4 Execution Plan

This Execution Plan identifies the actions and enablers that Duke Energy has identified as necessary to achieve the CO_2 emissions reductions and energy transition targets identified in the Carbon Plan, along with potential challenges. Successful execution of the Carbon Plan requires Commission approval of a defined set of near-term activities that are needed to affordably and reliably continue the energy transition and pursue HB 951's CO_2 emissions reductions targets.

This Execution Plan addresses a number of important implementation-related issues. First, the Execution Plan introduces the planning horizons for Carbon Plan execution, with information on monitoring risks and signposts to navigate uncertainty. Second, the Companies describe their approach to developing the near-term Execution Plan that is generally consistent with all pathways and portfolios. Third, the Execution Plan outlines near-term and intermediate-term actions, enablers and challenges across each of the following major components of the Carbon Plan:

1. Existing Supply-Side Resource Optimization
2. New Supply-Side Resources
3. Transmission System Planning and Grid Transformation
4. Consolidated System Operations
5. Grid Edge and Customer Programs

Finally, the Execution Plan addresses the Companies' plans for a longer-term planning strategy toward 2050 and concludes by proposing a strategy for future Carbon Plan updates to be filed biennially starting in 2024 with the Companies' next comprehensive IRPs.

Execution Planning Horizons and Navigating Uncertainty

This Execution Plan represents an evolution from the short-term action plan framework presented in past IRPs. More specifically, the Execution Plan provides the Commission and stakeholders a more detailed overview of the Companies' near-term, all-of-the-above, energy transition strategy for executing the Carbon Plan, as well as intermediate- and longer-term strategies to meet the interim CO_2 emissions reductions target and to achieve carbon neutrality by 2050. Through the sections that follow, the Companies describe the Carbon Plan execution actions and procurement strategies by resource type (supply-side resources, grid resources and demand-side resources) across three horizons:

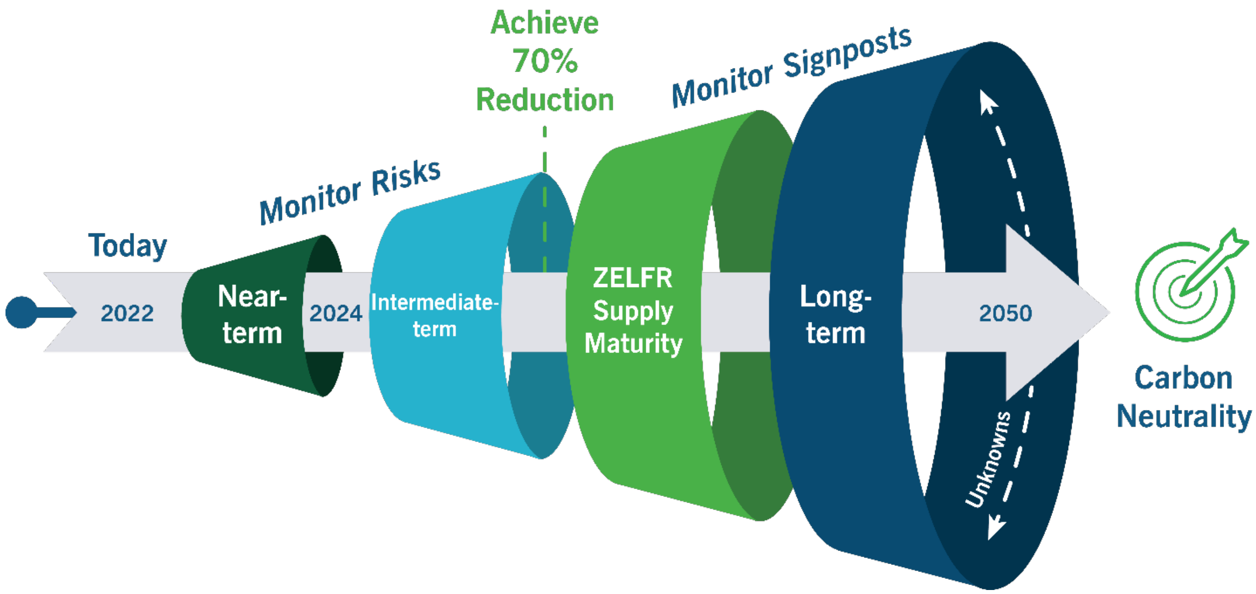
1. **Near-Term Actions** are those plans and legal/regulatory actions required in the 2022-2024 time frame to enable the development, procurement and integration of the resources identified as needed and in the best interest of customers across all pathways and portfolios. The Companies view these near-term actions as prudent and necessary to execute all pathways and portfolios and to stay on track to meet the Carbon Plan's intermediate and long-term CO_2 emissions reductions targets.

2. **Intermediate-Term Actions** reflect actions the Companies are planning to achieve the initial 70% interim CO_2 emissions reductions target under the Carbon Plan. For this planning period, this execution plan presents an intermediate-level view of the Companies' business planning and assessment of risks and legal/regulatory execution strategy for the Carbon Plan.

3. **Long-Term Planning** addresses strategies, considerations and signposts that the Companies are actively monitoring and plan to explore over time to help ensure the Carbon Plan achieves the least-cost path to 2050 carbon neutrality. For this long-term planning period, the Execution Plan presents high-level qualitative business planning and sign-post monitoring to ensure the Companies are on the least cost path to providing affordable, reliable emissions-free electricity to the Carolinas by 2050 and beyond.

The need to execute on the Carbon Plan to continue the energy transition and meet CO_2 emissions reductions targets requires the Companies to implement near-term activities while monitoring risks and signposts across all planning horizons, as illustrated in Figure 4-1 below and discussed in more detail later in this Chapter. While the long-term planning and modeling processes are able to assess many of these risks to make informed planning decisions, such modeling presents a resource planning "snapshot in time" and relies on numerous assumptions that become increasingly difficult to predict out into future years as the band of uncertainty widens with regard to technology, cost, policy, consumer trends and economic conditions. Risk and signpost monitoring will provide key information that will be used to check and adjust plans during future biennial updates of the Carbon Plan.

Figure 4-1: Execution Plan Time Horizons and Navigating Uncertainty



Overview of Near-Term Actions Supported by Pathways and Portfolios

Central to the Companies' Execution Plan are activities that are required in the near term and for which the Companies request approval under HB 951.[1] The near-term execution activities identified by the Companies are those that are generally consistent with all portfolios.

Due to the long lead times of new supply-side resources and their associated grid upgrade requirements, Commission approval of this near-term action plan and public policy support for needed transmission system upgrades are critically important for executing activities in the near-term that advance the deployment of resources in the 2026 through 2029 timeframe, and into the early part of the 2030s. The accelerated time frame to deliver new resources, along with the interdependencies between generation and transmission needed to achieve the target in service dates presented in the Carbon Plan, underscores the importance of Commission approval and support for near-term Execution Plan activities in this initial Carbon Plan.

Importantly, many of these actions are interdependent on one another to achieve the CO_2 emissions reductions targets while maintaining or improving upon the adequacy and reliability of the system. For example, coal facilities cannot be retired independent of the timely in-service of adequate replacement capacity, along with any needed upgrades to the transmission system to ensure bulk power system reliability is maintained. Though near-term Execution Plan activities can be organized in independent categories, many are interrelated to fully achieve Plan targets. Finally, the Carbon Plan is a long-term plan, so the dates and quantities in the portfolios should be considered directional and not exact. The specific resources (technology, design, capacity) to be developed and optimal in-service dates will be

[1] HB 951, Section 1(1) (directing that "new generation facilities or other resources [shall be] selected by the Commission in order to achieve the authorized reduction goals . . .")

refined through the development and siting processes as Plan components are executed, considering a multitude of practical factors that are beyond the scope of the long-term planning process presented in the Carbon Plan. As more information is gathered through execution, the Companies will keep the Commission apprised of material developments through future biennial Carbon Plan updates, as well as through seeking resource-specific regulatory processes or approvals (e.g., a CPCN proceeding).

Optimizing Existing Supply-Side Resources

All portfolios require retiring coal units, expanding the flexibility of existing gas units, and subsequent license renewals ("SLR") for existing nuclear generation units that provide over 10,000 MW of zero-carbon, cost-competitive capacity through 2050 to achieve CO_2 emissions reductions targets. Importantly, coal unit retirements are dependent upon the replacement of their capacity that maintains or improves system reliability.

New Supply-Side Resources

As explained in the Executive Summary and re-introduced above, the Companies have identified a proposed set of near-term activities for supply-side resources as part of the Carbon Plan for which the Companies request Commission approval. Table 4-1 below provides a summary of the proposed near-term actions with respect to these supply-side resources and delineates the supply-side resources that the Companies request to be selected by the Commission and the project development activities proposed by the Companies for Commission approval.

Table 4-1: Supply-Side Resources Requiring Actions in Near Term

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2029		
Carbon Plan Solar	3,100 MW	• Begin Public Policy Transmission projects in 2022[6] • Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage
Battery Storage	1,600 MW	• Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar
Onshore Wind	600 MW	• Engage wind development community in preparation for procurement activities • Procure 600 MW in 2023-2024
New CT[1]	800 MW	• Submit CPCN for 2 CTs totaling 800 MW in 2023
New CC[2]	1,200 MW	• Submit first CPCN for 1,200 MW in 2023 • Evaluate options for additional gas generation pending determination of gas availability
Proposed Resource Development: Options for 70% Interim Target		
Offshore Wind[3]	800 MW	• Secure lease • Initiate development and permitting activities for 800 MW[7] • Conduct interconnection study • Initiate preliminary routing, right-of-way acquisition for transmission
New Nuclear[4]	570 MW	• Begin new nuclear early site permit ("ESP") for one site • Begin development activities for the first of two SMR units
Pumped Storage Hydro[5]	1,700 MW	• Conduct feasibility study for 1,700 MW • Develop EPC strategy • Continued development of FERC Application for Bad Creek relicensing

Notes:
1 – CPCN for two CTs (800 MW) estimated for in-service 2027-2028.
2 - CPCN for one CC (1,200 MW) estimated for in-service 2027-2028, CPCN for second CC (1,200 MW) will be evaluated for submittal in 2024 with estimated in-service 2030 as fuel supply is determined.
3 – Retaining optionality through early development activities, in-service date assumption dependent upon portfolio.
4 – New nuclear capacity represents first two SMR units, planned in-service date through 2034.
5 – Pumped storage hydro capacity represents second powerhouse at Bad Creek, planned in-service 2033.
6 – Projects subject to North Carolina Transmission Planning Collaborative ("NCTPC") approval.
7 – Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan ("SAP"); or ii) a combined SAP and Commercial Operation Plan.

Achievement of the 70% interim target will require decisive near-term procurement and development actions across various new supply resources.

In the case of those supply side resources with potentially shorter or more defined lead times—solar, energy storage, natural gas, and onshore wind—the Companies are requesting the Commission to "select" a defined amount of such resources, and have proposed substantial near-term development and procurement activities consistent with such defined amounts. The Commission will have further opportunity to assess such projects through future CPCNs, or through other regulatory processes as deemed necessary.

