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Natural Gas, Low-Carbon Fuels and Hydrogen

Highlights

- The Companies' natural gas supply strategy ensures adequate supply for economic development growth, preserving reliability and the decarbonization of the Duke Energy generation fleet. Until new low-carbon or zero carbon fuels become economically available for utility-scale use in dispatchable generation, traditional fossil fuels will be required to maintain least-cost and reliable operations.

- Hydrogen-enabled new natural gas assets (approximately 900-megawatt combustion turbines and 1,360-megawatt combined cycle) are nearing Certificate of Public Convenience and Necessity submittal.

- Hydrogen analysis and projects are in flight. United States government agencies are aligning on future hydrogen use to lower emissions from dispatchable assets, and the Companies are making provisions for the potential for both immediate and expanding hydrogen capability on these and other future new combustion turbine and combined cycle assets.

- Advancing efficiency improvements and flexibility via uprates at seven existing combined cycle generating units will reduce fuel costs and emissions and enable integration of renewables to further reduce customer exposure to fuel cost volatility.

A Changing Energy Landscape

To reliably meet growing load profiles, particularly with increasing renewables needed to achieve the ongoing energy transition while maintaining or improving reliability, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") also need fast ramping, dispatchable resources. Natural gas-fired combustion turbine ("CT") generation ensures system reliability and least-cost operation, while providing significant benefits from an environmental and supply chain risk perspective versus coal. Meanwhile, there is continued momentum toward developing a hydrogen supply chain to fuel existing and future turbines to further lower the system's carbon intensity and reduce exposure to regulatory risk. The United States ("U.S.") Environmental Protection Agency's ("EPA") recently proposed changes to Clean Air Act ("CAA") Section 111 – which would impose more stringent emissions limitations on new and existing natural gas units than the current rules – could have a profound impact on the implementation of hydrogen-capable gas units in the U.S. if Section 111 is finalized in its current proposed form. The potential impacts of the proposed changes are covered later in this Appendix.

Natural Gas

Supply and Transport

The Companies' natural gas supply strategy is critical to ensuring adequate supply for economic development growth, preserving reliability and the decarbonization of the Duke Energy generation fleet. Duke Energy customers have long benefited from a secure and diverse portfolio of coal, natural gas, diesel, and other energy sources. Until new low-carbon or zero carbon fuels become economically available for utility-scale use in dispatchable generation, traditional fossil fuels will be required to maintain least-cost and reliable operations. As the generation fleet transitions away from coal, the importance of natural gas supply security will continue to increase.

Currently, the Companies' generating units that utilize natural gas rely on interstate pipeline firm transportation ("FT") or on-site coal or diesel dual-fuel capability for fuel security; however, the Companies' combined cycle ("CC") fleet currently needs more interstate pipeline FT capacity, in part, driven by the cancellation of the planned Atlantic Coast Pipeline ("ACP"). The realities of the Companies' need for additional FT and diversity of gas supply, which formed the basis of the ACP project, have not changed. This need, coupled with load growth and further planned coal retirements, requires the Companies to procure additional interstate natural gas FT rights to reliably serve their Carolinas customers. With the transition from dispatchable coal to weather-dependent and variable-energy renewables, firm generator capacity and operational flexibility provided by natural gas generation with adequate fuel security will play an important role in mitigating reliability risks. To that end, FT is essential to manage the natural gas supply security needed for reliable cost-effective generation. Not only does interstate FT allow access to lower cost natural gas supply, but it maintains reliability through increased fuel security of dispatchable gas generation. Operationally, interstate FT is necessary for the flexibility to balance the system's hourly gas demand swings that inherently accompany intermittent renewable generation. Without additional interstate pipeline FT, the Companies have increased fuel assurance risk, increased customer fuel cost exposure, and increased risk of delayed coal retirements.

Meeting the Companies' fuel security needs requires a flexible and reliable gas supply. To meet the natural gas fuel security objectives of resource planning and the overall energy transition, the Companies continue to pursue a balanced "all of the above" strategy. This includes increasing access from both Appalachian and Gulf Coast gas supply markets via incremental FT, while also ultimately increasing on-site fuel storage. To meet this requirement, the Companies need additional FT capacity on interstate pipelines because there is no natural gas underground storage or production in the Carolinas. The Transcontinental Gas Pipe Line ("Transco"), the primary interstate gas infrastructure through the Carolinas, is fully subscribed and oftentimes constrained. Over the past decade in the Carolinas, natural gas demand growth has outpaced increases in gas delivery capacity.

The Companies currently have a combined long-term portfolio of 434,560 dekatherms per day ("Dth/day") of interstate FT service subscribed on Transco. The peak burn requirement of the Companies' existing baseload CC fleet is approximately 960,000 Dth/day. The Companies' resource planning modeling assumes the same amount of additional interstate FT volumes as previous Integrated Resource Plans for existing generation to meet the full load burn requirements of the CC fleet. Furthermore, any new CC generation will necessitate the need for additional interstate FT to support those units' burn requirements. Without additional interstate FT, the Companies would continue to have an interstate portfolio that is less than half of its current CC design capacity need and less than a quarter of the current gas fleet's historical peak gas burn.

