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Mar 29 2022

March 29, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Third Stakeholder Meeting Summary Report
Docket No. E-100, Sub 179

Dear Ms. Dunston:

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke Energy" or the "Companies") hereby provide this update to the North Carolina Utilities Commission ("Commission") regarding the Companies' ongoing Carbon Plan stakeholder engagement process as contemplated by Part I, Section 1.(1) of Session Law 2021-165 ("HB 951") and the Commission's November 19, 2021 *Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines* ("Carbon Plan Procedural Order"). Among other things, the Carbon Plan Procedural Order directs the Companies to conduct at least three stakeholder meetings targeted to gather and incorporate stakeholder input as the Companies develop their initial Carolinas Carbon Plan to be filed with the Commission on May 16, 2022, and to file a report with the Commission within five business days after each stakeholder meeting.

On March 22, 2022, the Companies held the third and final full Carbon Plan stakeholder meeting. Approximately 130 Duke Energy representatives and 275 external stakeholders attended the session, and stakeholders engaged in a robust discussion.

At this third meeting, the Companies responded to input from the second stakeholder meeting regarding stakeholders' desired outcomes from the Carbon Plan and discussed ongoing development of the Companies' "grid edge" programs (including energy efficiency, demand response, distributed energy resources, and others) as well as the Companies' ongoing analysis and methodology for estimating potential transmission cost impacts arising from the Carbon Plan. The Companies also hosted two additional presentations by non-Duke Energy personnel. First, Mr. Rich Wodyka, consultant to the North Carolina Transmission Planning Collaborative ("NCTPC"), provided a process overview on the NCTPC. Second, in response to request from the Clean Power Suppliers

Association ("CPSA"), the Companies allotted time to CPSA's consultant to present its preliminary modeling results.

Finally, the Companies provided an update on their modeling and preliminary portfolio development efforts. This update included detailed information concerning key modeling assumptions and selectable resource options. The Companies' presentation also provided significant new information on the Companies' potential Carbon Plan portfolios and pathways to achieve 70% carbon emissions reductions under a range of potential future conditions.

As directed by the Carbon Plan Procedural Order, the Companies hereby submit their Third Carolinas Carbon Plan Stakeholder Meeting Summary Report ("Summary Report"), which provides an overview of the third Carbon Plan stakeholder meeting and a summary of topics discussed. As previously explained, the Companies have retained Great Plains Institute ("GPI") to serve as the facilitator of the stakeholder process, and GPI prepared the Summary Report for the Companies (included as Attachment 1). In addition to the Summary Report, the Companies are submitting the materials presented to stakeholders (included as Attachment 2) during the March 22 Stakeholder Meeting. The materials in Attachment 1 and Attachment 2 will also be posted on the Companies' dedicated website (www.duke-energy.com/CarolinasCarbonPlan).

Like the first and second stakeholder meetings, the third stakeholder meeting received substantial participation, and the Companies appreciate the engaged participation and diverse feedback that has been provided throughout each meeting. The Companies look forward to further engagement with interested stakeholders across the Carolinas as these critical issues related to the Companies' system-wide energy transition are considered. Interested stakeholders may contact GPI at DukeCarbonPlan@gpisd.net to receive future communications about the ongoing stakeholder process.

The Companies have also developed plans for further Carbon Plan data sharing and presented preliminary information concerning such plans at the March 22 Stakeholder Meeting. On the same day, the Commission issued its *Order Regarding Data Inputs and Assumptions, and Scheduling Additional Update on Stakeholder Process Sufficiency* ("March 22 Order"). The plans described by the Companies in the March 22 Stakeholder Meeting are largely consistent with the requirements of the Commission's March 22 Order. The Companies are continuing to evaluate the March 22 Order and will make a subsequent filing concerning its plans in this respect.

If you have any questions, please do not hesitate to contact me. Thank you for your attention to this matter.

Sincerely,

Jack Jirak

Jack E. Jirak

cc: Parties of Record

Attachments

Duke Energy's Carolinas Carbon Plan Stakeholder Meeting Summary Report

Meeting 3

March 22, 2022 | 9:30 am to 4:30 pm ET

Contents

Meeting Summary

On Tuesday, March 22, 2022, the Great Plains Institute (GPI)[1] convened the third of three stakeholder meetings (plus three additional technical subgroups meetings) to inform the development of Duke Energy's Carolinas Carbon Plan. The meeting was held virtually from 9:30am to 4:30pm Eastern. There were approximately 407 individuals who attended the meeting. The full list of attendees is attached to this summary document.

All interested parties were welcome to attend this meeting. To solicit participation, GPI initially sent invitations to a list of over 900 stakeholders provided by Duke Energy and those that have asked to be added to the email distribution list. Recipients were encouraged to pass on the invitation to other stakeholders who they felt may be interested in the process.

Process Employed

PROCESS OBJECTIVES

Overall, this series of three meetings was designed to meet the following objectives:

1. Ensure the Carolinas Carbon Plan is informed by input from a wide range of stakeholders.
2. Enable a transparent conversation about how to plan an energy transition that prioritizes affordability and reliability for North Carolina and South Carolina customers.
3. Build on areas of agreement, clarify areas of disagreement, and seek opportunities for collaboration in advance of filing the Carolinas Carbon Plan.

MEETING 3 OBJECTIVE AND CONTENT COVERED

This third stakeholder meeting was designed to respond to stakeholder requests and feedback that arose during the first meeting two meetings as well as the three technical subgroup meetings. Below, we have described each major section of the agenda and highlights of the content covered.

1. **Duke Response to Stakeholder Desired Outcomes**

During this section of the agenda, Duke Energy staff provided an update on the Carbon Plan development process and responded to the stakeholder desired outcomes that were put forth by stakeholders in Meetings 1 and 2.

On the Carbon Plan development process, Duke Energy staff clarified that on April 15th, they will provide a subset of draft preliminary modeling inputs to all intervenors that have signed an NDA, and will provide the final modeling inputs on May 16th.

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[1] GPI has been hired by Duke Energy to serve as a third-party convener and facilitator for the stakeholder engagement process to inform development of the Carbon Plan.

On the Stakeholder Desired Outcomes, Duke Energy Staff described how each desired outcome would be addressed in the following phases of the Carbon Plan development process or in other workstreams:

- Development of the proposed plan
- Issuance of the plan by the Commission
- Execution of the plan
- Other workstreams related to but outside of the plan itself

Duke Energy staff also noted that the Carbon Plan development process will repeat every two years, allowing the opportunity to iteratively refine the plan over time.

2. Discussion on Grid Edge and Customer Programs

During this section of the agenda, Duke Energy staff provided an update on the various programs and offerings that Duke has in place and is developing to support energy efficiency, demand response, integrated volt-var control and distribution system demand response, rate design, and distributed technologies. Duke Energy staff also clarified the extent to which these offerings will be included or addressed in the Carbon Plan. This section was intended to respond to stakeholder requests for more information on demand-side considerations and distributed energy resources.

3. Overview of the Methodology to Develop Transmission Impact Estimates to be Used in the Carbon Plan

This section of the meeting, and the next section, were designed in response to stakeholder requests to hear more about transmission expansion, including how Duke plans to address that in the Carbon Plan and how the North Carolina Transmission Planning Collaborative process works.

Duke Energy staff presented on the methodology and context for transmission impact estimates in the Carbon Plan, clarifying that they will use proxies for the location, size, and sequence of resource additions to estimate impacts, based on studies and past transmission interconnection requests.

4. Overview of the North Carolina Transmission Planning Collaborative (NCTPC)

In this section, Rich Wodyka, independent third-party advisor to the NCTPC, presented on the history, roles, process steps, and current work of the collaborative. Wodyka clarified that the NCTPC has its own annual timeline that may not allow perfect integration of the collaborative process and the Carbon Plan, but that the collaborative members are watching the Carbon Plan process closely over time the two would be able to inform one another.

5. Clean Power Suppliers Association and Brattle Group Presentation of Carbon Plan Modeling

During this section, Tyler Norris of Cypress Creek Renewables on behalf of the Clean Power Suppliers Association (CPSA) and Mike Haggerty of the Brattle Group presented modeling that CPSA hired the Brattle Group to complete to inform stakeholder discussions around the Carbon Plan. The modeling was designed to analyze the least-cost future resource mix that achieves a

70 percent reduction in emissions from Duke Energy's North Carolina power generation plants by 2030, looking at the full Duke Energy system in North Carolina and South Carolina through 2035.

The modeling found that by 2030, to meet the 70 percent target at least cost, Duke would need to add 11,690 MW of utility-scale solar, 900 MW of onshore wind, 2,000 MW of 4-hour battery storage, and 3,200 MW of combined cycle gas generation. Haggerty clarified that the gas combined cycle generation addition may be overestimated compared to modeling that would look towards 2050.

6. Duke Update on Modeling and Development of Potential Pathways

In the final session of the agenda, Glen Snider of Duke Energy provided an update on Company's preliminary draft modeling inputs and assumptions for the Carbon Plan as well as a set of preliminary draft pathways to least-cost compliance under consideration. Snider showed that several inputs and assumptions had been updated in response to stakeholder feedback from the previous two stakeholder meetings, as well as the three technical subgroup meetings.

For the modeling pathways (collections of resources from which the model may select to find the least-cost pathway that complies with the carbon reduction requirements), Snider presented three different preliminary draft pathways under consideration, each with two versions based on more or less availability of Appalachian gas:

- 70 percent by 2030 with limited offshore wind and no new nuclear
- 70 percent by 2032 with additional offshore wind and no new nuclear
- 70 percent by 2034 with new nuclear and no additional offshore wind

Importantly, offshore wind and new nuclear are specifically called out in these pathways because HB 951 allows more flexibility to meet the interim target if those specific resources are needed.

GROUND RULES

To support a constructive meeting environment, GPI established and asked all attendees and panelists to agree to the following ground rules for this and future meetings:

- **Respect each other**: Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.
- **Focus on values and outcomes**: Today's discussion is about what stakeholders value in the energy future, and how the Carolinas Carbon Plan can align with those values. Pending legal issues are outside the scope of this conversation.
- **Chatham House Rule**: Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).
- **Respect the time**: Our time together is limited and valuable, and we have a large group, so please be mindful of the time and of others' opportunity to participate.

- **Use the chat:** Please submit your comments and questions in the chat. GPI staff will monitor the chat to pull out questions for Q&A portions. Please be respectful and focus on issues, not people.
- **Raise your hand**: During dedicated Q&A portions of the meeting, use the "Raise Hand" feature to indicate you would like to voice a question or comment.

MEETING LOGISTICS AND PARTICIPANT INTERACTION

The meeting was held via Zoom Webinar. Stakeholders were allowed to freely chat one another and speakers and facilitators. They were also allowed to raise their hand to be unmuted and ask questions or provide their thoughts orally during Q&A and discussion portions of the meeting. Staff from GPI facilitated the meeting and took meeting notes, which are included in this summary. In keeping with the ground rules detailed above, the meeting notes have been anonymized. GPI will also be sending an anonymized export of the meeting chat to meeting attendees. The meeting was recorded for the purpose of sharing the presentations, however in keeping with the ground rules, the Q&A and discussion portions of the recording will not be shared. The meeting recordings will be posted on the Duke Carbon Plan webpage[2]

Identifying Points of Consensus

As with the first two stakeholder meetings, this meeting was not designed to drive towards consensus given the large number of participants. Instead, facilitators sought to provide the opportunity for stakeholders to express their thoughts through the chat and orally during the Q&A and discussion portions of the meeting. All comments and questions have been recorded so that Duke Energy can consider them in developing the Carbon Plan.

Accessing Meeting Materials

All meeting materials, including the agenda, slide decks, recordings of the presentations, and meeting summaries will be posted on the Carbon Plan website at www.duke-energy.com/CarolinasCarbonPlan.

In addition, stakeholders are encouraged to send additional feedback and comments to inform the development of the Carbon Plan to DukeCarbonPlan@gpisd.net.

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[2] www.duke-energy.com/CarolinasCarbonPlan

Meeting Notes

I. Welcome, Introductions, Process Updates

Doug Scott, Great Plains Institute

1. Overview of today's agenda and meeting ground rules.
2. Participant introductions via chat.

Swati Daji, Duke Energy

3. Welcome from Duke Energy
    a. Appreciate the time commitment and engagement on these complex and important issues.
    b. Duke values stakeholder feedback and sees it as a business imperative to listen, thoughtfully consider other views, share their view, be challenged on that view, and incorporate stakeholder feedback.
    c. Duke has changed inputs and assumptions to the modeling in response to stakeholder feedback. Examples include the following:
        i. Have significantly expanded the utility scale solar interconnection limits
        ii. Re-assessed timing of the inclusion of resources in the portfolios, including offshore wind and new nuclear.
        iii. Counting carbon emissions as if all fossil plants are located in North Carolina.
        iv. Will be sharing what we are seeing as initial portfolio options.
        v. While today is the final stakeholder meeting, stakeholder engagement will continue on a vast array of issues, including solar procurement, energy efficiency and demand response, and others.

II. Duke Response to Stakeholder Desired Outcomes

Duke Energy Staff: Rebecca Dulin, Jack Jirak

Facilitated by Doug Scott, Great Plains Institute

1. Carbon plan development process
    a. Today is the last day for this specific process, but there will be ongoing stakeholder engagement activities.
    b. There will be an additional meeting on community and environmental justice impacts – looking to schedule in April.
    c. From April through mid-May, Duke will be working to finalize modeling pathways and results.
    d. On April 15th, Duke will provide a subset of draft preliminary modeling assumptions. On May 16th, will provide the full set of final modeling assumptions.

    i. These will be made available to all intervenors that have signed a non-disclosure agreement (NDA) as the data contains confidential information.

e. What to expect in terms of next steps for this process:
    i. Commission has already provided some details on what happens after May 16th in their orders, including the following:
        1. Opportunity to provide written comments in the docket
        2. Public hearings around the state, including one virtual hearing.
        3. Process by which parties can file technical comments and alternative proposals within 60 days of May 16th (July 15th)
    ii. There will also be opportunities for discovery, in which all parties seek to understand other parties' viewpoints and assumptions.

f. Q&A
    i. Will the final modeling assumptions include the full and complete EnCompass data?
        1. Yes, though an NDA will be required for confidential information. The bulk of the body of the Carbon Plan will not be confidential.
    ii. Will non-intervenors that have signed an NDA have access?
        1. Still working on the best way to handle that – still under development.
        2. Will provide more communications soon on the mechanics of executing NDAs.
    iii. What specifically will be provided on April 15th?
        1. Still working through that and will provide more details soon. Seeking to provide information that has been requested by stakeholders.

2. Stakeholder Desired Outcomes
    a. Three phases of carbon plan development and execution:
        i. Development of proposed plan
        ii. Issuance of the plan by the NCUC
        iii. Execution of the plan
        iv. NOTE: This process will repeat every 2 years, so the plan will continue to be updated over time.
    b. Outcomes to be addressed in the development of the Carbon Plan:
        i. Engagement
            1. Consider stakeholder input and recognize where changes occurred in response – focus of today and will be discussed in the plan as well.

    2. Identify areas of consensus on as many issues as possible prior to filing.
    3. Integrating outcomes from other stakeholder engagement processes (Clean Energy Plan, Low-Income Affordability Collaborative, Working Group on Climate Risk and Resilience) – will be incorporated as those outcomes are available and applicable.
        a. Also shows up in execution phase.

ii. Modeling
    1. Consider new or expanded customer-facing programs for energy efficiency, DSM, and renewables.
    2. Consider a modeling approach that begins with a few alternative end states that meet the goal.

iii. Analysis
    1. Maintain a long-term view towards achieving a net-zero system (keep the end goal in mind).
        a. Net zero by 2050 is the end state, and the pathways will show variations on the trajectory to achieve that.
    2. Strive to achieve fair and affordable rates and total costs for all customers, including at-risk/low- and moderate-income households and communities.
        a. In the plan, will be showing the different cost implications of pursuing different pathways. Also will be addressed in the execution phase in terms of program development and rate design.
    3. Enhance resilience and grid hardening through changes over time.

iv. Transparency
    1. Transparently present modeling and measurement assumptions, inputs, and tools to the extent possible while protecting trade secret and copyrighted information. Ensure no inherent bias. Include analysis of improvements to the transmission grid.
    2. Transparently present metrics and principles being used to develop pathways and make modeling decisions.
    3. Transparently present the impacts of the plan, including costs.
    4. Clarify policy and regulatory interdependencies with the other components of HB 951.
    5. Clarify consideration of carbon costs and carbon policies in the selected scenarios.
    6. Clarify definition of net zero.

            a. For the next decade, pursuing a plan that has no dependence on offsets, but may be considered later on the path to net zero by 2050.
        7. Clarify the approach to siting facilities between North Carolina and South Carolina.
            a. Siting is not part of the planning phase, but with respect to counting the emissions impacts, Duke is clarifying that for the purposes of the development phase, emissions from all fossil plants will be counted as though sited in North Carolina.

c. Outcomes to be addressed in the <u>execution</u> of the plan:
    i. Siting and community impacts
        1. Take a holistic and intentional approach to the siting of new facilities, avoiding areas already disproportionately impacted by energy generation or other industrial facilities.
        2. Provide support for coal plant host communities to address the economic and community impacts of plant retirements.
        3. Center environmental justice communities in the development of the carbon plan.
    ii. Integrate other efforts
        1. Incorporate recommendations from related stakeholder engagement processes, including but not limited to the Clean Energy Plan stakeholder process, the Low-Income Affordability Collaborative, and the Working Group on Climate Risk and Resilience.

d. Outcomes that are being addressed through <u>other workstreams</u>:
    i. Environmental impacts beyond carbon
        1. Address all greenhouse gas emissions beyond carbon dioxide, including upstream methane leakage from natural gas being delivered to electric power plants.
        2. Consider life cycle assessment of all system resources, including but not limited to construction of infrastructure, etc., to get to net zero
    ii. Grid resilience/hardening
        1. Enhance resilience and grid hardening through changes over time.
    iii. Support a favorable business environment
        1. Support the ability of businesses and industries to operate competitively, preserve existing jobs, and/or to create new jobs.
        2. Consider the carbon reduction goals and plans of cities and businesses in Duke's service territories.

        iv. Affordability for all customers.
            1. Strive to achieve fair and affordable rates and total costs for all customers, including at-risk/low- and moderate-income households and communities.

3. Q&A
    a. Will the modeling include market purchases?
        i. Yes. Long-term purchases already in place will be in the plan, and also recognize the need for short-term purchases, but overall this is focused on Duke's footprint.
    b. In prior discussions the approach Duke articulated was to use a shadow price for carbon in the modeling, and also to attribute larger reductions in Carbon emissions to SC-sited facilities. Is this no longer the approach?
        i. Have decided that, for the purposes of planning, counting emissions from all new carbon-emitting resources as though those resources are located in North Carolina.
    c. It's great to see that the plan will recognize where stakeholder input changed assumptions and what those change were. We've found at the local level that it can also be instructive for stakeholders to understand where input did not change the plan and why. Would it be possible to include/provide this kind of information as well?
        i. Can't promise that every issue will be addressed, but will generally seek to address why requested changes were not made.

III. Discussion on Grid Edge and Customer Programs: Empowering Customers to Reduce Carbon Emissions

Time Duff, Duke Energy

1. Energy Efficiency (EE) and Demand Side Management (DSM)
    a. IRP Forecast – Budget + MPS Blend
        i. Cumulative EE with roll-off – looking at essentially meeting what we think we can do in our IRP for load planning purposes. Roll-off means that for measures that have been installed in the past, the efficiency of those measures is no longer counted as additional efficiency and is instead counted in the load forecast.
    b. Base forecast – 1% of available retail load
        i. Not significantly more than what's in the IRP, but that's because the IRP already had significant levels of energy efficiency. Over time, it adds up to a lot more efficiency than the IRP.
    c. High forecast – 1% of total retail load
        i. Much higher levels of efficiency, especially in the long term.
    d. EE program spending comparison

    i. High forecast shows some increase in EE costs in the near term, but huge increase as you move out towards 2050.

e. IRP forecast -- What makes up the EE forecast?
    i. Behavioral, residential equipment, and non-residential equipment.
    ii. See a significant roll-off effect and fewer gains, because at that point you've reaped the bulk of the physical potential.

f. Base forecast
    i. Amount of physical equipment is increased. The wind-down is less, because seeking to maintain 1% of retail sales over time. See impact of opt-out as you don't have the additional sales on which to apply that 1%.

g. High forecast
    i. The potential from expanding the eligible portion of the retail load on which you can apply the 1% is significant. There is huge dependency on getting customers to participate in EE programs. In other words, subject to market conditions. Have seen impacts from COVID and inflation, so need to continue to find ways to get customers to participate in efficiency programs. Working on this with the EE/DSM collaborative.

h. Putting 1% of retail sales in context.
    i. Carolinas does more than the national average, but have to look in context of annual residential sales. Duke Energy North and South Carolina has among the highest average residential usage, with relatively low electricity rates, so achieving 1% means achieving much higher levels of energy efficiency on a kWh basis than in other states.

i. Moving beyond the Carolinas' base EE/DSM forecast
    i. EE/DSM collaborative has been and will continue to actively discuss these enablers that can increase energy efficiency capabilities.

j. Potential enablers for delivering EE/DSM in the Carolinas.
    i. See full list on slide 25. These are things Duke and stakeholders have identified to unlock more energy efficiency, are not specific initiatives that Duke is proposing at this point.