In the case of supply-side resources with longer lead times and greater external dependencies – offshore wind, SMRs, and pumped storage hydro – substantial development work will be needed in the near-term to maintain optionality and the in-service dates contemplated in the Plan. However, the Companies are not requesting the Commission to "select" such resources at this time. Initial development work is needed both to gather information to provide a more refined cost estimate to the Commission, as well as to be positioned to implement such resources on a timeline consistent with the portfolios. Stated simply, if the Companies do not undertake development activities in the near-term for these long-lead-time resources, these new resources will not be available on the timelines contemplated by the portfolios. But it is also important to note that all three resources are likely to be needed to achieve carbon neutrality by 2050, and therefore, the development work performed in the near term is likely to be needed as the Companies progress the energy transition towards carbon neutrality.

The nature and scope of the development activities needed in the near term with respect to each of these three longer-lead time resources varies and is described in greater detail in this Execution Plan, as well as the respective technology appendices. In the case of SMRs, near term action is needed, primarily to perform a new nuclear siting study (or studies), conduct final technology evaluations, and prepare and submit a nuclear early site permit ("ESP") application for one site. In the case of pumped storage hydro, near-term action is needed to complete the Bad Creek II feasibility study and determine and refine the potential EPC strategy.

While the assumed timelines for all the longer-lead time items are aggressive, the timelines for offshore wind assumed in the Plan, informed by stakeholder input, are extremely aggressive, particularly under P1. Achievement of such timelines will require the immediate commencement of more substantial development activities in the near term. Substantial development work is needed both for the offshore wind site and for the associated onshore transmission and interconnection facilities. Furthermore, due to the limited number of potential wind energy areas ("WEA") available, it will be necessary for the Companies to secure a WEA lease in the near term (assuming consistency with the estimated costs in the Carbon Plan modeling). Without securing a WEA lease in the near-term and initiating key project development activities, it will be impossible to even have the potential to achieve the offshore wind timelines assumed in the modeling.

Once again, all of these near-term development activities are needed if the Commission desires to preserve the potential for these resources to be utilized in achieving the 70% interim target on the targeted timelines. Approval of such development work does not mean that the Commission is thereby "selecting" these long-lead time resources for purposes of this initial Plan. Instead, such activity will allow the Companies to take additional critical steps toward refining the final cost estimates and then to present such information to the Commission in the biennial 2024 Carbon Plan update. Importantly, if the Commission ultimately determines that one or more of these resources is not part of the least cost path to achieve the 70% interim target, such resources will nevertheless likely still play a role on the pathway to carbon neutrality by 2050.

As stated in the Executive Summary, the Companies request that the Commission make the following three findings with respect to the proposed near-term project development activities and associated costs relating to long-lead-time new supply side resources:

(1) engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;

(2) to the extent not already authorized under applicable accounting rules, that the Companies are authorized to defer associated project development costs[2] for recovery in a future rate case (including a return on the unamortized balance at the applicable Company's then authorized, net-of-tax, weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and

(3) that in the event such long-lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time.

This forward-looking approval is necessary and appropriate in this unique context where substantial development activities are needed in advance of final selection by the Commission in order to ensure that such resources can achieve commercial operation on a timeline consistent with the Companies' proposed portfolios and HB 951's targeted timelines. Such forward-looking approval is also consistent with N.C. Gen. Stat. § 62-110.7, which contemplates the Commission's preapproval of project development costs in connection with a potential nuclear electric generating facility.

With respect to (1), the Companies believe that the development activities proposed are reasonable and prudent because they are necessary to keep such long-lead time resources on a timeline that is consistent with the portfolios and HB 951, as explained in this Execution Plan and the related technology appendices. With respect to (2), while many of the project development costs to be incurred are capitalizable under applicable accounting rules, the Companies believe that it is appropriate to

[2] Duke Energy's use of the term "project development costs" is informed by N.C. Gen. Stat. § 62-110.7(a) and is intended to include all "costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs."

ensure full clarity that any such project development costs that are not capitalizable will be deferred for future recovery. Finally, with respect to (3), the Companies believe that it is appropriate for the Commission to find that, in the event such long-lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time. This outcome is also consistent with N.C. Gen. Stat. § 62-110.7(d), which mandates that, after preapproval of the incurrence of project development costs, the utility is entitled to recover such project development costs in the event such project is ultimately not required.

In summary, the Companies proposed initial procurement and development for new supply-side resources are “reasonable steps” that are generally consistent with pace of deployment contemplated across all portfolios but will also allow for subsequent adjustment based on Commission direction and other factors such as improvement in the current supply chain for key components such as solar panels, batteries, and offshore wind components; support for proactive transmission investments; reduction in inflationary pressures on key commodities required for the generation transition; and progress in permitting, engineering, and public acceptance for offshore and onshore wind development (including associated right of way for new high-voltage transmission). The Companies believe that this set of proposed near-term supply-side activities represent reasonable and prudent steps and a balanced approach that commits the Companies to procuring a meaningful amount of those resources while minimizing near-term cost and risk exposure for customers, as a more complete picture of the Carbon Plan forms over the next two years.

Transmission System Planning and Grid Transformation, Consolidated System Operations

Pursuing proactive transmission investments is a common critical path component to all portfolios necessary to integrate renewables and allow for the accelerated retirement of coal, as further described in Appendix P (Transmission System Planning and Grid Transformation). Additionally, the Companies plan to initiate regulatory proceedings in the near-term to implement a generation replacement queue process and to consolidate the Companies’ system operations functions to facilitate a more cost-effective and efficient energy transition for customers across all portfolios, as further described in Appendix R (Consolidated System Operations).

Grid Edge and Customer Programs

Commission support of the Companies’ planned near-term activities in the first prong of the planning approach, “shrinking the challenge” is critically important to achieving Carbon Plan targets through advancing available tools to reduce demand and modify load through enhanced and new Grid Edge and Customer Programs outlined in Appendix G (Grid Edge and Customer Programs). As highlighted earlier in this Carbon Plan and addressed in more detail in Appendix G (Grid Edge and Customer Programs), the Companies’ Carbon Plan modeling assumes nation-leading amounts of EE and DSM (targeting 4,230 MW of contribution by 2035 in all scenarios). These important enablers to CO_2 emissions reductions do not change across portfolios.

Detailed Execution Plan: Existing Supply-Side Resources

Retiring Existing Coal

Reducing risk for customers and achieving CO_2 emissions reductions targets will require continued retirement of the Companies' remaining coal units across North Carolina. As discussed in Chapter 3 (Portfolios), there is very little difference in the projected coal retirement dates across the portfolios, with all portfolios resulting in a full exit from coal-fueled generation by 2035 (retiring over 8,400 MW of coal capacity). Executing on these coal unit retirements must be coordinated with the development of new low-carbon and zero-carbon resources and transmission system improvements to maintain resource adequacy and reliability for customers.

In the near term, the Companies will work with existing coal and railroad suppliers to maintain service reliability and fuel assurance needed to maintain reliability as the Companies continue to plan their intermediate and longer-term coal unit retirement strategy. The Companies will also perform transmission evaluations, outlined in Appendix P (Transmission System Planning and Grid Transformation), to identify any necessary system improvements that are needed to allow coal unit retirement while ensuring bulk power system reliability is maintained. If transmission improvements are necessary, they must be factored into the retirement schedule.

Table 4-2 below describes the Companies' near-term and intermediate-term Execution Plan for coal retirements and additional information on how coal retirements were evaluated in Plan modeling is provided in Appendix E (Quantitative Analysis).

Table 4-2: Execution Plan – Coal Retirements

Near-Term Actions (2022-2024)	

2023	• Retire Allen Units 1 & 5
	  • DEC will retire Allen units 1 and 5 by the end of 2023, including completion of all regulatory notices and filings.
	  • Final retirement date is contingent upon completion of South Point switching station transmission project, already under construction

Intermediate-Term Actions (Achieve 70% Target)	

2025-2026	• Retire Cliffside Unit 5
	  • Planning analysis does not identify any major transmission upgrades to be required to retire Cliffside Unit 5
	• Complete environmental/operational projects necessary for coal unit retirements
	  • Marshall Station (DEC) - complete auxiliary steam boiler needed for Units 3 and 4 startup to allow Units 1 and 2 to retire;
	  • Roxboro/Mayo Stations (DEP) – complete auto-load tap changer enabled transformers at Harris Nuclear Plant to reduce necessary voltage support runs at Roxboro and Mayo plants

Intermediate-Term Actions (Achieve 70% Target)	
2027-2033	• Retire subcritical coal units (Marshall, Roxboro and Mayo) when replacement generation and supporting electric and/or gas transmission are in service

Expanding Flexibility of the Existing Gas Fleet

As coal units are retired and the integration of renewable resources increases, the flexibility of dispatchable gas-fired resources becomes an increasingly important resource for maintaining system reliability in a least-cost manner. Today, the Companies' gas-fired generation fleet consists of 55 CTs, nine CC units, and one combined heat and power ("CHP") unit, having a combined total capacity of 11,991 MW. To increase the flexibility of the existing gas-fired fleet, the Companies will need to equip a number of its CC/CT stations to support more flexible operational capabilities, such as lower load operations, increased ramp rates, and the ability to cycle more often to respond to increased variability in the output of renewable resources. In the near and intermediate term, the Companies will plan and implement gas unit control upgrades and equipment changes and seek regulatory approvals for operational and air permit changes.

Table 4-3 below outlines the Companies' near-term and intermediate-term Execution Plan to increase the flexibility of the existing gas fleet and additional information on the existing CT/CC fleet is provided in Appendix M (Natural Gas).

Table 4-3: Execution Plan – Existing Gas Fleet

Near-Term Actions (2022-2024)	
2022-2023	• Perform engineering studies and model impacts of heavy renewables integration on existing CC fleet • Submit air permit revisions to allow for increased flexibility of select CTs/CCs (run hours, turndown, etc.)
2022-2024	• Ensure long-term fuel security for existing CC and dual fuel optionality fleet • Implement smaller unit flexibility projects on existing CCs
Intermediate-Term Actions (Achieve 70% Target)	
2025-2030	• Verify need and then implement larger Unit Flexibility projects on existing CCs

Extending the Life of Existing Nuclear Fleet with Subsequent License Renewal

Extending the life of the Companies' existing nuclear fleet is a bedrock assumption for the Plan, providing for the continuation of a major source of reliable, zero-carbon, cost-competitive power through 2050 in every portfolio. Accomplishing this important Carbon Plan objective requires federal regulatory approval of 20-year subsequent license renewals ("SLRs") for the 11 existing nuclear generation units operating at six nuclear stations across the Carolinas, totaling 10,773 MW of generation. The current operating licenses will begin to expire in the 2030s, and the regulatory process may take up to 4 years per SLR application. The Nuclear Regulatory Commission ("NRC") accepted the Companies' first SLR application for review in mid-2021 and is currently in the process requesting additional information to support its review. The Companies plan to develop and submit an SLR application for each nuclear station approximately every three years, with the remaining submittals tentatively planned for 2024, 2027, 2030, 2033 and 2036.