Natural gas is delivered just-in-time for generator consumption via pipelines. Thus, mitigating the risks of natural gas transportation and delivery of supply is of utmost importance to ensure reliability. In recent years, the Transco pipeline system has become increasingly constrained and less flexible, limiting the amount of swing and daily imbalance through frequent issuance of daily Operational Flow Orders with low percentage tolerances. Given that Transco has moved to a strict daily pipeline tolerance, the Companies' flexibility is reduced to meet the need of potential daily over burns where natural gas demand has exceeded supply, potentially subjecting the Companies to daily tiered charges from Transco and penalties of $50/Dth. Transco is proposing additional restrictions that will further limit the Companies' ability to serve their respective gas fleets as needed, especially given such a high reliance on delivered Zone 5 supply and the increasing penetration of intermittent generation. These restrictions, compounded by Transco's physical flow limitations, bind the Companies' ability to operate their respective gas fleets at full capacity throughout the year. The Companies, however, currently successfully manage this through the usage of alternative fuels, namely diesel and coal. To transition away from coal, however, the Companies need to increase the fuel security of natural gas so that they will have the reliable supply the combined fleet needs during peak demand periods. Failing to do so only increases the likelihood of and risks related to delayed coal retirements as described in Appendix F (Coal Retirement Analysis).

Per North Carolina Utilities Commission ("NCUC") Order, the Companies worked with the NCUC's Public Staff to develop realistic assumptions regarding the availability of gas FT capacity for resource planning modeling assumptions, which resulted in the Companies utilizing Gulf Coast sourced gas supply as the base modeling assumption for incremental FT via brownfield expansion(s). Any access to Appalachian gas via Mountain Valley Pipeline ("MVP") is modeled in the Alternate Fuel Supply Scenarios Sensitivity. This work is also consistent with the Public Service Commission of South Carolina's directive that the Companies address the risks of natural gas transportation and delivery. For modeling purposes in this resource planning cycle, the Companies are assuming incremental Gulf

Coast gas for any new CCs in its base case. For clarity, the Companies are continuing to plan for MVP-sourced gas supply if it ultimately enters service.

On April 21, 2023, the U.S. Department of Energy's ("DOE") Secretary of Energy, Jennifer Granholm, filed a letter in support of MVP to the Federal Energy Regulatory Commission. In this letter, the DOE submits the view that the "MVP project will enhance the Nation's critical infrastructure for energy and national security."[1] Below is some additional selected language from Secretary Granholm's letter that speaks to MVP's importance to the Carolinas' energy transition and security:

> "Energy infrastructure, like the MVP project, can help ensure the reliable delivery of energy that heats homes and businesses, and powers electric generators that support the reliability of the electric system…. Natural gas—and the infrastructure, such as MVP, that supports its delivery and use—can play an important role as part of the clean energy transition… As extreme weather events continue to strain the U.S. energy system, adequate pipeline and transmission capacity is critical to maintaining energy reliability, availability, and security. The MVP project will extend the Equitrans transmission system to the Transcontinental Gas Pipeline Company's Zone 5 compressor station 165 near Gretna, Virginia. It is designed to move 2.0 Bcf/d of natural gas and is intended to further alleviate pipeline congestion. It can also help unlock additional natural gas supplies and delivery, which, in turn can enhance regional and national energy security."

On June 3, 2023, the Fiscal Responsibility Act ("FRA") was signed into law. In the FRA, Congress found and declared that the timely completion and operation of MVP is required in the national interest. To help do so, Congress ratified and approved all authorizations, permits, verifications, extensions, biological opinions, incidental take statements and any other approvals or orders issued pursuant to Federal law necessary. On June 28, 2023, after reobtaining all outstanding permits, the Federal Energy Regulatory Commission ("FERC") issued an order authorizing MVP to resume all construction activities.

However, on July 11, 2023, the U.S. Court of Appeals for the Fourth Circuit ("Fourth Circuit") granted a temporary stay of construction on the pipeline so it could consider the merits of an environmental impact study related to MVP's approval that environmentalists have argued is flawed. Additionally, there are now arguments that within the FRA, Congress improperly removed jurisdiction over MVP's approval from the Fourth Circuit to the U.S. Court of Appeals for the District of Columbia Circuit, potentially violating the Separation of Powers clause of the U.S. Constitution. In response, on July 14, 2023, MVP filed an Emergency Application to the Chief Justice of the Supreme Court of the U.S. ("SCOTUS") requesting that the SCOTUS vacate the Fourth Circuit's orders staying construction on the MVP project. In addition, the U.S. House of Representatives, Senator Joe Manchin (Democrat-West Virginia), at least nine other members of the U.S. Congress, the U.S. Chamber of Commerce, the American Gas Association and numerous other parties, entities, and groups, including DEC, DEP,

[1] U.S. Department of Energy, Letter from Secretary Granholm to FERC regarding MVP, April 2023, available at elibrary.ferc.gov via filename: 20230424-4000_MVP-DOE-CP21-57-000.pdf.

Dominion Energy South Carolina, Inc., Dominion Energy Services, Inc., Public Service Company of North Carolina, Inc., and Southern Company Gas, Inc. (collectively, “Utility Amici”), filed amicus briefs with the SCOTUS requesting that it grant MVP’s Emergency Application and vacate the Fourth Circuit’s temporary stay. On July 27, 2023, the SCOTUS granted MVP’s Emergency Application to vacate the Fourth Circuit’s stay, and MVP was free to resume construction on the pipeline, which they have since done. The Companies view the SCOTUS ruling as a consequential and positive step forward and will continue to monitor MVP developments such as any potential further associated risks of project cancellation. Although there is now a much higher likelihood of completion, if for whatever reason MVP is not completed, the Companies believe they could obtain adequate fuel security through incremental expansions from the Gulf Coast and additional on-site fuel storage.

Incremental on-site fuel storage can further improve fuel security beyond additional interstate FT. Depending on the ultimate in-service volumes of interstate pipeline infrastructure into the Carolinas, the Companies likely will require additional on-site fuel supply. Fuel storage could be utilized for management of both peak day needs due to coal retirements as well as intraday needs to support the intermittent nature of the growing volumes of renewables. Fuel storage, for example, provides increased reliability in the event of extreme weather, a force majeure event, or other supply limitations. Additionally, such on-site storage could include liquified natural gas (“LNG”), diesel, or other alternative fuels. While diesel storage is a proven solution, there is a need to diversify back-up fuels. Thus, the Companies may move forward in validating LNG or other alternative fuel storage technologies for power generation applications. The Companies are currently evaluating fuel storage and plan to include more details in future resource planning filings once there is increased clarity on incremental interstate natural gas pipeline infrastructure into the Carolinas.

