I

Renewables and Energy Storage

Highlights

- Duke Energy is a leader in reliably integrating fuel-free renewable energy resources as solar and other renewables become an increasing part of the generation resource mix that will serve customers in the future. Renewables and energy storage resources selected in the Carolinas Resource Plan portfolios include solar, solar paired with energy storage, battery energy storage systems, pumped storage hydro, onshore wind, and offshore wind.
- Integrating renewable energy resources helps Duke Energy achieve Carolinas Resource Plan planning objectives, including supporting reliability by diversifying electricity supply and fuel source, mitigating exposure to commodity price risk and volatility and bolstering resource adequacy, and adding clean energy.
- Renewable resources continue to receive support through legislative policy, such as the Inflation Reduction Act of 2022, which will help lower the cost of the energy transition.
- The energy landscape is undergoing a shift in generation mix that will replace large amounts of traditional dispatchable generation with variable renewable energy, which requires Duke Energy to plan for and meet new operational complexities and challenges.
- To allow for increased solar penetration, Duke Energy is focused on accelerating solar interconnections by concentrating on key factors in the interconnection process, such as solar project size, transmission coordination and processes, and strategically identifying transmission network upgrades that support solar interconnections and provide other benefits to the system.
- Integrating third-party resources into the generation portfolio can be challenging, as evidenced by recent solar purchased power agreement counter-party defaults and decisions by third-party developers to not proceed with projects selected through recent competitive bidding processes.

Changing Energy Landscape

This Appendix details Duke Energy Progress, LLC's ("DEP") and Duke Energy Carolinas, LLC's ("DEC" and, together with DEP, the "Companies") approach to planning their existing and future fleet of renewable and energy storage resources, including solar and solar paired with energy storage ("SPS"), stand-alone battery energy storage ("BESS"), pumped storage hydro ("PSH") — Bad Creek II —, onshore wind and offshore wind. To adapt to the changing energy landscape, Duke Energy's approach to long-term planning for each of these resource types requires balancing the need for these increasingly clean resources, understanding the diverse and complementary nature of each of the resource types, evaluating operational considerations and weighing economic impacts.

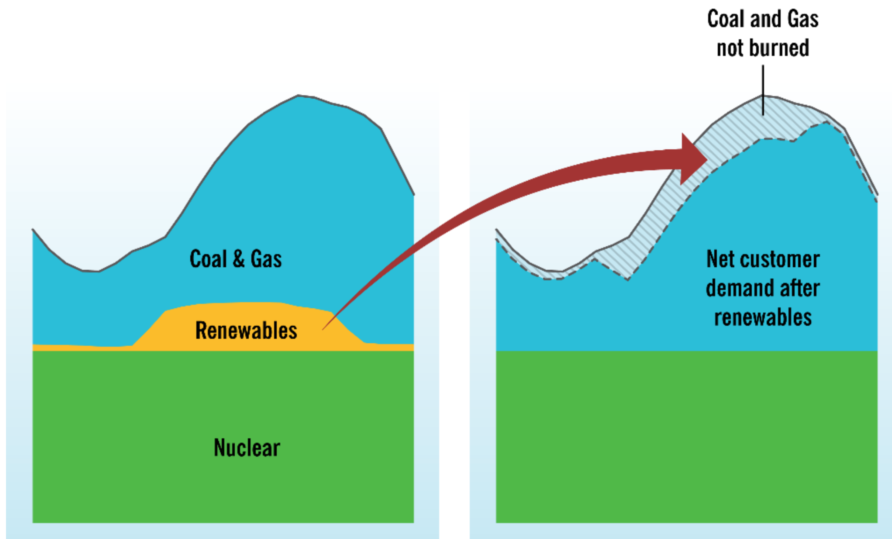
Need for Increasingly Carbon-Free and Fuel-Free Resources

Many changes in the energy landscape are driving a need for increasingly clean resources. The Companies are planning to retire over 8,400 megawatts ("MW") of dispatchable coal unit capacity over the next decade as the industry exits coal. To take advantage of incentives for renewable energy, hedge against the evolution of environmental regulation and to meet mandated emission reduction targets, the mix of resources that replaces retiring generation and meets growing customer needs must be balanced to include cost-effective and fuel-free resources such as solar and wind. Customers and communities are increasingly demanding cleaner energy resources, particularly large commercial and industrial customers that have environmental stewardship and emission reduction objectives. The ability to source an increasingly clean power supply that is also reliable and cost-competitive is an important driver of economic development across the Carolinas.

Diverse and Complementary Resources

Duke Energy is evaluating multiple types of renewable energy and energy storage systems to deploy a diverse generation mix that will help the Companies serve customers in a reliable and cost-effective way. A diverse portfolio of new resources will allow the Companies to withstand a wide array of future regulatory and market conditions, weather-related events and seasonal variability. Renewable resources support and augment traditional fuel cost hedging by reducing customers' overall exposure to sometimes volatile fuel commodity markets. Figure I-1 below illustrates how renewable resources reduce the total amount of fuel required to meet customer needs and complement traditional baseload resources.

Figure I-1: Role of Renewable Energy in Meeting Customer Demand



Deploying a balanced mix of new wind and solar resources that provide energy and capacity at different times and seasons is important to cost-effectively deliver the cost and risk mitigation benefits described above while improving plan executability. Balancing complementary renewable resources together with energy storage systems, such as battery and PSH, which ensure energy is available at times of peak need, will help maintain or improve system reliability. Energy storage resources also provide additional ramping and peaking functions that can complement traditional generation, such as combustion turbines. As discussed in Appendix M (Reliability and Operational Resilience), these renewable and storage resource types must be able to respond to system operator instructions to mitigate operational challenges from high levels of renewable integration. Carefully planning and integrating renewable resources is an increasingly important issue as they make up a greater portion of the total resource portfolio over time.

Operational Considerations for Integrating Renewables and Storage

When renewables are paired or augmented across the system with storage, operational flexibility can be enhanced. As part of an orderly energy transition, careful consideration must be given to both emission and commodity risk reduction benefits of renewables and their dependency on the sun and wind to generate electricity — particularly in light of the dramatic seasonal variability of the weather in North Carolina and South Carolina. This seasonal — as well as shorter timescale, such as day-ahead or intra-hour — variability is illustrated in Appendix M. Storage provides system capacity and operational flexibility by shifting energy and not creating new energy on the system. Rather, storage moves energy from other, often non-dispatchable, sources through time, and therefore charging and discharging must be carefully managed for reliable system operations. The availability of adequate energy resources in addition to energy storage is required to meet customer demands during peak hours and prolonged weather periods when renewable generation and storage capacity are insufficient. This additional dispatchable capacity is critical for reliability and to enable the integration of higher levels of renewables and storage over time.

Execution Risk Management

Understanding the risks associated with the execution of each resource type discussed in this Appendix is critical to the Companies successfully navigating the changing energy landscape during the near-term and over the decade to come. The risks pertinent to each resource are discussed throughout the technology-specific sections of this Appendix. Additional detail on the near-term actions relevant to renewables and energy storage can be found in Chapter 4 (Execution Plan).

Solar, Solar Paired with Storage

Current & Future Planning Considerations

Duke Energy has been an industry leader in solar integration, resulting in significant expansion in the Carolinas. As of December 31, 2022, approximately 4,650 MW of utility-scale solar is connected on the Companies' systems. North Carolina ranked 4th in the country in total solar capacity online as of 2022 while South Carolina ranked 14th.[1] SPS is also a rapidly growing component of the least-cost resource mix in the near-term; the Companies are planning to procure SPS in 2023 and future request for proposals ("RFPs") as well as add BESS to select existing Duke Energy solar facilities. As Duke Energy's resource fleet continues to change and the need for clean energy resources grows, solar and SPS will be important zero-carbon and fuel-free energy and capacity resources to meet that need.

Procuring Solar and Solar Paired with Storage

The Companies recently completed the 2022 Solar Procurement procuring 965 MW, including 343 MW of utility-owned solar and 622 MW of purchased power agreements ("PPA"), 286 MW of which are competitive procurement for renewable energy ("CPRE") PPAs. Approximately 549 MW were procured in DEP and 416 MW were procured in DEC. These projects are expected to complete the interconnection study process in early 2024 and are targeted to come online in 2026–2027. The Companies are currently seeking a public interest determination of the 2022 Procurement framework and competitive bidding results from the Public Service Commission of South Carolina ("PSCSC") at the time of the filing of this Carolinas Resource Plan ("Resource Plan" or "the Plan").[2]

On August 15, 2023, the Companies issued the 2023 Request for Proposals ("2023 RFP") which is designed to procure 1,435 MW of new solar and SPS between DEC and DEP (split roughly 735 MW of solar-only, and 700 MW of solar paired with approximately 260 MW of storage), expected to come online in 2027 or beyond.[3] The 2023 RFP includes a minimum 300 MW targeted procurement in DEC and DEP, with the remaining MW procured on a highest ranked, lowest cost basis between the two Balancing Authority Areas. The 2023 RFP design includes a volume adjustment mechanism based on the volume and cost competitiveness of proposals bid into the 2023 RFP. The Companies may increase the solar-only facility target quantity by 165 MW to 900 MW (from 735 MW) if prices are 5% or more lower than the 2022 Solar Reference Cost, and the Companies may reduce the solar-only facility target quantity by 145 MW to 590 MW if the weighted average prices come in 10% or more

[1] Solar Energy Industries Association, Solar State by State, available at https://www.seia.org/states-map.

[2] See PSCSC Docket Nos. 2022-239-E & 2022-240-E.

[3] The Companies may file for a public interest determination from the PSCSC as related to the 2023 RFP in the future.

higher than the 2022 Solar Reference Cost. The 2023 RFP also recognizes the importance of "market depth" to competitively procure new solar resources for customers, and sets a minimum requirement of at least three times as many MW of bids as the target, or the Companies may reduce the size of the procurement (to as low as a third of the total valid proposals) or reallocate MW between DEC and DEP. The 2022 Solar Procurement RFP saw over 5,000 MW of bids, so it is not anticipated that the market depth will alter the 2023 procurement target. However, even beyond the procurement process, there are risks that the proposals may terminate and not follow through, as recent history with CPRE has indicated.

