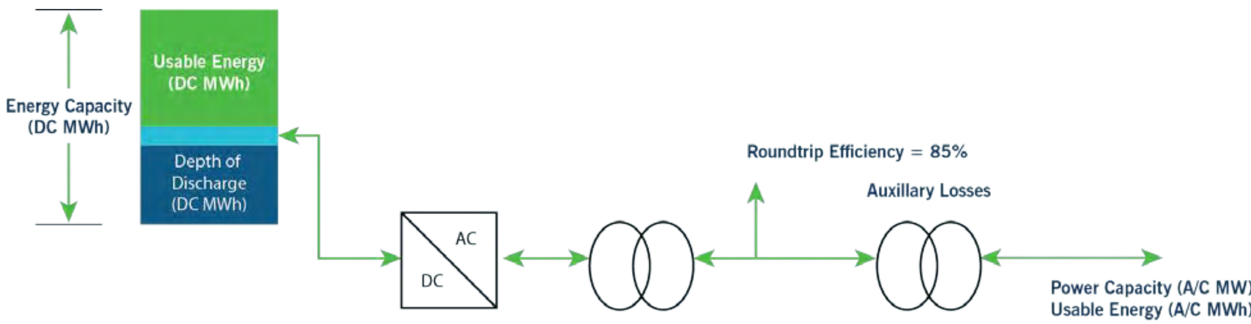
Finally, in order to appropriately estimate the capacity value battery storage can provide, the Company hired a third-party consultant to conduct an Effective Load Carrying Capability (ELCC) study to quantify the contribution to winter peak demand that battery storage could provide in DEP. The results of the ELCC study are described in the following sections and the Battery Storage ELCC study has been filed along with the IRP filing.

BATTERY STORAGE TERMINOLOGY AND OPERATING ASSUMPTIONS

Some of the terminology that the Company uses to describe batteries in the IRP is detailed below. Importantly, while many of the terms and definitions below are standard across the industry, some of the terms are specific to how battery storage is described in this IRP and may not match what is described in other publications. Where appropriate, definitions that are taken directly from outside publications are cited. The following is a diagram of a standalone battery storage system that is modeled in the 2020 IRP.

FIGURE H-1

SIMPLIFIED BATTERY STORAGE SYSTEM MODELED IN 2020 DEP IRP



- **Battery size –** Battery sizing is generally provided in capacity and energy values or capacity value and duration. The terms "capacity", "energy", and "duration" are discussed below. An example of battery size nomenclature is "50 MW / 200 MWh" which represents a 50 MW battery with a 4-hour duration.

- **Capacity –** Generally referred to as "power capacity" in the industry and represents the total possible instantaneous discharge capability of the battery storage system, or the maximum rate of discharge the battery can achieve starting from a fully charged state.[1] The Company measures power capacity at the point of interconnect to the transmission system and the units are "MW AC." The IRP represents the cost of a battery in $/MW where the numerator, or dollars, is the total cost of the battery system and the denominator is the power capacity in MW AC of the system. The components of the total cost of the battery system are described in further detail below.

- **Energy –** The energy that a battery can hold can be represented differently between publications which can make comparing costs between sources of data difficult. For the purposes of this IRP, the Company considers energy in the following manners:

  - **Usable Energy –** Refers to the amount of energy that can be discharged at the point of interconnection over the duration of the battery. Usable energy can be described in units of "MWh AC" or "MWh DC." When the Company discusses the cost of a

[1] https://www.nrel.gov/docs/fy19osti/74426.pdf.

battery on a $/MWh basis, the numerator is the total cost of the battery system and the denominator is the usable energy in units of MWh AC.

- **Depth of Discharge (DoD) –** "Indicates the percentage of the battery that has been discharged relative to the overall [energy] capacity of the battery."[2] In the 2020 IRP, this number represents the amount of energy that must remain, unused, in the battery to satisfy the warranty of the battery and/or allow the battery to complete the expected number of cycles over the life of the asset. For instance, the Company uses a 20% depth of discharge limit which simply means the battery cannot discharge more than 80% of its energy capacity. Some publications only provide battery costs based on the usable energy of the battery thereby ignoring the DoD; however, the Company calculates the cost of a battery based on the energy capacity, which includes the DoD limitation.

- **Energy Capacity –** The total amount of energy that can be stored or discharged by the battery storage system.[3] In the diagram above, energy capacity is the sum of the usable energy and the depth of discharge limit. Energy capacity is defined in units of "MWh DC." The Company did not include additional costs for other "unused" energy required to maintain the contracted usable energy of the battery, such as additional energy capacity to account for DC or AC losses that occur during charge and discharge of the battery. However, within the production cost model, the Company does account for the production cost impacts of losses on roundtrip efficiency of the battery as discussed below.

- **Duration –** "Amount of time storage can discharge at its power capacity. "[4] For example, a battery with 50 MW of power capacity and 200 MWh of usable energy capacity will have a storage duration of 4 hours.

- **Roundtrip Efficiency –** "Measured as a percentage, is a ratio of the energy charged to the battery to the energy discharged from the battery. It can represent the total DC-DC or AC-AC efficiency of the battery system, including losses from self-discharge and other electrical

[2] https://news.energysage.com/depth-discharge-dod-mean-battery-important/#:~:text=A%20battery's%20depth%20of%20discharge,DoD%20is%20approximately%2096%20percent.
[3] U.S. Battery Storage Trends, U.S. Energy Information Administration, May 2018
[4] https://www.nrel.gov/docs/fy19osti/74426.pdf

losses."[5] The Company uses A/C - A/C efficiency as the production cost models only consider the charging/discharging at the point of interconnect to the power system. The Company assumed a roundtrip efficiency of 85% for all lithium-ion (Li-ion) batteries modeled in the 2020 IRP.

- **Auxiliary Losses -** Included as part of other electrical losses in the calculation of round-trip efficiency and can include power required for HVAC systems associated with the battery storage system.

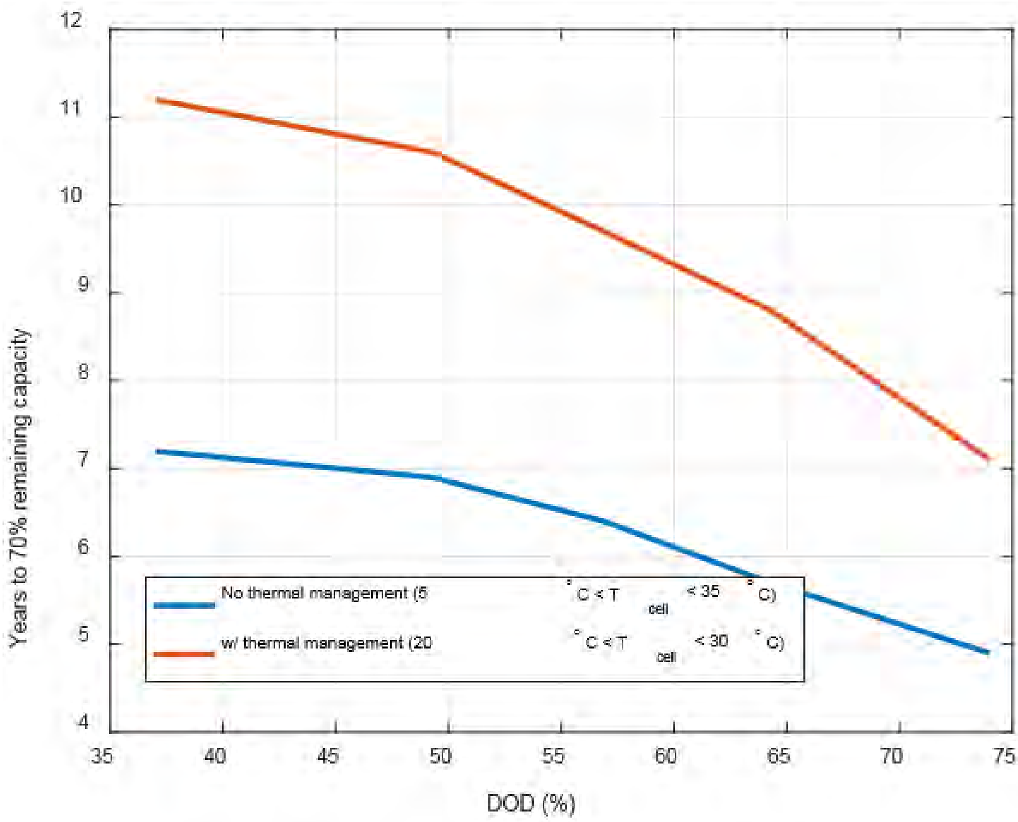
- **Degradation –** The loss of energy capacity of a battery storage system overtime. "Degradation of lithium-ion batteries is impacted by several variables. Known drivers of degradation include: temperature of operation, average state of charge over its lifetime, and depth of charge-discharge cycles."[6] Figure 2, sourced from NREL's "Life Prediction Model for Grid Connected Li-ion Battery Energy Storage System" demonstrates the effects that DoD and temperature management of the battery storage system can have on degradation.

[5] https://www.nrel.gov/docs/fy19osti/74426.pdf

[6] https://www.energy-storage.news/blogs/is-that-battery-cycle-worth-it-maximising-energy-storage-lifecycle-value-wi#:~:text=Battery%20storage%20degradation%20typically%20manifests,need%20for%20replacement%20of%20batteries.

FIGURE H-2

IMPACT OF BATTERY OVERSIZING AND THERMAL MANAGEMENT ON LIFETIME FROM NREL [7]



- **Battery Augmentation –** As a battery storage system experiences degradation, battery cells can be replenished on a regular, or semi-regular, basis to maintain the usable energy of the battery storage system. This strategy to counteract degradation leads to lower initial capital costs but incurs higher on-going costs throughout the life of the asset. For IRP purposes, the Company assumes a Battery Augmentation strategy to minimize total costs over the 15-year assumed life of the battery asset, while recognizing that this approach does present some challenges with maintaining stable performance of the system.

- **Overbuild –** Refers to an increase in the nameplate energy capacity to account for expected degradation. As an alternative strategy to augmentation, the battery storage system can

[7] https://www.nrel.gov/docs/fy17osti/67102.pdf.

initially be physically oversized beyond depth of discharge limits to account for degradation. This strategy yields higher initial capital costs but lower on-going costs versus an augmentation strategy.

BATTERY STORAGE COST ASSUMPTIONS

Battery storage costs have been declining rapidly over the last several years, and they are expected to continue declining for the foreseeable future. In fact, the Company assumes that battery prices will drop by nearly 50% over the next 9 years.[8]

The Company's capital cost assumptions are developed by a third party and are benchmarked against both internal and external sources. Often, the Company's prices appear higher than published numbers. As discussed above, there are several factors that can drive this difference including:

- The Company calculates the cost of a battery storage device assuming a 20% DoD limit while other publications likely only calculate the cost of the battery based on the rated energy of the battery from their information sources, which often do not specify whether their energy rating factors in DoD. In cases where the energy rating does not account for DoD, the cost of the battery can differ by over 10%.

- The Company assumes interconnection costs based on historical costs on the DEP system. Other publications may include lower interconnection costs or may not account for interconnection costs altogether.

- Because the Company expects to rely on these assets for at least 15-years to provide reliable capacity and energy to its customers on a real-time basis, some of the Company's assumptions of software and controls may lead to higher capital costs than a device that is designed to provide capacity and energy with lower reliability standards or on a more standard schedule.