In addition to extending the operating licenses at each site, Duke Energy continues to optimize the use of power uprates where cost-effective. Several of the nuclear facilities (e.g., Harris, Robinson and Brunswick) have already been uprated extensively while the remaining facilities (e.g., Oconee, McGuire and Catawba) are at the early stages of being evaluated for major modifications to increase their power output. Uprates to the Oconee Nuclear Station for Measurement Uncertainty Recapture are included in the modeling for the Carbon Plan, which results in an additional 15 MW per unit over the 2022-2023 period. The remaining potential uprates would require extensive component replacement; therefore, more investigation is needed into the cost and timing of the potential projects. If implemented, these power uprates would provide additional zero-carbon capacity and energy to Duke Energy's customers in the Carolinas.

Table 4-4 below outlines the Companies' near-term and intermediate-term Execution Plan to extend the life of the existing zero-carbon nuclear fleet and additional information is provided in Appendix L (Nuclear).

Table 4-4: Execution Plan – Existing Nuclear

Near-Term Actions (2022-2024)	
2021	• SLR Application for Oconee Nuclear Station submitted to NRC
2022-2023	• Implement Oconee Measurement Uncertainty Recapture
2023 – into intermediate-term	• Explore other potential uprates for Catawba and McGuire
Intermediate-Term Actions (Achieve 70% Target)	
2024-2025	• SLR Application for second nuclear plant to be submitted to NRC
2027-2028	• SLR Application for third nuclear plant to be submitted to NRC

Detailed Execution Plan: New Supply-Side Resources

The Carbon Plan identifies the need for a diverse portfolio of new zero- and low-carbon emitting generating assets across both pathways and all four portfolios. This section addresses the actions that the Companies intend to commence immediately in the near term and to continue over the intermediate term relating to the development and procurement of new supply-side resources. Note that each of the resources has an associated Appendix that provides further technical background regarding the resource.[3]

General Procurement Approach

The Execution Plan anticipates implementation of the Carbon Plan will include a range of procurement methods. Foundational to the procurement activities outlined below is the need to preserve customer value by pursuing least cost across each procurement action the Companies undertake. Specific categories of procurement include utility self-development, asset acquisitions and, for solar and solar paired with storage, solicitations for controllable purchase power agreements. In all cases, the information gained through the procurement process will be used to inform and refine future Carbon Plan analysis and filings. This iterative process involving subsequent procurement efforts and their associated regulatory proceedings informing future carbon plan updates will provide the Commission and the Companies with opportunities to adjust the pace and volumes of procurement activities in response to changing market conditions relative to planning assumptions at any given point in time.

Self-Development

In some cases, the Companies anticipate leveraging utility self-development for projects that are location specific, long lead-time resources that the Companies have evaluated for the best combination of siting, fuels, transmission and timing to meet their customers' future needs and to achieve CO_2 emissions reduction goals. Self-development will leverage the Companies' existing property, station workforce, electric and/or gas transmission, access to water, permits, etc. to the benefit of customers. For self-development projects, the Companies will be responsible for project siting and development, managing permitting as well as obtaining engineering, procurement and construction ("EPC") services. The Companies have substantial self-development experience with internal processes to competitively bid major equipment and EPC services to ensure the best value for customers considering project specific costs and risks. The Companies may also pursue joint development projects in which a third-party development partner shares in the responsibility for project siting, development, permitting and engineering, but the Companies will have responsibility for procurement and construction activities. The Companies would also competitively bid construction services for joint development projects.

Asset Acquisition

The Execution Plan anticipates the potential for acquisition of resources from third-party developers and potentially existing asset owners. Asset acquisitions can be accomplished through procurements or bilateral negotiations and are generally utilized when there is flexibility as to where the assets are located and the market for development is more mature. Specific types of acquisitions for new assets include asset transfers, asset transfers plus EPC services, Build-Own-Transfers, and acquisition of operating assets. Details of each type of acquisition are further detailed below:

[3] *See* Appendix I (Solar), Appendix J (Wind), Appendix K (Energy Storage), Appendix L (Nuclear), Appendix M (Natural Gas), Appendix N (Fuel Supply), Appendix O (Low-Carbon Fuels and Hydrogen) for additional information.

- **Asset Transfer**: A third-party developer proposes to sell a fully developed project and is responsible for, but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, limited engineering, and all interconnection studies. The developer assigns or transfers all assets, rights, etc. to the Company upon satisfaction of all development and closing conditions, which generally occurs prior to the start of construction. The Utility is responsible for final engineering, procurement and construction of the facility.

- **Asset Transfer plus EPC**: A third-party developer proposes to sell a fully developed project and is responsible for, but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, engineering, all interconnection studies and all procurement and construction of the facility pursuant to an EPC Agreement. The developer and Utility enter into an agreement in which the developed project assigns or transfers all assets, rights, etc. to the Utility upon satisfaction of all development and closing conditions, which generally occurs prior to the start of construction. The parties also enter into an EPC Agreement in which the developer is responsible for final engineering, procurement and construction of the facility.

- **Build, Own, Transfer**: A third-party developer proposes to sell a fully developed and constructed, turn-key, facility. The developer is responsible for all project development activities, including but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, engineering and all interconnection studies. The developer and utility enter into a Built Transfer Agreement ("BTA") in which the developer is responsible for all development scope, engineering, procurement, and construction of the facility. The facility is assigned to the Utility at BTA closing, which is generally between mechanical completion and placed in-service milestones.

- **Acquisition of current operating facilities**: A third-party asset owner agrees to sell an existing facility already constructed and in operation by the facility owner to the Utility.

Solar Procurements for Controllable PPAs

The Companies will also leverage established and evolving competitive procurement processes to secure controllable PPAs from third-party owners of solar and solar paired with storage resources. Under HB 951, 45% of new solar generation selected by the Commission under the Carbon Plan is required to be owned by third parties and delivered to the Companies under controllable PPAs. The Companies have robust experience with procuring new third-party owned solar resources and have requested Commission approval to implement the 2022 Solar Procurement. Specific procurement actions including the anticipated procurement method are discussed in further detail in their respective resource subsections that follow.

Transitioning with Additional Dispatchable Natural Gas Resources

New dispatchable natural gas-fueled resources are needed under both Carbon Plan pathways and across all four portfolios in order to retire coal, reliably integrate renewables and maintain system reliability, as discussed in Appendix M (Natural Gas) and Appendix Q (Reliability and Operational Resilience Considerations). By 2035, all portfolios identify the need for at least 1,200 MW of new CTs (three advanced class CTs) and 2,400 MW of new CCs (two units). As further discussed in Chapter 3 (Portfolios), future access to Appalachian gas supports the need for developing an additional CC unit and the Companies plan to pursue access to Appalachian fuel supply in the near term as part of the new natural gas resource execution strategy discussed in Appendix N (Fuel Supply).

The Companies' near-term and intermediate-term Execution Plan for dispatchable new hydrogen capable natural gas resources, outlined in Table 4-5 below, presents an aggressive development timeline designed to enable the Companies to achieve commercial operation of two CTs by the end of 2027 and the first CC unit by the end of 2028. A select number of additional units will follow closely to provide dispatchable capacity needed to enable coal unit retirements outlined in the portfolios and provide system flexibility to back stand growing amounts of intermittent renewable resources on the system.

Assuming no material delays in siting and permitting, the timeline for construction of new natural gas-fueled generation is minimally five to six years, thus requiring the Companies to take immediate action to begin developing new CT and CC units to achieve the planned in-service dates. To meet these aggressive target in-service dates for dispatchable new gas assets and to achieve the planned coal unit retirement schedule, the Companies plan to self-develop the initial new CT and CC gas assets to be located on the Companies' existing sites. These initial CT/CC assets would be brownfield additions at existing power stations that can utilize the Companies' existing transmission, infrastructure, and workforce. The new replacement generation will be sized at similar or lower capacity than the existing coal generation to be retired, which would enable the Companies to use existing transmission and to net emissions from existing air permits. Importantly, the Companies are only commencing development activities at this time and will return to the Commission at a later date for a CPCN.

Table 4-5: Execution Plan – Natural Gas Assets

Near-Term Actions (2022-2024)	
2022	• Select Owner's Engineer • Begin preliminary site work • Begin CPCN preparations for two CTs (2027) and first CC (2028) across two sites
2022-2023	• Contract for interstate firm transportation fuel supply
2023	• Submit Interconnection Requests (expedited replacement generator process, if approved) • Begin preparation of air permit applications • Bid turbines • Submit CPCN applications for two sites (two CTs at one & one CC at the other) • Submit air permit applications at two sites

Near-Term Actions (2022-2024)	
	• Receive Facility Studies
2023-2024	• Contract for intrastate firm transportation fuel supply
2024	• Commence construction if CPCN approved • Award turbines- full NTP • EPC- full NTP • Receive Interconnection Agreement • Begin transmission build-out/modifications
Intermediate-Term Actions (Achieve 70% Target)	
2025-2027/2028	• Site construction
2025	• Transmission backfeed available
2027/2028	• Commissioning begins
EOY 2027	• First new CTs in service (brownfield site)
EOY 2028	• First new CC in service (brownfield site)

Intermediate-term actions beyond 2024 are dependent upon issuance of CPCNs to construct the new CT and CC units and other needed regulatory approvals including receipt of air permits. Once necessary regulatory approvals are received, the selected EPC contractor can begin construction. Transmission build-out required to support each facility must be completed in time to support back-feed, which will allow commissioning activities to begin. Once commissioning is complete, each site will be placed in service. The Companies will continue to assess development timelines and resource needs for additional CT/CC units and/or storage builds necessary to maintain system reliability depending on the pathway selected and the success of implementing other generation and non-generation solutions.

Procurement Plan – New Gas Assets

The time frame to meet the aggressive desired in-service dates (2027 for earliest CTs and 2028 for earliest CC) requires self-development activities to begin in 2022, generator interconnection studies and CPCN applications to be pursued in 2023 and likely does not allow sufficient time for bidding of new future sites through a RFP where all sites would need to progress through full DISIS Cluster Study and full transmission studies performed prior to awarding bids. Siting the initial CT/CC builds at brownfield sites will also leverage existing resources and mitigate transmission upgrades to retire existing coal units and to build new dispatchable capacity. For future CT/CCs, Duke Energy will also explore potential acquisitions of available capacity from existing or late stage developed gas generators to the extent such resources are available.

Significantly Expanding Utility-Scale Solar

As of December 31, 2021, approximately 4,350 MW of utility-scale solar (i.e., solar projects that are greater than 1 MW) are connected to the DEC and DEP systems and this level will need to grow to over 12,000 MW of solar capacity to meet the 70% interim target.

Looking beyond the solar resources that are already mandated by existing programs and procurements, the Carbon Plan portfolios identify the need for between 3,450 MW and 5,400 MW of incremental solar between 2026 and the start of 2030. These future solar resources will primarily be larger, transmission-connected projects with higher capacity factors than existing solar facilities, delivering significant zero-carbon electricity to the Companies' combined systems.