Beyond the now-open 2023 RFP, Duke Energy's Resource Plan proposes procuring 1,350 MW of new solar resources in a 2024 Procurement and an additional 2,700 MW to 3,150 MW of solar and SPS resources by the end of 2026 to help replace retiring coal facilities and meet growing energy needs. Many solar generation projects are in various stages of the interconnection process with planned online dates in the next few years, and the Companies will continue to facilitate competitive procurements to procure additional solar and SPS resources. For more information about the competitive procurement process see Chapter 4, which details the near- and long-term timelines and targeted amounts for future procurements.

Unlocking Solar Resources through Strategic Transmission

To achieve the procurement amounts forecasted as needed over the intermediate-term and Base Planning Period[4], transmission investments will be needed. There are multiple factors that impact expected solar interconnection levels, such as solar project size, transmission outage coordination, improvements made to the interconnection process and additional transmission network upgrades. While large projects sometimes trigger more complicated interconnections, having higher MW per facility and fewer facilities could also reduce the number of outages needed for interconnection and help improve the annual interconnection MW totals. These factors will be reviewed in future procurement evaluations. For additional details on impacts and targets for solar and SPS interconnections, see Appendix L (Transmission System Planning and Grid Transformation).

Policy Support for Solar Resources

Solar and SPS resource selection in the Resource Plan benefits from many supportive state and federal policies, such as extension of the federal Investment Tax Credit ("ITC") and a Production Tax Credit ("PTC") in the Inflation Reduction Act of 2022 ("IRA"). Under the Companies' IRA assumptions, new solar facilities will utilize a PTC of roughly $2.75 per kilowatt hour in 2022 with annual escalation. SPS facilities are assumed to utilize the PTC for the solar portion and the 30% ITC on the storage portion of the project. See Chapter 2 (Methodology and Key Assumptions) for more details about how the Companies plan on utilizing the benefits of the IRA for solar and SPS.

Supply Chain Considerations

In addition to positive beneficial policies, there are many other economic impacts that Duke Energy is monitoring and evaluating, such as supply chain. The United States procures less than 10% of the

[4] The Base Planning Period is the 15-year resource planning horizon that meets North Carolina and South Carolina long-term planning requirements.

solar panels produced globally, with a majority going to nations with relatively higher average electricity costs that translate to a willingness to pay higher prices for comparatively cost-effective solar generation. This tightness in the market for solar panels is expected to persist as global demand continues to increase and supply chains remain strained.[5]

In addition to highly competitive market conditions, political tensions between the United States and Southeast Asian countries, such as the People's Republic of China, are impacting United States import policies for solar panels and other equipment. Currently, over 90% of the solar and energy storage components, such as solar cells or lithium-ion battery packs, that are produced globally are produced and manufactured in Southeast Asia. The combination of the highly volatile trade environment and incentives in the IRA is causing some manufacturers to begin to shift and expand production capacity in the United States, but this shift will take several years to begin to meaningfully impact the domestic market.

Many solar developers are deciding to secure their supply of batteries and solar components by purchasing products multiple years in advance, increasing early-stage cost and development risk, while providing a pipeline of equipment to develop and execute projects in the future. These developers are competing with utilities, who are adopting the same tactics to secure equipment and materials. A result of the increased competitiveness to acquire batteries and solar components is an increase in manufacturing and delivery lead times of key components (modules, batteries, transformers). Another challenge is obtaining the skilled labor resources required to build the projects once the equipment has been acquired. The solar industry and market are growing at an exponential rate and the number of skilled workers required will need to grow at a similar or faster rate. This enables a job market for additional skilled workers to perform installation and monitor operations of the new solar projects but will need to be closely observed as the demand continues to rise.

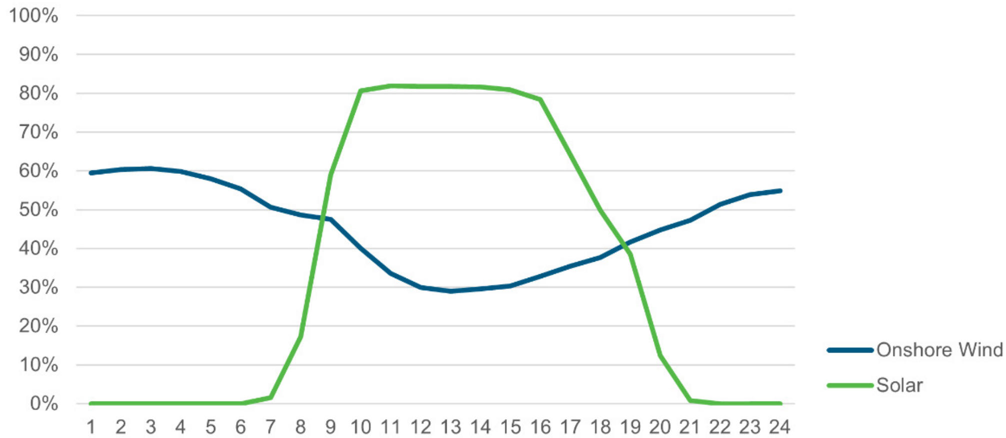
Duke Energy will continue to monitor and evaluate supply chain issues and the economic impacts from these potential issues. Having a diverse set of complementary resources, in addition to solar and SPS, is critical to help potential supply chain risk as Duke Energy reliably transitions to a clean energy resource mix.

Solar and Solar Paired with Storage Contributions to a Diverse, Complementary Resource Mix

Solar is a fuel-free resource that provides energy throughout the day and the entire year, dependent on weather conditions. It provides energy during certain times of high usage, such as hot summer afternoons, but conversely provides minimal energy during other times of high usage, such as cold winter mornings, illustrating the need for more than just solar energy to meet energy and load requirements. Solar energy is also complementary to some other fuel-free resources, such as onshore wind, due to different production at different times of day. Figure I-2 below illustrates the complementary nature of solar and onshore wind energy profiles in the Carolinas where solar has a higher capacity during the day (when onshore wind has a lower capacity) and the reverse occurs in the evening and early mornings when solar capacity factor is the lowest and onshore wind capacity peaks.

[5] NREL, Spring 2022 Solar Industry Update, available at https://www.nrel.gov/docs/fy22osti/82854.pdf.

Figure I-2: Solar and Onshore Wind Complementary Energy Profiles



Adding energy storage systems to solar can increase the availability of solar energy production and decrease the intermittency of solar sites injecting power into the grid. It also helps diversify and complement other types of generation.

Solar and Solar Paired with Storage Operational Considerations

As Duke Energy procures solar and SPS to meet the growing need for zero-carbon and fuel-free energy resources, it is evaluating the operational relationship between solar and energy storage. Storage paired with solar provides a way to further increase the energy output of a solar resource, as well as an enhanced contribution to peak. The storage element that is paired to a solar resource also helps enable flexibility and load following capabilities. This can help mitigate the risk and variability associated with intermittency and help with operational challenges resulting from current and pending solar penetration. Specifically, the Companies experience periods where the installed solar energy causes the system to reach its Lowest Reliability Operating Limit ("LROL"). The LROL is the point at which the system reaches the minimum level of regulating resources required for system reliability and all dispatchable resources on the system have been reduced to their minimum safe operating limits. The only options at the point of LROL are to move the excess energy off-system or curtail solar energy production. As greater amounts of solar connect on the DEC and DEP systems, there will be an increased likelihood of curtailment needed to avoid reaching the LROL. Energy storage can help minimize solar curtailment in these situations and enable the excess energy to instead be utilized when there are limitations in solar energy production. Appendix M illustrates the pattern and impacts to net load as more solar penetration occurs, as well as the increased need for further flexibility to help meet the changing demand. As Duke Energy reliably transitions its portfolio to a cleaner energy resource mix, integrating and operating solar and SPS resources will be an essential part of the transition.

Execution Risk Management

Significant expansion of utility-scale solar will be required to achieve all three Pathways described in Chapter 3 (Portfolios). Though solar is a mature energy generation technology, developing and interconnecting the amount of solar needed to deliver on the planned clean energy transition is not without risk. The challenges of interconnecting such large volumes of solar year over year and the constraints around sourcing materials, equipment and labor for building the projects are two identified areas of execution risk.

Interconnection Risks: As highlighted above and discussed in detail in Appendix L, the ability to construct needed system upgrades and complete interconnections of solar and other resources at the speed and scale required is a significant challenge. Duke Energy is devoting significant attention to accelerating the pieces of the interconnection timelines that are within Duke Energy's control and will continue to identify opportunities to enhance the interconnection process. To reach these ambitious timelines and quantities of solar will require solar project developers to complete their milestones and requirements faster, as well. Duke Energy's recent experience is that project developers often prefer to delay spending as long as possible on things like detailed engineering work. However, many aspects of the interconnection process after the Interconnection Agreement is established rely on the timing of a developer's response, and if they choose to drag out their responses, it will undermine the best efforts of Duke Energy. As progress is made on this front, the improvements will be reflected in future solar interconnections that can then inform future assumptions around maximum annual solar interconnection limits in resource plan updates.

Beyond the physical challenges of interconnecting the significant volume of solar, timely regulatory approvals from all required authorities and jurisdictions will be needed to ensure projects meet their development and construction timelines.

Supply Chain and Workforce Constraints: As previously discussed, constraints persist in the supply chain for solar panels, steel, electronics, transformers, other resources for interconnection and the labor required for solar installations. Events like COVID-19 and current socio-political and economic drivers are creating challenging market conditions impacting the entire industry. 229 MW of the selected winners in the 2022 Solar Procurement declined their win, presumably due to changing market conditions.

Third Party Contracting Risk: A significant number of solar projects with executed PPAs have terminated recently, many of which have identified increased costs and risks as described above. However, other terminations have cited a better business opportunity for the land has come up, thus they have chosen not to execute their interconnection agreement or a permitting issue has prevented the project from moving forward. The Companies are now relying on third parties to both deliver and maintain these resources, and recent experience shows that there is a risk of additional resources terminating even before they reach commercial operation. Approximately 700 MW of solar purchased power contracts have either terminated or have been terminated by Duke Energy for failure to meet PPA milestones since the start of 2022. Contracts choosing to terminate could increase the timeline risk associated with being able to interconnect the amount of solar identified in the Plan because replacing terminated contracts has a timing cost to it. For the solar projects it owns, Duke Energy is actively engaged to help alleviate these resource constraints, issuing solicitations, building supplier relationships and evolving best practices.