- Similarly, the Company may be including more expensive HVAC and fire detection and suppression assumptions when calculating the cost of the battery storage system. It is the Company's belief that this cost is warranted for safety and protection of employees as well as the assets.

[8] Real 2020$; prices drop by 34% in nominal terms assuming 2.5% inflation rate.

- Due to low installed capacity and limited operational experience with battery storage on the DEP system, the Company assumes that system integration costs of a battery would be on the level of a custom application rather than a basic, or turnkey, level of cost. It is likely however, that as battery storage becomes more pervasive on the DEP system, system integration costs will decline, and battery storage costs could decline further than the near 50% decline already assumed in the IRP. The Company will monitor developments in this area and adjust as appropriate in future IRPs.

As stated previously, it is very difficult to determine what is included in the cost assumptions for battery storage in publications, particularly with regards to software and controls, HVAC, fire detection and suppression, and system integration costs. The following are the assumptions the Company includes for the percent contribution of costs from various components of a battery storage system along with the projected cost trend through 2029 in nominal terms assuming 2.5% inflation.[9]

TABLE H-1
COST COMPONENTS OF BATTERY STORAGE IN 2020 IRP

COMPONENT	% OF TOTAL COST [10]	PROJECTED COST TREND THROUGH 2029
Battery Pack	53%	-51%
Power Electronics	3%	-40%
Software and Controls	1%	-8%
Balance of Plant	9%	-15%
Systems Integration	15%	-30%
Site Installation	8%	3%
Project Development Fees	6%	-24%
Interconnection Fees	5%	25%

As further context to the above cost allocations and assumptions, EPRI recently conducted a survey of its members regarding cost assumptions of battery storage. Many members use public sources such as NREL, Lazard, and EPRI, in addition to commercial third-party forecasts and in-house SME

[9] Initial value based on 2020 cost of a 50 MW / 200 MWh battery storage system in the 2020 IRP.
[10] Values based on total cost without owner's costs. Owner's costs are consistent with the costs incurred during the development of the Company's previous storage projects.

input, when developing battery storage price forecasts. Importantly, members do not simply rely on published numbers without making some adjustments. Members identified adding costs for items such as interconnection, A/C balance of plant, substation, land, and civic infrastructure. Nearly half of respondents factor in costs associated with a state of charge (SOC) window or depth of discharge limitation when developing cost estimates. Finally, one cost that DEP does not account for are end-of-life costs for disposal and recycling of battery storage components. Just over half of respondents account for these costs and the Company will evaluate adding end-of-life costs in future IRPs.

EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) OF BATTERY STORAGE

The Company commissioned Astrape Consulting, a nationally recognized expert in the field, to conduct a Storage Effective Load Carrying Capability (ELCC) Study of battery storage to determine the capacity value that short-duration storage can provide towards meeting DEP's winter peak demand. The ELCC study evaluated both standalone storage, as well as DC coupled solar plus storage over a range of storage penetrations, durations, and solar levels. The results of the study are highlighted below, and the full report is filed with the IRP as Attachment IV. Importantly, the study confirmed that initial additions of storage can provide nearly 100% contribution to winter peak, however the ELCC contribution of energy storage decreases rapidly with increasing penetration of battery storage as is the case with any energy limited resource.

STANDALONE STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study under a base level of solar (4,000 MW) and a high level of solar (5,500 MW).

TABLE H-2
STANDALONE STORAGE RUN MATRIX FOR ELCC STUDY

	STANDALONE BATTERY DURATION (HRS)		
Duration / Cumulative Battery Capacity	2	4	6
800 MW			
1,600 MW (incr 800)			
2,400 MW (incr 800)			
3,200 MW (incr 800)			

The sensitivities analyzed in the matrix above were conducted separately for each battery duration. For example, 6-hour batteries were studied as if there were no 4-hour or 2-hour batteries on the DEP system. In this manner, the ELCC represents the value of a 6-hour battery without the impacts of other incremental storage on the system. An additional sensitivity was analyzed which studied the impacts of 6-hour storage if up to 1,600 MWs of 6-hour storage were placed on the system *after* 3,200 MWs of 4-hour storage were already operating in DEP.

The ELCC of standalone storage was determined separately under the following three conditions:

- Preserve Reliability – Assumes full control of the battery and only dispatches the battery during emergency events to avoid firm load shed, maintains charge at all times possible. Results in highest possible capacity value but low economic value.

- Economic Arbitrage – Assumes DEP maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.

- Fixed Dispatch – Assumes DEP has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEP did not have dispatch rights to the storage asset.

The following three charts depict the capacity value of 2-hour, 4-hour, and 6-hour storage under the three operating conditions described above.

FIGURE H-3
AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN PRESERVE RELIABILITY MODE

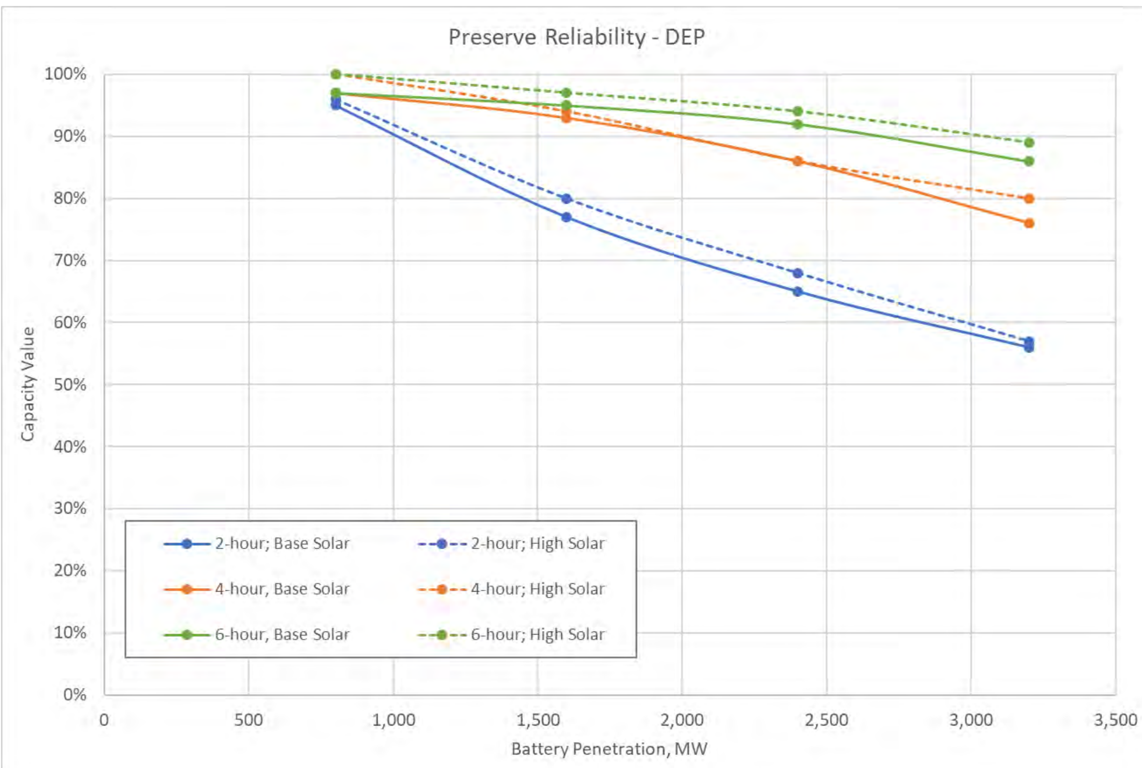


FIGURE H-4

AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN ECONOMIC DISPATCH MODE

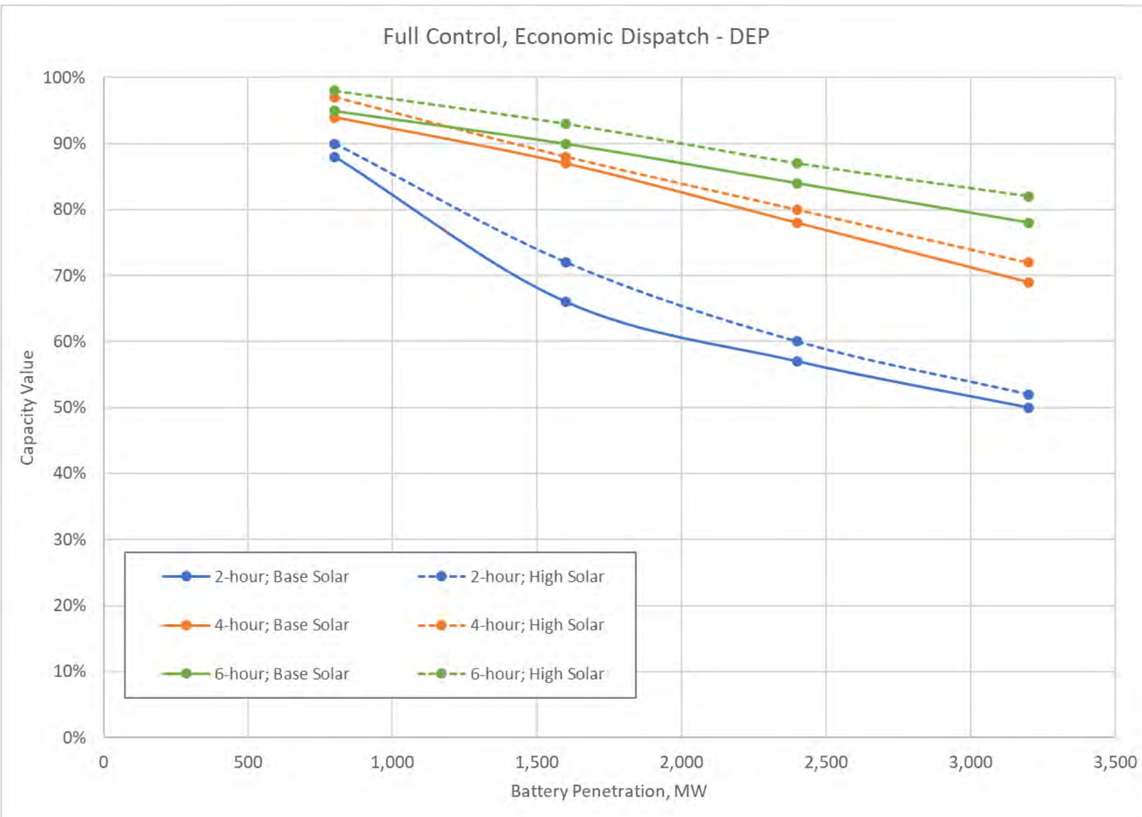
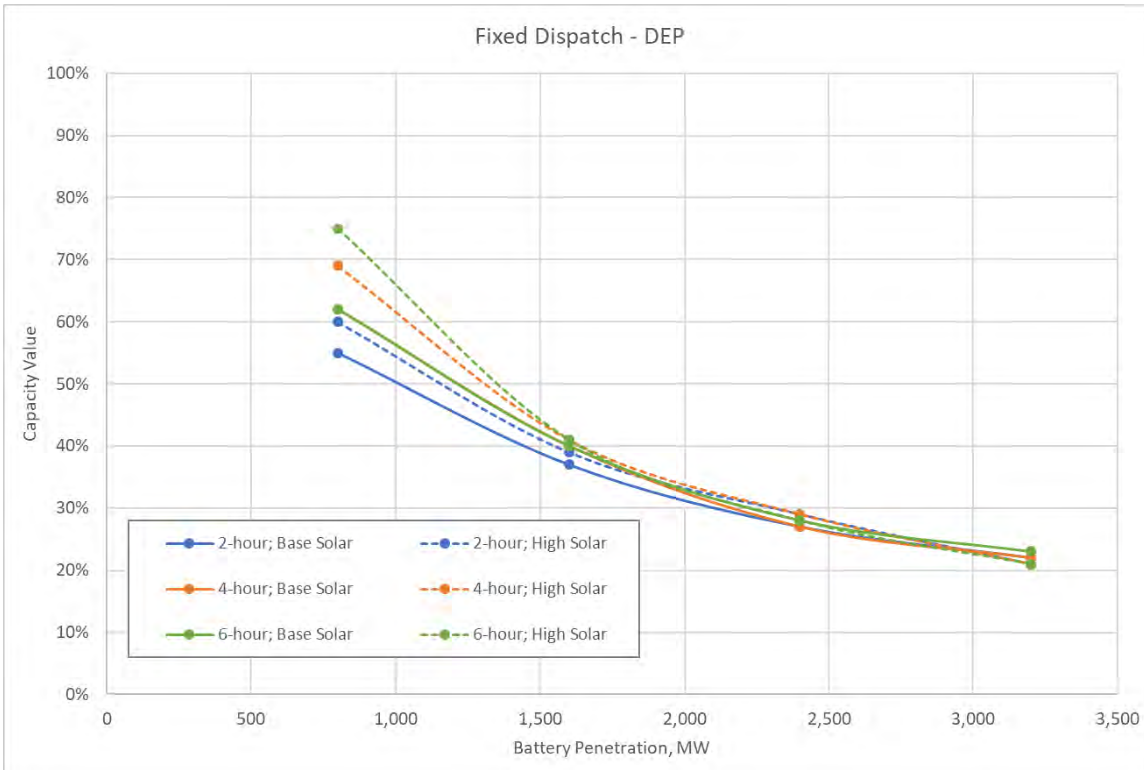