New Hydrogen-Capable Natural Gas-Fired Generation

In the 2022 resource plans, the Companies proposed working toward near-term hydrogen-enabled natural gas assets. The Companies have made significant progress toward developing these projects. The following are status updates:

- The Companies are moving forward with installing new hydrogen-capable dispatchable gas assets (1,360 MW Advanced Class CC at Person County Energy Complex located at Roxboro plant in Semora, NC (“Person County Advanced CC”) and 900 MW Advanced Class CTs at Marshall Steam Station located in Terrell, NC (“Marshall Advanced CTs”)). There is also potential for further hydrogen-enabled gas assets at Person County (potentially a second Advanced Class CC or additional advanced class CTs depending on gas supply considerations, resource needs and timing).

- The Marshall Steam Station, which currently consists of four coal units, will leverage existing gas infrastructure installed with the previous gas co-firing project for the two new advanced class CTs. Once completed, the project will allow existing Units 1 and 2 to retire while Units 3 and 4 will continue co-fired operations.

- Both sites are using the Generator Replacement Request process approved by FERC for the Companies in 2022. This process allows the Companies to apply to use the transmission rights at the existing coal plants when installing new generation on-site and connecting to the transmission system at the same point of interconnection as the generation being replaced. With using the existing transmission, staff, land, permits, security, and — in Marshall's case — gas lines, the brownfield sites offer significant savings to customers over greenfield construction while lessening the impact to the local communities with coal retirements.

- Both the Person County and Marshall projects are currently targeting in-service dates at Q4 2028/Q1 2029. Exact timing will depend on a combination of permitting, on-site transmission reconfiguration work, potential offsite transmission expansions, in-service of new intrastate gas supply infrastructure and the new gas asset construction timing including supply chain constraints (transformers, etc.). To achieve these in-service dates, pre-Certificates of Public Convenience and Necessity are being prepared and are planned to be submitted this year.

- Due to load growth and increased reserve margin requirements, the recommended portfolio P3 Base calls for additional near-term hydrogen-capable dispatchable gas assets beyond the two projects mentioned above. Therefore, the Companies will begin the development process for additional sites as mentioned in Table 4-2 in Chapter 4 (Execution Plan).

Environmental Protection Agency Clean Air Act Section 111 Proposed Rule and New Gas

On May 23, 2023, the EPA published in the Federal Register a CAA Section 111 Proposed Rule to address carbon dioxide ("CO_2") emissions from new (gas) and existing (coal and gas) fossil-fired power plants, which, if finalized, would be applicable to the Companies' planned Person County Advanced CC and Marshall Advanced CTs. The EPA CAA Section 111 Proposed Rule would impose emission limitations on new natural gas CTs, with the standard varying by capacity factor. For the first time, the EPA also establishes standards in several phases, with more stringent standards coming into effect over time.

The first phase, also known as Phase 1, applies to any natural gas CTs that commence construction after May 23, 2023. Large baseload units (above 45–55% capacity factor), such as the Person County CC, would be subject to the most stringent 12-month rolling average standard of 770 pounds ("lbs.") CO_2/megawatt hour ("MWh") gross. Intermediate load units (above 20% and below 45–55% capacity factor) would have to meet a 12-month rolling average standard of 1,150 lbs. CO_2/MWh-gross, and low load units (below 20% capacity factor) would not be subject to an output-based standard.

For baseload units, there are two options for subsequent phases as follows:

- **Hydrogen** – A 12-month rolling average standard of 680 lbs. CO_2/MWh gross based on 30% low-greenhouse gas ("GHG") hydrogen co-firing in 2032, increasing to 96% low-GHG hydrogen co-firing by 2038 to meet 90 lbs. CO_2/MWh gross, or,

- **CCS** – A 12-month rolling average standard of 90 lbs. CO_2/MWh gross starting in 2035 based on 90% carbon capture and sequestration ("CCS").

For intermediate load units, there is a subsequent Phase 2 12-month rolling average limit of 1,000 lbs. CO_2/MWh gross starting in 2032.

The Companies have reviewed and commented on the EPA CAA Section 111 Proposed Rule in light of proposed hydrogen-capable natural gas assets in flight. The Companies believe that both the proposed Marshall Advanced CTs and the Person County Advanced CC would be industry-leading in efficiency and therefore achieving low CO_2 emission rates, as they are designed as Advanced Class. With an eye toward Phase 2 of the EPA CAA Section 111 Proposed Rule and long-term strategy for hydrogen-enabled gas units, the Companies are planning to incorporate improvements in these new units with the goal of enabling future hydrogen capability from the outset as mentioned in more detail in Table K-1 below.

It should be noted that obtaining low-GHG hydrogen supply in sufficient quantities to meet the proposed required 30% by volume in 2032 and 96% by volume in 2038 for baseload CCs would necessitate tremendous infrastructure buildout of a nascent market in the Carolinas, which the EPA assumes will occur. State and Federal support of these infrastructure projects would be paramount for successful implementation. As the EPA has segmented the standards by capacity factor, one option for continued compliance in the event the required hydrogen infrastructure/supply does not materialize for the 2032 and 2038 thresholds would be to reduce capacity factors consistent with the intermediate load category and comply with the 1,000 lbs./MWh gross emission standard.[2]

Provisions for Hydrogen future use on new assets – Being that the industry, U.S. government agencies (e.g., DOE (Hydrogen Hub and Hydrogen Energy Earthshot) and EPA (in the CAA Section 111 Proposed Rule) are aligning on future hydrogen use to lower emissions from dispatchable assets, the Companies are making provisions for the potential for both immediate and expanding hydrogen capability on these and other future new CT/CC assets, shown below in Table K-1.