Stand-alone Energy Storage

Current & Future Planning Considerations

Stand-alone energy storage is expected to play a critical role in ensuring that the Companies cost-effectively meet their system balancing and reliability requirements as they continue to integrate renewables and to transition away from aging coal generation. In Chapter 4, the Companies discuss near-term plans for installing 300 MW of stand-alone BESS on its system through 2026, which is comprised of the projects listed below in Tables I-1 and I-2. The Companies' Near-Term Action Plan ("NTAP") also identifies plans for developing a total of 1,650 MW of stand-alone BESS (including the projects listed below in Table I-1 and Table I-2), all of which are planned to be placed into service by the beginning of 2031. For more details on the near-term action plan timeline, see Chapter 4.

Table I-1: Planned Near-Term Stand-alone Storage Projects – DEP

Project	MW	Location	Interconnection Queue/Status
Riverside	4.6	Buncombe Co	IA Signed
Lake Julian	17.3	Buncombe Co	IA Signed
Warsaw	30.0	Duplin Co	Surplus IC Study
Knightdale	100.0	Wake Co	IA Signed
Craggy	31.0	Buncombe Co	IA Signed
Elm City	22.0	Wilson Co	Surplus IC Study

Table I-2: Planned Near-Term Stand-alone Storage Projects – DEC

Project	MW	Location	Interconnection Queue/Status
Frieden	3.6	Guilford Co	IA Signed
Monroe	25.0	Union Co	Surplus IC Study
Allen	50.0	Gaston Co	IA Signed
Longtown	4.6	Fairfield Co	DISIS 22 / Ph3
Nebo	2.7	Burke Co	DISIS 22 / Ph3
Lowgap	2.7	Surry Co	DISIS 22 / Ph3
Farrs Bridge	5.3	Pickens Co	DISIS 22 / Ph3

The recent passage of the IRA has also improved the economics of stand-alone energy storage. For the first time, stand-alone energy storage projects can monetize the ITC. Under the Companies' IRA planning assumptions, as addressed in more detail in Chapter 2, 40% of BESS will qualify for the 30% ITC and 60% of BESS will qualify for the higher 40% ITC by meeting the energy community bonus criteria.

Passage of the IRA has also jump-started a domestic supply chain for energy storage. Significant announcements of new United States-based energy storage manufacturers have been made in the months following the passage of the bill, but this additional supply will take time to impact the domestic battery market.

The Companies are also actively pursuing federal funding opportunities which may further improve the benefit/cost ratio of a limited number of stand-alone energy storage projects which would support the Companies' resource planning needs. The status of opportunities to secure federal funding for stand-alone storage projects (as well as projects centered on other technology types) is in-progress.[6]

With the planned significant increase of variable generation, such as solar and wind, increasing energy storage capacity in the Carolinas will be critical for managing fluctuations in net load and for matching new generation with that fluctuating demand. The nature of energy storage allows energy to be injected back onto the grid when it is needed most to increase system reliability.

The battery energy storage space is also rapidly expanding in the types of chemistries being brought to market. Lithium-ion chemistries including nickel manganese cobalt and lithium iron phosphate are the predominant chemistries being deployed in the power system today; however, there are numerous other technologies being developed. Each energy storage technology has its own profile of unique benefits and limitations. Siting needs, intrinsic material hazards, degradation rates, round-trip-efficiency ("RTE"),[7] operational limitations, maintenance costs and ability to meet cost projections all vary significantly. Duke Energy is tracking numerous emerging technologies to consider for future Resource Plan modeling, potential pilot development and cost-effective deployment at scale.

The following list includes technologies that have been studied for deployment in the Carolinas and/or are at various stages of pilot deployment across Duke Energy, but have not been modeled within this resource plan. Appendix C (Quantitative Analysis) describes the technology, size and configuration of the storage systems available for selection by the capacity expansion model underlying this filing. Appendix E (Screening of Generation Alternatives) elaborates on the need for paring down the possible "selectable" resources and the Companies process for resource plan modeling.

- **Advanced-Compressed Air Energy Storage:** Unlike traditional compressed air energy storage ("CAES"), advanced-CAES uses an engineered cavern built in hard rock about 2,000 ft deep and a water reservoir at the surface to provide hydrostatic head pressure on the cavern. This static water column allows the rock cavern to be smaller than traditional CAES volumes and allows the system to be sited in more locations. The presence of suitable hard rock formations allows for advanced-CAES to be a possible solution in the Carolinas. Round trip efficiency is approximately 60% and is achieved by adiabatic compression of the air. Thermal storage is used to heat the air back up during discharge compared to combusting fossil fuels like traditional CAES designs. The cavern construction methods come from the hydrocarbon storage industry and are well understood but require long construction times. The magnitude of constructing this technology is comparable to PSH installations.

[6] *See* NCUC Docket No. M-100, Sub 164 and PSCSC IIJA-Docket 2022-168-A.

[7] RTE (often expressed as a percentage) conveys the ratio of the total energy output or returned by a storage system to the total energy input to the system, net of losses from processes such as conversion between AC and DC, balance of plant equipment, and "leakage" while in storage.

- **Flow Batteries:** Flow batteries are comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped-circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference. Because the electrolyte is stored external to the cell in bulk tanks, longer durations of energy storage are achievable at a lower incremental cost. Popular inorganic chemistries include vanadium and iron, and organic chemistries with a lower Technology Readiness Level are also being developed that have more benign chemical properties to reduce the safety risk. Flow batteries have struggled to gain momentum due to high costs, increased operational complexity with the addition of balance of plant equipment and lower performance characteristics than projected. RTE largely depends on chemistry but can range from 55%–70%. The vendors generally claim no degradation and fire risk, however some of the chemistries are dissolved in acid and thus could cause a safety risk if exposure occurs which must be mitigated.

- **Nickel Hydrogen:** Using the same technology developed by the National Aeronautics and Space Administration for space projects, the technology has been re-engineered with less exotic metals to make the technology more affordable for ‘planetary’ storage applications. The technology offers a comparatively long life of 30,000 cycles, with a slight linear degradation of 5% after 10 years. The round-trip efficiency is expected to be around 80% with a moderate self-discharge rate. A challenge with the technology is utilization of nickel. Nickel is one of the main components used in the chemistry and it is not immune to supply chain constraints. Another issue is energy density, however with less auxiliary equipment needed for the system and low maintenance, stackable configurations may be viable to help improve energy density.

- **Liquid CO_2 Energy Storage:** The system stores gaseous carbon dioxide (“CO_2”) in a closed loop near ambient pressure in a large dome. During charge mode, the CO_2 is compressed adiabatically with the heat generated being stored in thermal storage. The high-pressure gas is then condensed to a liquid and stored in pressure vessels at ambient temperatures. In discharge mode, the liquid CO_2 is heated and expanded into a gas, which powers a turboexpander. Round trip efficiency is approximately 75% due to the unique physical properties of using CO_2 as the working fluid. Energy density of the technology is lower than others, but not significantly different than PSH.

- **Sodium Sulfur:** This battery operates at high temperatures of greater than 300°C to maintain molten sodium and sulfur as the electrolyte. The discharge of the battery is exothermic and generates enough heat to keep the system at temperature; however, the concern is if the battery can be dispatched optimally to reduce the auxiliary load requirements of the resistance heating to maintain temperatures. The expected RTE is 75%, but this will ultimately depend on the how the battery is dispatched to reduce to auxiliary loads.

- **Thermal (Pumped Heat):** In charge mode, these systems use a working fluid such as air or CO_2 in a thermodynamic cycle to generate heat. This heat is stored in a medium such as molten salt, sand, gravel or concrete. In discharge mode, the cycle is reversed turning the heat pump into a heat engine, and power is generated using the heated working fluid in a turboexpander. Due to the higher Coefficient of Performance of a heat pump configuration versus resistance heating, these technologies generally have a RTE in the 55%–60% range.

- **Zinc Aqueous:** This battery uses a zinc bromine solution as the electrolyte at moderate temperatures. The advantages of the battery are that there is no inherent fire risks and less degradation than Li-ion. The main concerns are the high self-discharge rate and the mandatory rest cycles. This battery achieves a round trip efficiency in the 70%–75% range. These issues may be mitigated with newer designs and automated control strategies, but this may add limitations to how the battery can be dispatched.

In addition to those listed above, Duke Energy has closely followed progress of Iron Air battery chemistry. At this time, the Companies have not commissioned a formal study or pilot project of the technology but is aware of projects by Xcel Energy and Southeast peer utility, Georgia Power Company.

- **Iron Air:** This chemistry utilizes iron sheets or pellets as an anode (often in solution) at approximately ambient temperature. The iron interacts in an iron/iron oxide reduction/oxidation (redox) reaction with oxygen from the atmosphere. The main advantages of this chemistry are the low production cost of the components due to the abundant and non-toxic elements which are the basis of the reaction. The technology is most effective as a multi-day (~100 hours) storage asset. The most significant concerns are the limited number of effective lifetime cycles and relatively low round trip efficiency (~40%) throughout asset life.

Ongoing Development Work to Deliver Stand-alone Energy Storage Resources

The Companies are taking prudent and reasonable steps to develop stand-alone battery storage resources, including progressing development of approximately 300 MW of stand-alone battery storage projects in the 2022 Definitive Interconnection System Impact Study ("DISIS") cluster and the submission of an additional approximately 500 MW as part of the 2023 DISIS cluster. The Companies are also taking proactive and prudent steps to plan for the significant stand-alone battery energy storage called for in the Execution Plan. Duke Energy has worked to secure advance procurement agreements with reputable integrators to tie future purchase costs of battery materials to published indexes to ensure a supply of said materials and to mitigate the risk of competition-driven price increase for materials necessary to enable the energy transition.