Stacy Phillips, Duke Energy

2. Demand Response (DR)
    a. DR is like a virtual peaker plant, where Duke compensates customers for the ability to curtail their usage during emergency events or times of high usage. However over-using DR can cause customers to leave programs.
    b. Traditionally have been focused on summer peak programs, but also looking to expand winter capabilities.
    c. Industry evolution
        i. DR 1.0 was manual control and interruptible tariffs
        ii. DR 2.0 is smart thermostats and two-way communication

        iii. DR 3.0 is expanding the use of smart home devices beyond thermostats, providing ancillary services, and deferring or avoiding transmission and distribution investments.

    d. DR plans

        i. Previously, Duke's DR offerings were focused on peak shaving and emergencies, system-level DR, generation avoidance, occasional usage, and summer afternoons.

        ii. In the future, will be adding load shaping and economic shaving, distribution-level DR, T&D investment avoidance/deferral, more frequent usage, and winter mornings and year-round afternoons.

    e. Key enablers

        i. Greater adoption of "low friction" measures – ones that customers will not notice, such as smart home device adoption, including water heaters.

        ii. Building codes, such as requiring DR-enabled water heaters and appliances when commercially available.

        iii. Greater non-residential participation.

        iv. Greater system value, to increase customer incentives.

        v. New summer thermostat use cases, including ramping.

3. Q&A on EE

    a. Does the percentage cost increase refer to program budgets only, or does it include lost revenues and performance incentives?

        i. Only program budgets. All of the other items are dependent on different assumptions around avoided costs and the actual energy savings,

    b. Are you making any assumptions on how technology will improve over time?

        i. The IRP market potential approach looks at technology available today. The 1% is agnostic to technology. It's not tied to any specific technologies known today.

    c. Going forward, are you making assumptions about technology improvements down the road?

        i. Yes, that's right. The 1% is just a more aggressive assumption than what's in the IRP, which is based on current market and technologies.

    d. Is this just Duke programs? It doesn't include EE outside of Duke's purview?

        i. That's right. Load forecast would take into account non-Duke program EE.

    e. Does this include everything that qualifies within the definition of cost effectiveness?

        i. Yes, that's right. Point out that as renewables increase, avoided energy costs will decrease; and as gas prices increase, avoided energy costs will increase. But the 1% of retail sales was not constrained by the economics.

   f. In EE collaborative, will more time be devoted to the Carbon Plan?
      i. Had a special meeting on March 3rd to give the EE collaborative members an update on what Duke is looking at in the Carbon Plan. Acknowledge it may not have been enough time, but EE/DSM is meeting again this week to discuss the Carbon Plan and solicit input.
      ii. Stakeholders outside of the collaborative can always email Tim or other members of the Duke team.

4. Q&A on DR
   a. How do you look at third party aggregators?
      i. We do use them for thermostats, testing one with batteries, and see value in the services they provide.
   b. Duke comment: Very interested in wifi-enabled water heaters.
   c. How are you factoring in DR enables by electric vehicles?
      i. Filed a pilot to do managed charging and agree it's critical, and customer experience needs to come first.

Jay Oliver, Duke Energy

5. Integrated Volt Var Control (IVVC) and Distribution System Demand Response (DSDR)
   a. Voltage optimization programs are the result of previous stakeholder engagement. View them as critical to the Carbon Plan.
   b. Duke Energy Progress (DEP)
      i. Had existing voltage optimization program. Generally the way this works us to flatten voltage profile from beginning to end of circuit, which provides the ability to lower voltage at the substation, which lowers usage. By lowering voltage 2%, you get about 1.4% load reduction (though this varies).
      ii. DSDR program was used for system peaks only, but now transitioning it to apply to 90 percent of the hours in the year for conservation purposes – Conservation Voltage Reduction (CVR). This will result in carbon emissions reductions.
   c. Duke Energy Carolinas (DEC)
      i. Didn't have ability to do voltage optimization. Currently installing that ability, and planning to enable more circuits than originally planned. Will need to install equipment on the distribution grid. Beginning in 2025, should have about 70 percent of available load covered.

Leland Snook, Duke Energy

6. Rate Design and Distributed Energy Technologies
   a. Rate design opportunities
      i. Time of use (TOU) and dynamic pricing
      ii. Intersection with DR

        iii. System beneficial electrification

    b. Rate Design – More Options and Control

        i. Need to update most of current TOU structures because they don't match the present-day system dynamics. On-peak windows are shrinking.

        ii. Also looking at critical peak pricing (penalty structure) and responsive rewards (incentive structure) as a complement to TOU.

        iii. Believe hourly pricing should drive price responsive behaviors. Would like broader and more diverse participation.

        iv. Believe new rate designs will facilitate more opportunities with behavioral demand response, bring your own battery programs, smart device controls, and other options.

        v. Smart electrification – would like to unlock system benefits with TOU/dynamic pricing and smart device bundles. Also looking at tariff on-bill financing and vehicle to home/vehicle to grid.

        vi. Heat map shows clear on-peak, off-peak, and discount periods.

    c. Distributed energy technologies

        i. Distributed solar

        ii. Storage

        iii. Smart thermostats

        iv. Electric vehicles

    d. Regulatory sandbox concept

        i. A space for innovation where you can address regulatory uncertainty by providing leeway from normal regulations for a limited period of time, in a limited environment, to gain clarity on new products and services.

7. Q&A on IVVC, DSDR, rate design, and distributed energy technologies (DETs)

    a. Are you evaluating smart inverters to improve hosting capacity for additional DERs?

        i. Yes, and believe this is important,

    b. Are there cons to CVR?

        i. It requires active management at our control centers. Historically devices have operated themselves in response to power factor getting too high or too low, but CVR requires closer attention to operations from a voltage perspective. But believe benefits outweigh the costs.

    c. The time it takes to turn off CVR and prepare for DR – is there any plan to include inverter-based DR?

        i. When we operate in CVR mode, we're operating in the lower portion of the middle voltage band (118-120). Can do directly to peak shaving mode from there and operate in the lower voltage band (116-118). Can also do something similar to charging up a home with cool or warm air – turn off CVR and operate in a higher voltage band, and then when peak hits go down to the lower voltage band. Will be testing all of this to figure out what worked best and when.

d. What does subscription management of DETs mean?
    i. If you look at managed charging for EV's, it's subscription to EV charging with a fixed price, and Duke has the ability to use the charger for load management.

e. Any plans to make real time energy generation visible similar to California CAISO?
    i. CAISO is effectively an operating market. We don't have that now, but we do make hourly information available a day ahead to participants in those programs. That type of information availability would continue.

f. What are the values of the heat map?
    i. Used cost duration curve for the system. Green areas are low price periods – that's where you get discount pricing periods. Yellow would be off-peak, and red would be on-peak when pricing is most expensive. It's not just hourly fuel costs, it's also how those hours affect operations and drive capacity.
    ii. Values aren't shown here, but they are in the comprehensive rate design study. The R-TOU-CPP rate is an approved rate, so those numbers are publicly available. Don't have them at hand right now.
    iii. Values are boiled down to a cost per kWh by hour – there are multiple components that make up that cost.

g. Could you provide more detail on what kind of rate design changes you are referring to?
    i. These are laid out in the rate design study. TOU is a foundational issue and it intersects well with the carbon plan and changes we're going through from a system standpoint. Unlocking technology is important. Need to update programs and make them available to a broader group of customers.

h. Are you looking at default TOU?
    i. Generally wanting residential rates to be voluntary. Think the new TOU pricing will be attractive, so not yet looking at default. Believe in customer choice.

i. Is the heat map for a system with 12GW of solar?
    i. It's based on the estimated grid mix in 2030, including solar.

j. Would the sandbox require legislation?
    i. It most likely would, depending on the specific details. A broad sandbox would require legislation, though something more narrow within the NCUC's purview might be doable by the Commission without legislation.

k. Integrated system operation and planning (ISOP) – are you looking at how distributed energy resources and ISOP could be factored into the cost effectiveness of DER programs?

   i. It's iterative. We do look at things like T&D deferral based on something like a battery for energy storage. Do have some successful projects on that. There could be opportunity in the future, even for demand response programs for T&D deferral. We're aware of that and are studying it. Have some experience and are looking to do more going forward.

l. Is there a breakout of different rates and incentives for MHD vehicles?

   i. Residential will have options specific to in-home charging. Will need to develop programs specific to DC fast charging. For fleets, looking at hourly pricing.

m. What about make-ready programs for things like water heaters or electric vehicles? Are you thinking about that?

   i. Yes. One example would be a new program in North Carolina to enable customers to more easily transition to electric vehicle charging, by helping customers pay for improvements behind the meeting to let them use a 240v charger, instead of a 120v. Some advantages for managed charging.

   ii. Have not yet looked at make ready for other types of programs.

n. Have you looked at including DER resources in CVR to avoid capital costs of new voltage regulator and capacitor and O&M of regulator and capacitor switching?

   i. Not necessarily. The key is we have to full control of those resources to be able to use them.

o. Previous content from Duke indicated that DER adoption forecasts were reliant on existing tariffs, but this slide indicates that rate design changes will "enable distributed energy technologies." Should we understand this disconnect as a limitation of the modeling approach?

   i. In carbon planning, have an expanded forecast based on suite we're bringing forward where rate design would enable use of DERs.

p. Are you looking at the impacts of new rate designs on existing net metering programs?

   i. We believe the suite of net metering reforms we've proposed will help to continue to see robust adoption of solar over time.

q. How is power quality maintained while reducing voltage particularly for customers with hi tech equipment

   i. Whole idea of voltage optimization is to maintain voltage at a steady level. We don't go down to the lower levels unless it's a peak shaving event, so customers should not notice any power quality issues. If there are issues, we can address them.

r. Has Duke studied/considered the long term impacts on equipment performance and manufacturer warranties for increased use of voltage reduction?

   i. Have experience running a CVR program in another jurisdiction for 6-7 years and have not seen any unexpected effects or premature failure of equipment.

- s. Peak on slide 41 – is that both DEC and DEP?
    - i. Yes
- t. Do current rates send a price signal that summer is more expensive than winter, and is there a plan to fix that?
    - i. The system has changed. Our current TOU periods are summer peaking, but winter planning, and that is evolving. Will need to see the results from a future cost of service study, but it could change.

IV. Overview of the Methodology to Develop Transmission Impact Estimates to be Used in the Carbon Plan

Rebecca Dulin, Duke Energy

1. Context for the next two sessions
    - a. Stakeholders have asked to hear more about transmission expansion and how Duke plans to address that in the carbon plan. Also heard that it's of interest for somebody to provide a primer on the North Carolina Transmission Planning Collaborative process. That's the intention for these two sessions.

Sammy Roberts, Duke Energy

2. Carbon Plan Transmission Cost Estimates
    - a. Development of transmission impacts and cost estimates have several determinants, such as location and size. The impacts and cost estimates will become more well known as the carbon plan implementation process moves forward. In the meantime, need to use proxies for location and size based on transmission planning studies and generator interconnection system impact studies.
    - b. Duke will continue to refine the impact and cost estimates as more information becomes available.
3. Carbon plan associated transmission considerations
    - a. Locating a resource in the red zone or on a greenfield site would likely require significant upgrades; locating outside the red zone or on a brownfield site would require little to no upgrades.
    - b. Sequence of interconnections also matters. Some resources such as solar will interconnect sooner than other resources like offshore wind.
    - c. Generation retirements and changing load forecasts can also change transmission impacts and planning considerations.
    - d. Need to keep in sight the longer-term view so that we're building the system that's needed to run a net-zero grid by 2050.
4. NCUC 2020 IRP Order
    - a. The Commission concludes that in developing their Carbon Plan for 2022 and for future IRPs DEC and DEP should:

        i. Continue to follow the directive contained in the Commission's August 27, 2019, Order in Docket No. E-100 sub 157 that the IRPs contain an analysis of anticipated or likely grid impacts associated with each alternative resource portfolio modeled in the IRPs and continue to refine transmission network upgrade cost estimates for incremental resources to take into account the most recent system impact study results;
        ii. Determine the feasibility of providing a timeline for necessary critical transmission network upgrades required to enable interconnection of incremental resources identified in each alternative resource portfolio modeled in the IRPs;
        iii. Incorporate the results of the North Carolina Transmission Planning Cooperative (NCTPC) offshore wind study results and associated cost estimates;
        iv. Incorporate applicable results from the 2021 NCTPC Future Resource Scenario Study, as was referred to and discussed at the Second Technical Conference;
        v. Refine import capability studies specifically for capacity purchase from PJM; and
        vi. Continue to assess costs, risks, and reliability aspects of potential off-system purchases.

5. Examples of why size, location, and sequence matter
    a. Consider interconnection a 200MW solar facility. Location A, in the red zone, would require several significant upgrades. Location B, outside the red zone, would not require significant upgrades to the Duke system.
    b. Consider 800MW of wind injecting into New Bern, likely no new 500kV line network upgrade needed. But for 1600 MW, a new 500kV line network upgrade is needed and additional 230kV line upgrades needed
    c. Would also need to consider the likely need of interconnecting solar before interconnection wind.
    d. Important for necessary transmission upgrades to be determined by transmission planning studies such as generator interconnection studies.
6. Current and future Carolinas solar
    a. Map represents over 4.5GW of solar already connected to transmission and distribution systems; does not represent 270MW connected at the wholesale level within DEC and DEP.
    b. 2021 – lots of solar in the queue and wanting to interconnect in the transmission-constrained region. Need to address those constraints to enable solar in the Carbon Plan.
7. Network upgrade cost estimates
    a. This slide reflects the consideration of network upgrades for interconnections in the Carbon Plan, using a cost proxy. The cost of upgrades continues to increase year over year.

   b. Graphs show the dollar/watt network upgrade costs for DEC and DEP transition cluster studies.

8. Offshore wind transmission considerations
   a. 2020 NCTPC Offshore Wind Study Report
      i. The 2020 NCTPC Offshore Wind Study Report reflects that New Bern substation would be one of the better sites to inject up to 3.2 GW of offshore wind.
      ii. A formal generation interconnection study will be needed to assess the upgrades and estimated cost to interconnect offshore wind.
   b. Schedule for Transmission
      i. Will leverage existing right-of-way (ROW) as much as possible, however there will be some new ROW.
      ii. New ROW, public engagement, scoping, routing, permitting, CPCN processes, and construction can all take time:
         1. 800MW – estimated 7 to 8 years
         2. 1600MW – 2400MW - estimated 9 to 11 years
9. PJM Capacity Purchase Transmission Considerations
   a. Cost of transmission reservation for firm capacity purchase – PJM border rate is currently $67,625/ MW-yr and has increased 21.5% since 2020.
      i. A transmission reservation for a 1500 MW purchase from PJM would cost $100M/yr
   b. For example: 300MW PJM transmission service reservation request was submitted by DEC in 2019. Completed a feasibility study, which showed time and money will be required:
      i. Allocated $411M in upgrade costs
      ii. 84 months estimate to get upgrades in-service
   c. Duke Energy's own assessment:
      i. Reveals significant upgrades needed – schedule and cost concerns.
      ii. Concerned with potential impacts from PJM queue reform. Seeing that this will delay when things can be studied.
   d. Duke will seek validation of cost and schedule through TSR request and considering this as a potential resource in the Carbon Plan.
10. Risk Assessment for Off-system Purchases
   a. System risks with relying on significant off-system capacity purchases for Carbon Plan resource needs include, but are not limited to:
      i. Delay in resource availability – delays in transmission network upgrades on the DEC/DEP transmission systems or neighboring transmission systems due to sitting, permitting, or construction issues. That can

        jeopardize when a resource becomes available and when you're able to retire a particular resource.

    ii. Impact on system ancillary needs – when purchase capacity off-system you forgo the ability to have voltage/reactive support, inertia/frequency response, AGC/regulation for balancing renewable output.
    iii. Vulnerability to neighboring system congestion issues (had this occur during a hot summer in 2007) – TLR curtailment due to transmission constraints in neighboring areas.
    iv. Transmission system stability – stability concerns due to added distance between the capacity resource and load.

11. Long-term Transmission Expansion Planning – Example
    a. Moving toward net-zero (2050)
        i. Hypothetical example of significant greenfield transmission (represented by the dashed lines) that will be needed as we go beyond 2030 toward net zero CO2 emissions
        ii. Most likely over $7B of greenfield and SIS identified common upgrades transmission represented on the map needed for interconnecting Carbon Plan resources
        iii. Greenfield transmission project schedules can take up to 10-15 years to complete.
    b. We need to execute on the near-term plan, but continue analyzing the long term needs
12. Q&A
    a. Slide 50 – why is New Bern selected?
        i. It was identified as one of the lower (or lowest) cost sites for offshore wind injection in the NCTPC study results.
        ii. There is some existing ROW that we can leverage for importing there.
        iii. Note that this is not conclusive – there are multiple landing sites.
    b. Slide 56 -- kV line appears to overlap with solar resource – are you modeling so as not to overcount the cost?
        i. In part, with the volume of solar that will be needed to meet the Carbon Plan, that is in part the reason for this example/vision. This can change, it's just a white board exercise. But the answer is yes, this transmission would help with solar.
    c. Slide 56 – what are the red lines for?
        i. DEP common upgrades identified by system impacts studies for projects queued in August 2021 timeframe. Red represents 5 different upgrades. One or two 115kV and three 230kV lines
    d. Slide 52 – Axes?

   i. Numbers on X axis represent queued projects in transition cluster study queue. Anonymized by showing regular whole numbers.
   ii. Y axis $/W network upgrades divided by size.
   iii. Both represent solar and a few solar+storage.

e. Are you planning on using the results of the transmission cluster study to inform transmission cost adders on a $/kW integration?
   i. Yes, we will continue to update the network upgrade cost proxies associated with the latest and best information that we have.
   ii. Transmission cluster study and next DISIS study will probably inform next Carbon Plan, with respect to cost proxies.

f. How do you consider the long term? Are there decisions you make now with respect to transmission that may not be a today or tomorrow issues, that may be further down the road? How do you avoid upgrading the upgrades?
   i. That's why we've been looking at long range transmission planning, which other entities are doing too.
   ii. In order to expand transmission to enable these resources, the sooner you start the more successful you'll be at meeting the Carbon Plan objectives. Issue is when you feel you have enough certainty of location and size of different resources.

g. Distributed resources – do you look at distributed generation as an influence on transmission needs?
   i. Yes, with system impact studies, we have requests in those studies that are both transmission and distribution connected.

h. Community solar – is that distribution or transmission connected?
   i. Distribution, based on the sizes we're seeing.

i. Are you considering a Southeastern RTO in terms of cost as opposed to transmission upgrades?
   i. We have Southeast Energy Exchange Market (SEEM), which is expected to provide substantial benefits for customers.
   ii. We don't see RTO modeling as part of the considerations for this Carbon Plan.
   iii. This is not a simple assumption – it would require a study of the same magnitude as the Carbon Plan.

j. Are off-system resources accounted for in their role in meeting CBM needs?
   i. Looking at capacity benefit margin – have to assess that on a periodic basis. We're already accounting for 2,000 MW of non-firm assistance with respect to meeting things like winter peaks in our planning reserve margin. Anything additional to that from an external neighbor needs to be firm with a capacity resource behind it, as discussed by Astrape and Duke in the 2020 IRP NCUC Technical Conference.

k. In terms of time to put new transmission in place, are you looking at sensitivities or assuming one timing value?
    i. There are estimates we get from resource and project management upfront, and then as we get closer to a facility study in the interconnection process we get better cost numbers and schedules. That's the process we follow today.