Table K-1: Summary of Current Adopted and Future Provisions for Hydrogen

Item to Enable Hydrogen for New Gas Assets (CT/CCs)	Included in Base CT Scope	Future Consideration
1. Inlet fuel piping designed for Hydrogen capability (pipe size, stainless steel materials, valves, connections, etc.)	Include 30% Hydrogen capability	100% would require significant upgrades
2. Real estate space/connections required for Hydrogen blending skid to tie into inlet fuel piping with minimal piping runs	Required	N/A
3. Hydrogen blending skid equipment	Provide space only	Deploy as needed for future firing

[2] EPA CAA Section 111 Proposed Rule is not clear when or if a turbine can switch between subcategories.

Item to Enable Hydrogen for New Gas Assets (CT/CCs)	Included in Base CT Scope	Future Consideration
4. Combustion system for 30% Hydrogen blend	Included	N/A
5. Combustion system for 100% Hydrogen	N/A	Future (not yet available from vendors)
6. Heat Recovery Steam Generator capability for 100% Hydrogen (space only for larger Selective Catalytic Reduction catalyst)	Required	N/A
7. Ammonia system (nitrogen oxides ("NOx") control) sized for 100% Hydrogen capability	Recommended/ Included	N/A
8. Fire protection/detection system designed for Hydrogen capability	Recommended/ Included	N/A
9. Inert Purge system for CT Enclosure, with space for purge gas bottle rack	Recommended/Vendor specific	N/A
10. Controls modifications for Hydrogen blending & startup	Provide Input/Output space only	Deploy as needed for future firing

Hydrogen use assumptions ramping over time in existing units – While it remains to be seen whether new interstate and intrastate hydrogen pipeline infrastructure systems could be implemented, a near term plausible solution is for pipelines to blend a low percentage of hydrogen with natural gas into the existing natural gas pipelines.

In the 2023 Carolinas Resource Plan modeling, clean hydrogen blending is represented with a starting point of approximately 1% by volume in 2035, 2% by volume in 2038 and approximately 3% by volume in 2041 and holding steady until significantly more hydrogen is required to meet carbon-neutral by 2050. This blend, considered an average across the units, is assumed to be via existing natural gas pipelines (i.e., pre-blended) and applied to all gas assets existing or added before 2040. It should be noted that the industry currently is studying and testing hydrogen blends into natural gas infrastructure. There are risks that high blends could lead to pipe material embrittlement, which is a limitation to injecting hydrogen into existing natural gas piping. For these reasons, the Companies are conservatively assuming a 3% blend until they can conduct further research. For hydrogen-only units, however, the Companies assume the use of new purity hydrogen pipeline infrastructure.

For any new peaker CTs built in the 2040s, the Companies assumed them to be 100% hydrogen fueled in resource selection, and plan to convert new CCs and CTs built in the 2020's and 2030's, that are added to enable coal retirements, to 100% hydrogen in 2050.

Asset life – For all new CT and CC assets, the Companies expect the traditional lifespan of 35+ years to continue to be appropriate. For the hydrogen capable natural gas-fired generation assets under development with targeted Q4 2028/Q1 2029 in-service dates, the Companies have made specification and design upgrades as well as future provisions for expanded hydrogen use (as mentioned above). These improvements will allow continued use of these dispatchable and fast responding assets for system reliability as the Companies continue to lower emissions profiles over time.

Natural Gas Execution and Risk Management

Executing an orderly energy transition will require expanding the flexibility of the Companies' existing natural gas fleet in the Carolinas, as well as building additional dispatchable natural gas resources. In Chapter 4, the Companies discuss the required near-term actions and general procurement approach concerning both the existing and new natural gas resources. The required actions come with execution risks, however, which the Companies discuss in detail in the remainder of this section, including some of the mitigation strategies to address these risks.

- **Pipeline Infrastructure:** As the recent volatility regarding MVP's legal chances of success has indicated, new gas pipelines and associated infrastructure have been increasingly challenged through every permit approval required. The ability to bring additional gas supply to the Carolinas via pipelines is important for reliability and to aid in the success of Companies' clean energy transition. The Companies have many years of successful experience of brownfield replacement of coal facilities with natural gas assets – which has been the largest contributor of carbon reductions to date, but adequate gas supply is the largest risk. The Companies can somewhat mitigate this risk with sufficient fuel storage to cover fuel needs over short winter peaks. If Congress passes more substantial permitting reform, risks may be reduced for pipeline development. It should be noted that to ultimately decarbonize the natural gas fleet, there will likely need to be new pipelines for each hydrogen and/or CO_2. It would be very difficult to execute such a buildout of new pipeline infrastructure in the current litigious environment.

- **Tightening Permitting standards**: The EPA's CAA Section 111 Proposed Rule, as discussed in this Appendix, Appendix C (Quantitative Analysis), and in Chapter 4, may impact future operations of gas assets pending rule finalization. As discussed above, the proposed rule calls for capacity factor restrictions, hydrogen use or CCS for operations through the 2030s.

- **Supply Chain constraints:** With the entire U.S. electric industry facing the same issues discussed in Chapter 1 (Planning for a Changing Energy Landscape), supply chain constraints for gas generation resources will continue to have an impact on the generation transition timing. For example, transformer suppliers reportedly have 2.5-year lead times. These constraints in supply chain will need to be closely monitored and planned for in the development of future resource plans and associated execution plans.