FIGURE H-5

AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN FIXED DISPATCH MODE



The results of the sensitivity of 6-hour storage added after 3,200 MW of 4-hour storage are shown in the following chart.

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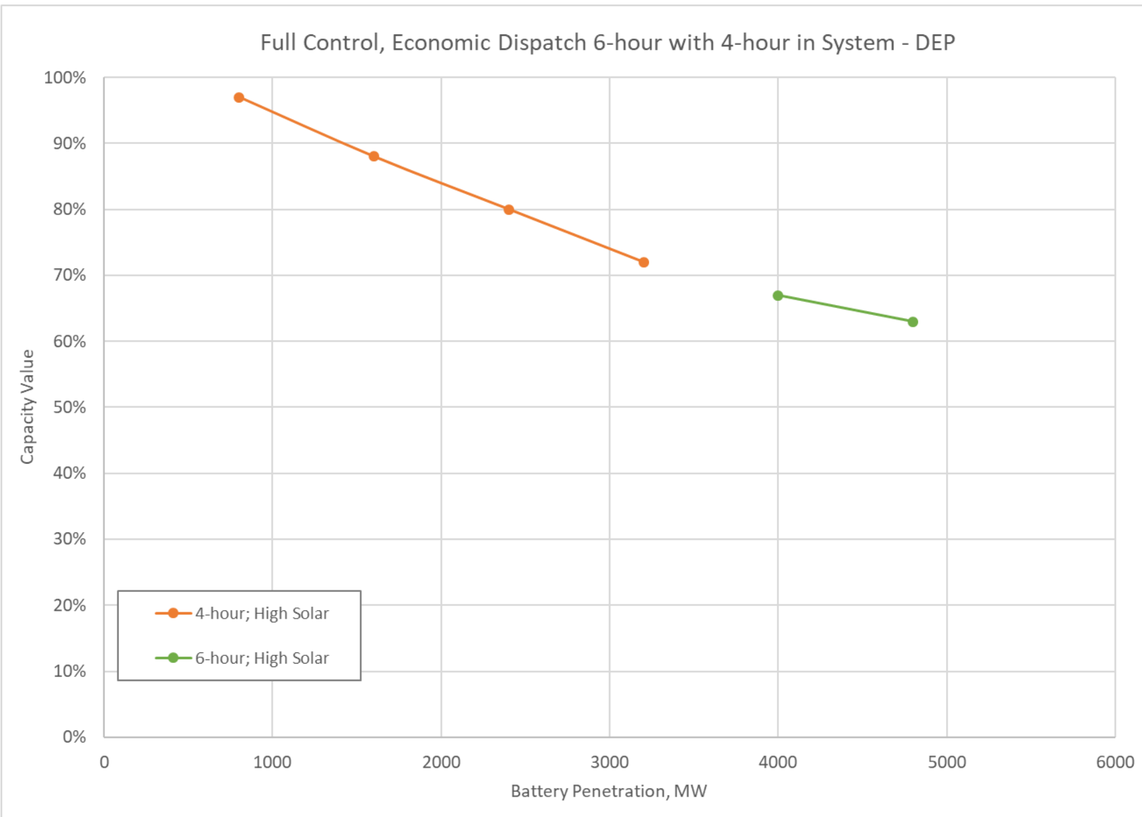
FIGURE H-6

AVERAGE CONTRIBUTION TO DEP WINTER PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM



Based on the results of the study, DEP made the following assumptions in development of the 2020 IRP:

- All storage capacity values based on Economic Dispatch – The IRP model maximizes the value of battery storage by charging the battery with lower cost energy and discharging the stored energy during periods where energy has more value. The model does not maintain full charge in all hours and forego economic benefit to customers to ensure the battery is available to meet demand if a generator on the system experiences an unplanned outage. Similarly, in practice, a board operator does not have perfect foresight of forced outages and would likely use the battery when it is economically prudent based on what they see at the time. Alternatively, as demonstrated in the results above, the value of battery storage for DEP's customers is maximized when the utility maintains dispatch rights for the battery asset. For these reasons, the Company relied on the ELCC results modeled under Economic Arbitrage conditions.

- Only 4-hour and 6-hour storage considered for standalone storage – Under all dispatch options, the value of 2-hour storage quickly diminishes as their penetration increases on the system. As shown in the Resource Adequacy discussion in Chapter 9, even though most of the LOLH occurs in the hour beginning 7AM, DEP has LOLH over a range of hours in the morning and evening which limits the value that 2-hour storage can provide to the system. Additionally, Two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish.

While the above results show the average capacity value attributed to varying levels of storage on the DEP system, the incremental value of adding 800 MW blocks of storage can be calculated from the results. The incremental values are useful when determining the capacity value of the next block of energy storage, particularly when evaluating replacing a CT with a 4-hour battery as discussed in Appendix A and the economic coal retirement discussion Chapter 11. The incremental capacity value of storage assumed in the IRP is shown in the following table.

TABLE H-3

INCREMENTAL CONTRIBUTION TO PEAK FOR 4- AND 6-HOUR STORAGE IN DEP

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
Base Renew	4-hour	0 - 800	95%
		800 - 1,600	80%
		1,600 - 2,000	70%
	6-hour	0 - 800	95%
		800 - 1,600	85%
		1,600 - 2,600	70%
High Renew	4-hour	0 - 800	100%
		800 - 1,600	80%
		1,600 - 2,100	70%
	6-hour	0 - 800	100%
		800 - 1,600	90%
		1,600 - 2,400	75%

For planning purposes, the Company installed a lower limit of 70% incremental contribution to winter peak before moving to 6-hour storage. In that case, DEP assumed the following incremental contribution to winter peak for 4- and 6-hour storage.

TABLE H-4
INCREMENTAL CONTRIBUTION TO PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
High Renew	4-hour	0 - 800	100%
		800 - 1,600	80%
		1,600 - 2,100	70%
	6-hour	2,100 - 3,000	65%
		3,000 - 3,800	55%
		3,800 - 4,800	45%

SOLAR PLUS STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study assuming a 2-hour or 4-hour battery were coupled with solar.

TABLE H-5
SOLAR PLUS STORAGE RUN MATRIX FOR ELCC STUDY

PROJECT MAX CAPACITY (MW)	SOLAR CAPACITY (MW)	TOTAL BATTERY (MW/% OF SOLAR)	REGION EXISTING SOLAR BEFORE ADDING COMBINED PLUS STORAGE PROJECT (MW)
800	800	80 (10%)	3,200
800	800	240 (30%)	3,200
800	800	400 (50%)	3,200
1,600	1,600	160 (10%)	3,900
1,600	1,600	480 (30%)	3,900
1,600	1,600	800 (50%)	3,900

Solar plus storage capacity value was analyzed with 2- and 4-hour battery storage representing 10%, 30%, and 50% of the nameplate solar MW. This evaluation was conducted with 800 and 1,600 MW of solar paired with storage out of 4,000 MW to 5,500 MW of total solar on the DEP system. The ELCC of standalone storage was determined separately under the following two conditions:

- **Economic Arbitrage –** Assumes DEP maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.

- **Fixed Dispatch –** Assumes DEP has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEP did not have dispatch rights to the storage asset.

The following chart depicts the contribution to winter peak of solar plus storage under the two dispatch modes. The contribution to peak is the contribution of the solar MWs (i.e. a 100 MW solar facility with 25 MW of storage that provides 25% contribution to peak provides 25 MW towards meeting winter peak demand).