V. Overview of the North Carolina Transmission Planning Collaborative (NCTPC)

Rich Wodyka, NCTPC Administrator (Independent 3rd Party Advisor)

1. Genesis was back in 2004, early 2005 timeframe. Prior to then, the transmission plans were developed independent by each IOU for their own control areas. Limited involvement with Coops and Muni's. Emphasis was solely on reliability.
2. Fundamental purpose was to get together and establish a process to improve transmission planning in North Carolina and DEP territory. Wanted a collaborative process that could involve more stakeholders. The NCTPC is the local transmission planning process included in the Duke OATT that covers the DEC and DEP transmission systems.
3. Original agreement executed May 20th 2005 by:
    a. Duke Power
    b. Progress Energy
    c. ElectriCities of NC – representing municipally owned electric utilities
    d. North Carolina Electric Membership Corporation (NCEMC) – representing NC electric cooperatives
4. NCTPC Goals
    a. Provide Participants and other stakeholders the opportunity to participate in the NC Transmission Planning Collaborative (NCTPC) process
    b. Preserve integrity of the current reliability and least cost planning process
    c. Provide analysis of increased access to resources inside and outside Progress and Duke control areas
    d. Develop a single Collaborative Transmission Plan that includes reliability and local enhanced access solutions while appropriately balancing costs, benefits and risks
5. Organizational Structure
    a. Oversight / Steering Committee (OSC) – like an executive committee
        i. Reviews and approves the Reliability and Local Economic Planning criteria, critical assumptions and scenarios to be used by the PWG
        ii. Oversee the study process and approves the final Coordinated Transmission Plan
        iii. Annual process from January to December every year.

   b. Planning Working Group (PWG) – experts that develop the overall plan for review and approval by steering committee
      i. Provides expertise in model development, running the transmission models, problem identification, solution development and overall plan development
      ii. Performs study analysis and reports results to the OSC
   c. Transmission Advisory Group (TAG) – membership open to any and all stakeholders interested in NCTPC process
      i. Provides advice and recommendations to the OSC which will aid in the development of a Coordinated Transmission Plan
      ii. Membership open to all stakeholders
   d. Independent Third Party (ITP) – independent advice, recommendations, facilitation
      i. Independent advisor to the OSC and PWG and will vote to break a tie in the OSC
      ii. Facilitates the TAG activities and advises on the entire NCTPC process
6. Process Flow Chart
   a. Reliability process and local economic planning process – PWG does both.
   b. Iterative study process that results in a report that is published and reviwed by the TAG.
7. Annual Local Economic and Public Policy Study Requests
   a. Participants and TAG can propose local economic hypothetical scenarios to be studied
   b. Requests can include in, out and through transmission service
   c. Participants and TAG can propose study scenarios related to public policies that are driving the need for local transmission
   d. TAG request is distributed annually in January
8. Annual Study Scope of Work
   a. Reliability Planning Process – primary reason this group was established
      i. Analyze forecasted transmission system conditions out in the next 5 and 10 years
      ii. Identify transmission problems and develop solutions
   b. Local Economic Study Process
      i. TAG, as well as Participants, provide input on proposed Local Economic Study scenarios and interfaces for study
      ii. TAG, as well as Participants, provide input in identifying any public policies that are driving the need for local transmission
   c. Development of Annual Study Scope

        i. PWG prepares a proposed annual study scope of work for both the Reliability and Local Economic Study Process
        ii. TAG has an opportunity to review and comment on the proposed study scope of work
        iii. OSC approves the final Annual Study Scope of Work

9. Past and Current Local Economic Study Scenarios
    a. Hypothetical Imports/Exports re-evaluated every other year (last performed in 2019)
        i. 12-14 1000 MW transfers
    b. Hypothetical NC Generation
        i. Fossil Fuel
        ii. Wind Energy – On-shore and Off-shore NCTPC only and NCTPC-PJM Joint Study
    c. Retirement of Coal Units
    d. 2022 - 4 Requests being considered
10. Past and Current Public Policy Study Scenarios
    a. 2020 - Study of Possible Offshore Wind Interconnection Points. Evaluated all connections for bringing in wind to Duke system. However, if somebody wants to interconnection they'll need to go through the interconnection process.
    b. 2021 - High Renewables Study (1 scenario) – sponsored by NCUC Public Staff. Encompassed several elements dealing with renewables (including solar, onshore wind, offshore wind).
        i. Preliminary results March 28th TAG meeting
    c. 2022 - 2 Requests being considered
11. Overview Schedule
    a. Reliability planning
    b. Local economic planning
    c. Single coordinated plan
    d. Final publications
    e. NOTE: TAG meetings happen quarterly throughout
12. Study Process Overview – 8 fundamental steps
    a. Assumptions Selected
        i. Study Year's for Reliability analyses:
            1. Near-term: 5 years from current year
                a. Analyze both summer and winter cases
            2. Longer-term: 10 years from current year
                a. Alternately analyzed summer and winter cases

        ii. Study Year's Local Economic Study analyses:
            1. Longer-term: 10 years from current year
                a. Use same cases as Reliability analysis
        iii. Load Serving Entities (LSEs) provide:
            1. Input for load forecasts and resource supply assumptions
            2. Dispatch order for their resources
        iv. Adjustments may be made based on additional coordination with neighboring systems
    b. Study Criteria Established
        i. NERC Reliability Standards
            1. Current standards for base study screening
            2. Current SERC and NERC Requirements
        ii. Individual company transmission criteria
    c. Study Methodologies Selected
        i. Thermal Power Flow Analysis
        ii. Each system (DEC and DEP) will be tested for impact of other system's contingencies
    d. Models and Cases Developed
        i. Start with latest series of NERC MMWG cases
        ii. Latest updates to detailed models for DEC and DEP systems will be included
        iii. Planned transmission additions from latest updated Transmission Plan included in models
    e. Technical Analysis Performed
        i. Conduct thermal screenings and analysis of the cases based on approved study criteria and methodologies
    f. Problems Identified and Solutions Developed
        i. Identify limitations and develop potential alternative solutions for further testing and evaluation
        ii. Estimate project costs and schedule
    g. Collaborative Plan Projects Selected
        i. Compare all alternatives and select preferred transmission solutions
    h. Study Report Prepared, Reviewed, and Published
        i. Prepare Draft report and distribute to TAG for review and comment
        ii. TAG provided OSC feedback on Draft report
        iii. OSC incorporates any TAG feedback received, if applicable

        iv. OSC publishes Final Collaborative Transmission Plan Report

13. NCTPC Process Results since NCTPC inception in 2005
    a. Transmission projects totaling more than $2.123 billion have been identified in the NCTPC plans
    b. More than $1.13 billion in projects have been placed in service through the end of 2021
    c. $664 million are still in the planning stage
    d. Another $329 million were deferred until after 2031 or cancelled as a result of changing transmission system requirements
    e. Collaborative Transmission Plan is updated annually
14. NCTPC Website
    a. NCTPC Website - nctpc.org/nctpc/home.jsp
15. Q&A
    a. Do the 4 founding participants of the NCTPC have representation on the oversight/steering committee?
        i. Yes, each participant has two representatives, plus the independent advisors.
        ii. On the PWG each participant has up to 3 members plus the independent advisor.
        iii. Stakeholder group is unlimited. Have about 50-60 participants currently.
    b. Curious to hear why there isn't a "Carolinas" TPC incorporating both NC & SC that would have inclusive OSC representation from wholesale entities in both states.
        i. The NCTPC represents the footprint of Duke and Progress, which includes areas of North and South Carolina.
        ii. Have South Carolina stakeholders, but not official members.
    c. You’ve completed the 2021 plan based on the reliability studies you’ve done, but you haven’t completed the policy study, so can the Public Staff Public Policy study be incorporated as an update?
        i. Reliability study is done. Renewables study is hypothetical and informative, not for changing the reliability plan at this point in time, but it could lead to changes in the future.
        ii. Results shared at the TAG meeting will be preliminary to allow for TAG feedback.
    d. Is there a procedure for mid-year plan update?
        i. Every year we provide an update of last year’s plan. Can’t say if the renewables study will affect the mid-year update because it’s happening soon in June. But still could change things in the future.

    ii. Need to have time to get a handle on what's happening in this process and make sense of it in the studies.

e. Can you speak to the level of detail included in the Public Policy studies, and whether these study results are sufficiently detailed to be incorporated into the LTP?
    i. The latest two policy studies, the wind study in particular, was really good because it looked at the best locations to bring offshore wind onshore, something like 29 locations. Depending on location, it can cost a little or a lot. Folks found this valuable for decision-making, including SE Wind Coalition.
    ii. Can't preview the results for the renewables study, but believe it will have similarly useful information that can help renewable energy developers.
f. What is the general process by which the results of a public policy study are incorporated into a transmission plan?
    i. Wind study as example – they were interested in identifying the best locations to interconnect offshore wind into the grid. It's informative, but you still need to go through the official generation interconnection process.
    ii. This Carbon Plan may change that. NCTPC is paying very close attention to this group and will be looking at the final Carbon Plan and considering how to make it work.
g. Are most of the proposed transmission projects based on meeting NERC TPL standards are there projects that a driven by congestion reduction or other economic reasons?
    i. It's a combination of everything. You have planning criteria based on NERC and other planning standards, plus criteria from the companies. All of that determines what the bottlenecks are, and what the solutions should be. It's an iterative process and some projects change as the conditions change over time.
h. Are non-wires alternatives considered?
    i. Just transmission lines.
i. Does the NCTPC planning group study stability performance and fault level increases on equipment?
    i. Get factored in through local companies criteria. Can't speak specifically to Duke and Progress though.
j. How do you evaluate end of life for transmission elements?
    i. Same. Get factored in through local companies criteria. Can't speak specifically to Duke vs Progress though.
k. How do the NCTPC process and Carbon Plan processes "talk" to each other? Will Duke submit a Public Policy Study scenario for its proposed Carbon Plan to the NCTPC so the NCUC can consider that in approving a final Carbon Plan?

        i. Understanding is Duke's proposed Carbon Plan will be filed in mid-May for NCUC consideration. It may change through the regulatory process. NCTPC is paying close attention.
        ii. There is a cluster analysis that may drive transmission development. There are multiple factors to be considered, and those factors will be folded into the NCTPC process as applicable and as it aligns to the established annual timeline.
        iii. Can't say for sure how the Carbon Plan will be factored in.
    l. Who ultimately regulates the NCTPC if we want to try to update it in light of these pressing needs?
        i. Part of Duke and Progress open access tariff filings. Regulated through that process and the NCUC. Legal aspect beyond my expertise.
    m. Can the plan/study be reviewed by TAG and responded to and issued finally before DISIS and the 2022 Carbon Plan? This year in particular, it seems that December is too late.
        i. Can't answer that at this time.

VI. Clean Power Suppliers Association and Brattle Group Presentation of Carbon Plan Modeling

Tyler Norris, Cypress Creek Renewables on behalf of Clean Power Suppliers Association

1. Background
    a. Goal was a modeling exercise to support stakeholder discussions. Results reflect the ouputs of Brattle model based on the identified inputs and methodology. Want to invite stakeholder input on the modeling – encourage to reach out to any member of CPSA and looking forward to refining the results.

Mike Haggerty, Brattle Group

2. Introduction
    a. Objective: Analyze least-cost future resource mix that achieves 70% reduction in emissions from Duke Energy's North Carolina power generation plants by 2030
    b. Scope: Model Duke Energy system in North Carolina and South Carolina under updated assumptions through 2035
    c. Approach:
        i. Update internal GridSIM model of Duke Energy system to incorporate GHG limits, new resource costs, and current natural gas prices
        ii. Identify the least-cost resource mix to meet GHG goals
        iii. Estimate annual solar additions from 2026 to 2030 to achieve the GHG goals
3. Modeling Approach

   a. Analyzed the combined Duke Energy system using Brattle's internal capacity expansion model GridSIM. Modeled DEC and DEP, allowing for a limited number of inputs.
   b. Simulates dispatch of generation and storage resources to meet demand and cost-effective resource expansion to meet resource adequacy needs and GHG limits.
   c. Captures chronological dynamics of a future power system that relies more heavily on renewable resources by analyzing 49 representative days (4 days in each month plus the peak demand day).
   d. Modeled the Duke service territory as an island with limited transactions with neighboring markets, similar to the approach in Duke 2020 IRP.

4. GridSIM Overview
   a. Takes a series of inputs that model supply, demand, transmission, and regulations and policies applicable to the system.
   b. The model then optimizes the resource mix – both new and existing resources, and dispatch of those resources – to meet energy balance.
   c. Output is the resource mix, emissions, market prices, and resource costs.
5. GridSIM vs EnCompass
   a. Similar to GridSIM, EnCompass identifies the least cost portfolio of resources to maintain system reliability, meet 2030 GHG limits, and meet hourly demand.
   b. Encompass uses a different modeling approach that optimizes unit commitment decisions and also simulates dispatch of resources chronologically throughout the year.
   c. Key point -- models themselves are likely not as consequential as the inputs that go into them.
6. Key Assumptions
   a. Generation
   b. Capital Costs
   c. Transmission Cost Adder
   d. O&M Costs
   e. Fuel Prices
   f. Fossil Heat Rates
   g. Renewable Capacity Factors
   h. Capacity Credit/ELCCs
   i. Generation Ownership
   j. Renewable Capacity Addition Constraints
   k. Carbon Methodology
7. NC and SC GHG Emissions Caps

   a. Duke North Carolina 2030 emissions cap of 22.6 million short tons is calculated as a 70% reduction from 2005 emissions levels (75.4 million short tons)
      i. Interpolate emissions linearly between 2030 and 2050 assuming NC reaches net zero emissions by 2050.
      ii. Results in a 2035 emissions limit for Duke NC plants of 16.9 million short tons.
   b. To limit GHG emissions leakage into SC, we limited Duke South Carolina emissions based on the average 2019-2021 emissions from existing plants
      i. We scale this value in each year according to the projected load growth by 2030 and 2035
      ii. Historical emissions data sourced from EV data hub; load growth forecast sourced from Duke 2020 IRP.

8. Coal Plant Retirement and Conversion Date Assumptions
   a. We assume that coal plants retire based on timing proposed during development of H951 legislation with retirement occurring 3 years after filing of replacement plans
      i. Belews Creek 1-2 and Cliffside 6 are converted to operate on natural gas
9. Resource Adequacy
   a. Retirement of coal plants will result in a significant shortfall in capacity.
   b. Estimated capacity shortfall for both DEC and DEP to meet their 17% reserve margin
   c. Started with 2020 IRP winter capacity balance and adjusted reserve margin based on alternative assumptions for coal plant retirements and new resource additions (only added mandated solar capacity under H589)
   d. Assumed ELCC of solar (1%), wind (33%), and 4-hour battery storage (100%) based on Duke IRP, and 45% for offshore wind based on average output during winter mornings
10. Available new generation and BESS Resources
    a. We allow GridSIM to select the following resources to meet capacity and energy demand and the GHG reduction target at least cost to ratepayers
    b. Resources include…
       i. Gas CC and CT
       ii. Solar – included
       iii. Onshore and offshore wind
       iv. Batteries
       v. NOTE: Have not modeled solar+storage, but will add that. Also did not consider Gas CC with CCS or Nuclear SMR due to the limited feasibility of these resources being built by 2030
11. Capital costs for new resources

  a. Capital cost assumptions based on 2021 ATB Conservative case
    i. Based on feedback from Duke, we adopted lower capital costs for Gas CT using recent PJM Cost of New Entry (CONE) study
    ii. For new Gas CC, we added $125/kW for the costs of new gas lateral based on EPA analysis of NC plants
  b. We added estimated transmission upgrades for each resource:
    i. Offshore wind: $441/kW in 2030 based on NCTPC study
    ii. All other resources: $100/kW
  c. Assume ITC and PTC phase out:
    i. 30% ITC for solar & storage online by Jan 1, 2024; phased down to 10% for projects online by Jan 1, 2027
    ii. 30% ITC for offshore wind commencing construction by Jan 1, 2026 with ten years to complete (available for 2030 and 2035)
    iii. PTC phases out for onshore wind resources entering after 2025
  d. Believe these are relatively conservative capital cost estimates.

12. Comparison of Levelized Costs
  a. The estimated 2030 LCOE for solar and onshore wind are similar ($65-70/MWh), while offshore wind is more than 2x higher ($140/MWh)
    i. We estimated the LCOE assuming the levelized costs remain constant in nominal terms over its economic life and assuming Duke's most recent cost of capital of about 6.5% ATWACC
    ii. LCOE values shown here are higher than ATB due to use of nominal 2030 dollars (instead of real 2019 dollars), assumption that levelized costs are constant in nominal terms (instead of real terms), and higher cost of capital
13. Delivered Fuel Price Projections
  a. Followed similar approach to what Duke has modeled.
  b. Delivered gas price forecast from recent forwards (first 5 years), then blend for 3 years with fundamentals-based forecasts (average of AEO2021 SERC and WoodMac TranscoZ6), then 100% fundamentals-based forecasts
    i. Monthly shapes based on average historical shape from 2018-2020 to account for commodity price and variable delivery charges
  c. Coal price by plant based on delivered coal prices in 2020 and escalated based on AEO2021 forecast for delivered cost of coal into SRCA region
14. Projected 2030 Generation and Storage Resource Mix
  a. (Figure on slide shows additions and retirements)
  b. Total new resources by 2030
    i. Utility-Scale Solar: +11,690 MW

        1. 2,690 MW due to H589 by 2026
        2. Additional 9,000 MW by 2030
    - ii. Onshore Wind: +900 MW (2028, 2029, 2030)
    - iii. 4-Hour battery energy storage system (BESS): +2,000 MW
    - iv. Gas CC: +3,200 MW (model preferred gas CC's to CT's due to their efficiency and the need for significant amounts of energy to replace retiring coal plants).