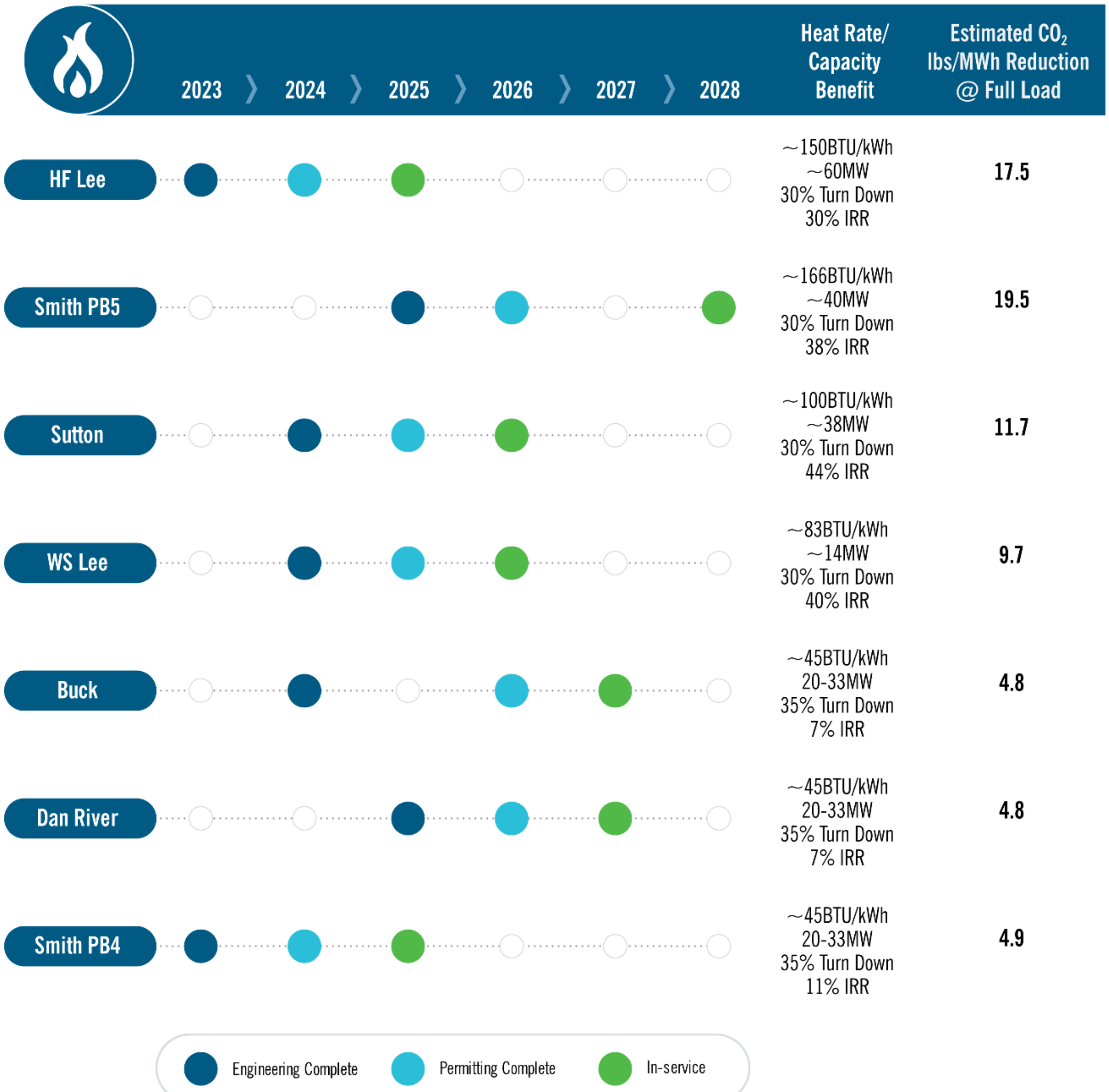
Other Gas Activities

Increased Flexibility of existing CT/CC Assets

In response to regulatory directives, the Companies have been screening and performing business cases on potential flexibility/uprate projects for the existing CC fleet. The Companies have arrived at potential uprate projects which will achieve additional unit flexibility while also increasing efficiency and generation capacity.

Unit flexibility will be achieved within the scope of the Company's proposed Unit Upgrades/Heat Rate Improvement projects which will provide increased output, efficiency and flexibility offered with the ability to increase turndown from approximately 50% (of rated output) to 30–35% range depending on the technology. Lower minimum loads allow more integration of renewables, and increased load range allows the system to avoid short duration cycling of peaking resources, which can help reduce maintenance costs. The projects are proposed at seven existing DEC and DEP CCs and are estimated to increase winter capacity by up to 251 MW of needed dispatchable capacity. The projects are to be implemented within the normal maintenance cycle to ensure cost prudency and are currently planned for an in-service year range of 2025–2028. In addition, the associated Heat Rate improvements will increase efficiency, lower fuel costs for customers and, if all implemented, provide an estimated collective CO_2 emissions reduction of approximately 30 tons per hour at full load operation. Due to the low implementation costs and the multi-pronged benefits, the following proposed Unit Upgrades/Heat Rate Improvement projects, listed below in Figure K-1, were assumed in the modeling.

Figure K-1: Planned CT Flexibility/Uprates of Existing CCs



Belews Creek 100% Gas Conversion

The Companies performed modeling to assess the economics of converting the Belews Creek units to 100% gas and cease burning coal. Year-round interstate FT would be needed to provide reliable capacity after removing coal as a back-up fuel. Without increased interstate FT rights, DEC could not count the winter capacity of Belews Creek (~2,220 MW) toward its reserve margin.