Stand-alone Energy Storage Complementary Contributions in a Diverse Resource Mix

Just as solar and SPS are zero-carbon technologies which complement other resources (as discussed in earlier sections), stand-alone BESS is best operated as part of a diverse resource portfolio. Aside from the technology's ability to avoid curtailment of zero-carbon generation, the responsiveness of BESS provides flexibility to respond to system imbalances due to unexpected customer load or generation intermittency and contingency. This responsiveness stems from minimal required startup/shutdown processes, remotely operated dispatch and quick ramp times (particularly of Li-Ion systems). In the sense of system planning, BESS can be incorporated as a part of a flexible strategy. Utility-owned battery storage is designed for flexibility to support a variety of use cases as grid needs change over time. Furthermore, augmentation projects can either increase megawatt-hour ("MWh") nameplate capabilities of an existing site or offset increased degradation stemming from higher usage than the amount envisioned at the time of initial construction. This capability is especially helpful over a multi-year time horizon to enable deployment of increasing levels of renewable energy generation.

Stand-alone Energy Storage Operational Considerations

Duke Energy's maturing efforts related to stand-alone energy storage continue to be significantly influenced by interconnection study and network upgrades. The commencement of Duke Energy's first DISIS cluster in 2022 has allowed for greater timeline certainty than would have been possible under legacy Federal Energy Regulatory Commission ("FERC") and state-jurisdictional procedures. Nonetheless, development of the Companies' first transmission-connected stand-alone storage systems has occurred against a backdrop of evolving business practices for the power flow study of BESS projects,[8] increasingly stringent standards for connection of Inverter-Based Resources[9] and lengthy timelines for constructing required network upgrades, all logically associated with relatively new technologies with expanding grid penetration.

Additionally, Duke Energy has a project underway incorporating people, process and technology considerations to enable an efficient end-to-end process for integrating and dispatching inverter-based resources (including stand-alone storage).

Specific to the deployment of lithium-ion technology, the Companies continue to refine the strategy for the management of cell degradation, which is an unavoidable part of Li-Ion fleet operations. Namely, the Companies are working on strategy formulation to ensure the best balance of battery state-of-health preservation with battery utilization in response to economic signals (understanding that higher utilization results in increased degradation).

Duke Energy's initial efforts at integrating BESS into its operations have allowed the Companies to validate and adjust planned operations and maintenance ("O&M") strategies, to include staffing and task organization, stocking spare parts, executing long term service agreements with integrators, creating maintenance and outage schedules, automating cell voltage balancing and forecasting cost. Strategies will be further refined and may be adjusted as the Duke Energy BESS fleet grows in the coming decade.

A final noteworthy consideration in the deployment of BESS facilities is Duke Energy's commitment to incorporate Environmental Justice and Community Feedback into construction of all new infrastructure. While many new BESS projects will be sited on land already owned by Duke Energy and permitted for use in utility operations, local permitting will remain a critical step in the development of most projects. In addition to the legal requirements to build new stand-alone storage, community engagement and feedback (especially related to the topic of battery fire safety) is expected to be a major focus area of the Companies' early lithium-ion BESS projects.

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[8] Duke Energy, Duke Energy Business Practice: Studying Storage Interconnection Requests in DEC and DEP, October 2022, available at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/Storage_Studies_-_Duke_Energy_Business_Practice_2022-10-26.pdf.

[9] Duke Energy, Duke Energy Transmission Connected Inverter Based Resource Technical Interconnection Requirements, March 2023, available at http://www.oasis.oati.com/woa/docs/CPL/CPLdocs/TECP-STD-TFP-00016_-_Rev._000__IBR_Technical_Interconnection_Requirements_(TIR).pdf.

Execution Risk Management

Energy storage will constitute a foundational pillar of the energy transition. However, as described in Chapter 4, the Companies recognize that all plans contain inherent risk which must be identified and monitored for consideration of mitigating actions and alternative strategies. Further discussion of thematic risk categories specific to Stand-alone Energy Storage is found below.

Infrastructure Dependencies: Like many of the other generation resources that need to be developed to execute the Plan, interconnection is a primary risk for energy storage projects. The maximum volume of new resources (including stand-alone energy storage) that can effectively be interconnected each year is uncertain but is recognized to be a risk for plans calling for integration of larger volumes of energy storage simultaneous with other resources.

Supply Chain and Workforce Needs: Development of the Companies' BESS portfolio is occurring within challenging market conditions for the entire industry in obtaining long lead-time electrical components. There are several impacts that the supply chain can have on the overall cost and availability of energy storage technologies, such as raw materials, freight and competition with other industries dependent on batteries such as cellular communications and electric transportation. For example, the resources and production capacity that are used for utility storage are the same that are used in the electric vehicle ("EV") market. Batteries placed in EVs tend to be more lucrative for suppliers, so it also makes purchasing batteries for the utility sector more difficult and expensive. Duke Energy will continue to gather information on the potential impacts of supply chain constraints and proactively engage in these industry issues.

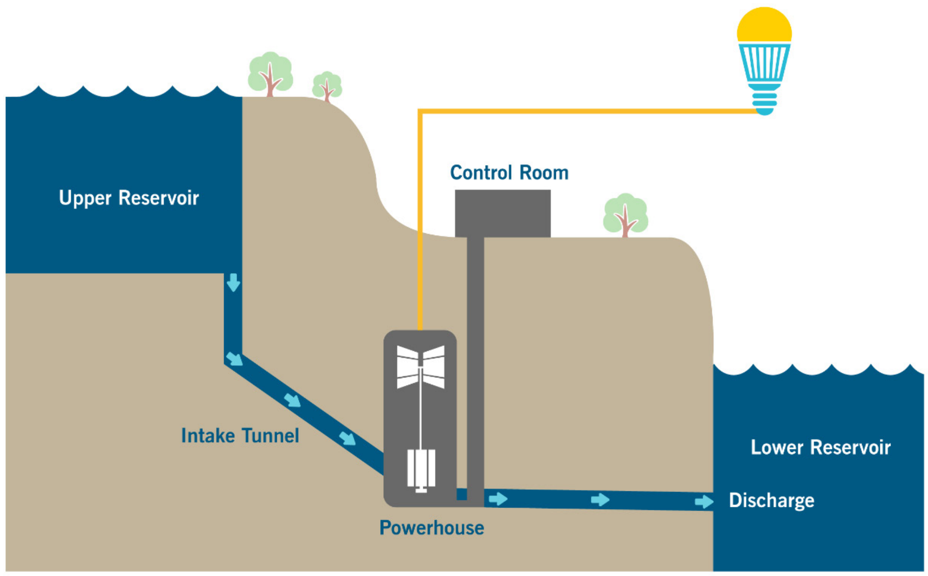
Additionally, the Companies are still developing deployment and operation of BESS as a core competency. As such, the internal cadre of subject matter experts is relatively small but growing amidst significant external competition for energy storage expertise. Duke Energy expects that the workforce educated to support design, installation and management of energy storage resources will increase over time. Externally, the near-term procurement strategy heavily leverages general contracting construction firms, meaning that installation of energy storage projects is likely to face the same high demand for labor resources as other generation technologies. Importantly, Duke Energy is acutely aware that a construction partner's ability to meet Wage and Apprenticeship Requirements of the IRA will materially affect the effective cost of new BESS resources.

Bad Creek Powerhouse II

Current & Future Planning Considerations

The Companies have operated PSH facilities for almost 50 years. The Companies operate two PSH plants — Jocassee (1973) and Bad Creek (1991). These existing facilities provide approximately 2,300 MW of capacity, which accounts for most of the storage on the Companies' systems. PSH plants store and generate energy by moving water between two reservoirs at different elevations, as illustrated in Figure I-3 below. During times of low electricity demand, such as at night or on weekends, excess energy is used to pump water to an upper reservoir and then during peak demand, the water is discharged to generate energy. These plants can also store excess renewable energy during the day and provide energy during the evening peak. The turbine acts as a pump, moving water back to the upper reservoir. During periods of high electricity demand, the stored water is discharged through the turbines to produce energy to meet demand. A PSH system works much like a conventional hydroelectric station but has the capability to store energy.

Figure I-3: How Pumped-Storage Hydro Works



Pumped hydro is a long-established, proven technology with an excellent safety record, but building new pumped hydro anywhere in the United States is extremely difficult for two reasons. First, many prime locations have already been utilized (since the right geography is critical) and second, adding an entirely new PSH facility would require the construction of a new station and upper reservoir, which would have substantial permitting challenges, construction time, and cost. Duke Energy, however, has the rare advantage of having an existing PSH with an expansive upper reservoir large enough to support doubling the capacity, as well as the space required to construct an additional powerhouse. The 1,680 MW Bad Creek II second powerhouse is included in all Resource Plan Portfolios and is a unique opportunity for the Companies to add new long-duration, large-scale PSH without the need for a new reservoir. Bad Creek II would add four additional units that would be similar to the existing four units of Bad Creek I, essentially doubling the hourly capacity at the site. Even though available duration would decrease since there is more output, the 11 hours (of all eight units at full load) would still significantly exceed the duration of Lithium-Ion batteries available today. The increased capacity provides system stability and critical flexibility to respond to system peaks and steep system ramps, as well as additional support for high penetrations of variable energy resources. Adding an entirely new PSH station would require the construction of a new station and upper reservoir, which would cost substantially more, take longer to permit and require a longer construction time.

Bad Creek II would share the existing upper reservoir utilized by Bad Creek I, increasing the total Bad Creek facility to over 3,300 MW of capacity. The added capacity at the site would support the retirement of coal facilities and allow for more effective use of the upper reservoir. Bad Creek II would also support the increased number of variable resources added to the system and provide increased reliability to customers. Furthermore, Bad Creek II would support the expected increase in solar resources added to the system, therefore reducing the risk of curtailment by storing the excess energy. For the execution timing and current progress updates for Bad Creek II, see Chapter 4.

Bad Creek II will benefit from the passage of the IRA by lowering overall project costs to customers. Duke Energy is modeling Bad Creek II to be eligible to receive a one-time ITC of 30%. Additional details on how the Companies plan on utilizing the benefits of the IRA for Bad Creek II can be found in Chapter 2 (Methodology and Key Assumptions).