Achieving this significant level of solar capacity growth will require an accelerated rate of solar interconnections. Reaching the 70% interim target by 2030 requires a rate of new solar interconnections approximately 2.5 times the maximum amount interconnected in any previous year as further discussed in Chapter 3 (Portfolios) and Appendix I (Solar). This will also drive the need for transmission investments to accommodate increased solar deployment, as discussed in Appendix P (Transmission System Planning and Grid Transformation).

2022 Solar Procurement Target Volume

The Companies have sought Commission approval to enable procurement of needed new solar resources through the 2022 Solar Procurement Program[4] ("2022 SP Program"). The Companies have requested Commission approval to procure a minimum target volume of 700 MW subject to determining a "Carbon Plan-informed" RFP target volume of new solar resources to be procured in the 2022 SP Program. The Companies have begun the pre-solicitation market participant engagement process and are targeting opening the 2022 SP Program RFP on or about May 31, 2022, pending Commission approval.

As presented in Appendix I (Solar), the Companies propose to procure 750 MW of new solar resources through the 2022 SP Program, which reflects the volume of new solar-only resources that the Companies forecast can interconnect in 2026 (which is also referred to as beginning-of-year 2027). The 2022 SP Program design includes a volume adjustment mechanism to mitigate pricing risk if bid prices exceed 110% of the Carbon Plan's assumed solar cost and to enable up to 20% more solar to be procured if bid prices are 10% below the Carbon Plan's assumed solar cost. As discussed further below, additional annual procurements for both solar and solar paired with storage resources are planned in 2023 and beyond to procure needed solar resources to be installed under moderately aggressive to extremely aggressive interconnection timelines that are dependent on the outcome of planned transmission investments as further described in Appendix I (Solar) and Appendix P (Transmission System Planning and Grid Transformation).

[4] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Petition for Authorization of 2022 Solar Procurement Program, Docket Nos. E-2, Sub 1297, E-7, Sub 1268 (filed March 14, 2022).

Table 4-6 below outlines the Companies' near-term actions associated with the 2022 SP Program and preparing for and executing the 2023 solar and solar paired with storage procurement, and intermediate-term actions to advance subsequent procurements.

Table 4-6: Execution Plan – Solar

Near-Term Actions (2022-2024)	
2022	• Finalize and issue 2022 SP Program to align with 2022 DISIS cluster (May 2022) • 2022 Solar Procurement Step 1 bid evaluation process (Q3-Q4 2022) • NCUC approval of final 2022 SP Program target volume (11/1/22) • Stakeholder engagement in preparation for 2023 Solar Procurement ("2023 SP") framework (Q4 2022)
2023	• 2022 SP Program Step 2 bid evaluation process and DISIS cluster Phase 2 study (Q1-Q2 2023) • Finalize 2023 Solar Procurement plan (Q1 2023), targeting procurement of 1,000 MW • Selection and contracting of 2022 SP winners (Q2-Q3 2023) • Finalize and issue 2023 SP to align with DISIS cluster (Q2-Q3 2023) • Stakeholder engagement in preparation for 2024 Solar Procurement, as needed (Q4 2023)
2024	• Selection and contracting of 2023 SP winners (Q2-Q3 2024) • Finalize and issue 2024 Solar Procurement to align with 2024 DISIS cluster (Q2-Q3 2024), targeting procurement of 1,350 MW
Intermediate-Term Actions (Achieve 70% Target)	
2025-2030	• Issue subsequent solar procurement RFPs in 2025-2030 in alignment with then-approved Carbon Plan

Procurement Plan – Solar

Both pathways and all four portfolios identify the need for significant expansion of new solar and solar paired with storage resources on the DEP and DEC systems in the near- and intermediate-terms.

The Companies anticipate multiple rounds of solar procurements of new solar and solar paired with storage resources between 2022 and 2030. The Companies have requested the Commission approve the final Carbon Plan-informed 2022 SP Program target volume by November 1, 2022.

Future procurements will solicit both utility-owned solar and solar paired with storage resources as well as third-party owned resources that provide the Companies rights to dispatch, operate and control the facilities in the same manner as utility-owned solar resources. The Companies plan to engage with stakeholders in late 2022 and early 2023 to discuss the structure of the next procurement. Subject to further guidance from the Commission, the Companies are targeting 1,000 MW to be procured in the 2023 solar procurement and 1,350 MW to be procured in a potential 2024 solar procurement (totalling 3,100 MW in the near term, including the 750 from 2022 SP Program). Like the 2022 SP Program, Duke Energy plans to utilize an Independent Evaluator to assist with RFP issuance and bid selection. As with the 2022 SP Program, the bid window and RFP dates will be established to align with the annual DISIS Interconnection schedule.

Exploring Advanced Nuclear Resources

The Companies have owned and operated nuclear plants in the Carolinas for over 50 years, generating carbon-free, reliable electricity, as well as supporting well-paying jobs, providing significant tax revenues, and creating many other benefits for their communities. The Companies cannot achieve the energy transition and CO_2 emissions reductions targets without nuclear power – their largest generator of zero-carbon electricity. In fact, all viable portfolios to achieving the 70% CO_2 emissions reductions target rely on existing nuclear facilities continuing to provide zero-carbon energy through 2030 and beyond. In addition, new advanced nuclear plants, such as small modular reactors ("SMRs") and advanced reactors will be critical to achieving carbon neutrality by 2050 as required by HB 951.

The Carbon Plan modeling performed by the Companies identifies the need for at least 570 MW of new nuclear (two SMRs) to be installed by 2035 under both pathways and all portfolios. As further addressed in Appendix L (Nuclear), the earliest date for having a new SMR unit online is mid-2032. The Companies believe it is prudent and necessary to begin development of new nuclear resources to ensure that these zero-carbon load-following resources are viable options to be selected by the Commission in the future. Table 4-7 below outlines the Companies' near-term and intermediate-term Execution Plan to advance new zero-carbon nuclear.

Table 4-7: Execution Plan – New Nuclear

Near-Term Actions (2022-2024)	
2022-2023	• Organize nuclear development staff for new nuclear builds • Perform new nuclear alternative siting study • Perform new nuclear technology selection
2022-2024	• Begin new nuclear early site permit ("ESP") development • Perform new nuclear technology due diligence review • Choose the advanced nuclear technology/company to build the first plant(s)
2023-2025	• Develop new nuclear construction and operating license
Intermediate-Term Actions (Achieve 70% Target)	
2026	• Submit COL application and obtain operating license approval

Intermediate-Term Actions (Achieve 70% Target)	
2027-2028	• Obtain CPCN siting approval to construct new advanced nuclear plant
2029	• Begin construction of new advanced nuclear plant • Determine reactor vendor and schedule for future builds

The actions above support the initial new nuclear SMR unit in-service date of mid-2032. Future units could follow in 18-month intervals as determined to be needed in the Carbon Plan.

Procurement Plan – New Nuclear

A mid-2032 in-service date for an initial new nuclear SMR unit presents an aggressive but currently feasible timeline if Duke Energy takes actions beginning in 2022 to start the licensing process, including potential early site permitting. Based on the unique nature of building new nuclear plants, the competitive selection comes when Duke Energy chooses the advanced nuclear technology/company to build the first plant(s). The ESP would allow Duke Energy to gain NRC approval for the future deployment of one or more reactor technologies at a site, prior to a specific technology/vendor being selected. The ESP allows for finality of the environmental and site safety regulatory issues before the reactor technology is chosen.

Planning for New Wind Energy Resources

Wind, both onshore and offshore, is an important resource to meet the HB 951 interim and long-term CO_2 emissions reductions targets. Meeting the 70% interim reduction target requires the development of between 600 MW (P1) to 1,200 MW (P2, P3 and P4) of onshore wind. In addition, three of the four portfolios identify the development of offshore wind as part of meeting the 70% interim target, 800 MW for P1 and P4 and 1,600 MW for P2.

Today, there are no operational or under-development onshore wind facilities within the Companies' balancing authority areas, as discussed in Appendix J (Wind). As such, the Companies' near-term efforts, outlined in Table 4-8 below, will be directed toward evaluating the establishment of a working group to build the market and strategies to bolster the development of onshore wind resources in achievement of the Carbon Plan onshore wind procurement goals.

Development of offshore wind is restricted to specified offshore wind energy areas ("WEA"), which begin at 3 nautical miles from shore and are under the jurisdiction of the Bureau of Ocean Energy Management ("BOEM"). Developers must win WEAs through competitive auctions, at increasingly rising prices, to gain the right to control the development of offshore wind resources, as discussed in Appendix J (Wind). On May 11, 2022, the Carolina Long Bay auction was held, and Duke Energy Renewables Wind, LLC, an unregulated affiliate of Duke Energy, was the provisional winner of the Carolina Long Bay OCS-A 0546 lease area.[5] Following the results of this lease decision, Duke Energy

[5] Carolinas Long Bay | Bureau of Ocean Energy Management (boem.gov).

will focus on executing the near-term and intermediate-term actions outlined in Table 4-9 below.[6] Maintaining progress toward these near-term actions will be critical, as development of offshore wind resources in the time frame necessary to deliver significant zero-carbon energy to support the HB 951 70% interim target is an aggressive timeline that could be challenged by a number of circumstances, including failure to obtain timely approvals of all required federal and state agency permits.

Table 4-8: Execution Plan – Onshore Wind

Near-Term Actions (2022-2024)	
2023	• Explore development of an onshore wind working group • Develop outreach plan to engage the wind development community and shape the wind industry for the Carolinas • Consider partnership approaches for future onshore wind development • Commence procurement of up to 600 MW onshore wind
2024	• Continue onshore wind development and procurement efforts
Intermediate-Term Actions (Achieve 70% Target)	
2025	• Continue onshore wind development and procurement efforts

Onshore wind activities beyond the near-term actions above would include continued RFP issuance, design, permitting, constructing and commissioning of onshore wind assets. Community outreach will be critical for enabling the development of onshore wind resources to contribute to the achievement of the CO_2 emissions reductions targets in HB 951.

Table 4-9: Execution Plan – Offshore Wind

Near-Term Actions (2022-2024)	

2022 - 2023	• Secure lease
	• Initiate development and permitting activities for 800 MW
	    • Develop and submit Site Assessment Plan and begin engaging stakeholders
	    • Begin developing Construction and Operations Plan
	    • Initiate local and state permitting processes
	• Initiate interconnection study process

2024	• Obtain Site Assessment Plan approval from BOEM

[6] Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan (“SAP”); or ii) a combined SAP and Commercial Operation Plan.

Intermediate-Term Actions (Achieve 70% Target)	
2025	• Launch construction planning activities
2027	• Submit Construction and Operations Plan to BOEM

Procurement Plan – Wind

Onshore Wind: Due to the history of onshore wind in the Carolinas, near-term actions will be needed to bolster the onshore wind market in the Carolinas to ensure wind resources are developed to deliver on the HB 951 CO_2 emissions reduction targets. The Companies are considering engaging with wind developers, trade groups and industry advocates in a working group to develop a comprehensive strategy to bring new onshore wind opportunities to the Carolinas. Duke Energy expects to leverage the working group for defining arrangements with wind developers, issuing RFPs for onshore wind projects, and considering wheeled wind opportunities. The Companies plan to include onshore wind in their 2023 RFP.