FIGURE H-7

AVERAGE CONTRIBUTION TO DEP WINTER PEAK OF SOLAR PLUS 2-HOUR DURATION STORAGE

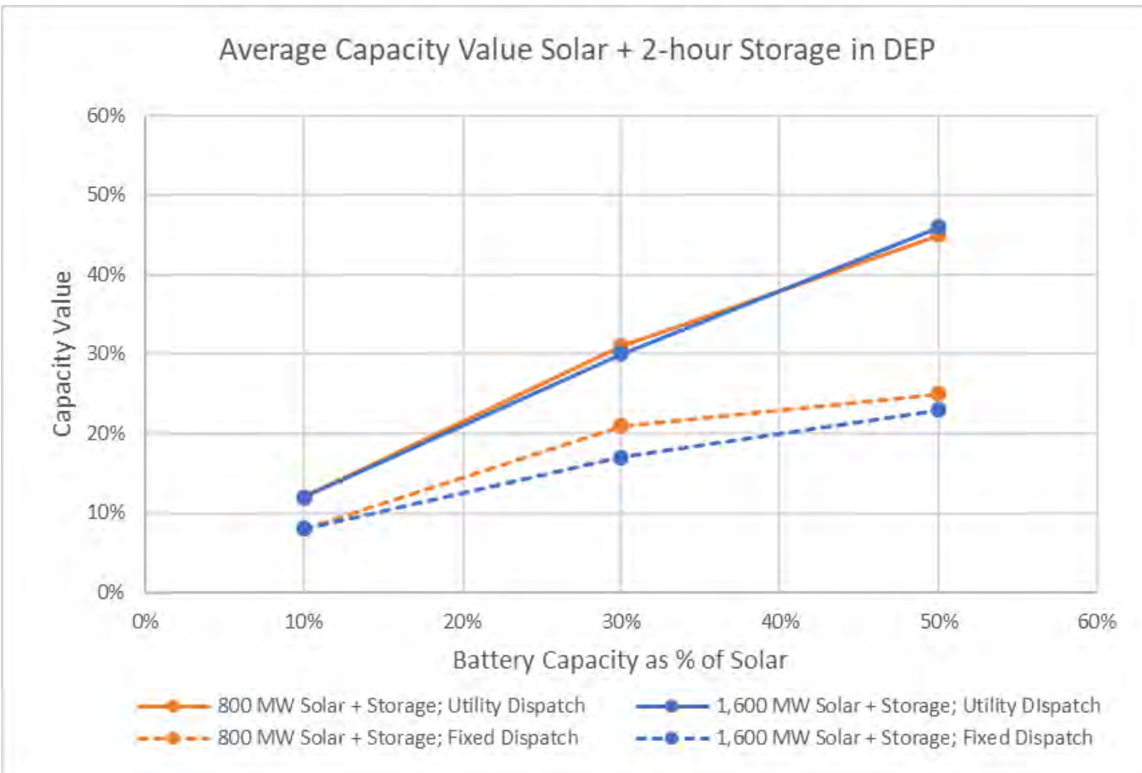
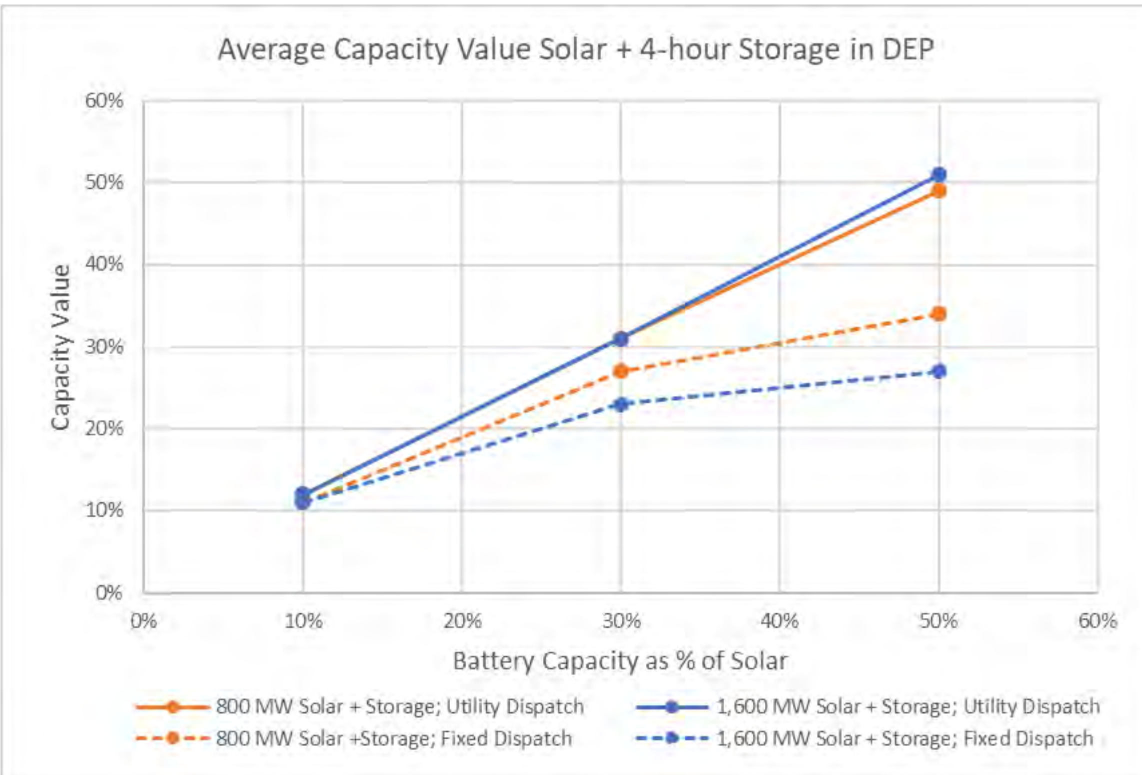


FIGURE H-8

AVERAGE CONTRIBUTION TO DEP WINTER PEAK OF SOLAR PLUS 4-HOUR DURATION STORAGE



Based on the results of the study, and for the same reasons as discussed in the standalone section above, DEP made the following assumptions in development of the 2020 IRP for solar plus storage:

- All solar plus storage capacity values based on Economic Dispatch. The Company will monitor how solar plus storage assets materialize on the system and will adjust this assumption in future IRPs if necessary.

- Only 4-hour considered for storage paired with solar

Additionally, for solar paired with storage in DEP, the Company assumed that the capacity of storage was 25% of the nameplate capacity of the solar the storage was paired with. Based on the results of the ELCC study, the Company assumed that this solar plus storage provided 25% of the solar nameplate capacity towards meeting winter peak demand. Also, the solar plus storage projects were capped at the solar capacity, so a 400 MW solar facility paired with 100 MW of battery storage provided a maximum output of 400 MW and was ascribed 100 MW of capacity value.

CONSIDERATIONS FOR FUTURE STUDIES

For some of the portfolios presented in the IRP, specifically the No New Gas Portfolio (Pathway F), and to a lesser extent, the 70% carbon reduction portfolios (Pathways D and E), the level of solar plus storage exceeded the penetration of storage evaluated in the ELCC study. Additionally, in the no new gas portfolios, significant levels of standalone storage would likely deteriorate the capacity value of solar plus storage resources. The combination of standalone storage and solar plus storage was also not evaluated in the ELCC. In all cases, the contribution to winter peak for solar plus storage was assumed to equal the percentage of storage paired with solar. For these reasons, the contribution to winter peak demand of solar plus storage later in the planning horizon is likely overstated. Future storage ELCC studies should evaluate:

- Higher penetrations of solar plus storage
- The impacts of standalone storage on the value of solar plus storage

I

ENVIRONMENTAL COMPLIANCE

APPENDIX I: ENVIRONMENTAL COMPLIANCE

Duke Energy Progress, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission, EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Progress is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

AIR QUALITY

Duke Energy Progress is required to comply with numerous State and Federal air emission regulations, including the federal Acid Rain Program (ARP), the Cross-State Air Pollution Rule (CSAPR) NO_X and SO_2 cap-and-trade program, the Mercury and Air Toxics Standards (MATS) rule, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with these regulations, Duke Energy Progress reduced SO_2 emissions by approximately 97% from 2000 to 2019 and reduced NOx emissions by approximately 92% from 1996 to 2019. While the NC CSA was instrumental in achieving significant emission reductions to benefit air quality in North Carolina, recent federal regulations now impose more stringent requirements, as noted below.

The following is a summary of the major air related federal regulatory programs that are currently impacting, or that could impact, Duke Energy Progress operations in North Carolina.

CROSS-STATE AIR POLLUTION RULE (CSAPR)

The "good neighbor" provision of the Clean Air Act requires states in their State Implementation Plans (SIPs) to address interstate transport of air pollution that affects downwind states' ability to attain and maintain National Ambient Air Quality Standards (NAAQS). If states do not submit SIPs or EPA does not approve them, EPA must issue Federal Implementation Plans (FIPs) as a backstop. EPA has created several regulatory programs via the FIP process to address these emissions, including the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR), and most recently, the CSAPR Update Rule. These programs establish state emission budgets for SO_2 and NOx on an annual basis, and NOx during ozone season (May 1-September 30.)

On September 7, 2016, EPA finalized the CSAPR Update Rule which reduces the ozone season NOx emission budgets from those promulgated in the original CSAPR Rule. The rule also removed North Carolina from CSAPR's ozone season NOx program beginning in 2017. However, Duke Energy units in North Carolina remain subject to annual NOx and SO_2 emission limits.

The Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) recently decided environmental and industry challenges to the 2016 CSAPR Update Rule. The Court remanded the rule back to EPA for revision, and DEP expects EPA to issue a proposal addressing the Court's ruling by October 2020. However, EPA's determination that North Carolina sources should be excluded from the CSAPR Update Rule because they do not significantly contribute to downwind ozone non-attainment was not challenged and was not included in the remand from the D.C. Circuit Court.

MERCURY AND AIR TOXICS STANDARDS (MATS) RULE

On February 16, 2012, EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which established emission limits for hazardous air pollutants (HAP) from new and existing coal-fired and oil-fired steam electric generating units. The rule required sources to comply with emission limits by April 16, 2015, or by April 16, 2016 with an approved extension. Duke Energy Progress is complying with all rule requirements.

In June 2015, the Supreme Court determined that EPA had unreasonably refused to consider costs when it determined that it was appropriate and necessary to regulate hazardous air pollutants from coal-fired and oil-fired steam electric generating units and remanded the case to the D.C. Circuit Court for further proceedings.

On May 22, 2020, EPA published a final rule and concluded that it is not "appropriate and necessary" to regulate power plant HAP emissions. However, EPA declined to rescind the 2012 MATS rule. In addition, EPA issued the results of its statutorily required Residual Risk and Technology Review (RTR) and determined that no changes to the MATS emission standards are needed.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

8-HOUR OZONE NAAQS

In October 2015, EPA finalized revisions to the primary (health-based) and secondary (welfare-based) 8-Hour ozone national ambient air quality standard (NAAQS), lowering them from 75 to 70 parts per billion (ppb.) EPA finalized area designations for the 2015 ozone standard and did not designate any nonattainment areas in North Carolina.

In August 2019, the D.C. Circuit decided challenges from state, environmental, and industry challengers to the 2015 standard. The Court upheld the primary standard but remanded the secondary standard to EPA for "further explanation and reconsideration."

SO_2 NAAQS

On June 22, 2010, EPA finalized revisions to the sulfur dioxide (SO_2) NAAQS, establishing a 1-hour standard of 75 ppb.

To demonstrate attainment of the NAAQS, the North Carolina Department of Environmental Quality was required to assess the air quality near large industrial sources of SO_2 emissions, including coal-fired power plants. Based on air quality modeling, NC DEQ provided a demonstration to EPA that the area surrounding the Mayo Station was in attainment. NC DEQ required Duke Energy Progress to conduct ambient air quality monitoring near the Asheville and Roxboro Stations for the period 2017 to 2019 to determine whether those areas were in attainment. Data collected during the period supports an attainment determination, and NC DEQ has submitted its recommendation for classification as attainment to EPA along with a request to discontinue the monitoring at those sites. EPA has a legal obligation to issue a final determination of the attainment classification by December 31, 2020.

On March 8, 2019, after the periodic review required under the Clean Air Act, EPA issued a final rule retaining the SO_2 NAAQS standards, without revision.

FINE PARTICULATE MATTER ($PM_{2.5}$) NAAQS

On December 14, 2012, the EPA finalized revisions to the $PM_{2.5}$ (fine particle) NAAQS, establishing an annual average standard of 12 micrograms per cubic meter and a 24-hour standard of 35 micrograms per cubic meter. The EPA finalized area designations for this standard in December 2014. That designation process did not result in any areas in North Carolina being designated nonattainment. On April 30, 2020, EPA proposed to retain the standards, without revision.

GREENHOUSE GAS REGULATION

On October 23, 2015, the EPA published a final rule establishing carbon dioxide (CO_2) emissions limits for new, modified and reconstructed power plants. The requirements for new plants apply to plants that commenced construction after January 8, 2014. EPA set an emission standard for new coal units of 1,400 pounds of CO_2 per gross MWh, which would require the application of partial carbon capture and storage (CCS) technology for a coal unit to be able to meet the limit. The EPA set a final standard of 1,000 pounds of CO_2 per gross MWh for new natural gas combined cycle (NGCC) units. Duke Energy Progress considers the standard for NGCC units to be achievable.