15. Duke Energy Generation Mix and GHG Emissions
    - a. Solar and wind generation increase from 9% of total generation in 2025 to 22% in 2030, with modeling choosing to dispatch down the remaining coal plant (Marshall 3-4)
        - i. Non-emitting resources (i.e., solar, wind, hydro and nuclear) account for 69% of total 2030 generation
        - ii. Coal generation decreases to nearly zero
        - iii. Natural gas generation increases in 2030 due to new Gas CC additions
16. Gas CC Entry Likely Overestimated
    - a. Modeling timeframe only extends to 2035, which does not consider that the value of generation from Gas CC will decrease after 2035 to achieve deeper GHG reductions. Extending timeframe would change this.
    - b. Low ELCC for solar increases demand for other resources to meet reserve margin requirements.
    - c. Normalized hourly demand and renewable generation conditions does not capture value of fast-start Gas CT and BESS to serve unexpected, sub-hourly market conditions.
17. Impacts of Limiting Solar Additions by 2030
    - a. Ran a case limiting solar additions from 2026 to 2030 to the capacity Duke identified in its Enhanced Transmission Policy Case. This results in the following:
        - i. Require alternative clean sources of generation to meet the 2030 GHG goal
        - ii. One approach: add about 5,300 GWh of wind generation (1.4 GW offshore or 2.0 GW onshore)
        - iii. Increases 2030 costs by about $400 million
18. Key Resource Dynamics
    - a. Gas vs BESS costs:
        - i. Currently selecting a mix of Gas CC and BESS resources, which both help to meet resource adequacy, such that even small shifts in costs will have a significant impact on capacity additions of each resource type by 2030

        ii. Modeling only to 2035 limits the long-term considerations of GHG limits and will tend to build more gas capacity
        iii. Reducing CT costs would tend to (1) reduce new CC entry, (2) increase coal generation, and (3) increase addition of renewable resources
    b. Solar vs Offshore wind costs:
        i. Solar costs are sufficiently low to be selected with 4-hour BESS instead of higher cost offshore wind, even though they have a low ELCC
        ii. Even at 25% lower offshore wind costs, no offshore wind is built
    c. Slower coal plant retirements will increase need for solar/wind additions
        i. With a GHG limit, the amount of combined gas/coal generation will depend on the average emissions rates from those resources
        ii. Earlier coal plant retirements will decrease the average emissions rate, increase gas/coal MWhs, and decrease need for wind/solar

19. Key Takeaways
    a. Based on our analysis of Duke Energy's options to achieve 70% reduction in GHG emissions, at least 8 GW of additional solar capacity (beyond the HB589 baseline) is necessary to meet the 2030 target, even under conservative solar cost assumptions. This will be the case unless one or more of the following occurs:
        i. Emissions leakage is allowed via imported gas generation (from SC or beyond Duke's system)
        ii. Higher cost offshore wind is selected by Duke
        iii. Large-scale renewable imports occur via Midwest wind or other resources
    b. Duke's proposed limits on annual solar installations results in the selection of offshore wind as the next least cost solution, but is likely to increase compliance costs of H951 or prevent achieving the 2030 target
20. Q&A
    a. We know there is interest in the possibility of Midwest wind imports. If we were to think about potentially running an updated scenario that allowed Midwest wind to be selected, what key inputs would be helpful to be able to model that?
        i. Import capability is determined by amount of firm capacity that can be used for those imports, as well as a levelized cost for those resources. Could then develop a profile for those resources. Key would be cost for procuring those resources and capacity credit.
    b. GridSIM versus EnCompass – could you explain how the difference would show?
        i. It would reflect decisions about the startup and shutdown of units more in line with how the units are operated. In GridSIM, similar types of units are aggregated and allowed to flex their output, which makes the system more flexible than it is in reality.
    c. Is land availability considered in the assumptions to install the modeled amount of solar and onshore wind?

    i. For onshore wind, assumptions were based on our understanding of feasibility. Solar was a flat supply curve, but looking at updated that to take into account interconnection and land costs. Hopefuilly can share in next iteration.

d. Gas from Zone 6 versus Zone 5 – why was Zone 6 selected?
    i. Prices tend to track each other closely. Zone 5 gas forwards tend not to have much liquidity a year out, so relied on Zone 6 as a proxy.
    ii. Follow-up Q: Do not agree. Zone 5 is more expensive than Zone 6. Have a real problem with capacity problems. AEO2021 – is that Henry Hub?
        1. We used the projected AEO2021 delivered prices for the SERC region.
    iii. Follow-up comment: believe your gas cost assumptions are low for the forward prices.
        1. Thanks. Will take another look. Intent was to track Duke's approach, but still willing to look into it.

e. Just reacting to the numbers I've seen in the presentation, so forgive me if I missed something, it looks like you're using a high cost forecast for offshore wind but a low to medium cost forecast for solar, could you clarify how you derived your LCOE or capital cost inputs?
    i. Brattle used NREL 2021 ATB Conservative Case for solar, storage, onshore wind (Class 9), and offshore wind (Class 5), Gas CC. It sounds like it could be helpful for us to have them run a scenario with ATB Moderate for each resource to see if/how that may impact results.
    ii. We saw a strong preference for solar at the costs we had assumed. If you move to the moderate case, it will reduce prices for all resources. There would need to be significant changes in the solar and wind cost assumptions to have a significant different in the results. Solar and wind cost declines tend to track each other.
    iii. However, would likely see a difference in the dispatch of fossil resources.

f. Did you model cost increases on rates?
    i. No. Though we did do an estimate of total costs as part of last year's study, but not yet for this analysis.

g. Can you comment on the generation mix shown on slide 16 as the modeling result - there is over 2GW of 4-hour storage added but the portfolio optimization does not select any storage?
    i. It doesn't show up there because it's not a generation resource.

VII. Duke Update on Modeling and Development of Potential Pathways

Glen Snider, Duke Energy

1. Key base case assumptions for selectable resources

a. Energy Efficiency
    i. EE 1% of eligible retail sales
    ii. IVVC growing to 90% of DEC circuits
    iii. DR programs and critical peak pricing

b. Solar
    i. Have dramatically increased solar interconnection potential to 1,350MW/yr. by start of 2029 (> 2.5X 2020 IRP)
        1. Duke uses a beginning of year convention – if you put 1350 MW on throughout 2028, all of the 1350 is available throughout 2029.
        2. Also running an increased high sensitivity of 1,800MW/yr.
    ii. Bifacial panels – update from stakeholder feedback
    iii. Additional solar + storage config – update from stakeholder feedback
    iv. Costs ~1% lower than moderate NREL costs

c. Storage
    i. Up to 3,000MW standalone batteries per year. Nearly unconstrained.
    ii. Costs within 1% of moderate NREL costs
    iii. Bad Creek II – long duration storage (12-hour) option in addition to battery storage

d. New Nuclear
    i. SMR – 600MW (300MW blocks) available 2033-2034
    ii. Advanced reactors or additional SMR available after 2036 as we move on the path to net zero.

e. Wind
    i. Onshore wind at 30% capacity factor – 300 MW/year starting 2029 up to 1,800MW total.
    ii. Offshore wind – Two 800MW blocks (beginning of year convention -- 1/1/2030, 1/1/2032)
    iii. Additional OSW available after 2040

f. Gas
    i. Plan will count emissions as if located in NC
    ii. Earlier and shorter transition from market-based to fundamentals-based natural gas commodity prices
    iii. Two versions – somewhat constrained, and heavily constrained:
        1. Constrained Appalachian gas supply (up to ~2400 MW of New CC)
        2. Constrained w/ No Appalachian gas supply (up to ~800MW of New CC)

    g. Hydrogen
        i. Assume H2 blending 2035+
        ii. Incorporate H2 turbine conversion costs for existing gas and upcharge for 100% H2 capable new gas

2. Selectable Resource Options (cumulative limits based on max annual potential)
    a. NOTE: This is not what's in the portfolio, this is what the model can select from to fill out a portfolio.
    b. Solar is a significant increase, in recognizing the need to interconnect more solar
    c. Onshore wind – nothing developed yet, so allowing to pick 300MW/yr up to 1800 MW over time. As we get more experience, may need to adjust up or down. This is the starting point for this specific Carbon Plan.
    d. Offshore wind – cumulative total of 1600MW through the 2030's, with potential for more as more lease options become available
    e. Nuclear – cumulative buildup over time of what could be selected by the model.
    f. Gas combine cycle plants – limited case without access to Appalachian gas (up to 800MW), and case with some access (up to 2400MW). Those limits remain over entirety of planning horizon.
    g. Batteries and peakers – can be selected to help cover short-term energy needs to complement intermittent resources. This plan will have considerably more batteries than in past plans, and likely to see more batteries than peakers being selected.
3. Selectable Resource Options (cumulative based on max annual potential)
    a. Slide shows the same thing as previous, with a time-specific view in 2040.
    b. Resource constraints acknowledge limits to many different resources, with solar having the highest limits by far.
4. Paths on the Way to Carbon Neutrality
    a. In HB951, there are two different options laid out for the interim target:
        i. 70% reduction by 2030 using currently available technology
        ii. 70% reduction, with some flexibility on timing, if time is needed to implement either new nuclear, offshore wind, or both.
5. Snapshot: Potential Carbon Plan Portfolios in Year 70% is Achieved
    a. 3 different pathways, and two versions of each based on the two gas views:
        i. Strictly 70% by 2030
        ii. 70% by 2030 plus offshore wind
        iii. 70% by 2030 plus new nuclear
    b. Total solar includes what is on the grid today
6. Snapshot: Potential Carbon Plan Portfolios in 2035

    a. Shows each scenario at a different point in time – looking at all the portfolios, what is being selected by 2035? Helps put things in an apples to apples comparison, given the flexibility on 2030 enabled by HB951

7. Execution Risks
    a. Transmission & Interconnection
        i. Significant transmission needs and associated lead times for build and generator interconnection challenge connecting the magnitude of resources needed to reach 70% reduction. Assumed interconnection levels are more than double current level. Siting, permitting, build, interconnection process and capacity constraints may hinder timely addition of renewables.
    b. Industry Resources
        i. High industry demand for skilled labor needed to develop and interconnect resources required for fleet transformation (generation, transmission, distribution, customer programs, engineering, etc.)
    c. Fuel Availability
        i. Declining coal mining and transportation industry presents concerns over fuel security and flexibility to manage transition to large scale renewables. Legal challenges of pipelines may restrict ability to provide adequate gas supply needed to replace coal generation and maintain system reliability.
    d. Regulatory Approvals
        i. Numerous federal and state agency regulatory approvals required across various components, including regulatory approvals supportive of continued joint system planning and allocation conventions between NC and SC.
        ii. Different approvals needed for different technology types.
    e. Technology Maturity
        i. Reliance on estimated timelines for technology maturation and cost reduction, as well as development and rapid scaling of domestic and global supply chain for emerging technologies.
    f. Supply Chain
        i. Constraints in material (e.g., solar, storage) and labor may restrict advancement of construction.
8. Q&A
    a. How quickly can you get nuclear on the system?
        i. 2032-2034 is estimated. There will be discussion in the Carbon Plan around the feasibility and development of new nuclear (small modular reactors). Believe it's roughly a 10-year process.
    b. How are you planning for residential solar?
        i. We have residential solar forecasts in the load forecast as a reduction in load. Will continually model and update those. There's a range, so we

have a baseline assumption of growth that will be included and will impact load shape during every hour of the year.

c. Purchases of renewables – trying to buy wind from Midwest or other places – how does that factor in?
    i. Different flavors of wind. Coastal Carolinas capacity factors – difference you get is transmission implications to bring in PJM wind, versus wheeling in from coastal Carolinas. Not looking at panhandle wind due to historic difficulty of doing that.
d. How about RE overbuild versus storage?
    i. Model inherently does that. If you overbuild, the storage helps you utilize what you otherwise would have curtailed. You need them both.
e. Have you maybe overshot on your storage capabilities?
    i. This will continue to get refined over time. Different options will evolve. Right now based on cost projections that are in line with NREL, they make economic sense at those prices. There may be supply chain or other issues that need to be considered as risks. Overall see storage playing a more significant role when paired with wind and solar.
f. What constraints on solar additions is Duke modeling in each year before 2029? Is it possible to mitigate those by building needed upgrades now?
    i. 2029 really is 2028, because you're getting to 1350MW by 2028 so that it's all available by 2029.
    ii. The ability to do permitting, construction, and all approvals takes time, so this is an aggressive timeline. Want to effectuate the transmission build as quickly as possible.
g. What if you modeled customer-sited DERs as supply side instead of demand reduction?
    i. DERs where you have control, such as BYO thermostat, will be modeled as supply side in the model.
h. The EE/DSM assumptions – are you forcing that into the model, or is the model selecting?
    i. They go in as a reduction to the load forecast.
    ii. Will file, execute, and refile in 2 years, so will have opportunities to update the EE/DSM assumptions iteratively over time.
i. You said that rooftop solar will be modeled as a demand-side reduction, and that DERs will be modeled as supply-side resources. So it is only solar+ (thermostat, battery, EV, etc) as supply side?
    i. When we think of distributed resources, we delineate between those that are actively controlled like a supply side resource to increase or decrease load and those that are not actively controlled. Things not actively controlled go into the load forecast.
    ii. For example, electric vehicles without managed charging would be in the load forecast, but EVs with managed charging would be supply side.

    iii. Follow-up comment: suggest to look at smart inverters and aggregation.

j. Is the hydrogen Green hydrogen? What is the company assuming for H2 fuel delivery costs? 100% H2 would require totally new/upgraded pipelines across the entire system.
    i. It will be carbon-free hydrogen. Going in starting in 2035 with all the known costs that we have today. Slight blending at that time, then increases over time. Also plants will have capability to transition to hydrogen. Not a significant player in the 70% target.

k. Why no offshore wind in 2030?
    i. It's the technology and the infrastructure to connect it to the grid? Depends how quickly you think you can move through the entire development process to build the wind and move it to load. Sometimes load in our territory is further from the coast than in other areas.

l. Is the model running just the fuel costs on hydrogen, or the necessary pipe upgrades since some natural gas pipes can't handle hydrogen without upgrades?
    i. Good question. Will need to get back on that.

m. Doesn't residential direct gas get priority? Why are you forcing the model with arbitrary limits on new CC construction – shouldn't the model be used to see if new CC will be uneconomic.
    i. The only extent to which we have non-electric utility considerations is on the market prices.
    ii. The limit is the constraint – you can't build CC's if you don't have the pipe to bring the gas to the CC's. Model reflects the realities of the marketplace.

n. Do the new generation numbers figure in capacity factors for different resources?
    i. Yes. We look at a full 8760 profile and how things change due to increasing penetration.

o. Can you speak more to how you're looking at storage and peakers together?
    i. 8760 hours throughout the year – how the interaction between storage and renewables manifests itself can't be done in depth by the model, so need a more detailed step with full production cost modeling on an hourly basis over a long horizon. Preliminary information from that modeling is showing many more batteries than in the past to move renewable energy to when it's needed. However, there are some longer gaps that need to be filled with a CT.

p. Do these pathways contemplate relicensing the nuclear stations?
    i. Yes, the licenses are foundational to achieving these goals. Those are in the baseline, so this is all in addition to the baseline.

q. How do you model the risks?
    i. Would like to quantitatively model all of this, but it's not possible. Will have some specific sensitivities to assess risks quantitatively, but some

        others will require qualitative discussions and judgment. These will be laid out in the Carbon Plan.

r. Are portfolios economic optimization only, or will Duke also optimize them?
    i. Economic optimization subject to mass caps and subject to 70% flexibility as previously discussed.
s. Are you considering new onshore wind with higher hub heights?
    i. Not for onshore, given we have relatively no experience with onshore wind in our geographic footprint, so will continue to evaluate that.
t. Limits on gas plants – if Duke were to model mass by putting limits on new CC's, but using a lower gas price, wouldn't the model max out construction of new CC's?
    i. Gas price sensitivities is one of the variable we do stress test. In a carbon-constrained environment, it's both gas price and the physical characteristics of being able to run when needed, without the high carbon emissions of a coal plant.

VIII. Next Steps

Rebecca Dulin, Duke Energy

1. Will be scheduling a meeting focused on community and environmental justice impacts, likely in April. Would like to explore those in a more dedicated forum. Look out for an email on that.
2. Thank you to all stakeholders for your input and your time throughout this process.
3. Information and feedback can be sent to DukeCarbonPlan@gpisd.net.

List of Meeting Attendees by Organization

Name	Organization
Jerome Wagner	350 Charlotte
Joe Bearden	350 Triangle
Karen Bearden	350 Triangle
John Ruoff	AARP
Patrick Cobb	AARP South Carolina
Brian Nelson	ABB Inc.
La'Meshia Whittington	Advance Carolina
Jayne Hickey	AES
Donald Zimmerman	Alder Energy Systems
John Gorman	Ameresco
Kathryn Chelminski	Ameresco
Sarah Cabot-Miller	Ameresco
Ashton Edge	APCO Worldwide
Moji Abiola	Apex Clean Energy
Justin Sykes	API SE Region
Josh McClenney	Appalachian Voices
Rory McIlmoil	Appalachian Voices
Kristen King	Ardagh Group
Elizabeth Ratner	Atrium Health
Greg Andeck	Audubon North Carolina
Becky Gallagher	Avangrid Renewables
Nick Phillips	BAI/CIGFUR
Christina Cress	Bailey & Dixon, LLP
George Baldwin	Baldwin Consulting Group, LLC
Kody Clark	Bank of America
Oliver Twitchell	BP
Mike Hagerty	Brattle
David Gordon	Bright Blue Door LLC
Michael Wallace	BrightNight Power
Sam Warfield	Broad River Energy
Craig Schauer	Brooks Pierce
Kevin Martin	Carolina Utility Customers Association
Kevin O'Donnell	Carolina Utility Customers Association
Chris Carmody	Carolinas Clean Energy Business Association
John Burns	Carolinas Clean Energy Business Association
Lindsey Sprague	CELI
Mason Milligan	Central Electric Power Cooperative, Inc
Nes Arnette	Central Electric Power Cooperative, Inc
Mark Svrcek	Central Electric Power Cooperative, Inc.
Ben Kessler	ChargePoint
Kevin Lindley	Chatham County
Charles Cooper	Chatham County Climate Change Advisory Committee
Preston Howard	CIGFUR
Yvonne Monroe	Citizen's Climate Lobby
Bridget Herring	City of Asheville
Heather Bolick	City of Charlotte
David Ingram	City of Wilmington
Brian Morgan	Clean Energy Buyers Association
Joel Porter	CleanAIRE NC

Thomas Suttles	Clemson University
John Slipke	Climate Reality Project
Lois Nilsen	Climate Reality Project
Eddy Moore	Coastal Conservation League
Jalen Brooks-Knepfle	Conservation Voters of South Carolina
John Brooker	Conservation Voters of South Carolina
John Gaertner	Consultant, Energy and Environment
Stavros Polyzoidis	Continental Tires
Steve Frank	Corning Incorporated
Karen Prus	CRP
Ryan Watts	Cypress Creek Renewables
Tyler Norris	Cypress Creek Renewables
Zander Bischof	Cypress Creek Renewables
Elizabeth McEldowney	Dominion Energy
Warren ReBarker	Draughon Farms, LLC
Adam Reichenbach	Duke Energy
Alicia Dasch	Duke Energy
Ameya Deoras	Duke Energy
Andrew Clarke	Duke Energy
Angela Tabor	Duke Energy
Arnie Richardson	Duke Energy
Bailey McGalliard	Duke Energy
Barb Davis	Duke Energy
Benjamin Passty	Duke Energy
Bill Norton	Duke Energy
Blain Atkins	Duke Energy
Bo Somers	Duke Energy
Bob Donaldson	Duke Energy

Bobby Moore	Duke Energy
Bradley Rash	Duke Energy
Brant Werts	Duke Energy
Brett Breitschwerdt	Duke Energy
Brian Lusher	Duke Energy
Bryan Dougherty	Duke Energy
Bryan Wright	Duke Energy
Camal Robinson	Duke Energy
Catherine Goza	Duke Energy
Chet Sigmon	Duke Energy
Chris Hixson	Duke Energy
Chris Nolan	Duke Energy
Christopher Courtenay	Duke Energy
Christopher Sharpe	Duke Energy
Clift Pompee	Duke Energy
Conitsha Barnes	Duke Energy
Dan Reilly	Duke Energy
Daniel Donochod	Duke Energy
Danny Brothers	Duke Energy
David Johnson	Duke Energy
Elizabeth Bennett	Duke Energy
Emily Felt	Duke Energy
Emma Goodnow	Duke Energy
Evan Shearer	Duke Energy
George Brown	Duke Energy
Glen Snider	Duke Energy
Grace Rountree	Duke Energy
Jack Jirak	Duke Energy
Jacqueline Walker	Duke Energy
Jason Handley	Duke Energy

Jason Martin	Duke Energy
Jay Oliver	Duke Energy
Jeff Chandler	Duke Energy
Jeffrey Day	Duke Energy
Jim Northrup	Duke Energy
Jim Umbdenstock	Duke Energy
Joe McCallister	Duke Energy
John Elliott	Duke Energy
John Lyerly	Duke Energy
Jonathan Landy	Duke Energy
Joshua Duc	Duke Energy
Justin Brown	Duke Energy
Justin LaRoche	Duke Energy
Karen Henderson	Duke Energy
Karen Ralph	Duke Energy
Kendal Bowman	Duke Energy
Kendrick Fentress	Duke Energy
Kenneth Jennings	Duke Energy
Kevin McLaughlin	Duke Energy
Kevin Shelton	Duke Energy
Kimberly Walton	Duke Energy
Ladawn Toon	Duke Energy
Layla Cummings	Duke Energy
Lee Grzeck	Duke Energy
Lee Mitchell	Duke Energy
Leland Snook	Duke Energy
Lizzy Underwood	Duke Energy
Mark Byrd	Duke Energy
Mark Goettsch	Duke Energy
Mark Oliver	Duke Energy

Martin Garvin	Duke Energy
Matthew Kalemba	Duke Energy
Maura Farver	Duke Energy
Michael Callahan	Duke Energy
Michael PIrro	Duke Energy
Michael Rib	Duke Energy
Mike Ruhe	Duke Energy
Molly Suda	Duke Energy
Nate Finucane	Duke Energy
Norm Kunkel	Duke Energy
Patrick Louka	Duke Energy
Pedram Mohseni	Duke Energy
Randall Heath	Duke Energy
Ravi Muj	Duke Energy
Rebecca Dulin	Duke Energy
Rhett Trease	Duke Energy
Robert McMurry	Duke Energy
Ryan McAward	Duke Energy
Ryan Minto	Duke Energy
Sam Wellborn	Duke Energy
Sammy Roberts	Duke Energy
Sarah Kutcher	Duke Energy
Stacy Phillips	Duke Energy
Stephen De May	Duke Energy
Steve Immel	Duke Energy
Susan Snow	Duke Energy
Swati Daji	Duke Energy
Terri Edwards	Duke Energy
Thomas Beatty	Duke Energy
Tim Duff	Duke Energy