Offshore Wind: Developing offshore wind depends on winning very select lease auctions. The Carolinas Long Bay auction was held by BOEM on May 11, 2022, and Duke Energy Renewables Wind, LLC, an unregulated affiliate of Duke Energy, prequalified as an able bidder for the auction. Duke Energy Renewables Wind, LLC is the provisional winner of the Carolina Long Bay OCS-A 0546 lease area and TotalEnergies Renewables USA, LLC, is the provisional winner of Carolina Long Bay OCS-A 0545.[7] In addition, BOEM awarded Avangrid Renewables, LLC, parcel OCS-A 0508 covering an area offshore near Kitty Hawk, North Carolina in 2017.[8]

Increasing System Flexibility and Maintaining Reliability With Energy Storage

Energy storage will play a critical role in the low-carbon future of the power system. With the significant increase of intermittent zero-carbon generation, such as wind and solar, increasing the energy storage capacity in the Carolinas will be critical for managing extreme fluctuations in net load and for matching the generation of zero-carbon energy to when the demand for energy exists. The nature of energy storage allows energy to be injected back onto the grid when it is needed most to increase system reliability. The Companies' Carbon Plan modeling includes 4-hr and 6-hr grid-tied battery energy storage, battery energy storage at solar paired with storage sites and new powerhouse at the Bad Creek Hydroelectric Station ("Bad Creek II").

Today, long duration storage, totalling 2,300 MW of capacity, is currently available via the Jocassee and Bad Creek pumped storage hydro systems. Through a series of upgrade projects that include the installation of four additional pump turbines, three higher-rated step-up transformers, and new generators, the Companies intend to increase the capacity of its Bad Creek facility by approximately se320 MW by 2024. Beyond these planned upgrades, the Companies are exploring the feasibility of

[7] Carolinas Long Bay | Bureau of Ocean Energy Management (boem.gov).

[8] Interior Department Auctions Over 122,000 Acres Offshore Kitty Hawk, North Carolina for Wind Energy Development | U.S. Department of the Interior (doi.gov).

a cond powerhouse (12-hour storage facility) at the Bad Creek Hydroelectric Station, with construction targeted to commence in 2027. Constructing Bad Creek II would add approximately 1,700 MW of baseload capacity with an expected in-service date in 2033. Table 4-10 below outlines the Companies' near-term and intermediate-term Execution Plan to advance pumped storage hydro.

Table 4-10: Execution Plan – Pumped Storage Hydro

Near-Term Actions (2022-2024)	
2022-2023	• Complete Bad Creek II Feasibility Study
2024	• Determine EPC strategy for Bad Creek II
2022 - 2024	• Continued development of FERC application for Bad Creek relicensing
Intermediate-Term Actions (Achieve 70% Target)	
2025-2030	• File state approvals for Bad Creek II • File final FERC application for Bad Creek relicensing
2027	• Construction of Bad Creek II begins

In addition to the pumped storage hydro systems, the Companies currently have 300 MW of grid-connected battery storage under development as part of inflight projects on the DEP and DEC systems.

While there are various types of storage technologies that may be available in the future to support the Companies plans for stand-alone battery storage and solar paired with storage, in the near-term, the Companies plan to deploy megawatt-scale electrochemical batteries while continuing to partner with diverse suppliers who can provide the latest battery technology expertise and resources. Table 4-11 below outlines the Companies' near-term and intermediate-term Execution Plan to advance 1,600 MW of new battery energy storage to be developed by 2029 (1,000 MW stand-alone storage, 600 MW storage paired with solar).

Table 4-11: Execution Plan – Energy Storage

Near-Term Actions (2022-2024)	
2022-2024	• Submit Interconnection Requests for battery energy storage projects at strategic grid locations supporting Carbon Plan needs through 2029 • Design controls, dispatch and software tools for a fleet of battery energy storage systems • Test and study non-lithium technologies at the R&D scale

Near-Term Actions (2022-2024)	
	• Finalize procurement strategy and initiate procurement activities relative to procurement strategy for 1,600 MW of battery energy storage (1,000 MW stand-alone storage, 600 MW storage paired with solar)
Intermediate-Term Actions (Achieve 70% Target)	
2025-2030	• Procure, construct and interconnect energy storage selected in Carbon Plan • Optimize control and dispatch of the Duke Energy fleet with a variety of energy storage technologies

Procurement Plan – Energy Storage

Bad Creek II Powerhouse: During the near-term period through 2024, Duke Energy will continue engineering work but will not need to commit to any major construction expenses. Beyond 2024, actions include filing for state regulatory approvals and the final FERC application. Once all required regulatory approvals to construct are obtained, which are targeted for 2027, construction of Bad Creek II would begin with an expected in-service date in 2033. To ensure cost competitiveness, Duke Energy will bid out EPC services at the appropriate time.

Standalone Battery Storage: The value of energy storage, specifically batteries, is maximized for the grid and customers if the assets are strategically located on the Companies' system and incorporate operational parameters into the designs. Many of these strategic locations are within or adjacent to Duke Energy-owned land. Due to these factors, the Companies believe the battery storage assets are best served via self-development while working with established component manufacturers and service providers that focus on certain project development activities, such as design, siting, permitting, and environmental due diligence. When cost-effective, the Companies will employ competitive solicitations for EPC services to qualified vendors, ensuring the best value for customers. Timing of EPC solicitations will be specific to the project schedules. Additionally, the Companies will seek to purchase components and services from local providers – to the extent that they provide the required functionality and are cost competitive in relation to other options – so as to promote economic development in the region.

Procurement of Battery Storage Paired with Solar: The Companies will utilize established and evolving procurement practices for battery paired with solar resources that align with the Companies' plans for procuring and self-developing new controllable solar resources, as discussed above.

Assessing the Viability of Hydrogen Resources

While the Carbon Plan does not assume any projected use of hydrogen by 2030, hydrogen supply and use will grow significantly to become an important component of the pathway to achieve carbon neutrality by 2050. The Companies anticipate the capability to use 100% hydrogen for fuelling new zero-carbon generation and as an avenue to decarbonize existing and future natural gas generation facilities. The Companies also envision hydrogen as a way of providing an alternative long-duration storage option for excess energy generated by renewable resources.

Table 4-12 below outlines the Companies' near-term and intermediate-term Execution Plan to participate in the necessary studies and demonstrations to advance the understanding and development of hydrogen production, storage, transportation and generation. Additional information is provided in Appendix O (Low-Carbon Fuels and Hydrogen). With a long-term need for hydrogen technologies anticipated, the Companies will continue to seek opportunities to understand, prepare for and implement hydrogen through government, university and industry partnerships. Hydrogen actions beyond the near term would include completing approved studies and demonstration projects and may include seeing the beginning and build out of hydrogen supply infrastructure and retrofitting selected existing units to high or full hydrogen capability.

Table 4-12: Execution Plan – Hydrogen

Near-Term Actions (2022-2024)	

2022-2024	• Develop clean hydrogen studies and demonstration projects
	  ◦ Submit information and proposals for potential federal funding to offset costs where appropriate
	  ◦ Leverage work to date on Clemson CHP Hydrogen study to implement an operational pilot project
	• Understanding and mapping hydrogen opportunities
	  ◦ Support and develop storage technology research and demonstrations
	  ◦ Collaborate with academic and industry research partners to advance low-carbon hydrogen production technologies
	  ◦ Support of combustion turbine manufacturers development of 100% hydrogen capable dry low-emission combustion
	  ◦ Improve hydrogen production, hydrogen transportation and hydrogen storage cost projections
	• Develop options and regulatory support for hydrogen transport infrastructure

2023-2024	• Commence approved studies and demonstrations • Determine hydrogen readiness scope for new unit builds • Plan for new CT/CC units built with max hydrogen feasibility
Intermediate-Term Actions (Achieve 70% Target)	
2025-2028	• Continue development of clean studies and demonstration projects
2025-2030	• Complete approved studies and demonstrations, incorporate learnings into planning

Transmission System Planning and Grid Transformation

Executing the Carbon Plan requires a transformation of the Companies' transmission system to achieve CO_2 emission reduction targets while ensuring adequate and reliable service is maintained. This transformation includes investments required to retire existing coal-fired generation and interconnect new solar, solar paired with storage, stand-alone storage, wind, SMRs, and gas generation. Additional details on how the Companies prudently plan and reliably operate their transmission systems are addressed in Appendix P (Transmission System Planning and Grid Transformation).

Enabling Coal Unit Retirements

Each of the Carbon Plan pathways and portfolios includes the retirement of existing coal units. Locating replacement generation at the same site of retiring coal-fired generation can provide the grid support necessary to ensure continued system reliability and reduce transmission network upgrade costs. The Execution Plan includes a near-term action to file with FERC in 2022 to establish a replacement generation study process to ensure efficient, timely, and cost-effective interconnection processing of new generation planned to be sited at retiring coal-fired generation locations.

For DEC, a switching station is currently under construction to enable the retirements of Allen Units 1 & 5 in 2023. Transmission planning studies completed to date have not identified major transmission impacts from the retirement of Cliffside Unit 5 scheduled by the end of 2025. Intermediate-term actions include the assessment and construction of additional transmission system upgrades to enable coal-fired generation retirements in the late 2020s and early 2030s. Retirement of the Marshall coal units will require new transmission that will need to be in service by December 2028 unless equivalent replacement capacity is located at the existing Marshall site. DEC plans to evaluate transmission upgrades to enable retirements as the Belews Creek mid-2030s planned retirement date approaches; preliminary analysis suggests that transmission upgrades will be required to retire this capacity if not replaced with new generation on-site and coincident with retirement.

For DEP, the retirement of the Roxboro and Mayo coal units will cause the need for additional transmission projects unless this generation capacity is replaced sufficiently at the Roxboro and/or Mayo sites and coincident with the retirements.

Intermediate-term actions include the continued assessment and construction of additional transmission system upgrades to enable coal unit retirements. Additional detail on transmission planning assessments to support coal unit retirements is addressed in Appendix P (Transmission System Planning and Grid Transformation).

Public Policy Transmission Projects

The Execution Plan also includes a near-term action to initiate, subject to NCTPC approval, public policy transmission projects necessary to allow for substantial incremental solar resource interconnections in existing "Red Zone" areas of DEC and DEP, as further described in Appendix P

(Transmission System Planning and Grid Transformation). The Companies' transmission planning process and recent interconnection planning studies have identified an initial group of projects (see Table P-3 in Appendix P) that the Companies will propose to be added to the NCTPC Local Transmission Plan by midyear 2022. The Companies will also continue to develop their transmission planning processes based on the outcome of the recently established FERC rulemaking proceeding on transmission planning and cost allocation and generator interconnection.[9]

In the intermediate term, more extensive transmission network upgrades will be required to integrate remote interconnected resources and ensure safe and reliable energy delivery to load centers under various grid conditions. Upgrades of existing transmission lines, although very successful with enabling interconnections of the first phase of Carbon Plan resources, will not be sufficient to interconnect later phases of incremental resources associated with Carbon Plan implementation. In addition to the initial upgrades of existing transmission, new transmission infrastructure with new rights of way will be required toward 2030 and through the 2030s to enable Carbon Plan resource implementations.