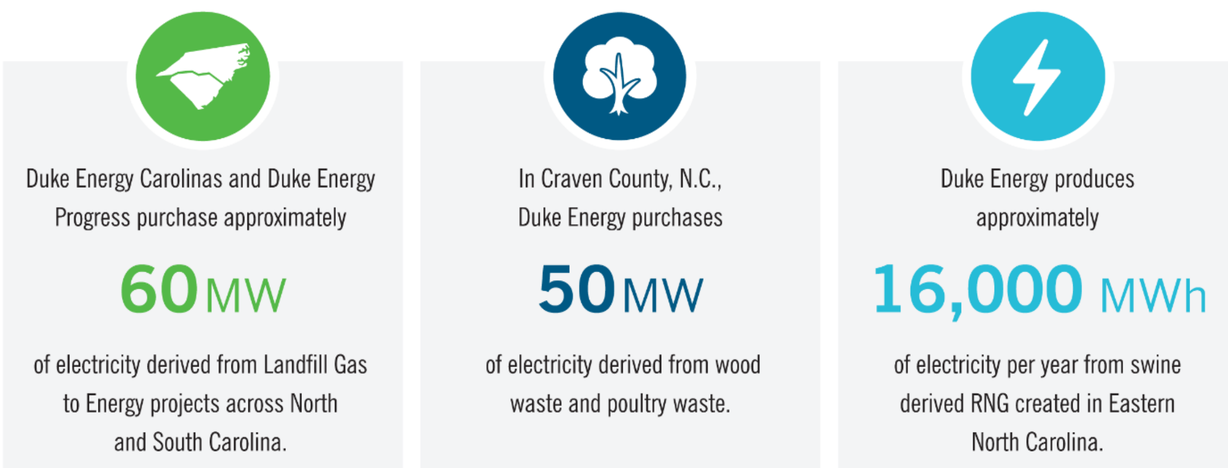
While the estimated costs to convert the station to be capable of burning 100% gas are approximately $40 million, the large hurdle would be the cost for interstate FT, which over 15 years would be approximately $5 billion. DEC derived this estimate using 500,000 MMBtu per day from the Gulf Coast on a minimum 15-year contract running from pipe in-service (estimated term of 2029–2046). Also, the conversion would take approximately four to five years to implement, which would put the station on 100% gas in 2029 at the earliest, assuming an early 2025 project start. DEC's analysis showed unfavorable economics for the potential expansion project. Modeling results can be found in Appendix C.

Low-Carbon Fuels

Renewable Natural Gas

The Companies continue to produce electricity from and physically receive renewable natural gas ("RNG") from various waste sources. Today, RNG is mainly sourced from anerobic digestion processes for waste-based feedstocks (e.g., landfills, wastewater, food waste, and animal manure), which are expected to become more plentiful over time. Figure K-2 below shows some of the current RNG consumption facilities in the Carolinas.

Figure K-2: Current Renewable Natural Gas/Low-Carbon Fuel Consumption Facilities



The Companies continue to explore future potential low-carbon fuel opportunities. The current barriers to low-carbon fuel technologies continue to be limited and inconsistent feedstock production volumes, regulatory uncertainty, quality specifications, drop-in fueling capabilities, and cost. As a result, many low-carbon fuel opportunities are in the early stages of development and are not cost-effective to implement at the present time.

Hydrogen

The Companies have been actively evaluating and planning for clean hydrogen production and utilization. Hydrogen can be produced in a variety of ways and the carbon intensity of hydrogen is very dependent upon the method of production. Power sources – such as natural gas, nuclear power, biomass, and renewable power like solar and wind – determine its carbon intensity. The most common production methods are natural gas reforming (a thermal process) and electrolysis. Other methods include solar-driven and biological processes.

Among other emerging technologies, the Companies have been focused on clean hydrogen produced by electrolysis. This process uses electricity to split water molecules into hydrogen and oxygen, so the only by-product is oxygen. There has been a focus to advance electrolyzer manufacturing and technology to reduce costs and increase the efficiency.

Combustion Turbine Hydrogen Firing Capabilities

Existing Units

Currently most of the Companies' CTs, in both simple cycle and CC configurations, are capable of firing varying blends of hydrogen with limited modifications – generally in the 10-30% range, to the extent hydrogen could be safely delivered. Such modifications could include new hydrogen capable combustors, new fuel piping, a new hydrogen and natural gas mixing skid, and control upgrades. Based on vendor conversations, the Companies assumed that the current emissions control systems are adequate for hydrogen cofiring.

New Units

The major CT vendors have all stated they are planning to have 100% hydrogen capable CTs available by 2030. While 100% hydrogen capable CTs with advanced dry low emissions/dry low NOx combustion technologies are under development, the Companies have estimated the incremental cost increases to design and construct 100% hydrogen capable CTs in both simple cycle and CC configurations. Increased cost categories include engineering, upgraded CT, support systems, and construction.

Inflation Reduction Act of 2022 and Hydrogen

The IRA provides significant incentives for clean hydrogen production. These incentives are tiered based upon the carbon intensity of the hydrogen produced. The carbon intensity is based on the Argonne GHG, Regulated Emissions and Energy Use in Transportation ("GREET") model, which considers well to gate CO_2 emissions. These incentives have the potential to greatly reduce the delivered cost of clean hydrogen. More detail can be found below in Table K-2.

Table K-2: IRS Section 45V – Hydrogen Production Tax Credits ("PTC")

Lifecycle Greenhouse Gas Emissions[1] ($kgCO_2/kgH_2$)			PTC ($/kg) – 2022 Shall Be Inflation Adjusted	
Less than or equal to	Equal to	% PTC	Non-Qualified Clean Hydrogen Facility	Qualified Clean Hydrogen Facility[2]
4	2.5	20	0.12	0.60
2.5	1.5	25	0.15	0.75
1.5	0.45	33.4	0.20	1.00
0.45	-	100	0.60	3.00

Note 1 : The term 'lifecycle GHG emissions' shall only include emissions through the point of production (well-to-gate), as determined under the most recent GREET model developed by Argonne National Laboratory, or a successor model (as determined by the Secretary).
Note 2 : Qualified Clean Hydrogen Production Facilities - owned by the taxpayer, construction of which begins before January 1, 2033, payment of prevailing wages and meet apprenticeship requirements.