Tom Davis	Duke Energy
Tyler Cook	Duke Energy
Whitney Gann	Duke Energy
Bill Currens	Duke Energy
Brian Bak	Duke Energy
Carl Phipps	Duke Energy
Chris Edge	Duke Energy
George Flowers	Duke Energy
Jeffery Cardwell	Duke Energy
Jennifer Canipe	Duke Energy
Joe Glass	Duke Energy
Marcus Preston	Duke Energy
Mark Tabert	Duke Energy
Michele deLyon	Duke Energy
Richard Knight	Duke Energy
Prakash Bhave	Duke University
Tobin Freid	Durham County Government
Brad Slocum	East Point Energy
Ginny Horne	Eckel & Vaughan
Harris Vaughan	Eckel & Vaughan
Tori Ludwig	Eckel & Vaughan
Seth Studer	Ecoplexus Inc.
Ed Ablard	Ed Ablard Law Firm Wilmington NC
Mike Smith	Electric Cooperatives of South Carolina
Andrew Fusco	ElectriCities of NC
Kathy Moyer	ElectriCities of NC
Marty Berland	ElectriCities of NC
Brad Rouse	Energy Savers Network
Steffi Rausch	Energy Savers Network

Michelle Allen	Environmental Defense Fund
Tracy Leslie	EPRI
Keith Lynch	Fayetteville Public Works Commission
Morgan Hylton	Fayetteville Public Works Commission
Ben Snowden	Fox Rothschild LLP
Taylor Speer	Fox Rothschild LLP
Holly Garrett	Gaia Herbs
Amy Wallace	GE
Brian Smith	GE
Kenneth Mayer	GE
Donna Robichaud	Geenex Solar LLC
Lesley Williams	Geenex Solar LLC
Ethan Blumenthal	Good Solar Organization
Jamey Goldin	Google, LLC Lenoir NC
Alissa Bemis	Great Plains Institute (facilitator)
Doug Scott	Great Plains Institute (facilitator)
Trevor Drake	Great Plains Institute (facilitator)
William McNeil	Greensboro Earth Quakers
Alexis Wright	Guidehouse
Ann Thompson	Guidehouse
Chip Wood	Guidehouse
Curt Anderson	Guidehouse
Dan Bradley	Guidehouse
Danielle Vitoff	Guidehouse
Jennifer Ahearn	Guidehouse
Latisha Younger-Canon	Guidehouse
Michael Kline	Guidehouse
Shalom Goffri	Guidehouse

David Mulcahy	Illuminate Power Analytics, LLC
Anne Lazarides	Individual
Bob Rodriguez	Individual
Fred Havasy	Individual
Gail Powell	Individual
Lawrence Toliver	Individual
Mark Nichols	Individual
Stephen McLaurin	Individual
Rosemary Robinson	Individual/Climate Justice Activist
Russell Outcalt	Interfaith Creation Care of the Triangle
Kaley Bangston	Invenergy
Eric Smith	Keystone Tower Systems
Jim Seay	Lockhart Power Company
Nathan Adams	Longroad Energy
Andrea Kells	McGuireWoods LLP
Tess Rogers	McGuireWoods LLP
Tracy DeMarco	McGuireWoods LLP
Erin Stanforth	Mecklenburg County
Sam Kliewer	Meridian Renewable Energy
Steven Castracane	Messer
Daniel Sistrunk	Milliken & Company
Amanda Levin	Natural Resources Defense Council
John Thigpen	Natural Resources Defense Council
Luis Martinez	Natural Resources Defense Council
Ming Zheng	NCDEQ-DAQ
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Chris Ayers	NCUC Public Staff
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Robert Josey	NCUC Public Staff
Scott Saillor	NCUC Public Staff
Shawn Dorgan	NCUC Public Staff
William Zeke Creech	NCUC Public Staff
Leo Woodberry	New Alpha CDC
Dana Villeneuve	New Belgium Brewing
Dan Bruer	New Energy Economics
Joshua Brooks	New Energy Economics
Cathy Buckley	North Carolina Alliance to Protect Our People and the Places We Live
Kristal Suggs	North Carolina Climate Justice Collective
Will Scott	North Carolina Conservation Network
Jennifer Mundt	North Carolina Department of Commerce
Michelle Boswell	North Carolina Department of Commerce
Katherine Quinlan	North Carolina Department of Environmental Quality

Paula Hemmer	North Carolina Department of Environmental Quality
Francisco Benzoni	North Carolina Department of Justice - Attorney General
Margaret Force	North Carolina Department of Justice - Attorney General
Teresa Townsend	North Carolina Department of Justice - Attorney General
Tirrill Moore	North Carolina Department of Justice - Attorney General
Jen Weiss	North Carolina Department of Transportation
Michael Abraczinskas	North Carolina Division of Air Quality
Deborah Britt	North Carolina Electric Membership Cooperative
James Manning	North Carolina Electric Membership Cooperative
Khalil Porter	North Carolina Electric Membership Cooperative
Lee Ragsdale	North Carolina Electric Membership Cooperative
Michael Youth	North Carolina Electric Membership Cooperative
Nicole Hensley	North Carolina Electric Membership Cooperative
Richard McCall	North Carolina Electric Membership Cooperative
Tim Dodge	North Carolina Electric Membership Cooperative
Robert Beadle	North Carolina EMC
Dionne Delli-Gatti	North Carolina Governor's Office
Jeremy Tarr	North Carolina Governor's Office
Gary Smith	North Carolina Interfaith Power & Light
Susannah Tuttle	North Carolina Interfaith Power & Light
Alfred Ripley	North Carolina Justice Center
Claire Williamson	North Carolina Justice Center
Robin Smith	North Carolina League of Conservation Voters
Ross Smith	North Carolina Manufacturers Alliance (NCMA)
Benjamin Smith	North Carolina Sustainable Energy Association
Daniel Brookshire	North Carolina Sustainable Energy Association
Peter Ledford	North Carolina Sustainable Energy Association
Robert Bennett	North Carolina Sustainable Energy Association
Taylor Jones	North Carolina Sustainable Energy Association
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Tommy Williamson	North Carolina Utilities Commission Public Staff
Christine Csizmadia	Nuclear Energy Institute
Jon Meyer	Nutrien
Hayes Framme	Orsted
Patrick Ballantine	Orsted

Skylar Drennen	Orsted
Scott Bragg	PactivEvergreen
Thomson Riley	Palantir
Mark Mirabito	Palladium Energy
Katherine Ross	Parker Poe
Merrick Parrott	Parker Poe
Sherry Wilborn	Person County ED
Adam Stein	Pine Gate Renewables, LLC
Steven Levitas	Pine Gate Renewables, LLC
Mary Perkins-Williams	Pitt County Board of Commissioners
Matthew LaRocque	PJM Interconnection LLC
Jeff Strickland	Plus Power
Ric Austria	Pterra Consulting
Matthew Delafield	Renewable Energy Services
Tom Delafield	Renewable Energy Services
Deb Wojcik	Research Triangle Cleantech Cluster
Becky Li	RMI
Diego Angel	RMI
Jacob Becker	RMI
Kirsten Millar	RMI
Julie Robinson	Robinson Consulting Group
Tommy Chapman	Rutherford Electric Membership Corporation
James Sun	RWE Renewables
Max Friedman	RWE Renewables
Weijian Cong	Santee Cooper
Will Brown	Santee Cooper
Jeff Solomon	Savion
Richie Ciciarelli	Schonfeld Strategic Advisors, LLC

Sharon Allan	SEPA
Cassie Gavin	Sierra Club
David Rogers	Sierra Club
Justin Somelofske	Sierra Club
Mikaela Curry	Sierra Club
William Blaine	Sierra Club
Stephanie Sienkowski	Soltage
Eliza Mecaj	South Carolina Department of Consumer Affairs
Joan Williams	South Carolina Department of Consumer Affairs
Anthony Sandonato	South Carolina Office of Regulatory Staff
Gretchen Pool	South Carolina Office of Regulatory Staff
O'Neil Morgan	South Carolina Office of Regulatory Staff
Robert Lawyer	South Carolina Office of Regulatory Staff
Stacey Washington	South Carolina Office of Regulatory Staff
Marvin Neal	South Carolina State Conference NAACP
Ann Livingston	Southeast Sustainability Directors Network
Caitlin Rose	Southeast Sustainability Directors Network
Jaime Simmons	Southeastern Wind Coalition
Forest Bradley Wright	Southern Alliance for Clean Energy
Maggie Shober	Southern Alliance for Clean Energy
Hamilton Davis	Southern Current LLC
Ronald DiFelice	Southern Current LLC

David Neal	Southern Environmental Law Center
Emma Clancy	Southern Environmental Law Center
Gudrun Thompson	Southern Environmental Law Center
Kate Mixson	Southern Environmental Law Center
Lauren Bowen	Southern Environmental Law Center
Nicholas Jimenez	Southern Environmental Law Center
Simon Mahan	Southern Renewable Energy Association
Stephanie Eaton	Spilman Thomas & Battle, PLLC
Bill Maloney	St Eugene Catholic Church - Care of Creation Team
Marshall Conrad	Strata Clean Energy
Edward Burgess	Strategen Consulting
Katherine Wyszkowski	Sunnova

Thad Culley	Sunrun Inc.
Tyler Fitch	Synapse Energy Economics
John Hammerly	The Glarus Group LLC
John Wadsworth	Thread Trail Enterprises
Floyd Keneipp	Tierra Resource Consultants
Megan Pendell	Town of Apex
Katie Rose Levin	Town of Cary
John Richardson	Town of Chapel Hill
Jonas Monast	UNC School of Law
Chip Estes	UTILICOM
Jackson Freeman	Vestas North Americas
*There were an additional 21 participants who called in by phone that are not listed here as Zoom webinar cannot capture the names of dial-in attendees.	

Duke Energy Carolinas Carbon Plan Stakeholder Meeting 3

Virtual Meeting – March 22, 2022

**Please note, this meeting is being recorded. Presentations will be posted on the Carolinas Carbon Plan website, and discussion portions will be kept for internal purposes only to ensure accuracy of meeting notes.*

GREAT PLAINS INSTITUTE

Better Energy.
Better World.

Welcome!

Please introduce yourself (name and organization) in the chat.

GREAT PLAINS INSTITUTE

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Better World.

Today’s Agenda

9:30am:	Introduction, Welcome, Housekeeping
9:45am:	Duke Response to Stakeholder Desired Outcomes
10:15am:	Discussion on Grid Edge and Customer Programs: Empowering Customers to Reduce Carbon Emissions
10:45am:	Break
11:00am:	Discussion on Grid Edge and Customer Programs: Empowering Customers to Reduce Carbon Emissions cont.
12:00pm:	LUNCH BREAK
1:00pm:	Transmission Impacts in Carbon Plan
1:45pm:	Overview of the North Carolina Transmission Planning Collaborative
2:30pm:	Break
2:45pm:	Clean Power Suppliers Association and Brattle Group Presentation on Carbon Plan Modeling
3:30pm:	Duke Update on Modeling and Development of Potential Pathways
4:30pm:	Wrap Up, Adjourn

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Duke Welcome

Swati Daji

Senior Vice President, Enterprise Strategy & Planning

Meeting Ground Rules

- **Respect each other:** Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations. We need everyone's wisdom to achieve better understanding and develop robust solutions.

- **Focus on values and outcomes:** Today's discussion is about what stakeholders value in the energy future, and how the Carolinas Carbon Plan can align with those values. Pending legal issues are outside the scope of this conversation.

- **Chatham House Rule**: Empower others to voice their perspective by respecting the "Chatham House Rule;" you are welcome to share information discussed, but not a participant's identity or affiliation (including unapproved recording of this session).

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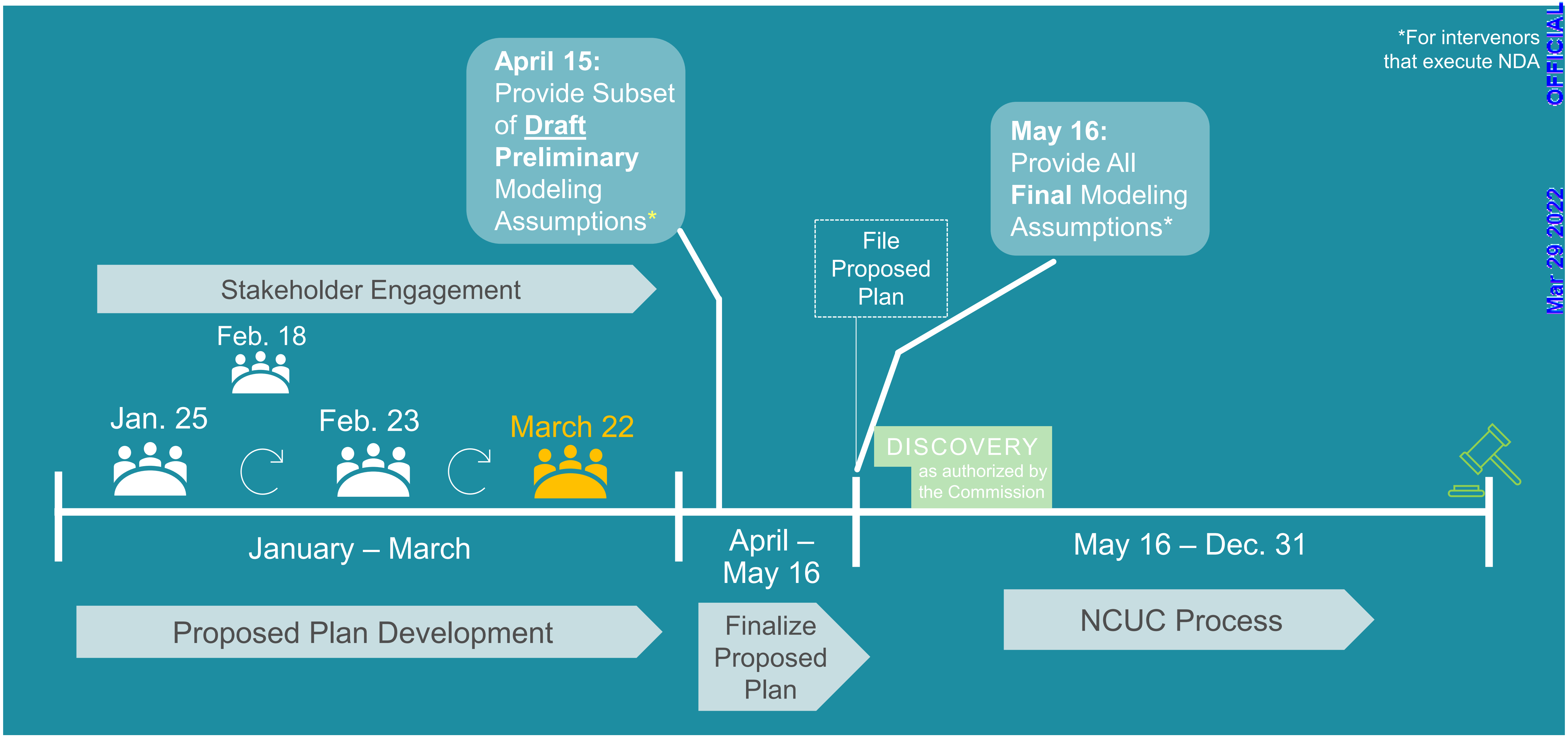
Meeting Ground Rules

- **Respect the time:** Our time together is limited and valuable, and we have a large group, so please be mindful of the time and of others' opportunity to participate.

- **Use the chat:** Please submit your comments and questions in the chat. GPI staff will monitor the chat to pull out questions for Q&A portions. Please be respectful and focus on issues, not people.

- **Raise your hand:** During dedicated Q&A portions of the meeting, use the "Raise Hand" feature to indicate you would like to voice a question or comment.

Carbon Plan Development Process



*For intervenors that execute NDA

April 15: Provide Subset of **Draft Preliminary** Modeling Assumptions*

File Proposed Plan

May 16: Provide All **Final** Modeling Assumptions*

Stakeholder Engagement

Feb. 18

Jan. 25

Feb. 23

March 22

DISCOVERY as authorized by the Commission

January – March

April – May 16

May 16 – Dec. 31

Proposed Plan Development

Finalize Proposed Plan

NCUC Process

Stakeholder Desired Outcomes

Duke Energy Response

MARCH 22, 2022

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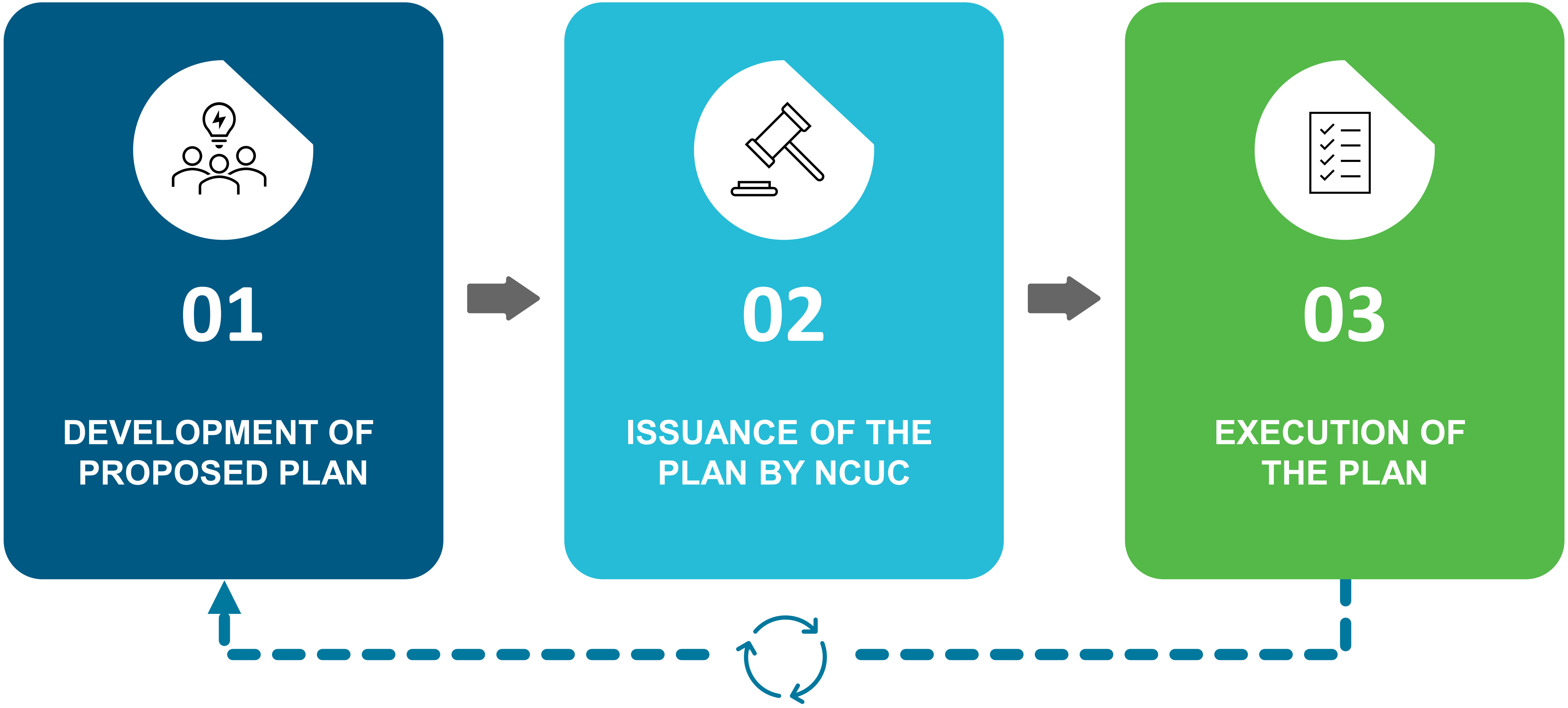
Phases of Carbon Plan Development and Execution



01

DEVELOPMENT OF PROPOSED PLAN

02

ISSUANCE OF THE PLAN BY NCUC

03

EXECUTION OF THE PLAN

UPDATE CARBON PLAN

Stakeholder Desired Outcomes

The following desired outcomes will be addressed in the **development** of the proposed Carbon Plan:

Engagement

- Consider input from stakeholders and recognize where input changed assumptions, and what those changes were.
- Identify areas of consensus on as many issues as possible prior to filing.
- Incorporate recommendations from related stakeholder engagement processes, including but not limited to the Clean Energy Plan stakeholder process, the Low-Income Affordability Collaborative, and the Working Group on Climate Risk and Resilience.