Offshore Wind-Enabling Transmission Projects

Carbon Plan portfolios P1, P2 and P4 include interconnection of 800 or 1,600 MW of offshore wind between the end of 2029 and the beginning of 2032. Previous screening studies have indicated that 800 MW of offshore wind can be injected at New Bern 230 kV without the addition of major new onshore transmission lines but with some significant upgrades to the existing system in the New Bern area. Studies have also indicated that injection of 1,600 MW of offshore wind into New Bern would likely require construction of a new 500 kV network line. The Execution Plan includes a near-term action to request an interconnection study for offshore wind interconnecting into New Bern Substation in 2023.

Intermediate actions include construction of the network upgrades to support the resource selected in the Carbon Plan. Completing the required transmission to support offshore wind injections in the 2029-to-2032 timeframe will be challenging as siting, permitting and constructing the transmission system upgrades are dependent on public engagement, routing, scoping, and the acquisition of new right of ways.

Table 4-13 below outlines the Companies' near-term and intermediate-term Execution Plan to advance the grid needs critical to the Plan described in this section.

Table 4-13: Execution Plan – Transmission Planning and Grid Transformation

Near-Term Actions (2022-2024)	
2022	• FERC filing to establish generation replacement queue process • Subject to Transmission Advisory Group stakeholder review and NCTPC approval, start public policy transmission projects included in

[9] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022).

Near-Term Actions (2022-2024)	
	Local Transmission Plan • Start preliminary routing, scoping, siting, right-of-way acquisition for OSW transmission projects with point of interconnection at New Bern Substation

2023-2024	**DEC**
	• Marshall Station (Units 1-4) - (Earliest planned retirement date Marshall 1,2 EOY 2028; Marshall 3,4 EOY 2032)
	  • Determine feasibility for upgrading McGuire – Marshall 230kV lines by EOY 2028. Study replacement generation located at brownfield site
	• Belews Creek (Units 1-2) - (Earliest planned retirement date EOY 2035)
	  • Transmission planning to evaluate transmission upgrades and replacement generation requirements to enable retirements by EOY 2035
	DEP
	• Roxboro Station (Units 1-4) and Mayo (Unit 1) (Earliest planned retirement dates Roxboro 3,4 EOY 2027; Roxboro 1,2 EOY 2028; Mayo EOY 2028) Transmission planning to evaluate transmission upgrades and replacement generation requirements to enable retirements by earliest planned dates
	• For contingency purposes, transmission planning to evaluate transmission upgrades needed to site Roxboro/Mayo replacement generation in DEC service area

2023	• Request interconnection studies for needed MW levels of offshore wind being injected into New Bern Substation

Consolidated System Operations

The Companies each currently operate as separate NERC registered Balancing Authorities, Transmission Operators, Transmission Service Providers, and plan as separate NERC registered Transmission Planners. To support implementation of the Carbon Plan and in response to stakeholder feedback, the Companies propose to consolidate these functions and consolidate the Companies' Carolinas' system operations through the appropriate regulatory filings in the near term. Specific benefits include enhancing portfolio flexibility, improving reliability, capturing production cost savings, and simplifying NERC compliance and transmission service provisions. Table 4-14 below provides a summary of system consolidation benefits, and a more detailed discussion of Consolidated System Operations can be found in Appendix R (Consolidated System Operations).

Table 4-14: Consolidated System Operations Benefits

Flexibility	Production	Simplification
• Optimization of existing resources • Less solar curtailment • Reduction in CO_2	• Reduced generation costs • Reduced dump energy • Improved market purchases • Improved storage utilization	• NERC Standard Compliance • One OATT • Single wholesale view
Reserves	**Response**	**Reliability**
• Reduction in day ahead planning reserves • Reduction in planning reserve margin	• Larger balancing area better able to aggregate greater amounts of variable generation and load	• Reserve sharing • Consolidated system operations

The Execution Plan, outlined in Table 4-15 below, includes near-term actions necessary to support a detailed evaluation of consolidated system benefits, stakeholder outreach, and development of North Carolina, South Carolina and FERC regulatory filings. These filings are expected to occur in the first quarter of 2023 and third quarter of 2023, respectively. Also, the Southeastern Reliability Corporation ("SERC"), the Regional Reliability Organization reporting to NERC, will need to certify the consolidated registered NERC entity functions and supporting technical infrastructure relative to their roles in meeting mandatory reliability standards. This certification is expected to occur in late 2024, closer to the effective date of the consolidated system operations.

The Companies estimate consolidated system operations could begin in the 2025 timeframe. However, the timeline for implementation of consolidated system operations by 2025 is aggressive and highly dependent on achieving the necessary regulatory approvals in a timely manner. State regulatory approvals need to be achieved by third quarter of 2023 and FERC approvals need to be achieved by third quarter of 2024 to meet a 2025 implementation date. Any significant delay or insurmountable barrier to implementing consolidated system operations would significantly hinder the ability to manage the variability and intermittency of variable energy resources such as solar and thus hinder the ability to meet the carbon reduction objectives laid out in the Carbon Plan.

Table 4-15: Execution Plan – Consolidated System Operations

Near-Term Actions (2022-2024)	
2022	• Conduct stakeholder outreach
2023	• Develop and submit State regulatory filings in order to receive State approvals by third quarter of 2023

Near-Term Actions (2022-2024)	
	• Develop and submit FERC filings in order to receive FERC approval by third quarter of 2024
2024	• Provide materials for SERC to conduct certification of consolidated NERC functions and achieve certification of the new registered NERC functions for consolidated system operations by year-end 2024

Grid Edge and Customer Programs

Grid Edge and Customer Programs are a foundational component of the Carbon Plan. Customer Programs include energy efficiency ("EE") programs, clean energy customer programs, and net metering programs aimed at helping customers reduce energy usage from the grid and access clean energy resources. Grid Edge programs include customer pricing, demand response, electric vehicle managed charging and system voltage optimization programs designed to allow management of the electric system and shape overall energy loads. Grid Edge and Customer Programs are enabled by the continued implementation of enabling grid improvement programs, such as Self-Optimizing Grid and the modernization of telecommunications infrastructure, which are required to support large-scale distributed energy resource ("DER") deployment.

These programs are discussed in more detail in Appendix G (Grid Edge and Customer Programs) and Appendix F (Electric Load Forecast). This Execution Plan, outlined in Table 4-16 below, addresses near-term and intermediate actions in each of these program areas.

Customer Programs

Energy Efficiency

The Carbon Plan includes the expansion of existing EE programs and the addition of new technologies to achieve a 1% reduction of eligible retail sales. This target reflects an aggressive long-term forecast of EE savings that is more than double the level assumed in the Companies' 2020 IRPs. To achieve this goal, the Execution Plan includes actions to expand the reach of existing programs, accelerate the development of new measures and examine ways to reduce barriers and unlock additional energy efficiency savings. Near-term actions are highlighted below.

On-tariff Financing: To expand program reach, the Companies plan to develop and file for regulatory approval a pilot to provide on-tariff financing targeting multifamily new construction for residential customers that implements savings measures through approved EE programs. Financing costs for improvements are expected to be paid for through reduced monthly energy bills. The Companies have already started work to pilot an on-tariff financing option with residential customers and plan to file for both a pilot approval and a broader five-year implementation plan during 2022. The Companies plan to investigate a non-residential on-tariff financing pilot by 2023 with the potential to seek approval of a full program rollout available to support programs in the 2025 timeframe.

Expansion of Low-Income Programs: As a near-term action, the Companies will seek approval to expand and/or add EE programs that ease the energy burden on income-eligible customers. Program changes include the following recommendations developed in collaboration with stakeholders.

- Work with the EE/DSM Collaborative in coordination with the Low-Income Affordability Collaborative ("LIAC") to redefine the definition of Low-Income and eligibility of customers for income-qualified programs to include what historically had been defined as moderately low-income customers with incomes <300% of the federal poverty level.

- Expanding existing DEC Weatherization program to DEP, including offering (i) weatherization measures and/or (ii) heating system replacement with a 15 or greater seasonal energy efficiency ratio heat pump and/or (iii) refrigerator replacement with an ENERGY STAR® appliance.

- Launching the Energy Burden Reduction Pilot Program that will install deep retrofits at no cost to the customer with an emphasis on low-income neighborhoods with mobile/manufactured homes.

- Expanding the existing Neighborhood Energy Saver Program measure to include additional deep retrofits and replacements including HVAC replacement, heat pump water heater and window improvements.

As Found Baseline for Energy Efficiency Measures*:* The Companies plan to seek approval to offer incentives using the "as found" baseline as a new option for identified measures as described in Appendix G (Grid Edge and Customer Programs). Using an "as found" baseline will allow the Companies to provide higher incentives and estimates that implementation of this recommendation could increase EE savings by approximately 20% on identified measures. The Companies will vet the need for the additional "as found" measures with the EE/DSM Collaborative and seek approval for this near-term action in 2022.

Incentives for Non-Lighting Measures*:* The U.S. Energy Information Administration projects that delivered energy for air conditioning will increase more than any other end use in commercial buildings through 2050. Many customers are not motivated to replace their air conditioner or heat pump units due to the low rebates and the high cost of replacing equipment. This program will seek approval to incentivize customers to replace equipment prior to failure with new units requiring minimum code standards only. The incentive will be offered in combination with a control system, thermostat or other identified measures for bundle. The Companies estimate implementation of this near-term action has the potential to increase participation by 15%.

Advance Codes and Standards Adoption*:* Fast-tracking the state of North Carolina's adoption of commercial building energy codes will ensure EE measures are implemented at the time of construction or retrofit. The Companies plan to seek approval to update the existing Smart $aver® tariff to allow the Companies to improve the market's compliance with existing and future standards through education, outreach and technical support. The Companies estimate this change could account for 5% of program savings.

Clean Energy Customer Programs

The Companies plan to engage stakeholders in the coming months regarding expansion of existing and development of new Clean Energy Customer programs. The Companies anticipate that these potential programs would be focused both on customer self-sourced renewable energy options, whereby customers may directly adopt or support new renewable energy facilities, as well as utility-sourced options, whereby the Companies would participate in transactions that provide customers with access to renewable energy credits or other clean energy opportunities. The Companies will also work with stakeholders to consider programs that help support the adoption of battery storage by customers to support their clean energy goals. The Companies are optimistic that working together with stakeholders, solutions can be identified that can be brought to the Commission for approval later in 2022.

Net Metering

Continued development of the customer-sited solar market is dependent upon customers having some level of price certainty through defined net metering programs. The Companies have worked in collaboration with the rooftop solar industry participants and environmental advocates to design programs that fulfil the needs of customers and industry alike. The Execution Plan includes near-term actions to:

- Offer a Solar Choice Net Metering program that will include dynamic rates that vary based on the time of day and peak demand and integrate with other EE and demand response measures to offer customers additional participation incentives.