On December 20, 2018, EPA proposed revised NSPS standards. The proposed emission limit for new and reconstructed coal units is 1,900 pounds of CO_2/MWh, which is intended to reflect what has been demonstrated by the most efficient coal units without the use of CCS. The requirements apply to plants that commenced construction after December 20, 2018. EPA did not propose to change the standard established in 2015 for new or reconstructed natural gas combined-cycle units.

On October 23, 2015, the EPA published the Clean Power Plan (CPP) final rule, regulating CO_2 emissions from existing coal and natural gas units. The CPP established CO_2 emission rates and mass cap goals that apply to existing fossil fuel-fired Electric Generating Units (EGUs). Petitions challenging the rule were filed by numerous groups, and on February 9, 2016, the Supreme Court issued a stay of the final CPP rule, halting its implementation.

On July 8, 2019, EPA finalized the Affordable Clean Energy (ACE) rule, and in a separate but related rule repealed the Clean Power Plan and established CO_2 emission standards for existing coal-fired power plants only. EPA declined to set standards for existing natural gas plants. States have until July 8, 2022, to submit plans based on application of efficiency improvements at existing coal-fired power plants to EPA for approval. Various environmental groups, states, and industry groups have filed petitions for review in the D.C. Circuit challenging the ACE rule, whereas many states and industry groups have intervened on behalf of EPA to defend the rule.

WATER QUALITY AND BY-PRODUCTS ISSUES

CWA 316(B) COOLING WATER INTAKE STRUCTURES

Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014, with an effective date of October 14, 2014. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrained (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All DEP nuclear fueled, coal-fired and combined cycle stations in South Carolina and North Carolina are affected sources.

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

- Closed cycle re-circulating cooling system; or
- Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or
- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 fps; or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent standards if the capacity utilization rate is less than 8% averaged over a continuous 24-month period. The rule, also, allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

The entrainment standard does not mandate the installation of a technology but rather establishes a process for the state permitting agency to determine necessary controls, if any, required to reduce entrainment mortality on a site-specific basis. Facilities that withdraw greater than 125 MGD are required to submit information to characterize entrainment and assess the engineering feasibility, costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

The rule requires facilities to submit all necessary 316(b) reports in accordance with its Clean Water Act (CWA) discharge permit and schedule developed by the state permitting agency. The Company expects the state permitting authority to determine necessary controls for the affected DEP facilities in the 2022 to 2024 timeframe and intake modifications, if necessary, to be required in the 2023 to 2026 timeframe.

STEAM ELECTRIC EFFLUENT GUIDELINES

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("ELG Rule") were published in the Federal Register on November 3, 2015, with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEP's existing coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology-based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual (CCR) landfills and impoundments. The rule also establishes technology-based limits on gasification wastewater, but this waste stream is not generated at any of the DEP facilities. Affected facilities must comply between 2018 and 2023, depending on timing of its Clean Water Act (CWA) discharge permit.[1]

[1] On September 12, 2017, EPA finalized a rule ("the Postponement Rule") to postpone the earliest compliance date for bottom ash transport water and FGD wastewater for a period of two years (i.e. November 1, 2020), but this rule did not extend the latest compliance date of Dec. 31, 2023 and did not revise the earliest compliance date for fly ash transport water. The Postponement Rule was subsequently upheld by the Fifth Circuit Court of Appeals on August 28, 2019.

Petitions challenging the rule were filed by several groups and all challenges to the rule were consolidated in the Fifth Circuit Court of Appeals. On August 11, 2017, the EPA Administrator signed a letter announcing his decision to conduct a rulemaking to consider revising the new, more stringent effluent limitations and pretreatment standards for existing sources in the final rule that apply only to bottom ash transport water and FGD wastewater. On August 22, 2017, the Fifth Circuit Court of Appeals granted EPA's Motion to Govern Further Proceedings, thereby severing and suspending the claims related to flue gas desulfurization wastewater, bottom ash transport water and gasification wastewater. Subsequently, challenges to the limits for fly ash transport water and gasification wastewater were voluntarily dismissed while litigation on the limits for legacy wastewater and CCR leachate continued.

On April 12, 2019, the Fifth Circuit vacated and remanded portions of the rule dealing with legacy wastewater and CCR leachate. It is unknown when EPA will propose new limits for these waste streams.

The proposed rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater was published on November 22, 2019. The public comment period ended on January 21, 2020. The rule is anticipated to be finalized in 3rd quarter 2020.

All DEP coal-fired units have technologies installed to meet the requirements in the 2015 ELG Rule. The anticipated final rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater is not expected to require the installation of any additional technology.

COAL COMBUSTION RESIDUALS

In January 2009, following Tennessee Valley Authority's Kingston ash pond dike failure, Congress issued a mandate to EPA to develop federal regulations for the disposal of coal combustion residuals (CCR). CCR includes fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. On April 17, 2015, EPA finalized the first federal regulations for the disposal of CCR. The 2015 CCR rule regulates CCR as a nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) and allows for beneficial use of CCR with some restrictions.

The 2015 CCR rule applies to all new and existing landfills, new and existing surface impoundments that were still receiving CCR as of the effective date of the rule, and existing surface impoundments that were no longer receiving CCR but contained liquids as of the effective date of the rule, provided these units were located at stations generating electricity (regardless of fuel source) as of the effective date of the rule. The rule establishes national minimum criteria that include location restrictions, design standards, structural integrity criteria, groundwater monitoring and corrective action, closure and post-closure care requirements, and recordkeeping, reporting, and other operational procedures to ensure the safe management and disposal of CCR.

The 2015 CCR rule was challenged in litigation by industry and environmental petitioners. In August 2018, the D.C. Circuit Court vacated provisions that allowed unlined and clay-lined impoundments to continue to operate, finding those provisions violated the RCRA protectiveness standard. In response to the D.C. Circuit decision, EPA proposed two rulemakings to address unlined impoundments. The "Part A" rule, which was proposed on December 2, 2019, would establish an August 31, 2020 deadline to cease placement of CCR and non-CCR wastestreams into unlined ash basins and initiate closure (although that date is expected to be moved back in the final rule.)

The "Part B" rule, which was proposed on March 3, 2020, would establish a process for owners/operators to make an alternate liner demonstration. The proposal also included other significant provisions, including EPA's reiteration of its view that the use of CCR in units subject to forced closure is prohibited under the current CCR regulations. However, EPA proposed two options for allowing the use of CCR in surface impoundments and landfills for the purpose of supporting closure. In addition, EPA proposed a new closure-by-removal option, which would allow owners/operators to complete groundwater corrective action during the post-closure care period.

In February 2020, EPA published a proposed rule to establish a federal permitting program for CCR surface impoundments and landfills in states that do not have approved state permit programs, as provided under the 2016 WIIN Act. Only Oklahoma and Georgia currently have approved state programs, so this rule would apply in North Carolina until such a time that a state CCR permit program is approved by EPA.

In August 2019, EPA proposed amendments addressing CCR storage and criteria for unencapsulated beneficial uses that would require CCR storage piles to be completely enclosed (four walls and a roof), or would require control of releases and demonstration that the accumulation is "temporary" and that all CCR will be removed at some point in the future. EPA also proposed replacing the mass-based threshold for unencapsulated non-roadway beneficial uses to location-based criteria based on landfill location restrictions.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by North Carolina. On September 20, 2014, the North Carolina Coal Ash Management Act of 2014 (CAMA) became law and was amended on July 14, 2016.

CAMA establishes requirements regarding the beneficial use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA required eight “high-priority” CCR surface impoundments in North Carolina to be closed no later than December 31, 2019 (although that date was subsequently extended to August 1, 2022, for the two Asheville Station impoundments.) CAMA also required state regulators to provide risk-ranking classifications to determine the method and timing for closure of the remaining CCR surface impoundments. The North Carolina Department of Environmental Quality (NCDEQ) categorized all remaining CCR surface impoundments as low-risk after Duke Energy completed required dam safety repairs and established alternate permanent replacement water supplies for landowners with drinking water supply wells within a one-half-mile radius of CCR surface impoundments. Despite Duke Energy having taken these measures, on April 1, 2019, NCDEQ ordered that all remaining CCR surface impoundments in the state be closed by removal of CCR.

The impact from both state and federal CCR regulations to Duke Energy Progress is significant.

J

NON-UTILITY GENERATION AND WHOLESALE

APPENDIX J: NON-UTILITY GENERATION AND WHOLESALE

This appendix contains wholesale sales contracts, firm wholesale purchased power contracts and non-utility generation contracts.

TABLE J-1
WHOLESALE SALES CONTRACTS

DEP AGGREGATED WHOLESALE SALES CONTRACTS COMMITMENT (MW)									
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
3,386	4,113	4,130	4,151	4,203	4,085	4,129	4,170	4,213	4,237

NOTES:

- For wholesale contracts, Duke Energy Carolinas/Duke Energy Progress assumes all wholesale contracts will renew unless there is an indication that the contract will not be renewed.
- For the period that the wholesale load is undesignated, contract volumes are projected using the same methodology as was assumed in the original contract (e.g. econometric modeling, past volumes with weather normalization and growth rates, etc.).

TABLE J-2

FIRM WHOLESALE PURCHASED POWER CONTRACTS

PURCHASED POWER CONTRACT	WINTER CAPACITY (MW)	LOCATION	VOLUME OF PURCHASES (MWH) JUL '19 – JUN '20
Peaking	850	SC	310,015
Peaking	800	NC	160,700
Intermediate	373	NC	N/A
Intermediate	415	NC	113,643

NOTES: Data represented above represents contractual agreements. These resources may be modeled differently in the IRP.

NON-UTILITY GENERATION FACILITIES – NORTH CAROLINA

Please refer to DEC and DEP Small Generator Interconnection Consolidated Annual Reports filed on March 12, 2020 in NCUC Docket No. E-100, Sub 113B for details on the DEP North Carolina NUGS. The DEP NUG facilities are comprised of 99% intermediate facilities while the remaining 1% represents baseload facilities. Currently, hydro is considered baseload, solar and other renewables are considered intermediate.

Please refer to Table J-3 DEP Non-Utility Generator Listing – North Carolina Facilities.

NON-UTILITY GENERATION FACILITIES – SOUTH CAROLINA

Table J-4 contains non-utility generation contracts for facilities located in South Carolina.

Please refer to the attachment, Table J-4 DEP Non-Utility Generator Listing – South Carolina Facilities.

QF INTERCONNECTION QUEUE

APPENDIX K: QF INTERCONNECTION QUEUE

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition; however, the current queue clearly supports solar generation's central role in DEP's NC REPS compliance plan and HB 589.