Modeling

- Consider new or expanded customer-facing programs for energy efficiency, DSM, and renewables.
- Consider a modeling approach that begins with a few alternative end states that meet the goal.

Analysis

- Maintain a long-term view towards achieving a net-zero system (keep the end goal in mind).
- Strive to achieve fair and affordable rates and total costs for all customers, including at-risk/low- and moderate-income households and communities.
- Enhance resilience and grid hardening through changes over time.

Stakeholder Desired Outcomes

The following desired outcomes will be addressed in the **development** of the proposed Carbon Plan:

Transparency

- Transparently present modeling and measurement assumptions, inputs, and tools to the extent possible while protecting trade secret and copyrighted information. Ensure no inherent bias. Include analysis of improvements to the transmission grid.
- Transparently present metrics and principles being used to develop pathways and make modeling decisions.
- Transparently present the impacts of the plan, including costs.
- Clarify policy and regulatory interdependencies with the other components of HB 951.
- Clarify consideration of carbon costs and carbon policies in the selected scenarios.
- Clarify definition of net zero.
- Clarify the approach to siting facilities between North Carolina and South Carolina.

Stakeholder Desired Outcomes

The following desired outcomes will be addressed in the **execution** of the Carbon Plan:

Siting and Community Impacts

- Take a holistic and intentional approach to the siting of new facilities, avoiding areas already disproportionately impacted by energy generation or other industrial facilities.
- Provide support for coal plant host communities to address the economic and community impacts of plant retirements.
- Center environmental justice communities in the development of the carbon plan.

Integrate Other Efforts

- Incorporate recommendations from related stakeholder engagement processes, including but not limited to the Clean Energy Plan stakeholder process, the Low-Income Affordability Collaborative, and the Working Group on Climate Risk and Resilience.

OFFICIAL COPY

Mar 29 2022

Stakeholder Desired Outcomes

The following desired outcomes are being addressed through other work streams:

Environmental Impacts Beyond CO_2

- Address all greenhouse gas emissions beyond carbon dioxide, including upstream methane leakage from natural gas being delivered to electric power plants.
- Consider life cycle assessment of all system resources, including but not limited to construction of infrastructure, etc., to get to net zero

Support Favorable Business Environment

- Support the ability of businesses and industries to operate competitively, preserve existing jobs, and/or to create new jobs.
- Consider the carbon reduction goals and plans of cities and businesses in Duke's service territories.

Grid Resilience/Hardening

- Enhance resilience and grid hardening through changes over time.

Affordability For All Customers

- Strive to achieve fair and affordable rates and total costs for all customers, including at-risk/low- and moderate-income households and communities.

Grid Edge and Customer Programs

EE/DSM Update

TIM DUFF
GENERAL MANAGER, RETAIL CUSTOMER AND REGULATORY STRATEGY

MARCH 22, 2022

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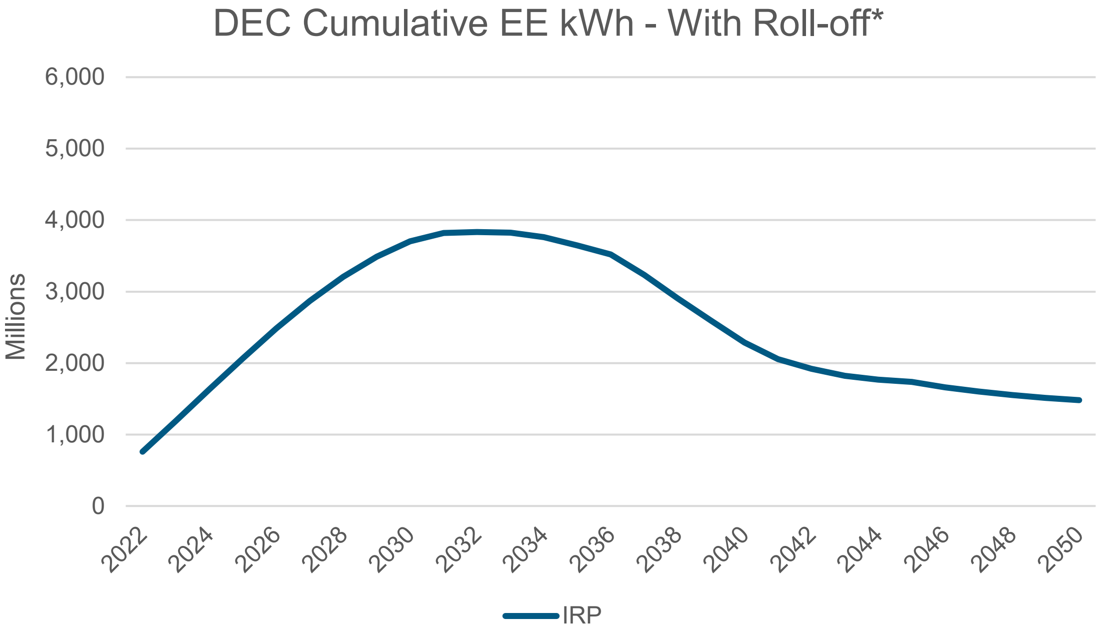
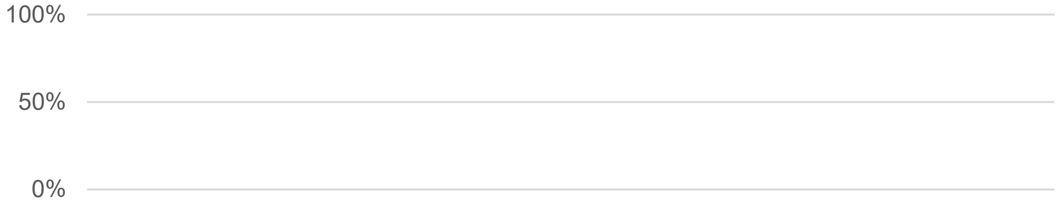
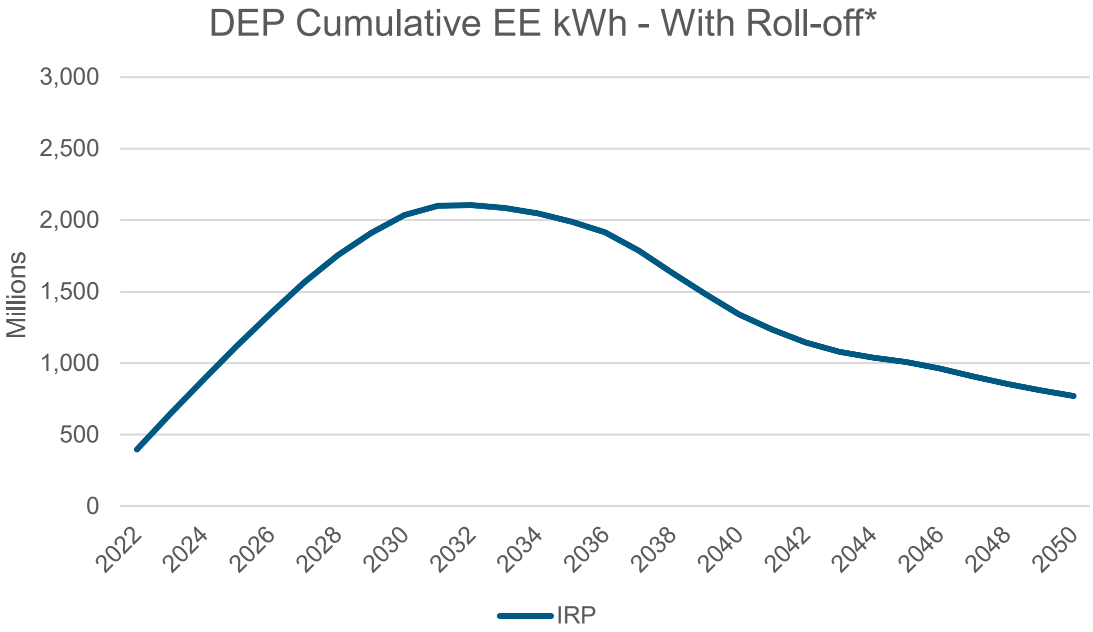
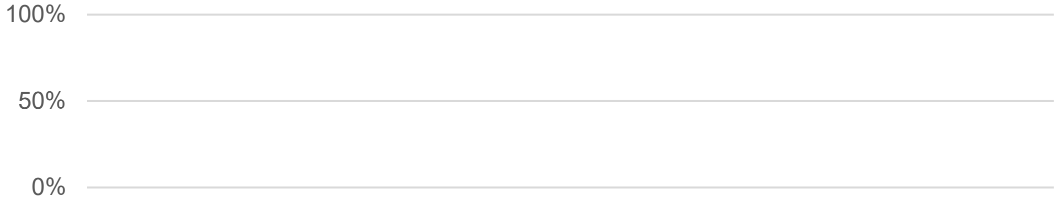
IRP Forecast – Budget + MPS blend





Cumulative 1% Available vs. IRP Case





Cumulative 1% Available vs. IRP Case

* Roll-off:

- Energy saving impacts no longer represented in our EE forecast as measures reach “end of life”
- Ongoing savings are accounted for in the load forecast.

Energy Efficiency Update

MARCH 22, 2022

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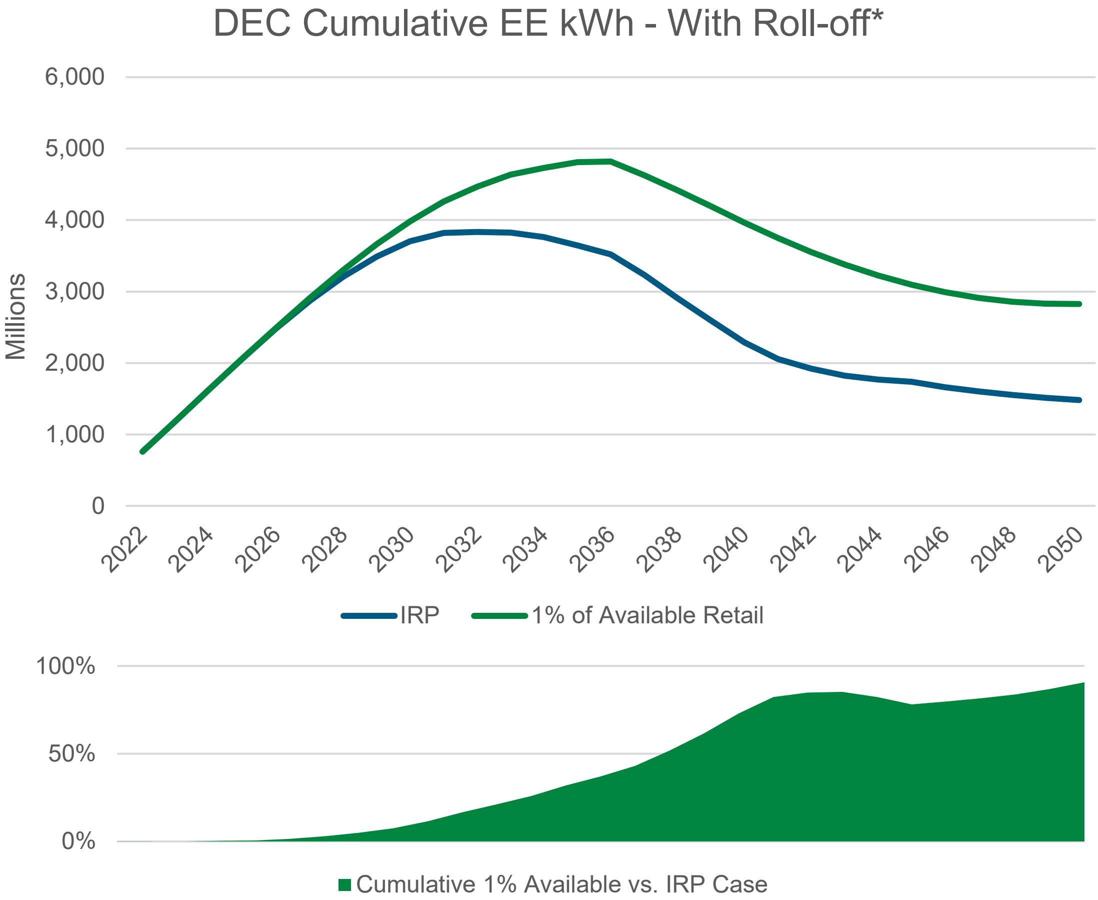
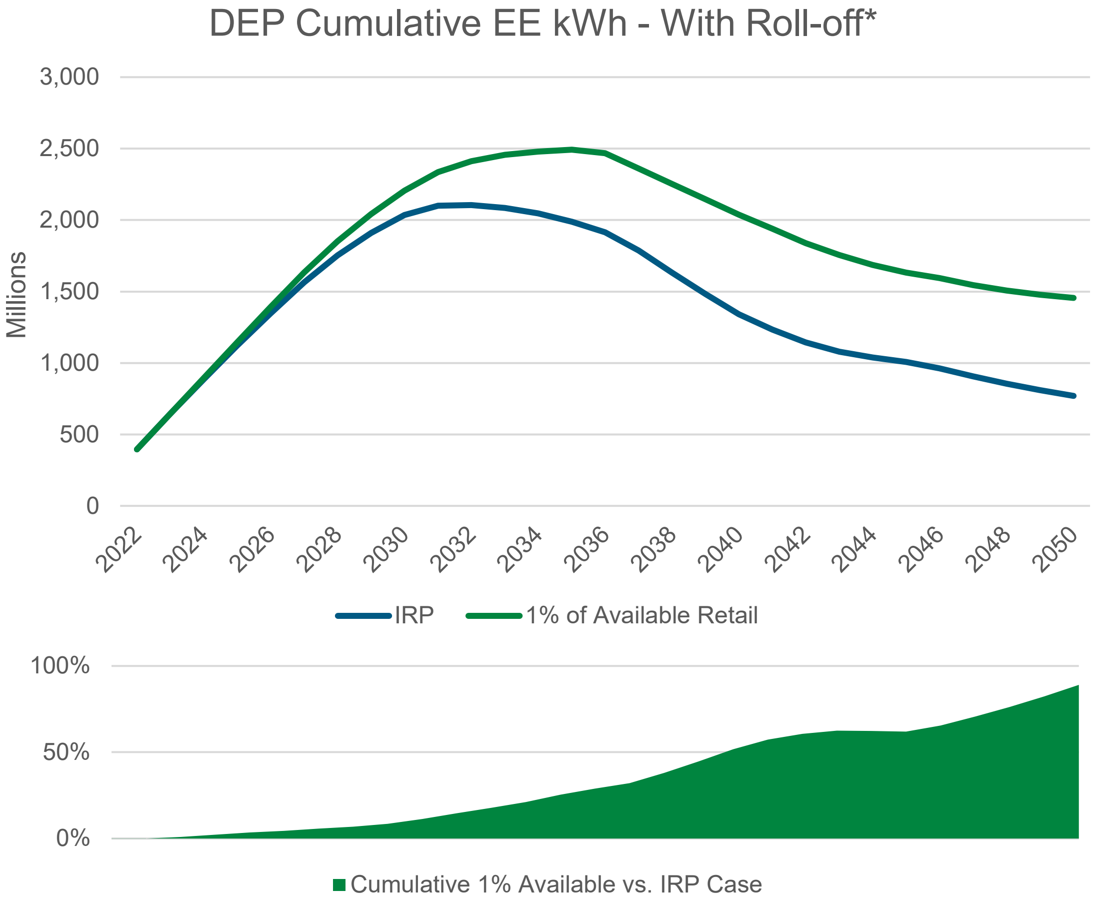
Base Forecast – 1% of Available Retail Load

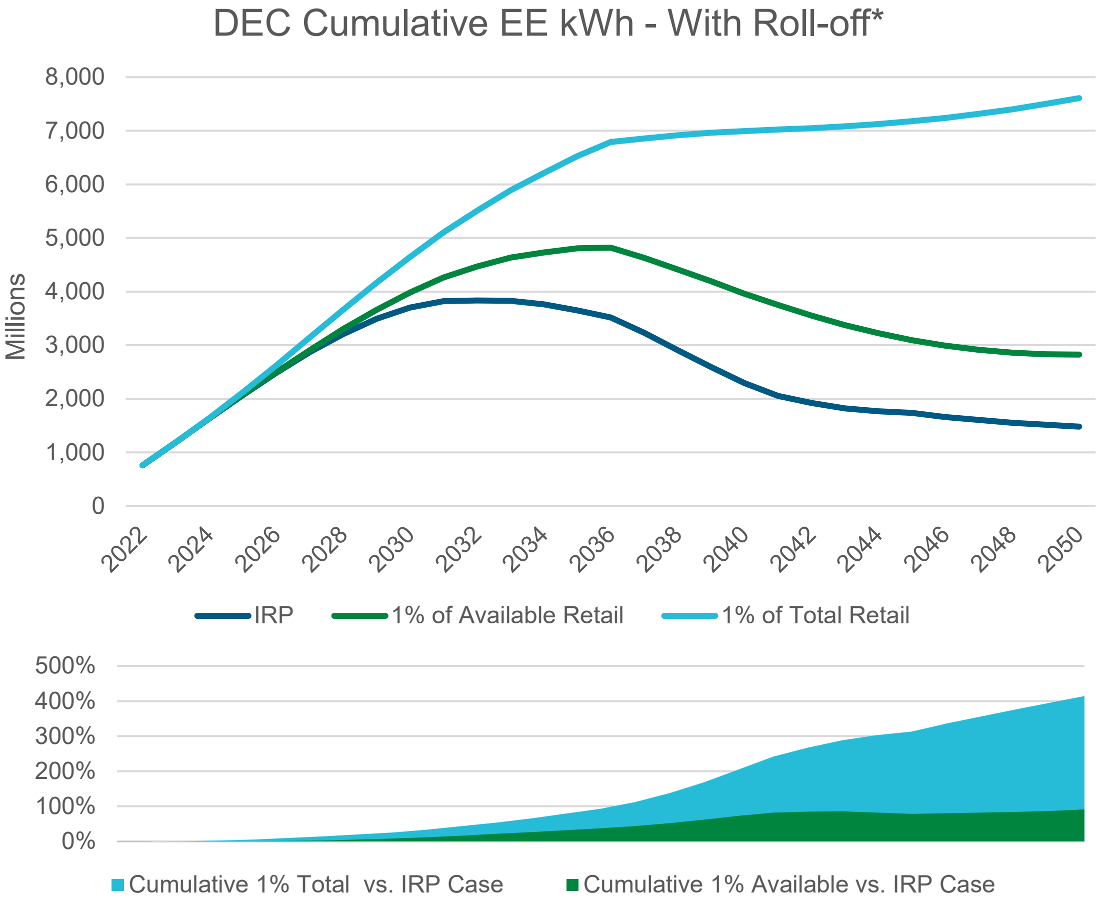


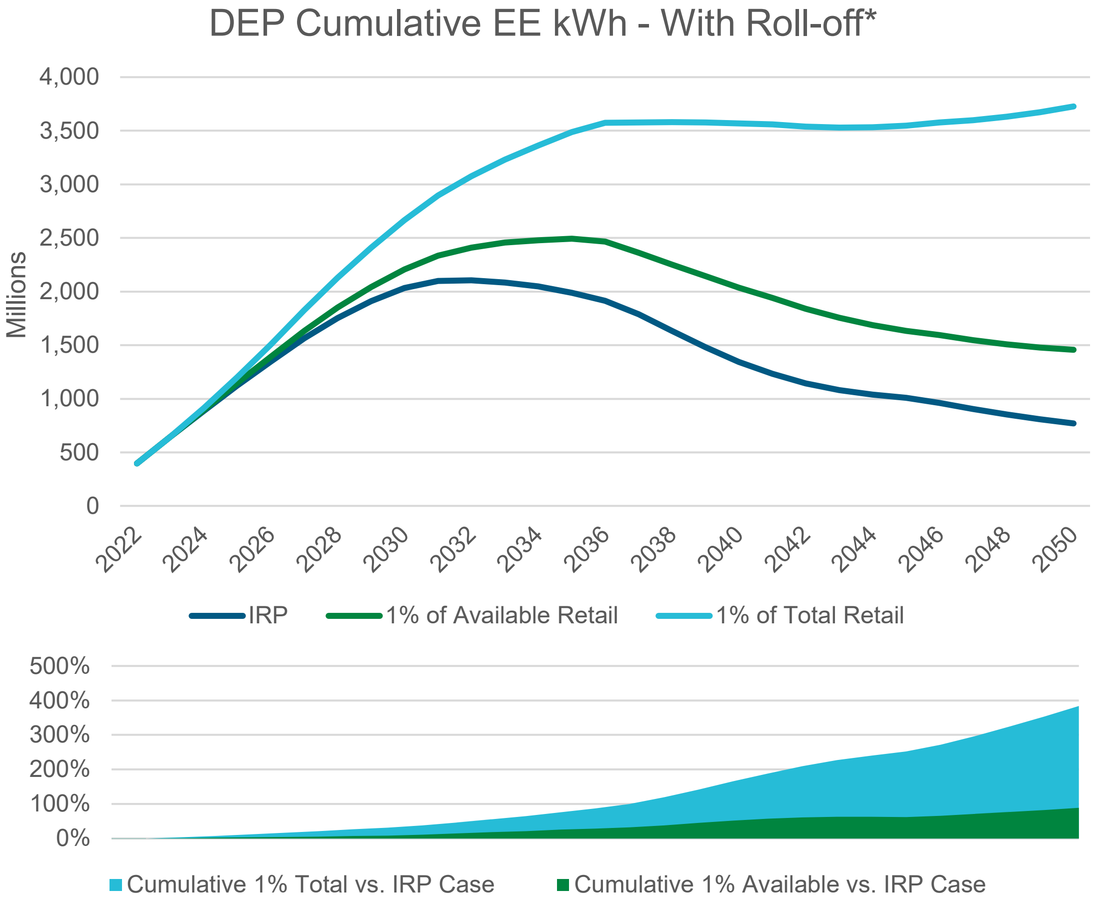


* Roll-off:

- Energy saving impacts no longer represented in our EE forecast as measures reach “end of life”
- Ongoing savings are accounted for in the load forecast.