- Implement a revised net metering design to more closely reflect the avoided costs associated with behind-the-meter solar generation.

- Secure regulatory approval and implement the proposed “Smart $aver Solar” EE program and expand the program concept to new product bundles and non-residential customers subject to regulatory approval.

The Companies recognize the potential need to bundle behavioural demand response programs, such as Peak Time Rebates, or other load management tools with rate design options to encourage adoption and enable additional responsiveness. As availability and customer interest in DER technologies increase, the Companies will seek ways to harness the usefulness of these various devices through product offerings that work with well-designed rate structures to provide value to both the customer and the overall system. These devices would potentially include in-home storage devices, EVs, load control technology, smart thermostats, and behind-the-meter solar systems with smart inverters. The potential for EVs to provide vehicle-to-home (V2H) or vehicle-to-grid (V2G) services also create opportunities to dynamically manage system load. The Execution Plan includes actions to continue to engage stakeholders and develop subscription concepts that seamlessly bundle these offerings in a manner that provides cost certainty for the customer while providing system benefits. These bundled offerings will also likely lead to a greater adoption of behind-the-meter solar.

Grid Edge Programs

Grid Edge Programs include a mix of customer programs and utility technology applications designed to allow management of the electric system and shape overall loads in a way that defer or eliminate the need for additional generation or system investments. These programs include new rate designs, demand response programs, and voltage optimization.

Rate Design

Rate Design is an important load shaping tool that uses time differentiated rates and other forms of dynamic pricing to encourage customers to change their load profiles in ways that better support the use of low-carbon and zero-carbon resources. A large-scale stakeholder engagement initiative (the Comprehensive Rate Reform Collaborative) has been ongoing to identify new rate designs that provide appropriate pricing structure and encourage behavioral changes that change load shape. Rate Design near-term actions include:

- Updating pricing structures to reflect a change in hourly energy costs due to increased solar penetration. The Companies anticipate offering lower pricing for residential and non-residential during times of high solar production and higher pricing in other time periods.

- Development of new real time pricing tariffs to enable broader, more diverse customer participation by large business customers. Duke Energy's customer research indicates customer interest could result in approximately 10%-30% of the current Large General Service customer class enrolling in an hourly pricing rate and becoming price-responsive loads. Assuming the midpoint of this range and a 65% load factor, the Companies estimate that approximately 790 MW of new price-responsive load.

- Piloting subscription rates and enabling products and services that provide even more attractive pricing options for customers who allow the Companies to actively manage their charging to target times when solar resources may otherwise be curtailed.

Demand Response Programs

Demand Response ("DR") programs are already incentivizing 500,000 Carolinas' customers to reduce peak demand on the electric system when and where needed. The goal is to significantly increase customer participation in the future. Traditional DR programs have historically enabled the Companies to decrease their reliance on older, more expensive generation and spot market power purchases. To support the Carbon Plan, the Companies plan to evolve their use of DR to both reduce peak load and shape load in ways that help the Companies maximize their use of zero-carbon resources. To accomplish this, the Companies intend to incorporate dynamic loads, such as EVs and customer-sited energy storage. Specific near-term actions include:

- Expanding Small and Medium Business ('SMB") program to allow additional flexibility in load types that can participate in the program
- Expand existing Heat Strip Program to DEC and DEP East
- Develop a cost-effective Water Heater program
- Pilot Electric Vehicle Charging programs
- Seek approval of Smart $aver Solar EE program
- Seek Commission approval for the need to grow summer capability.

Voltage Optimization (Conservation Voltage Reduction)

The Companies are utilizing systems designed to control distribution grid equipment in both DEC and DEP, as well as deploying new technology to optimize voltage, which results in reduced peak demand and energy usage. Conservation Voltage Reduction ("CVR") technology allows the Companies to conserve energy at a circuit or system level. CVR coordinates the settings of devices to lower the voltage for an entire circuit. This in turn reduces the load of the system, thereby lowering generation fuel consumption which leads to lower CO_2 emissions. The Companies plan to expand CVR rollout in the DEC service territory and introduce CVR in the DEP service territory to support achieving Carbon Plan targets. Near-term actions to expand CVR include seeking Phase II approval to expand CVR from 67% to 90% of eligible circuits in DEC.

Transportation Electrification

Transportation electrification will lead to a significant increase in the amount of electricity consumed by vehicles as more consumers switch to EVs. It is expected that a collection of rates, deployed assets and customers programs will be needed to support this significant change. Managed EV charging is a valuable solution to support lower CO_2 emissions by reducing existing load peaks and eliminating risks from new ones. Managed charging strategies for residential, fleet and commercial customers vary, but each approach will leverage customer-focused design processes combining usage monitoring and control geared to avoid higher-emission generation and to improve grid stability and efficiency. Near-term actions to effectively manage the impact of EV charging and support broader policy objectives include implementation of the EV programs filed in 2021 and continued engagement with the EV Collaborative to identify and develop additional EV charging programs that enable effective EV integration.

Table 4-16: Execution Plan – Grid Edge and Customer Programs

Near-Term Actions (2022-2024)	
2022	**Energy Efficiency** • Seek and obtain approval of On-tariff Financing Pilot for multi-family new construction

Near-Term Actions (2022-2024)	
	• Seek and obtain approval of On-tariff Financing program (DEC/DEP five-year rollout) • Seek and obtain approval of expansion of low-income EE programs (Weatherization program for DEP, new low-income pilots, and LIAC Report recommendations) • Seek and obtain approval of "as found" Baseline measures for equipment replacement • Seek and obtain approval to update Smart $aver program to include education, outreach and technical support for new construction market • Seek and obtain Commission approval to update the inputs underlying the determination of the utility system benefits in the Companies' approved EE/DSM Cost Recovery Mechanism **Demand Response Programs** • Seek and obtain approval for Load Shaping DR with SMB incentive expansion • Seek and obtain approval for Heat Strip program expansion to DEC and DEP East **Transportation Electrification** • Seek and obtain approval for Electric Vehicle Supply Equipment Tariff • Seek and obtain approval for subscription EV Managed Charging pilot • EV Make-Ready Credit rollout (approved in 2022)
2022 - 2023	**Smart $aver Solar** • Obtain NCUC approval and launch the proposed Residential Smart Saver Solar Program **Clean Energy Customer Programs** • Seek and obtain approval for suite of new Clean Energy Customer Programs **Demand Response Programs** • Expand outreach to increase adoption of existing thermostat programs **Rate Design** • Seek and obtain approval for enhanced Real Time Pricing Pilot program **Transportation Electrification** • Seek and obtain approval for V2X pilots
	Energy Efficiency • Seek and obtain approval of increased incentives for non-lighting measures

Near-Term Actions (2022-2024)	
2023	**Rate Design** • Contingent on Commission approval, rollout new Net Metering Rate (DEC/DEP implementation) • Seek and obtain approval for updated pricing structures to reflect a change in hourly energy costs due to increased solar penetration • Seek and obtain approval for behavioral demand response program and supporting infrastructure to encourage dynamic rate adoption **Grid Edge** • Seek and obtain approval for new locational grid pilots (including regulatory framework) and measures **Electric Transportation** • Complete Park & Plug Pilot Phase 1 (approved in 2021) • Complete EV School Bus Phase 1(approved in 2021) **Voltage Optimization** • Complete DEC IVVC/CVR Phase 1 rollout to 73% of eligible DEC circuits
2024	**Voltage Optimization** • Complete DEP DSDR CVR software implementation
Intermediate Term Actions (Achieve 70% Target)	
2026	**Voltage Optimization** • Seek and obtain approval for Phase 2 expansion of DEC IVVC/CVR to 90% of eligible circuits

Long-Term Grid Edge and Customer Programs Considerations

Achieving the Carbon Plan modeled EE target will require collaboration and commitment from the Companies, customers, stakeholders, regulators, and potentially policy makers. The Companies will build upon their existing region-leading EE portfolio but achieving the new levels of energy efficiency will ultimately depend upon customers investing to reduce energy usage. Feedback from existing program participants have shown that customer awareness and implementation of energy efficiency measures is directly tied to customer awareness, program marketing and incentive levels and recommend modifying program cost-effectiveness tests to appropriately value the cost of CO_2 emissions reductions and avoided demand costs. The Companies estimate that including valuing carbon reduction and demand in a manner that increases the cost-effectiveness threshold by 35% could yield a 12% and 8% increase in total residential and nonresidential kWh savings, respectively.

Similarly, the shift toward flexible demand management will be dependent on customer participation in new rate design and demand response programs enabled by the continued expansion of automated technologies. Subscription and bundled services that allow utility management of loads will be increasing important, especially as EV adoption and load increase significantly over the next decade.

Implementation of building code standards that drive the market toward compliance with existing or greater standards also has the potential to reduce energy usage and demand resulting in reduced carbon emissions. Additionally, building code changes that drive residential customer adoption of Wi-Fi-enabled water heaters, thermostats, smart panels and smart inverters could unlock value for customers and the energy system.

Monitoring Risks in the Near Term and Intermediate Term

Integral to executing the Carbon Plan is the identification and monitoring of risks throughout execution to determine when external factors require the Companies to take mitigating actions, consider alternative strategies, or pivot to alternative options to achieving Carbon Plan targets. Assessment of risks in the near term and intermediate term is also key to the Commission's decision-making regarding the optimal timing and generation and resource mix to accomplish the least-cost path to achieving HB 951's targets.

Risks tend to be related to executable components of the Carbon Plan, such as programs, projects, or resource types; however, some risks are also a result of the interdependencies between Plan components. The Companies have identified initial execution risks and, as activities launch, the Companies will monitor those risks and include appropriate adjustments to biennial Carbon Plan updates or in related regulatory dockets. Execution risks categories are outlined below, and the Appendices provide additional information on risks specific to the planning area or technology.

Supply Chain

Material and equipment supply chain disruptions may lead to construction delays or inability to develop certain types of programs or projects on the timeline identified in this Execution Plan or at the costs or amounts assumed in the modeling. Capacities of vendor supply chains may be challenged as entities compete for limited resources, leading to delays or cost escalations. Inflationary pressures on components, material and equipment may lead to cost escalations.

Siting and Permitting

Inability to site and receive timely permits and environmental reviews for new energy resource facilities and supporting electric transmission and gas pipeline infrastructure may inhibit or slow advancement of execution activities, including:

- Electric transmission system expansion and modification supporting larger volume of renewable resources and the retirement and replacement of generation; and
- Gas infrastructure needed to supply incremental natural gas facilities.

Labor Supply

Shortages in qualified craft and engineering labor may cause delays or increased costs in constructing new energy resource facilities and supporting infrastructure or implementing new programs.

Regulatory Approvals

Ability to receive timely regulatory approvals from all required authorities and jurisdictions for proposed activities may impact progression toward Plan targets. This risk cuts across all prongs of planning, including enhanced existing and new supply-side resources, transmission planning and grid requirements, Customer and Grid Edge programs, and the development and demonstration of breakthrough technologies.