The construction of Bad Creek II will be a large-scale project with a significant amount of excavation to create the necessary tunnels and caverns. This work will have less supply chain risk and less reliance on overseas materials compared to other renewable technologies, such as batteries. Some of the major equipment will rely on overseas material but it will make up a much smaller portion of the cost, and the materials needed will not be in competition with other industries. A large share of the cost will be the civil construction of the power tunnels and the powerhouse cavern, which will constitute excavation, concrete and labor.

Bad Creek Powerhouse II's Contributions to Diverse, Complementary Nature of Resource Mix

PSH will allow the Companies to integrate other renewables and more zero-carbon resources to the grid and provide customers savings by storing excess energy during times of low demand or excess renewable energy, and then providing generation when demand is high, as well as providing ancillary services to ensure system balance, frequency and reliability. During times when the system is generating the highest amount of solar energy between the hours of 10 a.m. and 3 p.m., net demand can fall below the LROL. Instead of curtailing solar and cycling down system regulation reserves, this excess energy can be stored at pumped hydro stations for later use, such as the evening system peak. Unique relative to inverter-based battery storage alternatives, the generators in the Bad Creek II project will provide physical inertia to the system which helps maintain optimal frequency and voltage levels. For additional details, see Appendix M which details planning and operational considerations for integrating inverter-based resources and managing reliable system operations.

The Resource Plan includes multiple types of energy storage technologies, including approximately 1.6 gigawatts ("GW") of battery storage, in addition to Bad Creek II. Bad Creek II assists in diversification of the physical operational characteristics of these storage technologies, but also provides diversity among supply chain needs. To assure competitiveness of Bad Creek II, an analysis was completed by replacing it with longer-term lithium-ion batteries. In this evaluation, the second powerhouse at Bad Creek was replaced with an equivalent amount of long-term lithium-ion storage and evaluated over an 80-year operating life. The present value of revenue requirements incorporating the operating and capital cost of each option were compared and thus, validated the benefits of Bad Creek II as opposed to adding longer-term lithium-ion batteries of the same capacity quantity. For additional details on this study, see Appendix C.

Bad Creek Powerhouse II Operational Considerations

DEC has owned and operated PSH facilities for almost 50 years and plans to continue to operate them for decades to come. DEC operates the stations daily to pump and capture energy and then generate in times of need. The Companies will use valuable operational expertise in operating pumped hydro to seamlessly integrate the addition of Bad Creek II into its generation portfolio and provide the reliability that is needed as the Companies transitions their fleet to a zero-carbon future.

Bad Creek Powerhouse II Development Activities

DEC continues to work on activities to progress initial development of the Bad Creek II project for a mid-2033 planned in-service date to support the Companies' energy transition. DEC has completed a pre-feasibility study and feasibility study for the project. Bad Creek II was entered into the 2022 DISIS to achieve receiving in an interconnection agreement for the plant. DEC issued an RFP for major equipment earlier this year and expects to receive bids later this year. The additional development activities presented in Chapter 4, Table 4-8 are estimated to be completed in 2023–2026, which will allow DEC to progress execution of the project, including obtaining important regulatory approvals and meet the planned in-service date. The estimated cost of current and planned activities to progress development of the Bad Creek II Powerhouse in the near-term period (2023-2026) and remain on the planned development schedule to achieve in project in-service in mid-2033 are shown below in Table I-3.

Table I-3: Bad Creek Powerhouse II Development Activities and Timeline

Activity Description	2023 ($M)	2024 ($M)	2025 ($M)	2026 ($M)	Total ($M)
EPC Tender Support Activities	3.0	4.4	9.4	22.5	39.3
Major Equipment	0.3	8.2	20.0	25.0	53.4
Studies/Permitting	0.2	0.6	0.5	0.5	1.8
Geotechnical Work	1.3	0.6	0.0	0.0	1.9
Project Develop/Other	5.6	7.0	28.6	28.1	69.2
Total	**10.3**	**20.7**	**58.5**	**76.1**	**165.6**

Execution Risk Management

Project Development Risk: While PSH is a known technology and Duke Energy has constructed both Jocassee and Bad Creek I, Bad Creek II is a long-duration project that does carry risks due to the project construction duration and cost. Bad Creek II has the advantage that the reliance on overseas materials is smaller due to a significant amount of the project being the civil construction site work. This work still carries risk because it involves major excavation to create the tunnels and the cavern needed for the project. This risk for Bad Creek II is minimized due to the site being situated close to the current Bad Creek facility, where the geology is known from prior construction and the project is very similar to the current Bad Creek facility.

Supply Chain and Materials Risk: As mentioned above, a significant amount of excavation is required to create the necessary tunnels and caverns. There will be a significant amount of material and labor required for the civil construction site work. In addition to the localized material and labor, a portion of the project cost will be dependent on overseas materials that carries an acquisition risk that procuring these materials could be difficult due to socio-political and market conditions. As Bad Creek II begins construction, Duke Energy will need to monitor and manage these risks.

Permitting Risk: Prior to the start of construction, anticipated in mid-2027, DEC will need to receive its FERC license and state regulatory approvals. If these approvals are not received by mid-2027 there will be a high risk of not achieving the projected in-service date of mid-2033 for Bad Creek II.

Onshore Wind

Current & Future Planning Considerations

Currently, the Companies do not have any onshore wind generation installed in the Carolinas, but the United States onshore wind market continues to grow with approximately 146 GW operational nationwide and approximately 40 GW coming online in the last three years.[10] As one recent example in the Carolinas, earlier this year Apex Energy's Timbermill Wind project received permit approval from the North Carolina Department of Environmental Quality's Division of Energy, Mineral and Land Resources for its 45 turbine (189 MW) project in Chowan County, North Carolina (located in PJM Interconnection, L.L.C. territory).[11] The Companies are expecting to develop new wind capacity, with 1,200 MW included in the NTAP. In support of these efforts, the Companies have taken reasonable steps in preparation of ramping up onshore wind development activities. This work started with engagement of third-party onshore wind developers to glean insights and further understandings regarding the onshore wind market specific to the Carolinas. The Companies also retained a leading consultant to perform a comprehensive siting feasibility study across the Carolinas.

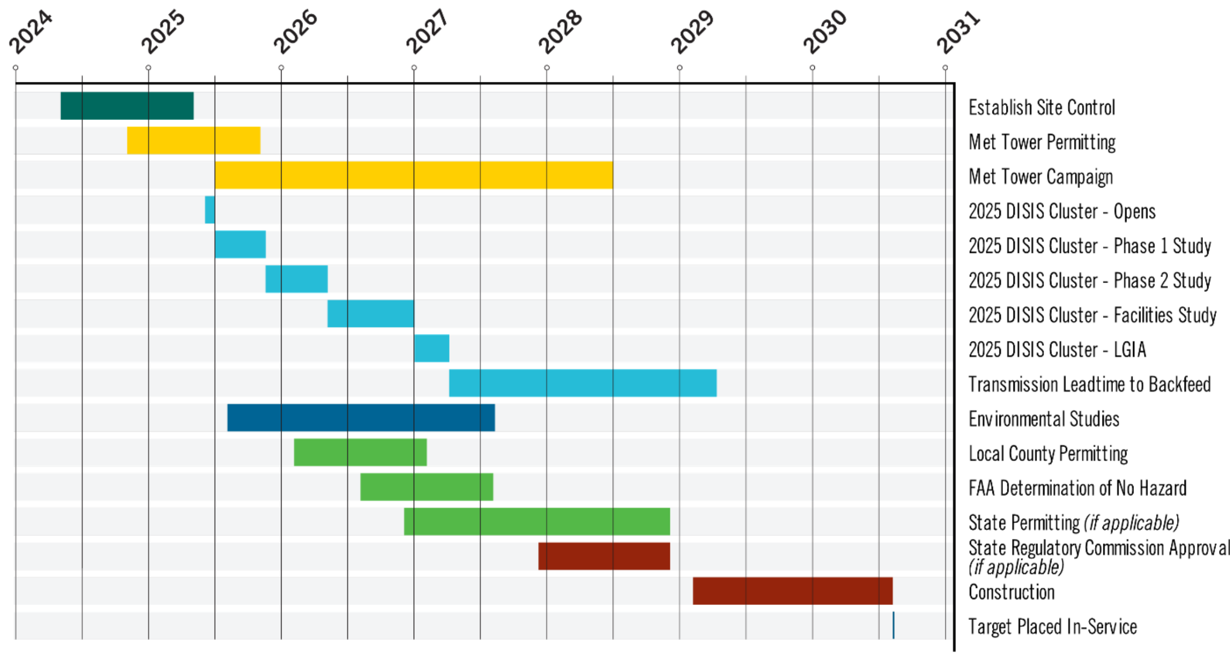
In support of the development of modeling assumptions and to inform the timing of resource additions, the Companies developed a preliminary resource development and execution timeline to capture the key milestones required to bring new onshore wind resources online. This considers (i) project siting and site control activities, (ii) permitting, construction and data collection from meteorological towers, (iii) interconnection cluster studies and timeline for interconnection availability, (iv) environmental studies, (v) local county and state (if applicable) permitting, (vi) Federal Aviation Administration ("FAA") approvals and (vii) construction. Feedback and input from third-party onshore wind developers was solicited and incorporated into the development of this timeline. Using this timeline assumption, 2025 would be the first feasible year for onshore wind projects to be studied in an interconnection cluster, translating to 2031 being the first year of availability. Figure I-4 below illustrates a hypothetical development and execution timeline for an onshore wind project targeting commercial operation in 2030. Many critical development activities would need to be pursued in parallel, with the target of completing all permitting and agency approvals by year end 2028, such that construction could start in early 2029 and commercial operation would be achieved by year end 2030.[12]

[10] American Clean Power Association | Clean Power Quarterly Mark Report 2023 Q1

[11] DEMLR issued permit to construct, operate and decommission the proposed Timbermill Wind project. This permit is the first for a facility under the session law passed in 2013 establishing a permitting program for wind energy facilities. The application was submitted on May 19, 2022. Source: https://www.deq.nc.gov/news/press-releases/2023/03/14/deq-approves-permit-onshore-wind-facility-north-carolina.

[12] Exact durations and timing subject to change, but this general outline of a schedule factors the sequencing of interconnection studies with onsite studies and local / state approvals.