High Forecast – 1% of Total Retail Load


DEC Cumulative EE kWh - With Roll-off*


DEP Cumulative EE kWh - With Roll-off*

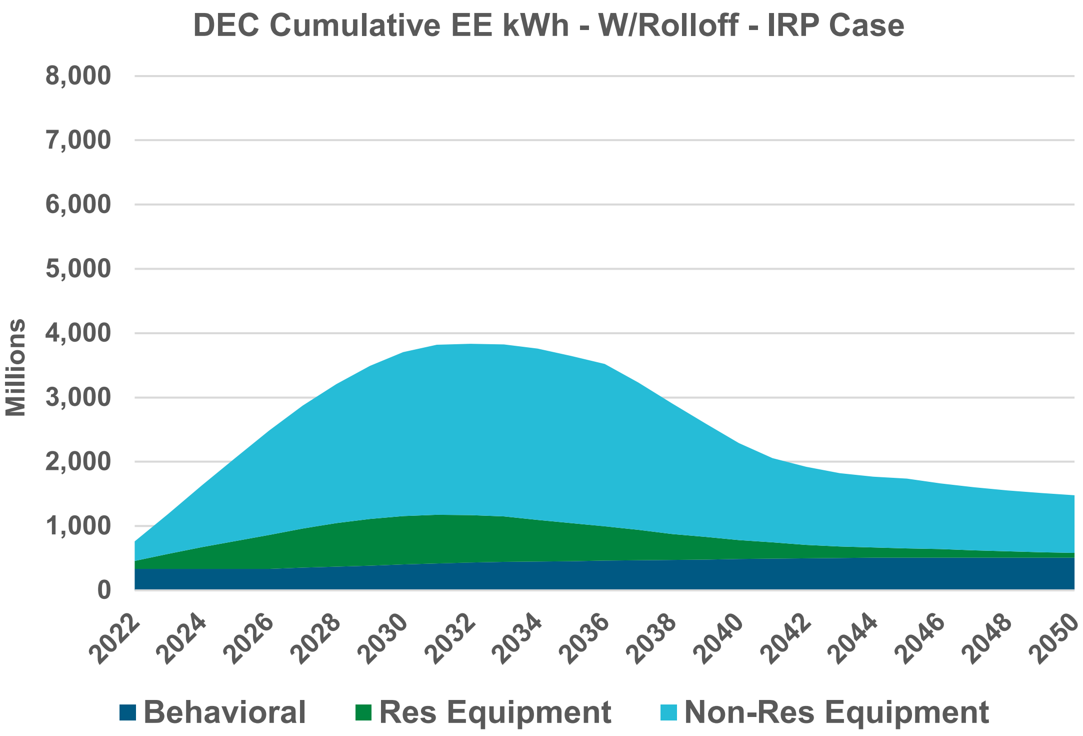
* Roll-off:

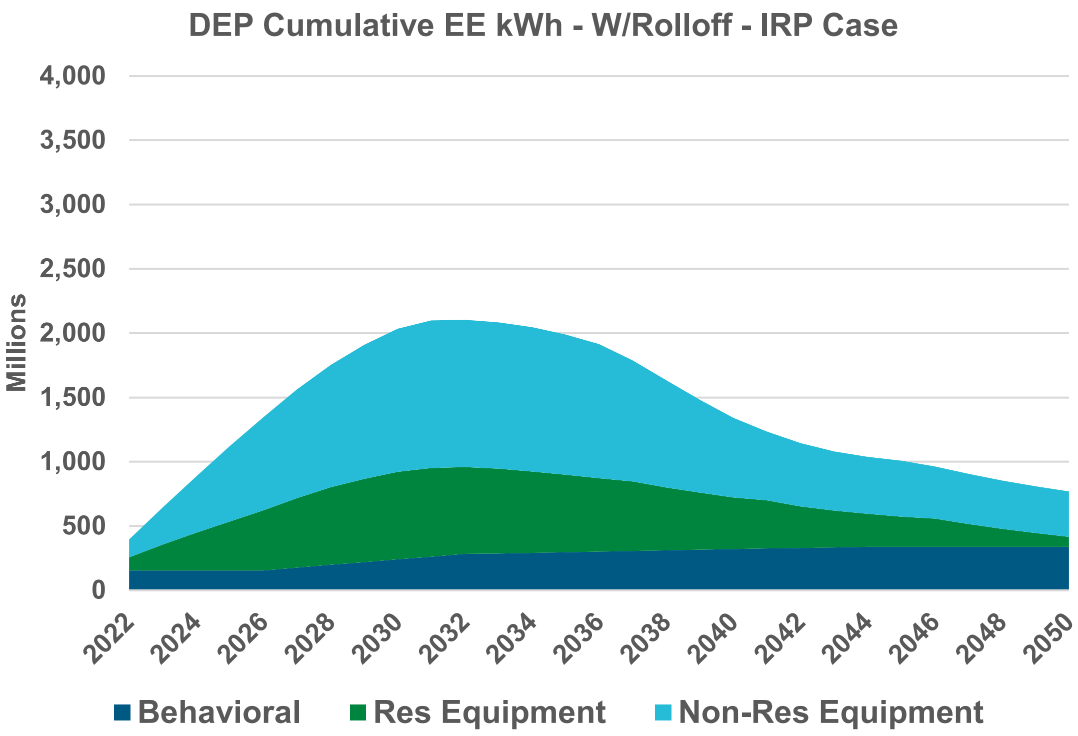
- Energy saving impacts no longer represented in our EE forecast as measures reach “end of life”
- Ongoing savings are accounted for in the load forecast.

EE program Spending Comparison

Period	Percentage Cost Increase vs IRP	
	1% Eligible Sales	1% of Total Sales
2022-2030	6.7%	13.0%
2030-2050	52.6%	156.9%
2022-2050	32.7%	94.3%

IRP Forecast – Budget + MPS blend

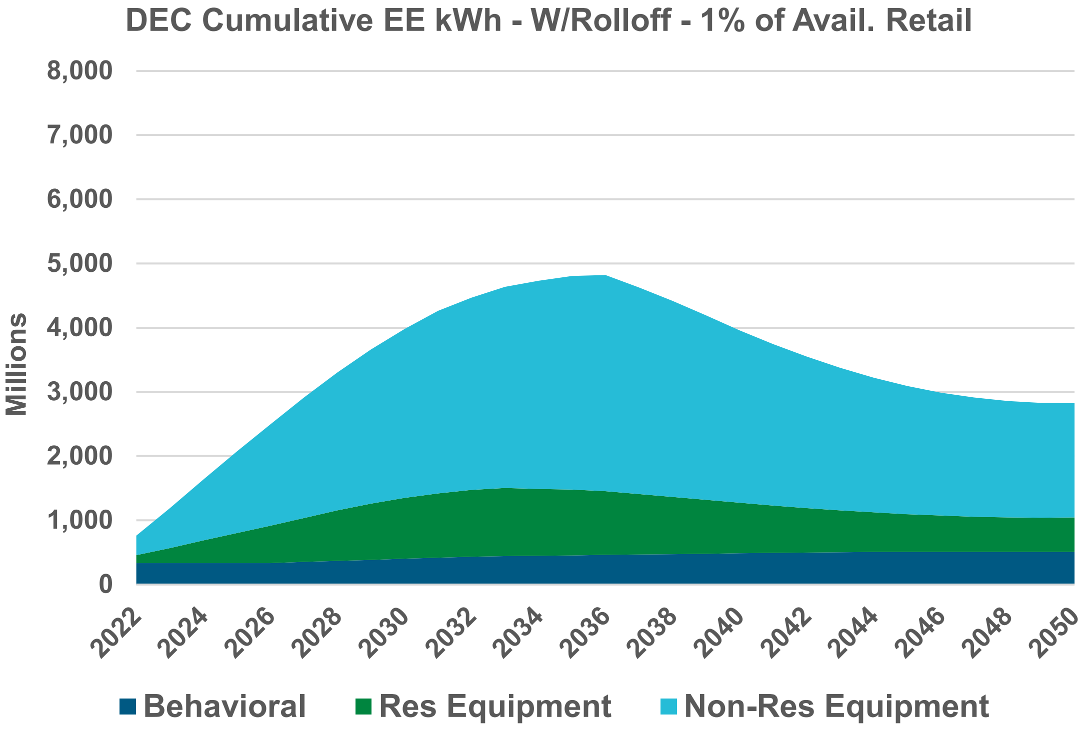


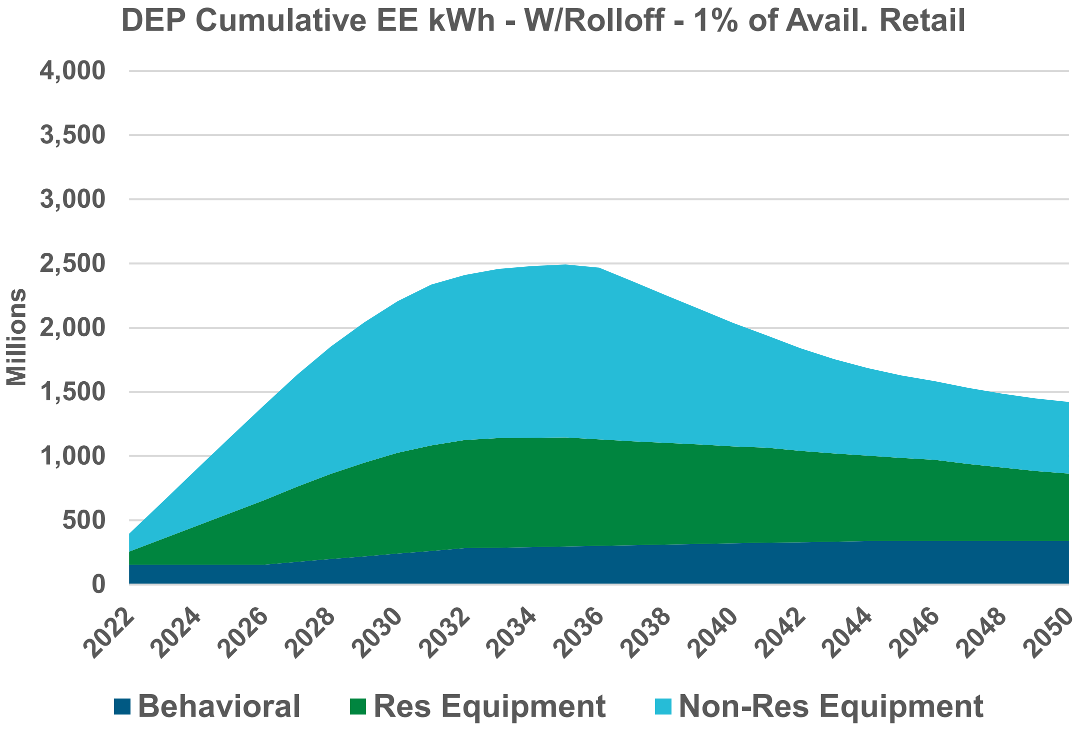


* Roll-off:

- Energy saving impacts no longer represented in our EE forecast as measures reach “end of life”
- Ongoing savings are accounted for in the load forecast.

Base Forecast – 1% of Available Retail Load





* Roll-off:

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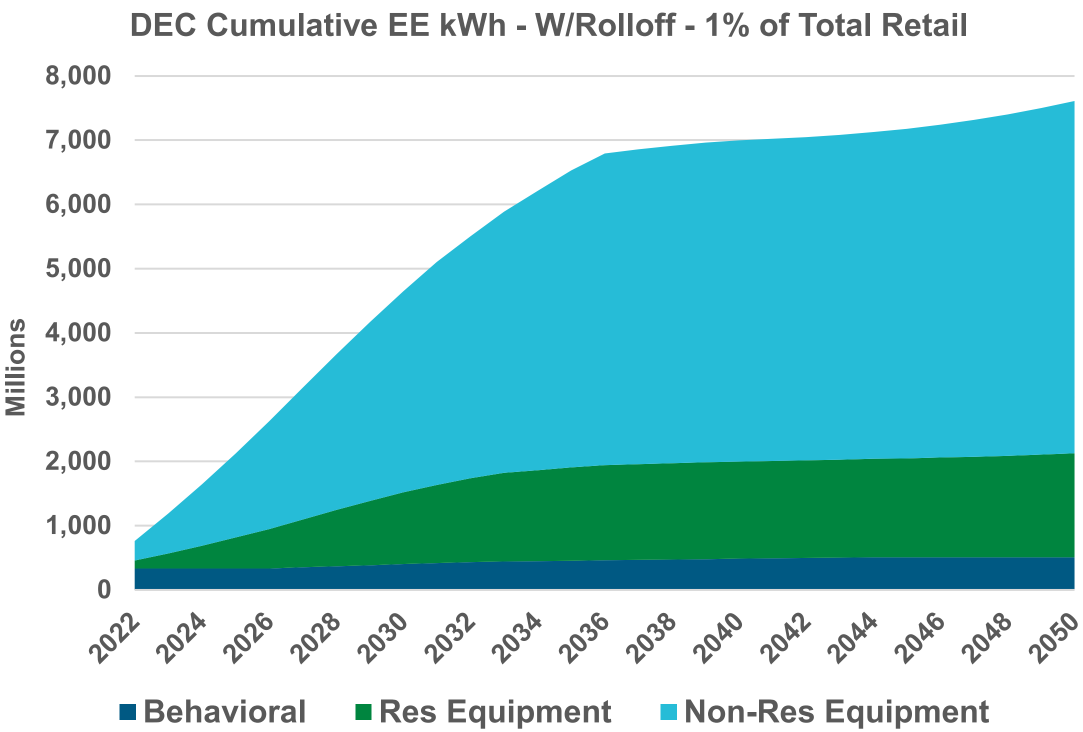
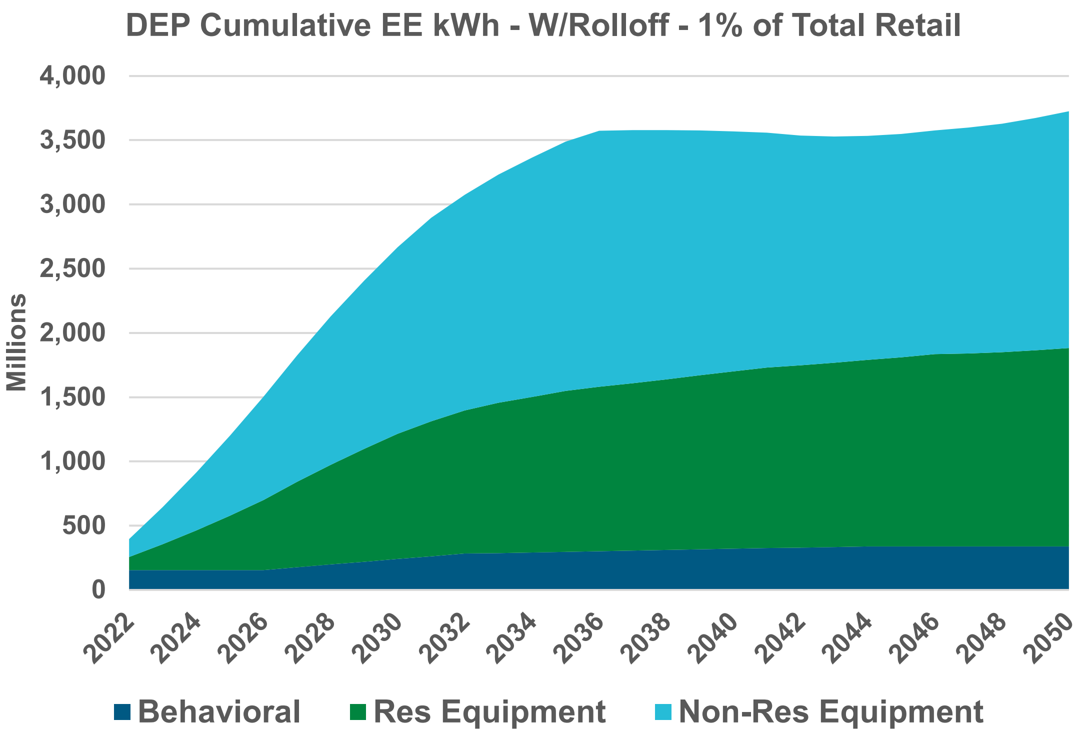
- Ongoing savings are accounted for in the load forecast.

High Forecast – 1% of Total Retail Load





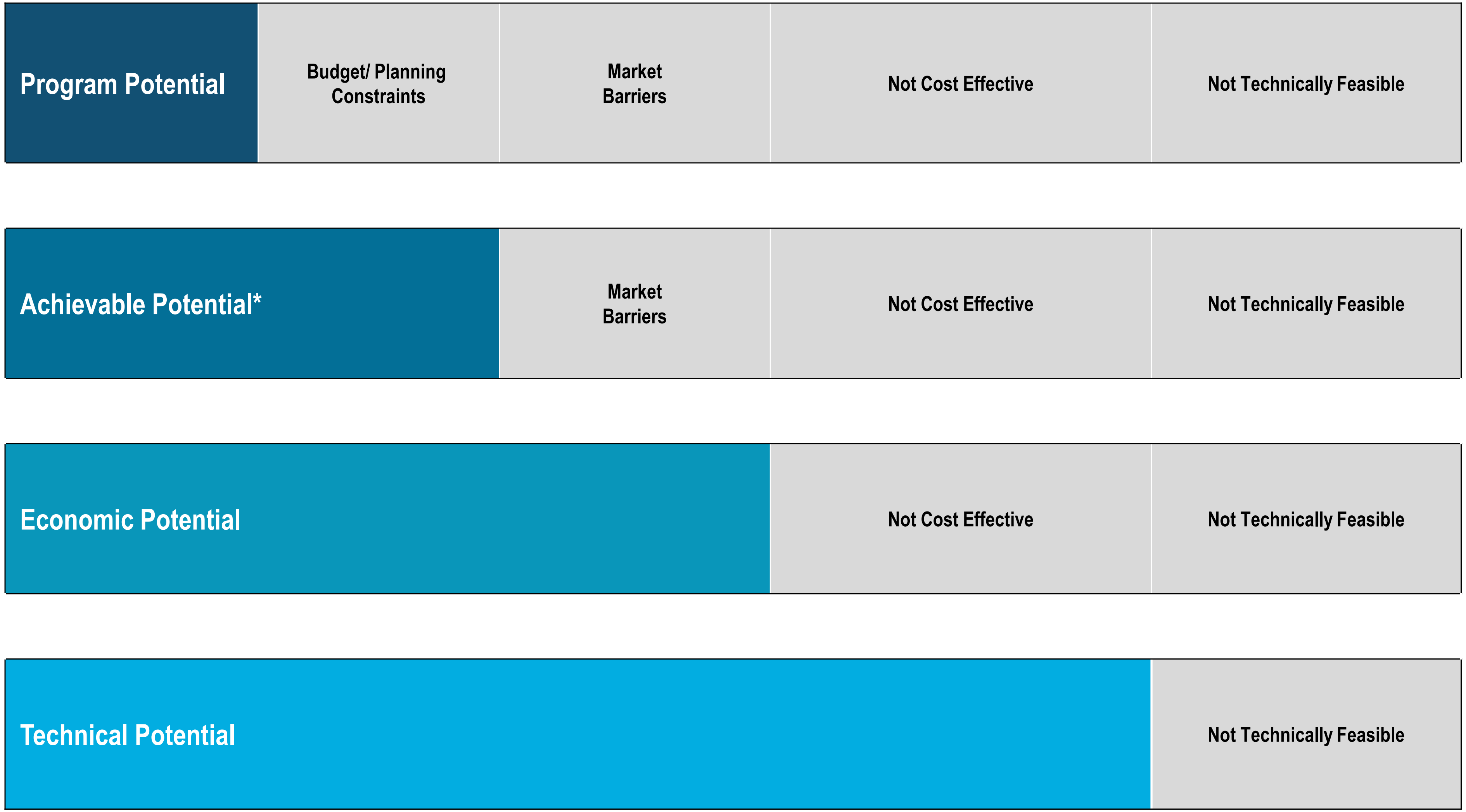
* Roll-off:

- Energy saving impacts no longer represented in our EE forecast as measures reach “end of life”
- Ongoing savings are accounted for in the load forecast.