Interdependencies on Transmission System Planning and Interconnection

As detailed in Appendix P (Transmission System Planning and Grid Transformation), coordinated proactive transmission planning and timely construction of the significant transmission that will be needed to interconnect new resources selected in the Carbon Plan presents a key interdependency and timing risk.

Interdependencies on Fuel Supply

As outlined in detail in Appendix N (Fuel Supply), future uncertainty or inability to secure additional interstate pipeline firm transportation causes increased fuel assurance risk, increased customer fuel cost exposure and potentially delayed coal retirements. Also, the inability to secure flexible coal supply through coal unit end of life may accelerate the need for their capacity replacement.

To manage these risks, the Companies near-term and intermediate-term planning strategy focuses on diversification across all three prongs of planning – demand-side and load modification, zero-carbon renewables and nuclear, and flexible and dispatchable supply-side and energy storage resources. Relying on diverse energy resources, rather than only one or two technologies, to achieve the CO_2 emissions reductions targets reduces exposure to execution risks such as labor shortages and supply chain disruptions that may become more pronounced for any one particular technology. Resource diversification also reduces integration challenges, prevents over-reliance on any one single emergent technology, and preserves optionality to achieve the least-cost requirement as technologies mature.

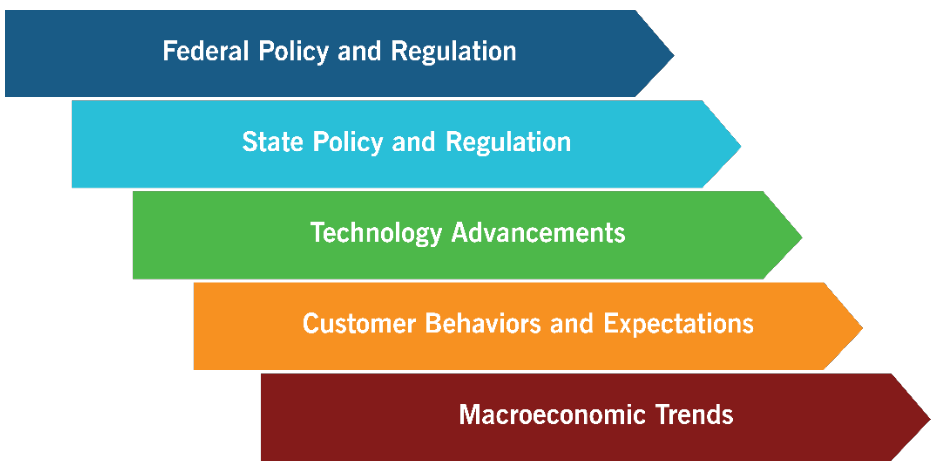
Long-Term Planning and Signpost Monitoring

In addition to executing the near-term and identifying the next phase of intermediate actions required to achieve the interim 70% reduction target, longer-term activities will be necessary to achieve carbon neutrality by 2050. Each of the Carbon Plan portfolios face challenges and uncertainty that may require pivoting as time progresses and the band of uncertainty narrows. Therefore, rather than identifying specific long-term actions in this initial Carbon Plan, the Companies have identified signposts to closely monitor, as illustrated in Figure 4-2 below.

Signpost Monitoring to Guide Planning

To navigate longer-term or disruptive uncertainties such as policy shifts, innovation, or economic trends, the Companies will actively monitor the signposts that could impact plan trajectory toward meeting carbon neutrality to guide their long-term planning assumptions and necessary future adjustments to the Carbon Plan. As these signposts emerge and evolve, the Companies will update planning assumptions, adjust for any new requirements or constraints, and integrate into future Carbon Plan modeling to determine whether modification of the Carbon Plan is required to achieve carbon neutrality reliably and cost-effectively. Signpost categories are shown in Figure 4-2 and described further below.

Figure 4-2: The Key Signpost Categories for Monitoring the Carbon Plan



Federal Policy and Regulation

Federal policies and regulations can influence the timing, costs and technical requirements for achieving carbon reduction targets at least cost. Aspects of this signpost include federal law and regulations of CO_2 emissions or other pollutants, federal trade policy, federal climate and clean energy policy goals, and federal appliance and equipment standards. U.S. Securities and Exchange Commission ("SEC") regulations, including those related to climate disclosures, can also influence the pace of clean energy technology advancement and shifting business customer preferences toward clean energy solutions. Examples under this signpost that could influence the selection and timing of energy resource investments include continuation or expansion of federal tax credits (e.g., production tax credits for wind and solar or tax credits for EV, or EV purchases) for certain technologies and federal incentives and funding for clean energy technology innovation and demonstration. Lastly, policy, regulations, and standards under the purview of FERC, including NERC, the NRC, BOEM, the U.S. Environmental Protection Agency, and U.S. Department of Commerce, among others, can influence aspects of electricity system planning.

State Policy and Regulation

Similar to national policies, state energy law and regulations can influence energy resource planning decisions. In many respects, state policies have a more significant influence than federal policies as North Carolina and South Carolina have jurisdiction over most energy resource planning issues. This includes authority over electric utility rates and other policies and regulations adopted and enforced by the Commission and the PSCSC. Aspects of this signpost are similar to federal policy and regulation and can include state-specific policies or regulations of the environment, state climate policy commitments, policies that influence transportation and building electrification, and building energy standards. Examples within this signpost include state tax credits or funding incentives for clean energy technologies and related infrastructure and special programs. Lastly, state policies can influence where new energy resources can be permitted and sited and impact Plan execution.

Technological Maturity and Cost

The maturity and efficacy of emerging clean energy technologies and grid technologies is critical to meeting the Companies' CO_2 emissions reductions targets. This can be measured by findings from pilots and other demonstration projects, studies that estimate current and future technology costs (reductions or increases), and evaluation of other technological maturity gains (e.g., efficiency). Key technologies include long-duration energy storage systems, renewable energy, advanced nuclear, and hydrogen fuel.

Achieving carbon neutrality will likely require reliance on breakthrough technologies, as is contemplated by HB 951[10], that are still in the development and demonstration phase and have not yet achieved widespread commercial availability and economies of scale. Duke Energy's emerging technology group identifies, prioritizes and tracks future technologies, which could contribute to achieving CO_2 emissions reductions. Prior to full large-scale projects, and consistent with industry best practice, Duke Energy prefers to perform educated pilots and demonstrations to explore the operation and integration of such new technologies on its system. The Companies are engaged throughout the industry in monitoring and assessing potential breakthrough technologies that have the greatest potential for benefit to customers. Ultimately, it may be prudent for the Commission to approve and the Companies to pursue one or more such breakthrough technologies in order to facilitate and even hasten industry and technology evolution. Such initiatives could be particularly beneficial where the Companies are able to leverage partnerships and external funding for the benefit of customers and gain experience in real-world operation on a small scale before large-scale deployment. The Companies are currently evaluating such opportunities involving long-duration storage and hydrogen production, storage, transportation and generation.

Customer Behavior and Expectations

Consumers across all customer classes can be influential in the decarbonization journey and dictate the adoption curve for certain low-carbon or zero-carbon technologies such as electric transportation, distributed solar, electric heat pump conversions, and investment in renewables. Trends in adoption

[10] HB 951 Section 1(1).

of customer-owned distributed generation (e.g., behind-the-meter solar and combined heat and power) and energy storage can inform the potential contribution to CO_2 emissions reductions, particularly when such resources can provide enhanced value to the resiliency of the electricity system.

The adoption of other distributed energy resources, such as EE, DR, and EVs can also influence the timing and costs associated with achieving decarbonization goals and objectives as these resources can either increase or decrease electricity demand. Additionally, consumer interest in electrifying their homes and businesses for space and water heating and cooking, particularly if coupled with financial incentives, could increase electricity demand. The capability and adoption of digital energy technologies could also provide a catalyst for new demand management strategies, including incentives for advanced energy management systems, smart devices with utility control, and virtual power plants.

Macroeconomic Trends

Duke Energy will also monitor macroeconomic trends and indicators that could require adjustments to ensure the Carbon Plan meets the least-cost objective. Macroeconomic indicators are measures that can be influenced by national or global economic conditions, including energy commodity prices, inflation and interest rates, taxes or other added costs, supply chain disruptions, labor shortages and other national or global disruptions due to macro-economic policies or geopolitical influences impacting the energy industry.

Planning for Future Updates to Carbon Plan

Planning for future updates to the Carbon Plan is an important issue to address proactively with the Commission and stakeholders as the Companies begin executing on the initial Carbon Plan. HB 951 provides that the Carbon Plan shall be reviewed every two years and may be adjusted as necessary in the determination of the Commission and the Companies.[11]

The Companies agree with the Commission's stated inclination in the November 19, 2021 scheduling order to sync the Carbon Plan proceedings with future IRP proceedings. While the November 19, 2021 scheduling order deferred the Companies' next comprehensive IRPs to September 2023 to allow the Commission and the Companies to focus on developing the initial Carbon Plan in 2022, the Companies believe the more appropriate step is to reestablish an "even-year" cadence for filing comprehensive IRPs and Carbon Plan updates starting in 2024, as illustrated in Figure 4-3 below. This approach aligns with the schedule required by the General Assembly for biennial Carbon Plan updates and would allow DEC and DEP time to begin executing the near-term execution plan before presenting the next full Carbon Plan update to the Commission. This approach would also allow time in 2023 for review of the Commission's IRP Rule R8-60 and related rules to ensure that the resource planning regulatory framework aligns with the new IRP/Carbon Plan requirements of HB 951.

[11] HB 951, Section 1(1).

Filing the Companies' next comprehensive IRP/Carbon Plan update in 2024 would also recognize the important role of the PSCSC, as the Companies necessarily must be able to execute on a single systemwide resource planning pathway as explained in more detail in Chapter 1 (Introduction and Background). Deferring the next comprehensive IRP/Carbon Plan Update to 2024 would allow the Companies to more fully focus in 2023 on developing and presenting comprehensive IRPs to the PSCSC, as required by S.C. Code Ann. § 58-37-40. Recognizing the benefits to customers of dual-state systems planning, the Companies strongly believe that regulatory clarity and resource planning alignment between the two jurisdictions will be critically important to obtaining these benefits for customers moving forward.

Figure 4-3: Near-Term Schedule for Carbon Plan Updates

Summary of Near-Term Execution Plan

The Companies' have taken a deliberate approach to near-term planning, developing a proposed set of prudent and necessary actions to initiate the energy transition and meet the CO_2 emissions reduction targets set forth in HB 951. The near-term actions identified for Commission approval in this Execution Plan are reasonable and prudent steps to commence during the near-term 2022-2024 timeframe in advance of the next biennial Carbon Plan update and will facilitate advancement of all three prongs of the Carbon Plan. As discussed earlier, in the context of an interconnected electric system and in support of the multipronged approach to planning, many of these actions are interdependent on one another to achieve the CO_2 emissions reductions targets while maintaining or improving upon the adequacy and reliability of the system, therefore the activities in this Execution Plan should be viewed as a complete plan.