Figure I-4: Illustrative Onshore Wind Development and Execution Timeline



In support of the timeline to bring 1,200 MW of new onshore wind facilities online by January 2033, with the first resources targeted to come online by January 1, 2031, the Companies need to begin development activities in 2024. As discussed earlier, the Companies intend to utilize a strategic partnership with an onshore wind developer to execute the development of new onshore wind resources. The Companies are on track to make a recommendation/selection on a strategic partner by year end 2023 and would then begin definitive agreement negotiations with the target of executing the agreement in Q1/Q2 2024. The agreement will likely take the form of a joint development agreement where each party, the Companies and the onshore wind developer, share in the development responsibilities to site and develop facilities. For facilities being placed in service in 2030, those facilities will need to submit interconnection applications into the 2025 DISIS interconnection cluster study (deadline to submit is June 2025). The Companies expect no less than twelve (12) months to secure site control with targeted participating landowners. Interconnection applications will be prepared and submitted by June 20, 2025. To understand the wind speed on site, a series of met towers will need to be erected on each secured project site to collect meteorological data over several years. Environmental studies, including but not limited to wetland delineation, Phase I Environmental Site Assessment, cultural and archeological, would need to be performed to refine facility design and support permitting. Species surveys will typically require multiple seasons of study, requiring these to be initiated as early as possible. Permitting will be critical path for any new onshore wind facility and would need to start in early 2026. Key permit approvals include the FAA, county zoning and discretionary permitting, state permitting (as applicable) and Commissions approval (i.e. Certificate of Environmental Compatibility and Public Convenience and Necessity/Certificate of Environmental Compatibility and Public Convenience and Necessity).

The same scope of work will be initiated for an additional 450 MW targeted for the 2026 DISIS cluster and 450 MW targeted for the 2027 DISIS cluster, thus there will be an overlapping portfolio of projects being sited and development initiated to achieve the in-service capacity by each target year. To achieve the target placed in service capacities of 300 MW by January 2031 and 450 MW by January 2032 and 2033 each, a multiple of each year's target capacity will need to be sited and initial development executed. Not all sited projects are expected to be built, some projects may be terminated due to interconnection costs, permitting issues, FAA or military conflicts, or other factors. As such, the Companies would seek to site three to four times the targeted capacity for each year.

Table I-4 below illustrates the onshore wind development plan, including the estimated MW, in-service date targets and approximate development costs through 2026.

Table I-4: Onshore Wind Development Plan

	DISIS Cluster	Target MW	Target In-Service Date	Estimated Cost ($Millions) 2023–2026
Tranche 1	2025	300	1/2031	$25.4
Tranche 2	2026	450	1/2032	$28.4
Tranche 3	2027	450	1/2033	$11.7
			Total	**$65.6**

In addition to development and execution, timing assumptions and considerations, facility hub heights and turbine technologies were analyzed to help inform modeling assumptions such as the capacity factor. Hub heights continue to grow taller, with the highest being approximately 120 meters for operational facilities. The highest hub heights for new onshore wind facilities constructed in the United States over the past three years were 122 meters in 2020 and 2021 and 119 meters in 2022. While higher hub height generally correlates with higher wind speed, it also comes with higher cost, taller turbine tower, so each facility must use location-specific wind data to establish its optimal hub height. The proposed Timbermill Wind project has a planned meter hub height of 105 meters, although the Companies believe that onshore wind facilities located within its service territory will need to reach a higher hub height than this to achieve optimal wind speeds. These data points formed the basis of the modeling assumptions. It should be noted that there are only two operational wind facilities with hub heights greater than 122 meters: one at 130 meters and one at 131 meters. There is one facility under construction in Mississippi with a 136-meter hub height. Additional, average rotor diameter grew to 127 meters with 162 meters being the largest. The Companies assumed and modeled a 120-meter hub height for onshore wind resources, as further discussed in Appendix C.

To support the modeling and execution of onshore wind and understand the feasibility and potential for siting onshore wind in the Carolinas, the Companies engaged DNV Energy USA Inc. ("DNV") to perform a multi-criteria geographic information system study to identify potential development sites for utility-scale onshore wind facilities of at least 50 MW.[13] The study considered wind speed data from multiple data sources, established certain exclusion zones where siting would be physically prohibitive, considered high risk or could lead to prohibitive costs. The exclusion zones considered included

[13] DNV is a world leading resource of independent energy experts and technical advisors with deep knowledge related to the siting of renewable energy projects and the evaluation of potential technical, social and environmental impacts. Over the last six years, DNV has completed more than 35 similar site selection and site characterization studies for wind and solar projects, spanning regional transmission organizations, including NY ISO, PJM, SPP, MISO and ERCOT.

inadequate wind resource (annual average wind speed in meters per second), distance to transmission infrastructure, setbacks to land constraints (e.g., major military installations, airports, radar systems, air navigation aid systems, North Carolina Mountain Ridge Protection Act, urban areas, coastline, highways, weather radars and topography/slope) and habitat or cultural constraints (protected and sensitive areas, federal, state and local protected areas, conservation easements, wetland or waterbody and flood hazard zone, important bird areas, national forests and cultural resources). Additional soft constraints were established and considered potential impacts with military and Department of Defense areas and uses, local zoning and planning ordinances and airport-controlled airspace. The DNV study identified a reasonable number of potential sites in North and South Carolina which were used to inform the modeling inputs and establish reasonable siting potential to support the onshore wind resource additions. The siting study identified over 240 potential sites. After initial screening and filtering for distance to transmission infrastructure, military use areas and restrictive county ordinances, the siting potential was refined to approximately 90 sites. This siting potential analysis informed the development of production resource profiles and system-wide cumulative resource constraints used in capacity expansion modeling, as further addressed in Chapter 2.

In addition to the DNV study, the Companies have engaged with stakeholders, primarily third-party onshore wind developers, to glean insights to inform IRP modeling and assumptions, including the development of timelines and execution approaches, and understanding of market conditions and structures that would attract onshore wind developers. Through these engagements, the Companies collected valuable input and feedback that informed the modeling assumptions. Key takeaways regarding market conditions include: (1) there are no onshore wind projects currently under development and planning to interconnect to the Companies' transmission systems, (2) third party developers are not prepared to site and advance projects to participate in a competitive RFP process in 2023 or 2024, (3) most of the stakeholder developers would be interested in some type of development partnership with the utility, and (4) development of onshore wind resources within the Companies' system will not occur without active participation or direction from the Companies. Through the in-depth analyses and engagements on timing and execution assumptions, hub height, and siting results, Duke Energy has confidence in its updated modeling assumptions that are further detailed in Appendix C.

The passage of the IRA expanded federal tax credits available for onshore wind facilities. Under the new IRA guidelines and the Companies' assumptions, onshore wind projects are eligible for 10 years of PTC of roughly $2.75 per kilowatt hour (2022 $) with annual escalation. See Chapter 2 for more details how the Companies plan on utilizing the benefits of the IRA for onshore wind.

Since the IRA clean energy incentives were passed in August 2022, signs of rapid growth for maturing American clean energy industries are emerging. Announcements have been made for eight American wind power manufacturing facilities: a combination of new facilities, expansion of existing facilities and reopening of previously shuttered or closed facilities.[14] These manufacturing expansions are signs of increased demand and the industry's efforts to meet domestic content requirements. However, like many aspects of the economy, the Companies anticipate supply chain pressures on components, electronics and raw materials, such as steel, to continue for the onshore wind market causing sourcing

[14] American Clean Power, Clean Energy Investing in America, April 2023, available at https://cleanpower.org/wp-content/uploads/2023/04/ACP_Clean-Energy-Investing-in-America_April-2023.pdf.

issues. Due to the later timeline of when these onshore wind facilities will enter the construction phase, it is believed that some of these supply chain risks may dissipate.

Onshore wind projects provide many economic benefits to neighboring communities: jobs (manufacturing, transportation, and project construction), a new source of revenue for landowners in the form of land lease payments and an increased local tax base. Because onshore wind turbines are spaced so far apart, surface activities like farming and silviculture can still take place on the land in between turbines.

Onshore Wind Contributions to Diverse, Complementary Nature of Resource Mix

Considering the amount of solar that will be added to the system in the coming years, onshore wind will be an important generation option due to its complementary nature. As mentioned previously and illustrated in Figure I-2, onshore wind complements solar due to its different daily and seasonal generation profiles.

Onshore wind provides key benefits that complement other energy resources, including renewables such as solar:

- It continues to provide electricity overnight and during cloud cover when solar is not producing electricity.
- It helps to support power supply reliability by providing electricity under unique operating circumstances (e.g., it is a fuel-free resource that is not reliant upon a sourced fuel source).
- As a fuel-free resource, it helps to mitigate commodity price risk and fuel price volatility.
- The land surrounding a wind turbine can continue to be used for other purposes, including agriculture.

Onshore Wind Operational Considerations

Bolstering the onshore wind market and ensuring adequate resources are developed requires successful execution of near-term actions. As previously mentioned, Duke Energy has identified siting development opportunities and will continue to evaluate appropriate sites for locating onshore wind facilities. Local permitting (zoning and condition use permits) and community acceptance will be challenges to overcome in the development of onshore wind in the Carolinas. This could be a significant challenge, as it has been in other states. The development of any onshore wind farm will likely require local county/town conditional use permitting and/or rezoning of participating properties. The ability of sited projects to secure these permits is critical to achieving the desired onshore wind capacities.

Interconnection of onshore wind facilities will be another variable the Companies will continue to monitor. As with other new generation, once an appropriate site is identified and site control has been established for the development of an onshore wind facility, the next critical risk is the timeline and cost to interconnect the generator. In addition to the fact that there are a limited number of interconnection projects that can be constructed and interconnected in a given year, onshore wind resources may be located further from population centers than other generation resources, resulting in more complex and expensive interconnection projects, which further exacerbates this constraint. Appendix L provides additional detail on how Duke Energy is managing interconnection constraints to enable needed resources to be interconnected on the timelines identified in the Near-Term Action Plan.

Once onshore wind facilities are sited, developed, constructed, interconnected and generating, weather will be an ongoing operational consideration. Due to the location and geography of the Carolinas, there is naturally a higher risk from hurricanes within eastern Carolinas, which could impact equipment design, operations and insurance costs. This hurricane risk is typically associated with offshore wind, but further assessment and investigation regarding hurricane risks is needed with equipment manufacturers, meteorologists and insurers for onshore wind, as well.