Department of Energy Regional Hydrogen

The Infrastructure Investment and Jobs Act ("IIJA") allocated $8 billion to develop a number of hydrogen hubs across the country. The Companies led the HyBuild Carolinas[3] hydrogen evaluation and are one of the five utilities leading the Southeast Hydrogen Hub coalition in its pursuit of IIJA funding to construct a multi-state hydrogen network.[4] One of the main goals of the federally incentivized hydrogen hub program is to catalyze hydrogen production and use and to jump start the hydrogen economy. In addition to increasing the supply of clean hydrogen, it is expected that the hubs will facilitate positive downward pressure on the cost of clean hydrogen.

The regional hub concept is a network in which hydrogen producers and consumers are located in close proximity and are connected via local infrastructure. The proposed Southeast hydrogen hub consists of approximately twenty nodes (points of hydrogen production or consumption). The majority of the Companies' proposed production nodes are co-located at generation facilities. This co-location would provide a ready supply of clean hydrogen that can be blended with natural gas to fuel gas generation at the site.

A hydrogen energy ecosystem has potential to provide abundant, reliable, and resilient energy for customers and communities. The Southeast Hydrogen Hub would benefit the region by providing thousands of construction jobs and hundreds of full-time jobs to operate and maintain the hub and its associated infrastructure and projects as well as by expanding economic development opportunities to local communities.

[3] Green Hydrogen Coalition, HyBuild™ Carolinas, available at https://www.ghcoalition.org/hybuild-carolinas.

[4] Duke Energy, Southeast Hydrogen Hub Coalition Submits Formal Application for Funding to the U.S. Department of Energy, April 2023, available at https://news.duke-energy.com/releases/southeast-hydrogen-hub-coalition-submits-formal-application-for-funding-to-the-u-s-department-of-energy.

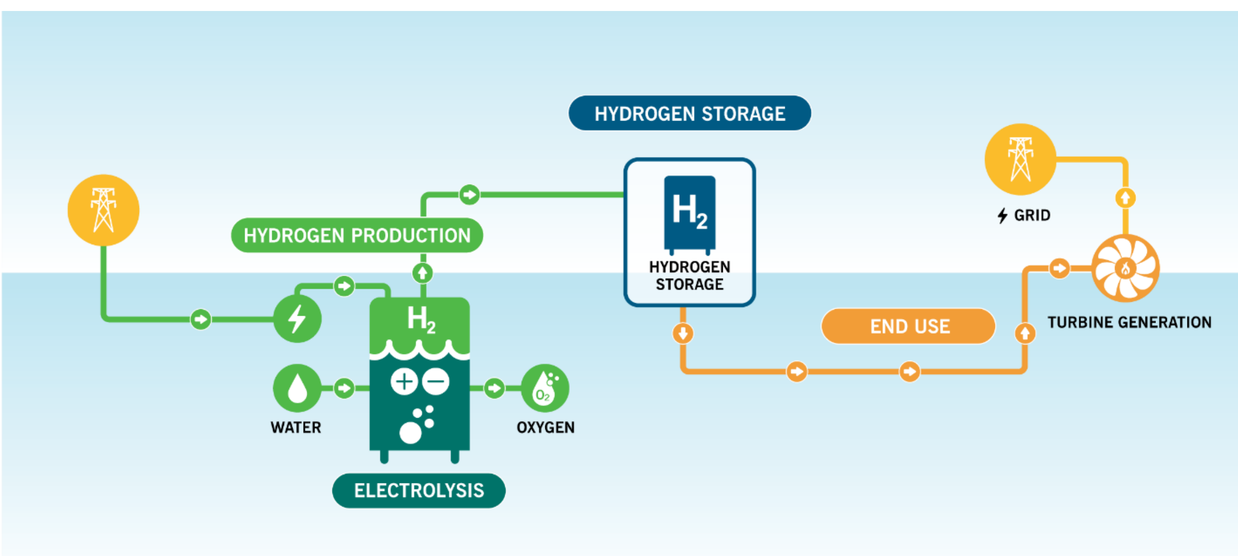
The DOE is expected to select applicants to proceed with negotiations in the late summer/early fall 2023.

Hydrogen Production with Electrolyzers

Electrolysis is the process of using electricity to split water into hydrogen and oxygen. This reaction takes place in a unit called an electrolyzer. Electrolysis produces carbon-free hydrogen from renewable and nuclear resources, and is also a leading hydrogen production pathway to achieve the DOE's Hydrogen Energy Earthshot goal of reducing the cost of clean hydrogen by 80% to $1 per 1 kilogram in one decade.[5]

Electrolyzers can range in size from small, appliance-size equipment that is well-suited for small-scale distributed hydrogen production to large-scale, central production facilities that can be powered by grid, renewable or nuclear energy. Electrolyzers consist of an anode and a cathode separated by an electrolyte. Different electrolyzers function in different ways, mainly due to the different type of electrolyte material involved and the ionic species it conducts. Alkaline electrolyzers that utilize a liquid alkaline solution of sodium or potassium hydroxide as the electrolyte have been commercially available for many years. Solid oxide electrolyzers use a solid ceramic material as the electrolyte. Solid oxide electrolyzers must operate at temperatures high enough for the solid oxide membranes to function properly (about 700°– 800°C, compared to polymer electrolyte membrane ("PEM") electrolyzers, which operate at 70°– 90°C, and commercial alkaline electrolyzers, which typically operate at less than 100°C). Figure K-3 below depicts the electrolysis process.