Below is a summary of the interconnection queue as of July 31, 2020:

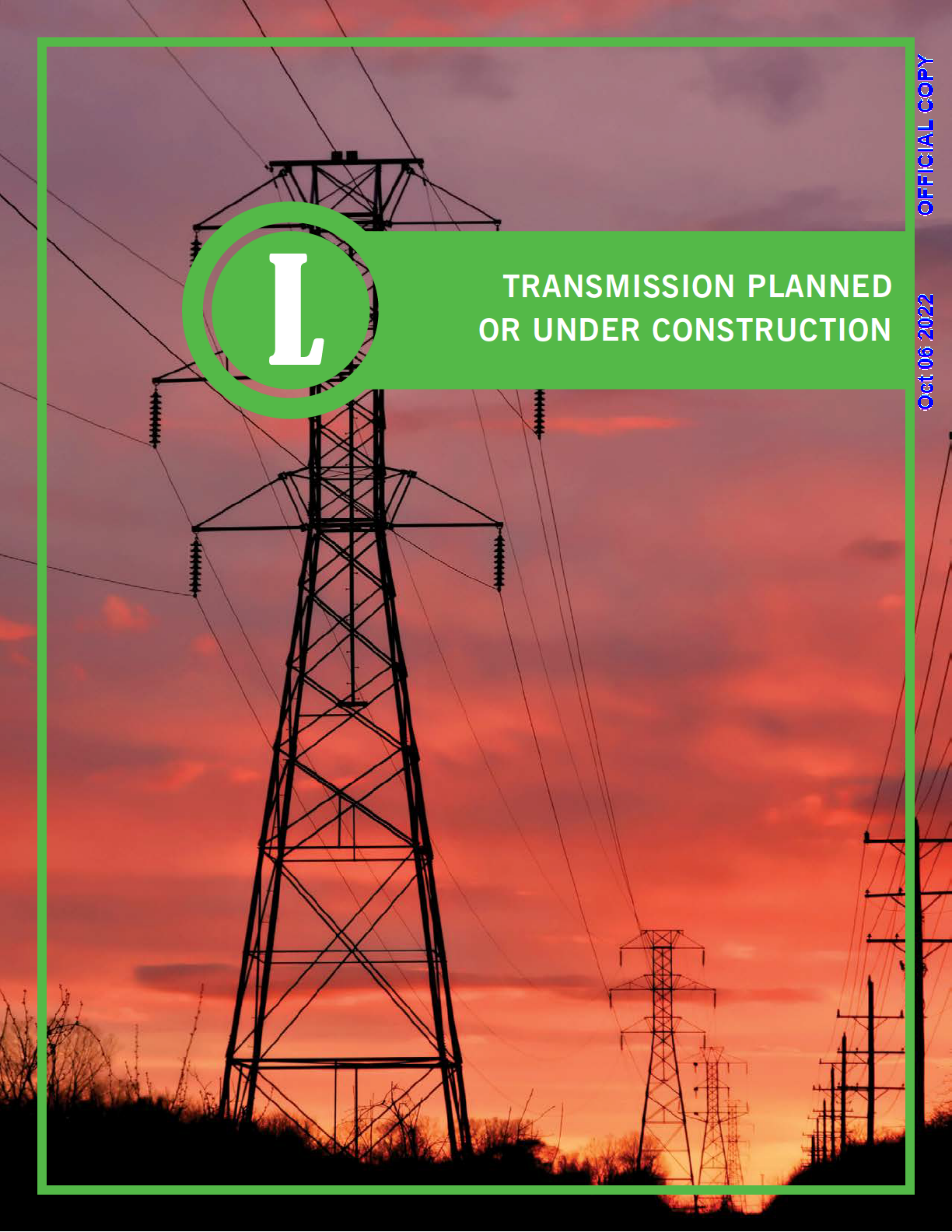
TABLE K-1
DEP QF INTERCONNECTION QUEUE

UTILITY	FACILITY STATE	ENERGY SOURCE TYPE	NUMBER OF PENDING PROJECTS	PENDING CAPACITY (MW AC)
DEP	NC	Battery	5	153
		Solar	188	4,612
	NC Total		193	4,765
	SC	Solar	140	2,332
	SC Total		140	2,332
	DEP Total		333	7,097

NOTE: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.

(2) Table does not include net metering interconnection requests.

TRANSMISSION PLANNED OR UNDER CONSTRUCTION



APPENDIX L: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

In this section, DEP provide details on transmission projects planned or under construction, as well as how DEP ensures transmission system adequacy.

DEP IN-SERVICE TRANSMISSION

Table L-1 below reflects Duke Energy Progress installed transmission circuit miles at each voltage class.

TABLE L-1

DEP INSTALLED TRANSMISSION CIRCUIT MILES BY VOLTAGE CLASS

CIRCUIT VOLTAGE	44 KV	66-69 KV	100 -199 KV	230 KV	345 KV	500+ KV
Duke Energy Progress		12	2,551	3,390		292

DEP TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This section lists the planned transmission line additions. A discussion of the adequacy of DEP's transmission system is also included. Table L-2 lists the transmission line projects planned to meet reliability needs. This section also provides other information pursuant to the North Carolina and South Carolina rules.

TABLE L-2
DEP TRANSMISSION LINE ADDITIONS

	LOCATION		CAPACITY	VOLTAGE	
YEAR	FROM	TO	MVA	KV	COMMENTS
2020	Cleveland Matthews Rd. Tap	Cleveland Matthews Rd	621	230	New
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New
2023	Porters Neck Tap	Porters Neck	442	230	New
2024	Brunswick #1	Folkstone Tap Line	594	230	New
2024	Folkstone Tap Line	Jacksonville	594	230	New

CECPCN / CPCN

Certificates of environmental compatibility and public convenience and necessity (CECPCN) for the construction of electric transmission lines in South Carolina and Certificates of Public Convenience and Necessity (CPCN) in North Carolina

(p) Plans for the construction of transmission lines in North Carolina and South Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's FERC Form No. 1 filed with FERC in April 2020.

(p) Plans for the construction of transmission lines in North Carolina and South

Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:

a. Commission docket number;

b. Location of end point(s);

c. Length;

d. Range of right-of-way width;

e. Range of tower heights;

f. Number of circuits;

g. Operating voltage;

h. Design capacity;

i. Date construction started;

j. Projected in-service date;

CLEVELAND MATTHEWS ROAD 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line from the Erwin-Selma 230 kV Line in Johnston County to the Cleveland Matthews Road 230 kV Substation in Johnston County.

a. NC Docket number: E-2, Sub 1150

b. County location of end point(s); Johnston County

c. Approximate length; 11.5 miles

d. Typical right-of-way width for proposed type of line; 125 feet

e. Typical tower height for proposed type of line; 80 – 120 feet

f. Number of circuits; 1

g. Operating voltage; 230 kV

h. Design capacity; 621 MVA

i. Date construction started; March 2019

j. Projected in-service date; December 2020

JACKSONVILLE – GRANTS CREEK 230 KV LINE

Project Description: Construct new 230 kV transmission line from the Jacksonville 230 kV Substation in Onslow County to the Grants Creek 230 kV Substation in Onslow County.

a. NC Docket number: E-2, Sub 1102
b. County location of end point(s); Onslow County
c. Approximate length; 15 miles
d. Typical right-of-way width for proposed type of line; 125 feet
e. Typical tower height for proposed type of line; 80 – 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 1195 MVA
i. Date construction started; September 2018
j. In-service date; June 2020

NEWPORT – HARLOWE 230 KV LINE

Project Description: Construct new 230 kV transmission line from the Newport 230 kV Substation in Carteret County to the Harlowe 230 kV Substation in Carteret County.

a. NC Docket number: E-2, Sub 1113
b. County location of end point(s); Carteret County
c. Approximate length; 8 miles
d. Typical right-of-way width for proposed type of line; 125 feet
e. Typical tower height for proposed type of line; 80 – 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV

h. Design capacity; 681 MVA
i. Date construction started; October 2018
j. In-service date; June 2020

The following pages represent those projects in response to NC Rule R8-62 part (3).

PORTERS NECK 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line from the Castle Hayne-Folkstone 230 kV Line to the Porters Neck 230 kV Substation in New Hanover County.

a. County location of end point(s); New Hanover County
b. Approximate length; 4.5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 442 MVA
h. Estimated date for starting construction; January 2022
i. Estimated in-service date; June 2023

BRUNSWICK #1-FOLKSTONE 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line segment from the Brunswick- Jacksonville 230 kV Line (Brunswick #1 side) to the Folkstone 230 kV Substation in Onslow County.

a. County location of end point(s); Onslow County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet

d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 594 MVA
h. Estimated date for starting construction; January 2023
i. Estimated in-service date; June 2024

FOLKSTONE-JACKSONVILLE 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line segment from the Brunswick- Jacksonville 230 kV Line (Jacksonville side) to the Folkstone 230 kV Substation in Onslow County.

a. County location of end point(s); Onslow County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 594 MVA
h. Estimated date for starting construction; January 2023
i. Estimated in-service date; June 2024

DEP TRANSMISSION SYSTEM ADEQUACY

DEP monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at projected generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEP transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEP works with DEC, North Carolina Electric Membership Corporation (NCEMC) and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEP and DEC systems in both North and South Carolina. In addition, transmission planning coordinates with neighboring systems including Dominion Energy South Carolina Inc. (DESC; formerly SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between DESC, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEP's Transmission Planning Summary guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Corporation (SERC) policy and North American Electric Reliability Corporation (NERC) Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that there are no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at projected peak load with selected equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT and the North Carolina and South Carolina Interconnection Procedures. It should be noted that location, MW interconnection requested, resource/load characteristics, and prior queued requests, in aggregate can have wide ranging impacts on transmission network upgrades required to approve the interconnection request. In addition, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor and materials costs in future years could be significant.

SERC audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEP in 2019 and DEP received "No Findings" from the audit team.

DEP participates in several regional reliability groups to coordinate analysis of regional, sub- regional and inter-balancing authority area transfer capability and interconnection reliability. Each reliability group's reliability purposes are to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;

- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and

- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year future periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Application of the practices and procedures described above ensures that DEP's transmission system continues to provide reliable service to its native load and firm transmission customers.

ECONOMIC DEVELOPMENT

APPENDIX M: ECONOMIC DEVELOPMENT

CUSTOMERS SERVED UNDER ECONOMIC DEVELOPMENT:

In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2020 is:

RIDER EC

14 MW for North Carolina
8 MW for South Carolina

RIDER ER

0.3 MW for North Carolina
0 MW for South Carolina

DEP WESTERN REGION PROJECT UPDATE

APPENDIX N: WESTERN CAROLINAS MODERNIZATION PLAN (WCMP)

The Western Carolinas Modernization Plan (WCMP) is often viewed as a collection of investments:

- New combined cycle power plant (in-service)
- Retirement of existing coal-fired power plant (demolition is underway)
- Transmission improvements (many improvements complete)
- At least 15 megawatts of solar (progress made)
- At least 5 megawatts storage (significant progress made)

These investments are critical to ensuring a cleaner and smarter energy future for Duke Energy Progress – West Region (DEP-West). But, the cornerstone of the WCMP's success is its community and stakeholder engagement.

This deliberate and purposeful engagement began in 2016 when a group of local leaders, representing the City of Asheville, Buncombe County and Duke Energy, attended the Rocky Mountain Institute's eLab Accelerator. This immersive experience started to create a foundation of trust and helped outline a wholistic community engagement effort to increase demand-side management, energy efficiency and distributed energy resources locally.

From this grew the Energy Innovation Task Force (EITF). The EITF was formed in 2016 and comprised of a diverse group of community leaders to:

- Avoid or delay the construction of the planned contingent combustion turbine (CT).
- Transition DEP-West to a smarter, cleaner and affordable energy future.

The co-conveners (City of Asheville, Buncombe County and Duke Energy Progress) then engaged Rocky Mountain Institute as a key partner early in the process to provide analytical support. Because of their participation and expertise, the company knows more about how customers in DEP-West use electricity than ever before. Their work also narrowed the focus on areas for the group to focus – primarily heating system efficiency. This work extended through 2017.

The research of Rocky Mountain Institute also identified the current lack of automated-metering infrastructure (AMI) in the region as a barrier to the effort's overall success. AMI deployment is now complete in DEP-West.

2018 was a pivotal year for the work of the Energy Innovation Task Force. This was when the group's 18-months of planning and analysis were put into action.