Additional consideration should be given to impacts and mitigation for avian and bat species. Bird and bat impacts from onshore wind has been an ongoing critical issue for onshore wind facilities. Avian and bat surveys will be required during the development process along with agency consultation. The Federal Endangered Species Act prohibits unauthorized take, by any person, including businesses and governmental entities, of threatened and endangered ("T&E") species, with take defined to include harassing, harming or killing. The United States Fish and Wildlife Services ("USFWS") may issue an incidental take permit ("ITP") to authorize take of listed species that is incidental to, and not the purpose of, carrying out an otherwise lawful activity. The ITP, if issued, would authorize a certain amount of take and would include actions to avoid, minimize, mitigate and address unintentional impacts of the activities (both construction and operation of the wind facility and associated infrastructure). Actions that may be required by an ITP for the construction and operation of a wind facility could include seasonal construction restrictions, curtailment of operations, installation of deterrent devices and implementation of avoidance and minimization strategies. The need for an ITP is based on the risk the activities pose to T&E species, which will be primarily based on the siting of the facility. T&E bat and avian species represent the greatest concern from the construction and operation of a wind facility in the Carolinas.

The Carolinas, especially the eastern parts, are home to or are used by several migratory bird species. The federal Migratory Bird Treaty Act prohibits the take (including killing, capturing, selling, trading, and transport) of protected migratory bird species (nearly 1,100 bird species) without prior authorization by the USFWS.

Bald eagles can be found across the Carolinas, mainly near large bodies of water, with a greater abundance in the northeast part of North Carolina. The Federal Bald and Golden Eagle Protection Act prohibits anyone, without a permit issued by the USFWS, from taking bald or golden eagles, including their parts (including feathers), nests or eggs. A site-specific individual permit can be obtained for the incident take of bald eagles and its nests. The USFWS has proposed a rule that would allow wind facilities to be eligible for a general permit based on eagle abundance data, and the majority of the Carolinas potentially would qualify for the general permit. The rule is scheduled to be finalized in late 2023.

There are methods and technologies available to mitigate impacts to birds and bats, such as targeted curtailment. These curtailment methods can identify protected species and initiate curtailment of specific turbines to reduce the risk of turbine collision.[15] Additional acoustic deterrent or detection and targeted curtailment are available to mitigate bat impacts.

Execution Risk Management

As detailed in Chapter 4, the recommended Near-Term Actions include development activities to support 1,200 MW of onshore wind. Due to the limited development of onshore wind in the Southeastern United States,[16] near-term actions will be needed to bolster the onshore wind market to ensure that adequate resources are developed. These near-term actions and procurement activities that will be required to deliver new onshore wind resources are discussed in Chapter 4. Risks associated with the development of onshore wind are discussed below.

Securing Development Locations: As discussed throughout this Appendix, one of the critical first steps in the development of onshore wind in the Carolinas is identifying and establishing site control for suitable wind farms. Siting and developing onshore wind facilities is higher complexity, higher development costs and longer development timeframe compared to utility scale solar. Understanding and navigating military restrictions will be critical. Since onshore wind farms require a significant amount of land control, securing land rights can take 12 to 18 months for a project. Given the onshore wind market is relevantly nascent in the Carolinas, establishing trust and participation from targeted landowners may be both a challenge and an opportunity.

Community Support and Local Zoning: It is perceived that onshore wind farms have a different impact to community aesthetics than utility scale solar facilities. Engaging with and educating local stakeholders will be paramount in successful project siting and development. Although the majority of counties in the Carolinas do not have ordinances that establish a permitting process and development standards for onshore wind facilities, it is anticipated that any project would likely require local county/town rezoning and/or conditional use permitting. The ability of the Companies to secure these onshore wind projects' permits is critical to achieving the desired onshore wind capacities described previously in this Appendix.

Interconnection Risks: Once an identified project site has secured a reasonable amount of site control, the next critical risk to the execution of onshore wind development is interconnection of that resource. As with other generation resources that need to be developed to execute the Resource Plan, interconnection is also a critical path item for the development of onshore wind. There are a limited number of interconnection projects that can be executed in a given year, and the timing of transmission line outages may impact the timing of when projects can be brought online. Due to the growing amount of new generation on the Companies system, there is the potential for affected system upgrades on neighboring systems that may need to be resolved.

Supply Chain Risks: Due to current socio-political, economic and COVID-19-related conditions, challenges exist to obtain the long lead-time items and material, such as steel, raw materials and

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[15] Example of bird detection and targeted curtailment include IdentiFlight. See IdentiFlight, About Us, available at https://www.identiflight.com/about-us-2.

[16] UNITED STATES Dept. of Energy, Office of Energy Efficiency & Renewable Energy, Land-Based Wind Market Report: 2021 Edition, 2021, available at https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2021-edition-released.

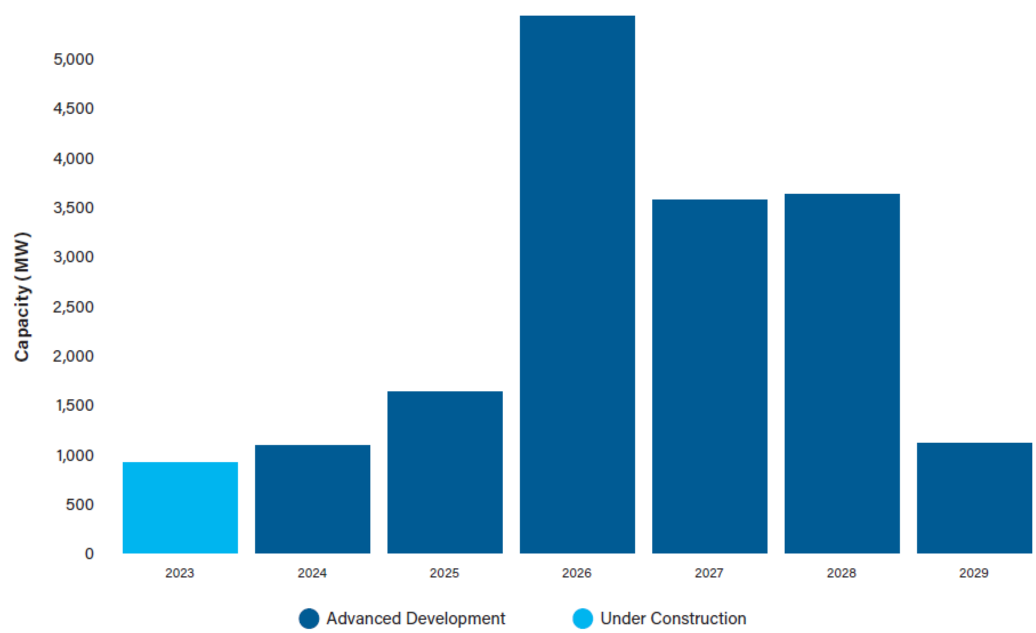
electronics needed to build a new onshore wind facility. Early engagement with major vendors of primary components will be key, along with early procurement (while a project is still under development and permitting is ongoing) and potential storage of equipment and materials when they are available. Due to the later timeline for when these onshore wind facilities will enter the construction phase, it is believed that some of the current supply chain restraints may have dissipated. It is uncertain however, how future supply and demand balances will evolve, particularly in light of IRA incentives.

Offshore Wind

Current & Future Planning Considerations

The offshore wind market is a new and developing industry in the United States with few wind turbines currently in operation. However, there are significant investments being made in the United States offshore wind market with an estimated 53 GW of projects in various stages of development. Of these, 17 GW have contract mechanisms for energy offtake in place and several projects are currently under construction or nearing construction. Figure I-5 below illustrates the planned commercial operations data for these 17 GW currently in the development process.

Figure I-5: United States Offshore Wind Pipeline by Commercial Operations Date[17]



Source: American Clean Power Offshore Wind Market Report, May 2023

Recognizing that DEP's service territory is contiguous to the Atlantic Ocean, the Companies have actively monitored offshore wind developments along the Atlantic and began actively planning for potential offshore wind development in the 2020 IRPs filed in both South Carolina and North Carolina.

[17] American Clean Power, Offshore Wind Market Report, May 2023, available at https://cleanpower.org/resources/offshore-wind-market-report-2023/#download.

Other peer utilities such as Dominion Energy Virginia are in more advanced stages of planning and development of offshore wind.

Figure I-6: Map of Existing Leased Wind Energy Parcels

In the initial 2022 Carbon Plan, Duke Energy was directed by the NCUC to evaluate the three wind energy parcels off the coast of North Carolina (shown above in Figure I-6): Carolina Long Bay, consisting of two parcels off Cape Fear south of Wilmington, and one parcel off the coast of Kitty Hawk, NC. Each of these parcels has the capability to generate at least 1 GW each, and an estimated 4 GW across all three. To perform this evaluation, the Companies hired DNV to facilitate the Companies' unbiased evaluation of potential costs to acquire and develop offshore Wind Energy Areas ("WEA") in Duke Energy's region. DNV received non-binding bids through a request for information process from three offshore wind developers, collected and organized the data into a consistent format and anonymized the data prior to providing it to the Companies for further analysis. The Companies took the anonymized WEA data and analyzed it to determine the levelized cost of energy for various project scenarios in the three WEAs. In general, the scenarios confirmed that projects become more economical as they increase in size. One developer submitted scenarios with offshore wind available as early as 2030, while the remaining developers submitted scenarios with 2031-2032 availability.

This evaluation was also a critical step to help create a generic profile for offshore wind that was used in the generation modeling tools to determine if offshore wind would be selected as a cost-effective resource to help meet future load requirements. The generic profile was used in modeling efforts to create generic offshore wind generation tranches that were also WEA agnostic.