Figure K-3: Electrolysis Process: Clean Hydrogen Production and Storage System



[5] U.S. Dept. of Energy, Office of Energy Efficiency & Renewable Energy, Hydrogen Shot, available at https://www.energy.gov/eere/fuelcells/hydrogen-shot.

A PEM electrolyzer utilizes an electrolyte that is a solid specialty plastic material. PEM electrolyzers are commercially available and are of interest due to their ability to quickly respond to variable grid conditions expected with increasing amounts of renewable generation.

The Companies are actively pursuing hydrogen through thoughtful and real projects. The demonstration described below will utilize PEM type electrolyzers and gaseous storage of hydrogen.

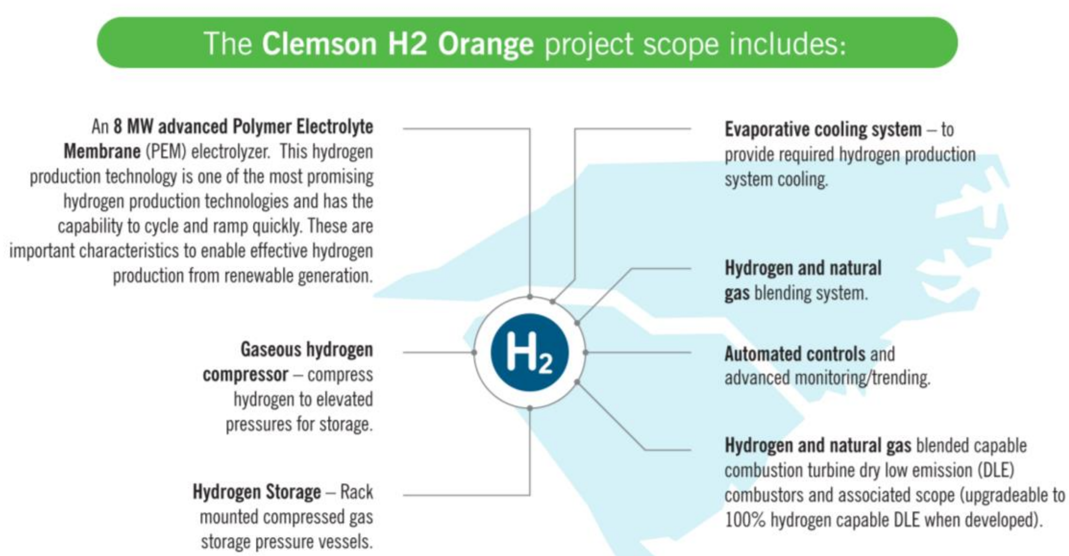
Clemson H_2 Orange

This proposed Hydrogen Project is a demonstration site with utility-scale hydrogen production, storage, and CT co-firing located at the Clemson combined heat and power ("CHP") plant on the Clemson University Main Campus.

This operational demonstration will test the dispatchable operational capabilities of an integrated hydrogen production, compression, storage, and generation system and define the future development requirements and operational needs to reduce the technology introduction risk for a utility-scale system. The project is a collaboration between Clemson University, Siemens Energy and the Companies, and the collaboration provides many benefits, including reduced project costs and access to academic research. The project has also benefited from a DOE award that helped to fund initial engineering, integration plans, cost estimates and scope definition.

Learnings will include improved understanding of the required capital expenditures, operations and maintenance costs, operational procedures, safety practices, future workforce needs and environmental and social impacts of this type of facility. This project also supports future needs identified in the Companies' resource plans.

Figure K-4: Clemson H_2 Orange Project Scope



The proposed project system, shown above in Figure K-4, will produce hydrogen fuel that the existing CHP plant can use to produce electric power for the Companies' electric system.

Low-Carbon Fuels Execution and Risk Management

Significant industry investments into research and development as well as operational pilot programs will be required by 2030 and beyond to make clean hydrogen a viable option to support the clean energy transition. Operational pilot programs and demonstrations are needed to further advance the technology and commercial feasibility of hydrogen. The current Clemson/Siemens/Duke Energy/DOE-supported studies can be economically expanded to a scalable demonstration phase and serve as a test bed to advance hydrogen production and storage technologies. Similar demonstrations with other technologies and use cases should also be considered. Duke Energy continues to evaluate relevant demonstrations and use cases that leverage available technologies and reflect the current market.

In the near-term, Duke Energy will continue to focus on studies and demonstrations that aim to advance the understanding and development of hydrogen production, storage, transportation, and generation. This work may allow the Companies to explore the possibility of converting existing natural gas generation assets to hydrogen and natural gas blends, or full hydrogen in the future.

Currently, the most significant limitations to the adoption of hydrogen as a clean energy transition solution are the cost of production, storage, transportation, and the volume of supply. The DOE has set aggressive targets for the production cost of hydrogen ($1/kg in one decade).[6] Meeting this target will require a combination of technology costs and performance improvements as well as lower energy costs to power hydrogen production. Hydrogen storage and transportation capabilities must be expanded, and the associated costs reduced. Beyond DOE's Earthshot, EPA's CAA Section 111 Proposed Rule would require tremendous hydrogen volumes to be produced, delivered, and stored to meet the 2032 and especially 2038 compliance deadlines to the extent the hydrogen pathway is chosen for compliance. Costs, supply chain constraints, logistical project timing and permitting would all present barriers for significant hydrogen use by 2032 and 2038.

[6] U.S. Dept. of Energy, Hydrogen Shot, available at https://www.energy.gov/eere/fuelcells/hydrogen-shot.