A critical milestone for the Energy Innovation Task Force was the launch of the Blue Horizons Project in March of 2018. This brand was created through community conversations facilitated by the Knoxville-based Sustainability marketing firm – The Shelton Group.

The Blue Horizons Project[1] is the brand associated with the community movement around energy efficiency, demand-side management, renewables and low-income weatherization locally. The primary gateway for customers to interact with Blue Horizons Project is a user-friendly website that directs customers to Duke Energy programs, local governmental initiatives and/or non-profit energy efficiency and weatherization opportunities.

Their work, along with canvassing by Duke Energy, helped expand the DSM program, EnergyWise[SM]. In 2016, when the Energy Innovation Task Force was formed, 7,183 DEP-West customers were enrolled in the program. As of August 13, 2018, 11,329 customers are enrolled in winter EnergyWise[SM] programs. Customer participation in this goal specifically addresses reductions in peak demand. In 2019, the focus was to grow participation in multi-family participation in EnergyWise[SM].

Both the City of Asheville and Buncombe County have made sizable investments to advance the work of the Blue Horizons Project for building audits, staff support and other direct investments in low-income weatherization.

Through this community collaboration in DEP-West, specifically Buncombe County, the contingent CT has been pushed out beyond the horizon of this 15-year planning analysis. This was a significant and celebrated milestone in the community's work.

In 2019, the initial work of the EITF and Blue Horizons Project started to shift from defining the problem, to enabling broader support for larger, community-driven goals. The co-conveners of the EITF worked to redefine the future goal and purpose of the task force. To that end, the EITF has been

1 https://www.bluehorizonsproject.com.

recast as the Blue Horizons Project Community Council (BHPCC). The purpose of this council will be to drive behavior and investments that help achieve the community renewable-energy goal.

In late 2018, both the City of Asheville and Buncombe County passed 100 percent clean/renewable energy goals. The goals require that both the City and County achieve the 100 percent targets for operations by 2030, and for all homes and businesses by 2042. The original conveners all agree that a continued commitment and partnership among the City, County, and Duke Energy is critical to enable success of these very ambitious local goals.

One area of focus is to fully leverage purposeful and deliberate investments in advanced and evolving technologies to help advance these lofty community goals. The Technology Working Group, a subcommittee of the Energy Innovation Task Force, has been meeting regularly for more than three years to look for cost-effective options for deployment of solar, battery storage, AMI, cold-climate heat pumps and other technologies. Their work has resulted in efforts to:

- Support and enable DEP-West's first ever microgrid (solar and battery) on Mt. Sterling in the Great Smoky Mountains National Park. (complete and in service)

- Advocate for and support a grid connected microgrid (solar and battery) to serve the Town of Hot Springs, should their radial feed go out. (initial construction is underway)

- Commit to at least 19 MW of battery storage in the region. A list of project updates is below:

  - Mt. Sterling Microgrid (Docket No. E-2, Sub 1127)
    - Haywood County
    - Approximate Capacity – 10 kW Solar PV and 95 kWh Battery Storage Facility
    - NCUC Order Granting CPCN – April 2017
    - Completion Date – May 2017

  - Asheville – Rock Hill Battery
    - Buncombe County
    - Sited at utility-owned substation
    - Approximate Capacity – 9 MW Battery Storage Facility
    - Completion Date – June 2020

- Hot Springs Microgrid (Docket No. E-2, Sub 1185)
  - Madison County
  - Approximate Capacity – 2 MW Solar PV and 4 MW Battery Storage Facility
  - NCUC Order Granting CPCN – May 2019
  - Anticipated In-Service Date – 2020

- Woodfin Solar
  - Buncombe County
  - Approximate Capacity – 4 to 5 MW Solar PV
  - CPCN Filed – July 2020
  - Anticipated In-Service Date – 2021

- Riverside Battery
  - Buncombe County
  - Sited at utility-owned substation
  - Approximate Capacity – 5 MW Battery Storage Facility
  - Anticipated In-Service Date – 2021

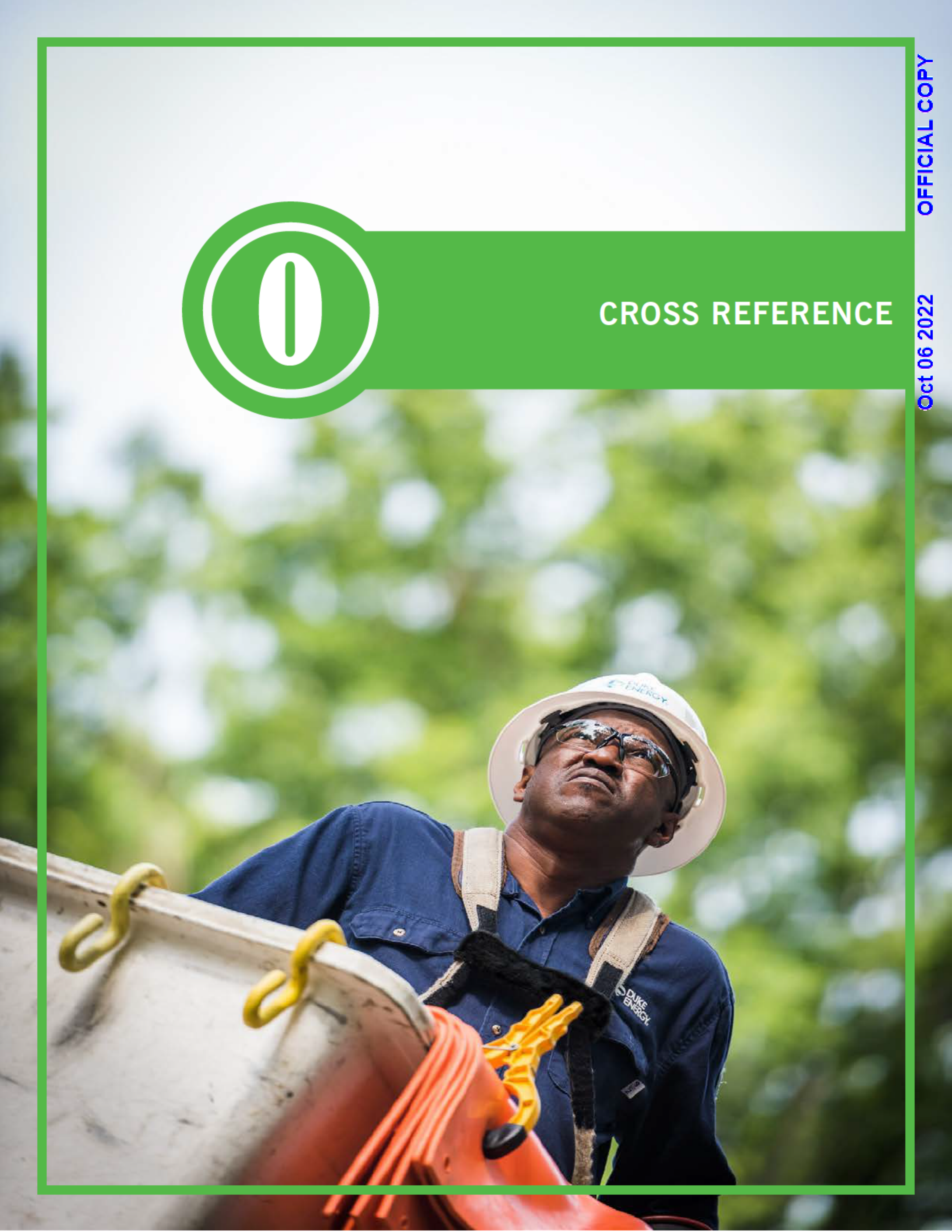
- Asheville Plant Solar and Battery
  - Buncombe County
  - Sited at utility-owned CC plant
  - Approximate Capacity – 9 to 10 MW Solar PV and 17 to 18 MW Battery Storage Facility
  - Anticipated In-Service Date – 2024

- Develop a pilot for cold-climate heat pump. This technology would operate more efficiently in the DEP-West region than other heat pump technologies.

- Partner with Buncombe County to site, design and build a large solar farm at the retired Buncombe County Landfill. (CPCN filed in July 2020)

- Enable an external pilot group for the real-time AMI usage app.

What makes the WCMP special is the engagement and community-centered approach to increasing participation in EE/DSM, making deliberate and strategic investments in technology, and supporting low-income customers with weatherization. Although collaboration with the DEP-West community has yielded strong results, the efforts to transition the region to a smarter, cleaner and affordable energy future for customers continues.



0 CROSS REFERENCE

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Oct 06 2022

TABLE O-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS

REQUIREMENT	REFERENCE	LOCATION
15-year Forecast of Load, Capacity and Reserves	NC R8-60 (c) 1	Chapter 3 Appendix C
Comprehensive analysis of all resource options	NC R8-60 (c) 2	Chapter 8 Chapter 12 Appendix A Appendix G
Assessment of Purchased Power	NC R8-60 (d)	Chapter 12 Appendix A Appendix J Attachment II
Assessment of Alternative Supply-Side Energy Resources	NC R8-60 (e)	Chapter 8 Appendix G
Assessment of Demand-Side Management	NC R8-60 (f)	Chapter 4 Appendix D Attachment V
Evaluation of Resource Options	NC R8-60 (g)	Chapter 5 Chapter 8 Appendix A Appendix D Appendix G
Short-Term Action Plan	NC R8-60 (h) 3	Chapter 14
REPS Compliance Plan	NC R8-60 (h) 4	Attachment I
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources * 10-year History of Customers and Energy Sales * 15-year Forecast w & w/o Energy Efficiency * Description of Supply-Side Resources	NC R8-60 (i) 1(i) NC R8-60 (i) 1(ii) NC R8-60 (i) 1(iii)	Chapter 3 Chapter 4 Appendix C Appendix D Attachment V

TABLE O-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS (CONT.)