As discussed in Chapter 4, offshore wind was not selected in the Companies' recommended Core Portfolio P3 Base through the end of the Base Planning Period by 2038 (though it was selected beyond the Base Planning Period), and the Companies' near-term actions do not include obtaining a lease and proceeding with more significant initial development activities required to make offshore wind available in the Carolinas in the early 2030s. However, as further discussed in Chapter 3 and Chapter 4, the Companies are actively monitoring offshore wind project developments in the region and plan to continue evaluating the option to procure and/or develop an offshore wind project to meet potential system needs in the mid-2030s given the potential for future adjustments to the Companies' base assumptions such as incremental "high" load growth and variability in commodity prices such as lower gas supply assumptions than assumed in the Core Portfolios. Due to the long-lead development timeline to competitively bid and execute 1,600 MW of offshore wind, the Companies would need a decision from the commissions by December 31, 2024, to pursue an offshore wind RFP to potentially achieve a 2033 in-service date. It is important to note that a 2033 in-service development timeline would also be dependent upon additional considerations, including a multi-year permitting process that must be completed before construction can begin and, consequently, commission approval must be aligned with permitting and onshore and offshore transmission development. As discussed in Appendix L, there are also supply chain and outage risks related to offshore wind enabling transmission that could potentially impact the 2033 in-service timeline. Additionally, the offshore wind supply chain in the United States is still nascent, which may impact certain long-lead manufacturing items (e.g., cables, offshore substations, etc.) and could pose a challenge to a 2033 in-service date if there is insufficient lead time to acquire the necessary materials and equipment.

Permitting for offshore wind is a complex, multi-year process that requires site assessment, surveys, site planning and local, federal and state approvals. However, at a high level, the permitting process consists of the following steps:

1. Site Characterization
2. Site Assessment Plan ("SAP")
3. Construction and Operations Plan ("COP")
4. Notice of Intent to Prepare an Environmental Impact Statement
5. Draft Environmental Impact Statement
6. Record of Decision from the Bureau of Ocean Energy Management ("BOEM")

There are currently nine projects in the United States at or beyond step five (this includes two projects currently under construction) and 12 at or beyond Step 4. As of May 2023, there are 18 projects in advanced development, representing over 16 GW.

Policy in the United States, at both the federal and state levels, is trending favorably to support offshore wind development. At the federal level, in 2021, the Biden Administration announced a goal of deploying 30 GW of offshore wind by 2030, to support United States' clean energy goals. The IRA also has positive financial impacts to offshore wind in the form of PTCs and ITCs.

In addition to policy support for offshore wind, technology advancements and supply chain developments continue to occur in the United States market. However, recent supply chain disruptions and inflationary pressures have negatively impacted current offshore wind projects. Many of these projects (primarily in the Northeast) have offtake or PPAs that were finalized before the COVID-19 pandemic. Since then, a number of these projects have attempted to renegotiate their PPA prices. In most cases, the project developer has pointed to rising costs associated with global supply chain inflation.

In addition to the technology advancements, more than $1.7 billion of American supply chain investments have been announced for major offshore wind components in the United States. Some examples of offshore wind supply chain enhancements that have either been announced, are under construction or are operational include those for components such as blades, towers, foundations, offshore substations and cables. On the construction and operations side, there are a number of offshore wind US-flagged (Jones-Act compliant) vessels announced, being built or being retrofitted for offshore wind use. These include piling installation vessels, feeder barges (used in conjunction with a European flagged installation vessel that does not port in the United States), crew transfer vessels and service operations vessels. This illustrates that there is a mature and increasing supply chain for offshore wind, globally and in the United States.

Offshore wind can be an economic driver in the United States. The construction, development and the ongoing operation of offshore wind provides many economic opportunities for the region where it is built. The National Renewable Energy Laboratory published a report entitled “Offshore Wind Jobs and Economic Development Impacts in the United States: Four Regional Scenarios” which states:

> In the Southeast region, offshore wind energy development has the potential to support between 14 and 44 full-time equivalent (FTE) jobs per MW during construction periods and 1.6 and 1.7 FTE ongoing (operations phase) jobs per MW. Many large ports in the Southeast region could be used as staging areas and for component manufacturing, such as the Port of Virginia, Port of Charleston and Port of Savannah. There is existing economic activity in industries similar to offshore wind in the Southeast, so the regional workforce and infrastructure could contribute to offshore wind in the future.

Another report by the United States Department of Energy states:

> How much of an economic impact a scenario will have depends most on the level of development and portion of expenditures made within the Southeast Atlantic region...a moderate scenario that falls between high and low cases – development is estimated to support approximately 4,200 total jobs by 2020 and an average of nearly 12,000 jobs thereafter through 2030...and commissioned offshore wind projects will need approximately 330 O&M workers by 2030. On an ongoing basis, a local supply chain would result in a greater employment impact than the installations. By 2030, approximately 4,000 ongoing local revenue and supply chain jobs are supported in this scenario. Employees with these jobs would be well compensated, with average annual earnings (including benefits) of $75,000 for workers involved with construction and $62,000 for O&M workers.

As these reports highlight, the addition of offshore wind resources will provide substantial positive economic impacts to the regions in which it is built.

Offshore Wind Contributions to Diverse, Complementary Nature of Resource Mix

Offshore wind has an average annual capacity factor of approximately 40%-48%, dependent on factors such as location, weather and resource characteristics. It has its highest seasonal generation on winter mornings. As the peak planning hour has shifted to winter mornings, partially due to high solar integration, having capacity during those times is critically important, which is when offshore wind is consistently producing and peaking.

Offshore wind is a non-dispatchable resource with specific, limited viable locations. However, the Carolinas are fortunate to not only have a long coastline, but to also already have multiple viable site locations for offshore wind turbines, 20 miles or more from shore, which will allow for larger wind farms, larger wind turbines and taller towers compared to onshore wind farms. These factors increase the capacity and capacity factor of offshore wind compared to onshore wind by enabling winds to produce more energy for a vast majority of hours, making this technology highly impactful to mitigating fuel price and volatility risk. Offshore wind farm capacities are typically orders of magnitude larger than onshore wind or solar farms, without the associated land use issues. While solar, onshore wind and offshore wind have potential annual transmission interconnection limitations, offshore wind has significant transmission infrastructure challenges, described in more detail in the Appendix L. This challenge can be minimized by having a variety of complementary resources to meet future energy needs.

Offshore Wind Operational Considerations

One important operational consideration is that the southeast United States site locations for offshore wind projects present risk for hurricanes. In response, Duke Energy gathered National Oceanic and Atmospheric Administration ("NOAA") hurricane information and determined that for potential sites, there is less than a 2% chance that a Category 4 or stronger hurricane would have a direct impact on the locations based on over 170 years of hurricane tracking data. This is important because the offshore wind turbines that would be used for any potential project in the Carolinas would be "Class-T" turbines that have been designed and hardened for typhoon wind conditions. Current wind turbine designs are rated to low Category 4 wind speed. Duke Energy has engaged with insurance providers to calculate and quantify potential property damage, loss of generation and restoration time associated with a major hurricane. Table I-5 below shows the annual probability of NOAA hurricane storm intensities to pass within 60 nautical miles of the Carolina Long Bay and Kitty Hawk parcels.

Table I-5: Annual Probability of NOAA Hurricane Storm Intensities

	Tropical Storm (>40 mph)	Hurricane (>74 mph)	Major Hurricane (>111 mph)	Category 4 Hurricane (>130 mph)	Category 5 Hurricane (>157 mph)
Offshore Wilmington, NC	68%	40%	6%	2%	<1%
Offshore Kitty Hawk, NC	65%	26%	3%	<1%	<1%

Execution Risk Management

Offshore wind resources have a long lead time, approximately a decade from leasing a WEA to commercial operation. During this time, many actions are required for an offshore wind site to go from planning, permitting, developing and constructing, to operating. Some of these actions are timebound, for example, completion of an SAP is required within 12 months and submittal of a COP within five years of a lease agreement. Some of the other actions that are required to develop offshore wind resources come with significant execution risks and are discussed in detail in the remainder of this section.

Permitting Approvals/Construction Timeline: As mentioned above, the development and construction timeline for an offshore wind project can span a decade or more. During this timeline, there are multiple permitting studies/approvals required to continue to move the timeline forward. All of these permitting processes offer the potential for delays or extensions to the timeline, that could extend the construction timeline by years. Duke Energy is continuing to gather data about the permitting and construction timeline to reduce the risk of delays due to permitting and construction should offshore wind be selected in the future.

Fisheries and Wildlife: There have been concerns around fisheries and wildlife related to the development of offshore wind. The USFWS concurred with BOEM's "no effect" and "may affect, but not likely to adversely affect" determinations for commercial wind lease issuance and site assessment activities. The USFWS met with BOEM to recommend deploying acoustic detectors at Motus Wildlife Tracking System receivers during site assessment to collect data on preconstruction bird and bat presence within the WEA. The BOEM environmental assessment did not identify any environmental justice concerns resulting from site assessment and site characterization activities.

Hurricane Risks: As mentioned above, the Carolinas face a higher probability of high category hurricanes than the Northeast. According to the NOAA tracking database, three Category 4 hurricanes have passed within 70 miles of Carolina Long Bay or Kitty Hawk in the over 170 years this has been tracked. It is important to recognize while a Category 4 or 5 hurricane is a low-probability event, the potential damage to the wind farm can be significant.

Supply Chain Risks: The supply chain risks facing offshore wind are similar to those previously discussed in the onshore wind section. Early engagement with vendors of primary components will be key, along with early procurement and storage of equipment and materials to mitigate supply chain risks. Due to the timeline of when these offshore wind facilities will enter the construction phase, it is believed that some of these supply chain restraints may have dissipated.

Jones Act Requirements: Another consideration is the use of Jones Act-compliant offshore wind vessels for the construction and operation of offshore wind turbines. The availability of offshore wind vessels to support offshore wind turbines requires more time because the development of these vessels is in its early stages. As the demand and development for more offshore wind turbines grow, the timeline for procuring such vessels should decrease.

It is expected that these vessels will be available for lease in the future to support operations. The costs for such an arrangement are reflected in the generic offshore wind profile used for the Plan modeling.

Interconnection Risks: Interconnection of a large amount of MW is an important factor in the development of offshore wind. Completing the required transmission to support the types of large injections needed to achieve the interconnection of offshore wind could be challenging from a timing and scheduling standpoint, and are dependent on the timing of identified future resource needs. For more details on interconnecting and the risks associated with offshore wind, see Appendix L.