REQUIREMENT	REFERENCE	LOCATION
Generating Facilities * Existing Generation * Planned Generation * Non-Utility Generation	 NC R8-60 (i) 2(i) NC R8-60 (i) 2(ii) NC R8-60 (i) 2(iii)	 Chapter 2 Chapter 12 Appendix B Appendix J
Reserve Margins	NC R8-60 (i) 3	Chapter 9 Chapter 12 Attachment III
Wholesale Contracts for the Purchase and Sale of Power * Wholesale Purchased Power Contracts * Request for Proposal * Wholesale Power Sales Contracts	 NC R8-60 (i) 4(i) NC R8-60 (i) 4(ii) NC R8-60 (i) 4(iii)	Chapter 12 Chapter 14 Appendix A Appendix J
Transmission Facilities	NC R8-60 (i) 5	Chapter 7 Appendix L
Energy Efficiency and Demand-Side Management * Existing Programs * Future Programs * Rejected Programs * Consumer Education Programs	 NC R8-60 (i) 6(i) NC R8-60 (i) 6(ii) NC R8-60 (i) 4(iii) NC R8-60 (i) 4(iv)	Chapter 4 Appendix D Attachment V
Assessment of Alternative Supply-Side Energy Resources * Current and Future Alternative Supply-Side Resources * Rejected Alternative Supply-Side Resources	NC R8-60 (i) 7(i) NC R8-60 (i) 7(ii)	Chapter 8 Appendix A Appendix G
Evaluation of Resource Options (Quantitative Analysis)	NC R8-60 (i) 8	Appendix A
Levelized Bus-bar Costs	NC R8-60 (i) 9	Appendix G
Smart Grid Impacts	NC R8-60 (i) 10	Appendix D
Legislative and Regulatory Issues		Appendix I
Greenhouse Gas Reduction Compliance Plan		Chapter 16 Appendix A
Other Information (Economic Development)		Appendix M
NCUC Subsequent Orders		Table O-3

TABLE O-2

CROSS REFERENCE – SC ACT 62 REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each electrical utility must submit its integrated resource plan to the commission. The integrated resource plan must be posted on the electrical utility's website and on the commission's website.	Part (C)(2)	Post - filing
a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Part (C)(2)	Chapter 3 Appendix A Appendix C
The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Part (C)(2)	Chapter 8 Appendix A Appendix F Appendix G
projected energy purchased or produced by the utility from a renewable energy resource;	Part (C)(2)	Chapter 5 Chapter 12 Appendix A Appendix E Appendix J Appendix N (DEP)
a summary of the electrical transmission investments planned by the utility;	Part (C)(2)	Chapter 7 Appendix A Appendix L

TABLE O-2

CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i)customer energy efficiency and demand response programs; (ii)facility retirement assumptions; and (iii)sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Part (C)(2)	Chapter 3 Chapter 4 Chapter 12 Appendix A Appendix B Appendix C Appendix D Appendix I
data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Part (C)(2)	Chapter 2 Appendix B
plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan	Part (C)(2)	Chapter 7 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A

TABLE O-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs	Part (C)(2)	Chapter 7 Chapter 8 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A Appendix G
a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Part (C)(2)	Chapter 3 Chapter 4 Appendix C Appendix D
An integrated resource plan may include distribution resource plans or integrated system operation plans.	Part (C)(2)	Chapter 7 Chapter 11 Chapter 15 Appendix A Appendix L

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The two Base Case Plans (i.e. Base CO2 Future and Base No CO2 Future) … encourages the Companies to carry forward both alternatives for their next IRPs due for 2020."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 12 Appendix A
DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company's existing coal-fired generating units are retired by the earliest practicable date. The "earliest practicable date" shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified. In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A Appendix I

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Commission expects that the "earliest practicable date" chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 7 Chapter 11 Appendix A Appendix L
The Companies should note that the directive in this order supplements and does not supersede the directive in the Commission's August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission's directive that the Companies present one or more "earliest practicable date" retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20 E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	IRP Filing Letters Chapter 9 Attachment III
In documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission will direct DEC and DEP to more fully explain and detail the study results.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The updated Resource Adequacy Study should provide additional clarity around outputs… At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR).	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina's electric membership cooperatives and municipally owned and operated electric utilities in this effort.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Executive Summary Chapter 15
The 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 15
The Commission determines that the "First Resource Need" section of DEC's and DEP's 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 13
Demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 3 Chapter 4 Chapter 8 Chapter 12 Appendix A Appendix D Appendix G Appendix J

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 12 Chapter 14 Appendix A Appendix J
A discussion of the following statement: "The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans."	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Chapter 12 Chapter 16 Appendix A
A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Appendix A Appendix D

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Provide a discussion of the advantages and disadvantages of periodically issuing "all resources" RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Include information, analyses, and modeling regarding economic retirement of coal-fired units	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Model continued operation under least cost principles in competition with alternative new resources	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
If continued operation until fully depreciated is least cost alternative, shall separately model an alternative scenario premised on advanced retirement of one or more of such units (including an analysis of the difference in cost from the base case and preferred case scenarios.)	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 4	Chapter 9 Attachment III
Future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 5	Filed Under Seal
Future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 6 E-100, Sub 1118 and Sub 124, Order Approving Integrated Resource Plans and REPS Compliance Plans (2008-09), dated 8/10/10, ordering paragraph 6	Chapter 3 Appendix C
IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 7	Appendix D

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 8 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Appendix D Attachment V
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.	E-100, Sub 141, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/26/15, ordering paragraph 9 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Chapter 3 Appendix C

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 14 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 14	Chapter 5 Appendix E Appendix K
Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 7) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 10

TABLE O-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Duke will include Li-ion battery storage technology in the economic supply-side screening process as part of the IRP.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 19) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 6 Chapter 8 Chapter 12 Appendix A Appendix G Appendix H
DEP will incorporate into future IRPs any demand and energy savings resulting from the Energy Efficiency Education Program, My Home Energy Report Program, Multi-Family Energy Efficiency Program, Small Business Energy Saver Program, and Residential New Construction Program.	E-2, Sub 1060, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 989, Order Approving Program, dated 12/18/14, p. 3 E-2, Sub 1059, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)	Appendix D

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16	Chapter 8 Appendix A Appendix F Appendix G
DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15	Chapter 5 Appendix A Appendix E Appendix N (DEP)
DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret.	E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3	Attachment I

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program.	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program)	Appendix D
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10).	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Chapter 14 Appendix D

GLOSSARY OF TERMS

10 CFR	Title 10 of the Code of Federal Regulations
AC or A/C	Alternating Current
ACE	Affordable Clean Energy
ACP	Atlantic Coast Pipeline
ACT 62	South Carolina Act 62
ADP	Advanced Distribution Planning
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
ARP	Acid Rain Program
ASOS	National Weather Service Automated Surface Observing System
BHPCC	Blue Horizons Project Community Council (DEP)
BCFD	Billion Cubic Feet Per Day
BFD	Bubbling Fluidized Bed
BOEM	Bureau of Ocean Energy Management
BYOT	Bring Your Own Thermostat
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMA	North Carolina Coal Ash Management Act of 2014
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals Rule
CCS	Carbon Capture and Sequestration (Carbon Capture and Storage)
CCUS	Carbon Capture, Utilization and Storage
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)
CEP	Comprehensive Energy Planning
CES	Clean Electricity Standard
CFL	Compact Fluorescent Light bulbs
CO2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COVID-19	Coronavirus 2019

GLOSSARY OF TERMS (CONT.)

COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity (NC)
CPP	Clean Power Plan
CPRE	Competitive Procurement of Renewable Energy
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DC	Direct Current
DCA	Design Certification Application
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEI	Duke Energy Indiana
DEK	Duke Energy Kentucky
DEP	Duke Energy Progress
DER	Distributed Energy Resource
DER	Duke Energy Renewables
DESC	Dominion Energy South Carolina, Inc. (formerly SCE&G)
DIY	Do It Yourself
DMS	Distribution Management System
DoD	Depth of Discharge
DOE	Department of Energy
DOJ	Department of Justice
DOM	Dominion Zone within PJM RTO
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSDR	Distribution System Demand Response Program
DSM	Demand-Side Management
EC or Rider EC	Receiving Credits under Economic Development Rates and/or Self-Generation deferral rate
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration

GLOSSARY OF TERMS (CONT.)

EITF	Energy Innovation Task Force
ELCC	Effective Load Carrying Capability
ELG Rule	Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction Contractors
EPRI	Electric Power Research Institute
ER or Rider ER	Receiving Credits under Economic Re-Development Rates
ESG	Environmental, Social and Corporate Governance
ET	Electric Transportation
EVs	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLG	Federal Loan Guarantee
FPS	Feet Per Second
FSO	Fuels and System Optimization
FT Solar	Fixed-tilt Solar
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GA-AL-SC	Georgia-Alabama-South Carolina
GHG	Greenhouse Gas
GIP	Grid Improvement Plan
GTI	Gas Technology Institute
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HB 589	North Carolina House Bill 589
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IA	Interconnection Agreement
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
ILR	Inverter Load Ratios

GLOSSARY OF TERMS (CONT.)

IPI	Industrial Production Index
IRP	Integrated Resource Plan
IS	Interruptible Service
ISOP	Integrated Systems and Operations Planning
IT	Information Technologies
ITC	Federal Investment Tax Credit
IVVC	Integrated Volt-Var Control
JDA	Joint Dispatch Agreement
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized Cost of Energy
LCR Table	Load, Capacity, and Reserves Table
LED	Light Emitting Diodes
LEED	Leadership in Energy and Environmental Design
LEO	Legally Enforceable Obligation
LFE	Load Forecast Error
Li-ION	Lithium Ion
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
M&V	Measurement and Verification
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MGD	Million Gallons Per Day
MISO	Midcontinent Independent Operator
MPS	Market Potential Study
MMBtu	Million British Thermal Units
MW	Megawatt
MW AC	Megawatt-Alternating Current
MW DC	Megawatt-Direct Current
MWh	Megawatt-hour
MWh AC	Megawatt-hour-Alternating Current

GLOSSARY OF TERMS (CONT.)

MWh DC	Megawatt-hour-Direct Current
MyHER	My Home Energy Report
NAAQS	National Ambient Air Quality Standards
NAPP	Northern Appalachian Coal
NC	North Carolina
NC HB 589	North Carolina House Bill 589
NC REPS or REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCDEQ	North Carolina Division of Environmental Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NEM	Net Energy Metering
NEMS	National Energy Modeling Systems
NERC	North American Electric Reliability Corporation
NES	Neighborhood Energy Saver
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
NUG	Non-Utility Generator
NUREG	Nuclear Regulatory Commission Regulation
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
OATT	Open Access Transmission Tariff

GLOSSARY OF TERMS (CONT.)

PC	Participant Cost Test
PD	Power Delivery
PEV	Plug-In Electric Vehicles
PHS	Pumped Hydro Storage
PJM	PJM Interconnection, LLC
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PRB	Powder River Basin
PROSYM	Production Cost Model
PSCSC	Public Service Commission of South Carolina
PSD	Prevention of Significant Deterioration
PSH	Pumped Storage Hydro
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificate
REPS or NC REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RICE	Reciprocating Internal Combustion Engines
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
RRP	Refrigerator Replacement Program
RTO	Regional Transmission Organization
RTR	Residential Risk and Technology Review
SAE	Statistical Adjusted End-Use Model
SAT Solar	Single-Axis Tracking Solar

GLOSSARY OF TERMS (CONT.)

SB 3 or NC SB 3	North Carolina Senate Bill 3
SC	South Carolina
SC Act 62	South Carolina Energy Freedom Act of 2018
SC DER or SC ACT 236	South Carolina Distributed Energy Resource Program
SC DER	South Carolina Distributed Energy Resources
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SEIA	Solar Energy Industries Association
SEPA	Southeastern Power Administration
SERC	SERC Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SG	Standby Generation or Standby Generator Control
SIP	State Implementation Plan
SISC	Solar Integration Services Charge
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SO	System Optimizer
SO2	Sulfur Dioxide
SOC	State of Charge
SOG	Self-Optimizing Grid
SPM	Sequential Peaker Method
SRP – SLR	Standard Review Plan for the Review of Subsequent License Renewal
STAP	Short-Term Action Plan
STEO	Short-Term Energy Outlook
T&D	Transmission & Distribution
TAG	Technology Assessment Guide
TCFD	Trillion Cubic Feet per Day
Transco	Transcontinental Pipeline
The Company	Duke Energy Progress
The Plan	Duke Energy Progress Annual Plan

GLOSSARY OF TERMS (CONT.)

TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCT	Utility Cost Test
UEE	Utility Energy Efficiency
UNC	University of North Carolina
USCPC	Ultra-Supercritical Pulverized Coal
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive
VCEA	Virginia Clean Economy Act
VVO	Volt-Var Optimization
WCMP	Western Carolinas Modernization Project (DEP)
WERP	Weatherization and Equipment Replacement Program
WIIN	Water Infrastructure Improvement for the Nation Act
ZELFR	Zero – Emitting Load Following Resource

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