Putting 1% of Retail Sales in Context

State	Average Residential Usage (KWH)	Average Residential Rate ($/KWH)	1% EE of Annual Retail Sales per Customer (KWH)	Equivalent Annual EE Savings Percentage for Duke Customer
Arkansas	12,720	0.126	127	0.98%
Massachusetts	7,224	0.243	72	1.73%
Oregon	10,992	0.112	110	1.14%
Colorado	8,532	0.135	85	1.46%
Iowa	10,380	0.116	104	1.20%
Vermont	6,804	0.196	68	1.84%
Illinois	8,652	0.135	87	1.44%
Duke Energy (NC & SC)	12,494	0.110	125	1.00%
California	6,864	0.232	69	1.82%
Rhode Island	7,128	0.251	71	1.75%
Minnesota	9,300	0.128	93	1.34%

Moving Beyond the Carolinas’ Base EE/DSM Forecast



Program Potential | Budget/ Planning Constraints | Market Barriers | Not Cost Effective | Not Technically Feasible

Program additions and modifications to optimize existing program portfolio impacts

Achievable Potential* | Market Barriers | Not Cost Effective | Not Technically Feasible

Structural modifications and mechanisms that remove market barriers to program participation

Economic Potential | Not Cost Effective | Not Technically Feasible

Modifications that will enhance the cost effectiveness of new programs and enable program modifications

Technical Potential | Not Technically Feasible

Modifications that will expand the number of potential measures and offers reducing consumption from the grid

Potential Enablers for Delivering More EE/DSM in the Carolinas

Structural modifications and mechanisms that remove market barriers to program participation

On-Tariff Financing	Establishing an on-tariff financing program and the necessary recovery mechanism consistent with HB951 to reduce upfront capital costs and credit barriers to undertaking energy efficiency
Marketing enhancements	AMI and other customer data allows better target marketing of programs to customer with high energy savings potential from specific measures

Modifications enhancing the cost effectiveness of new programs and enabling program changes

Recognition of the value of carbon	A financial value recognizing the value of avoided carbon emissions from energy efficiency programs in cost effectiveness evaluation (UCT).
As Found Energy Savings Recognition	Currently energy savings only recognize savings versus a device's efficiency standard despite the fact true carbon reduction is the energy reduction versus the actual device replace
Recognition of localized customer programs values	Identify overloaded circuits/substations and target localized customer programs to offset specific required high T&D spend

Modifications expanding the potential measures and offers reducing consumption from the grid

Utility Codes and Standards Program	Currently advancement of building codes and appliance standards reduces potential savings. Creating opportunity for attribution associated with code advancement and compliance
Customer owned assets that reduce grid consumption	Opportunity to incentivize customers to adopt assets like rooftop solar that reduce energy consumption and carbon emissions from the utility grid.not currently shown as potential
Development of energy efficiency programs for new electrification loads	Currently electrification adds load to the forecast, but little to no energy efficiency opportunities associated with load that actually reduces non-utility carbon emissions
Modifications to Non-Residential Customer Opt Out	Currently energy and carbon savings associated with efficiency potential for industrial and customers using over 1,000,000 KWH not able to be achieved through utility programs
Expand EE Programs to wholesale customers	Opportunity to expand potential EE savings and carbon savings to include potential from customers that take generation from the Duke Carolinas' system.

Grid Edge and Customer Programs

Demand Response

STACY PHILLIPS
DIRECTOR, DEMAND SIDE MANAGEMENT

MARCH 22, 2022

DUKE ENERGY®

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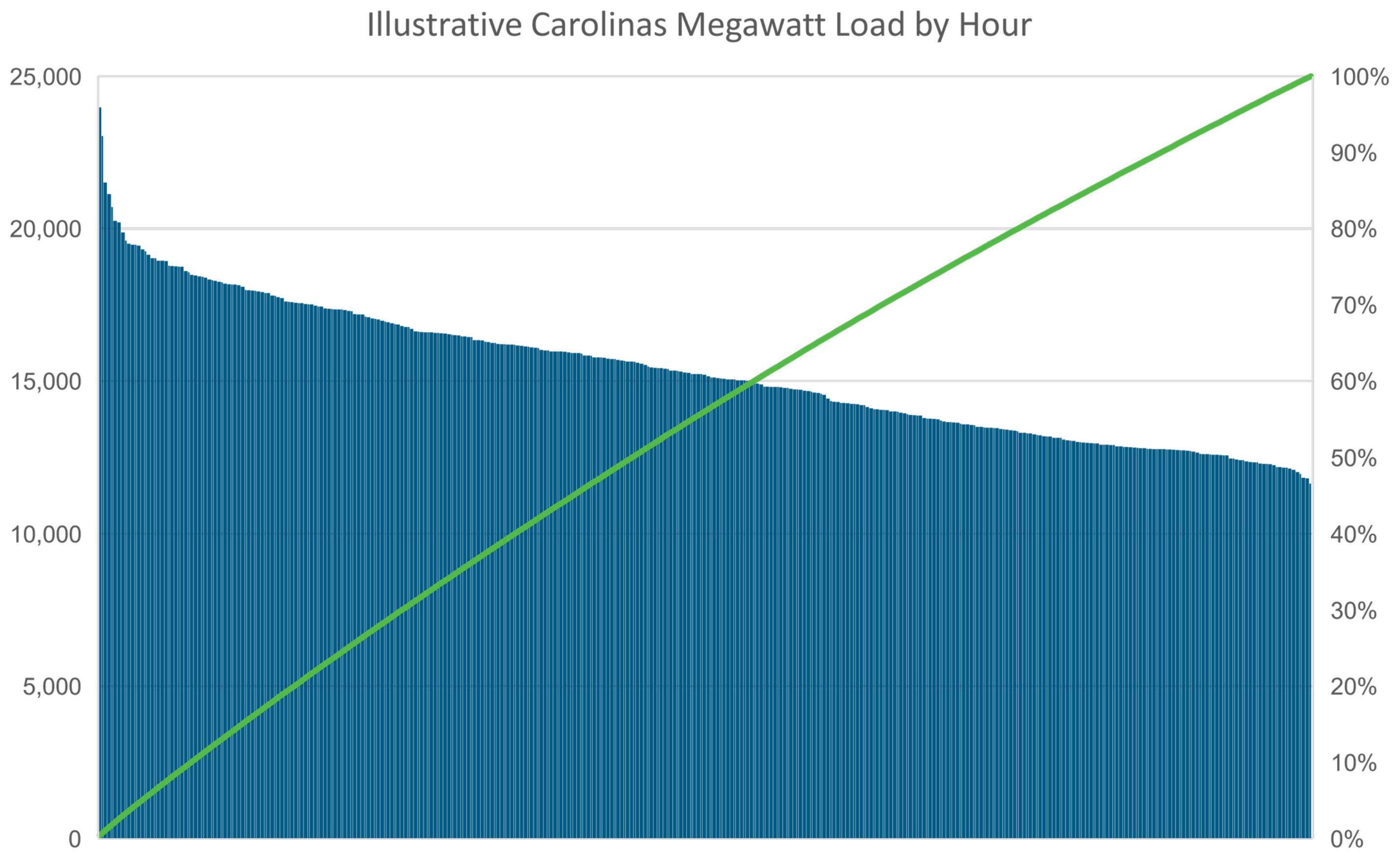
Demand Response Overview

Virtual Peaker Plant

- Duke compensates customers for the ability to curtail their usage during times of extreme load or temperatures.
- Load shed capability is included in IRP planning.

Everyone Wins

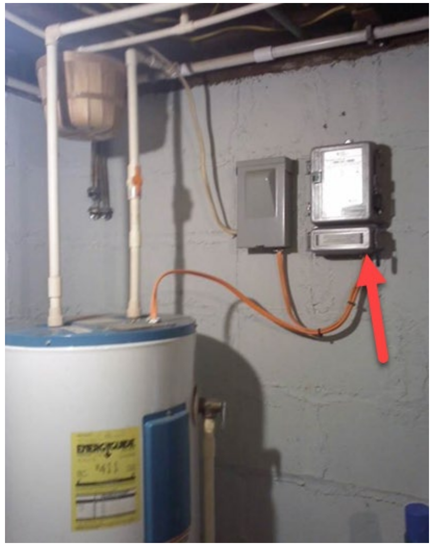
- Utility does not build a little used plant, mitigating rate increases
- Customers earn bill credits
- Improves reliability



Carolinas Demand Response Portfolio

Duke Energy Carolinas

		Summer – 897 MW	Winter – 412 MW
Res	Power Manager Switch	419 MW	0 MW
	Bring Your Own Thermostat	41 MW	9 MW
Non - Residential	PowerShare	363 MW	318 MW
	Interruptible Service	61 MW	81 MW
	EnergyWise Business	11 MW	2 MW
	Standby Generation	2 MW	2 MW



Duke Energy Progress

		Summer – 707 MW	Winter – 276 MW
Res	Power Manager Switch	406 MW	14 MW
	Bring Your Own Thermostat	20 MW	8 MW
Non - Residential	Demand Response Automation	35 MW	22 MW
	Large Load Curtailable	242 MW	232 MW
	EnergyWise Business	4 MW	0.2 MW

Almost 500,000 residential customers participate across the Carolinas.

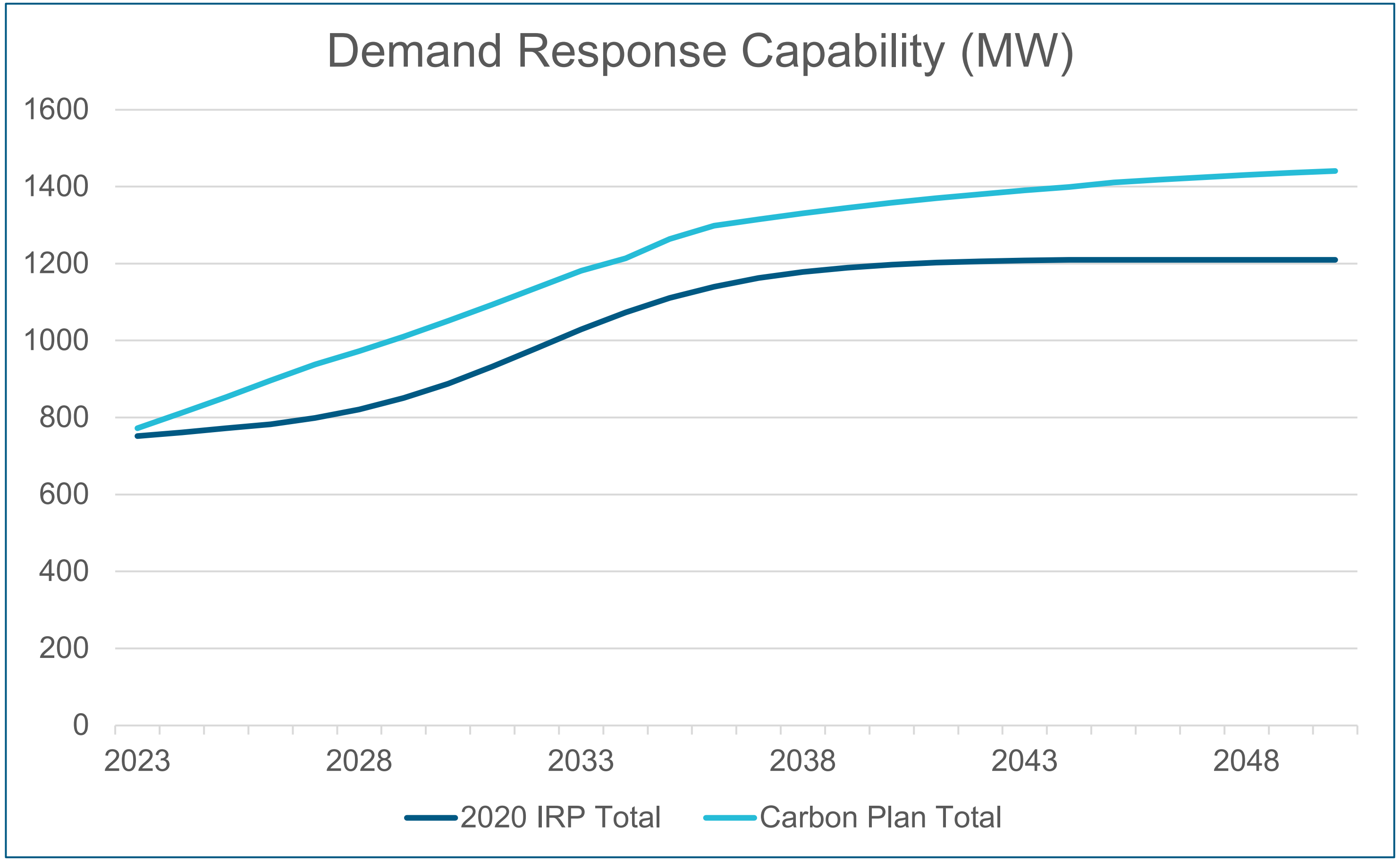
Winter Capability Growth

Virtual Peaker Plant

- Currently modeling approximately 1050 MW of winter capability in 2030.
- 18% increase over the previous IRP
- Minimal winter capability before 2021

Initiatives

- Focusing on residential heat load, growing Bring Your Own Thermostat
- Small / Medium Business program enhancements
- Auto DR capability
- Programs outside of the Winter Peak Study



Demand Response Industry Evolution

DR 1.0 Demand Response

- Largely manual control
- One way paging, can't confirm load shed
- Commercial / industrial interruptible tariffs
- Used for capacity and planning

1970's – 2000's

DR 2.0 Auto Demand Response

- Smart thermostats
- Increased automation and precision
- Two way communications with devices – aware of device status
- Near real-time visibility

2000's – 2010's

DR 3.0 Demand Flexibility

- DR is just one of many DERs used to manage the grid
- Rate enabled devices and appliances
- Provide multiple grid / ancillary services
- Building controls to continuously optimize load
- Distribution and transmission investment deferral or avoidance

2020's & Beyond

Duke Energy Demand Response Plans

You May Know DR For…	In the Future We Will Also Be…
Peak Shaving and Emergencies	Load Shaping and Economic Shaving
System Level	Distribution Level
Generation Avoidance	T&D Investment Avoidance / Deferral
Occasional Usage	Frequent Usage
Summer Afternoons	Winter Mornings, Afternoons Year Round

Key Enablers

Low Friction Measures

- Customers are more willing to participate in programs that they don't notice in operation
- Examples include smart home device adoption, especially thermostats, water heaters, storage, energy management systems

Building Codes

- Requiring Demand Response ready water heaters and other appliances when commercially available
- Examples include wi-Fi enabled water heaters, smart panels, smart inverters

Pathway for Greater Non-Residential Participation

- The cost of the Demand Response rider is only offset by full load program participation. More customers may participate with smaller, less critical loads.

Greater System Value

- With lower friction measures, the system can be used more, creating more system value and increased customer incentives
- Changes to inputs used in valuing Demand Response in cost effectiveness tests

New Summer Thermostat Use Cases

- When viewed as a Flexible Demand Management, instead of emergency capability, thermostats can help balance intermittent renewable generation
- NCUC approval for the need to acquire customers for summer capability
- May help avoid transmission or distribution investment as many circuits are still summer peaking.

Break

Please return at 11:05AM.

Questions?

Grid Edge and Customer Programs

Integrated Volt Var Control (IVVC)

Distribution System Demand Response (DSDR)

JAY OLIVER
MANAGING DIRECTOR, GRID SYSTEMS INTEGRATION

MARCH 22, 2022

BUILDING A **SMARTER** ENERGY FUTURE ®

INTEGRATED VOLT VAR CONTROL (IVVC)

- Distribution System Demand Response (**DSDR**) supports peak shaving and MW (demand) reduction
- Conservation Voltage Reduction (**CVR**) supports energy (MWH) reduction on a year-round basis

<table>
<tr><th></th><th>DSDR to CVR [DEP]</th><th>CVR [DEC]</th></tr>
<tr><td>Objective:</td><td>Move DEP from a predominant DSDR (peak shaving) operational strategy to a CVR operational strategy, targeting an estimated 2% voltage reduction.</td><td>Deploy an IVVC program in DEC that would primarily operate in CVR year-round, targeting an estimated 2% voltage reduction.</td></tr>
<tr><td>Scope:</td><td>• Scale up over 2-3 years
• Enable all eligible circuits by 2025
• Run CVR ~ 90% of the time 2025 and beyond
• Operate DSDR less than 10% of the time</td><td><table>
<tr><th colspan="2">Phase 1</th></tr>
<tr><td>% Eligible Circuits</td><td>72%</td></tr>
<tr><td>Approx. % of base load</td><td>70%</td></tr>
<tr><td>Year Enabled</td><td>2025</td></tr>
<tr><th colspan="2">Phase 2</th></tr>
<tr><td>% Eligible Circuits</td><td>17%</td></tr>
<tr><td>Approx. % of base load</td><td>10%</td></tr>
<tr><td>Year Enabled</td><td>TBD</td></tr>
<tr><td>TOTAL % Eligible circuits</td><td>89%</td></tr>
<tr><td>TOTAL % of base load</td><td>80%</td></tr>
</table></td></tr>
<tr><td rowspan="2">Benefits:</td><td>• Reduce load by approx. 1.4% on enabled circuits
• $119M avoided generation fuel costs
• Approximately 186,000 Tons of CO_2 benefit
• Benefits to Cost Ratio (BCR): 23.9</td><td>• Reduce load by approx. 1.4% on enabled circuits
• $369M avoided generation fuel costs
• Approximately 548,000 Tons of CO_2 benefit
• Benefits to Cost Ratio (BCR): 1.2</td></tr>
<tr><td colspan="2">• Less peak load on the grid reduces the need to build additional peaking generation
• Fuel savings passed directly to customers
• Optimized control of Volt/VAR devices improves the grid’s ability to respond to intermittency
• Enable integration of distributed energy resources (i.e.- rooftop solar) and electric vehicles (ev)</td></tr>
</table>

Grid Edge and Customer Programs

Rate Design Opportunities & Distributed Energy Technologies

LELAND SNOOK
MANAGING DIRECTOR, RATE DESIGN AND REGULATORY SOLUTIONS

MARCH 22, 2022

DUKE ENERGY®

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Rate Design Opportunities

Time of Use and Dynamic Pricing

Intersection with Demand Response

System Beneficial Electrification

Rate Design – More Options and Control

Dynamic & TOU Pricing

- Time periods based on system dynamics
- Critical peak prices or response rewards
- Shift use to lower cost times if possible
- Enable distributed energy technologies (DETs)
- Optional subscription management of DETs

Intersection with Demand Response

- Behavioral demand response
- Peak time rebates (PTR)
- Optional subscription management
- Bring your own battery (BYOB)
- Smart device control

Hourly Pricing

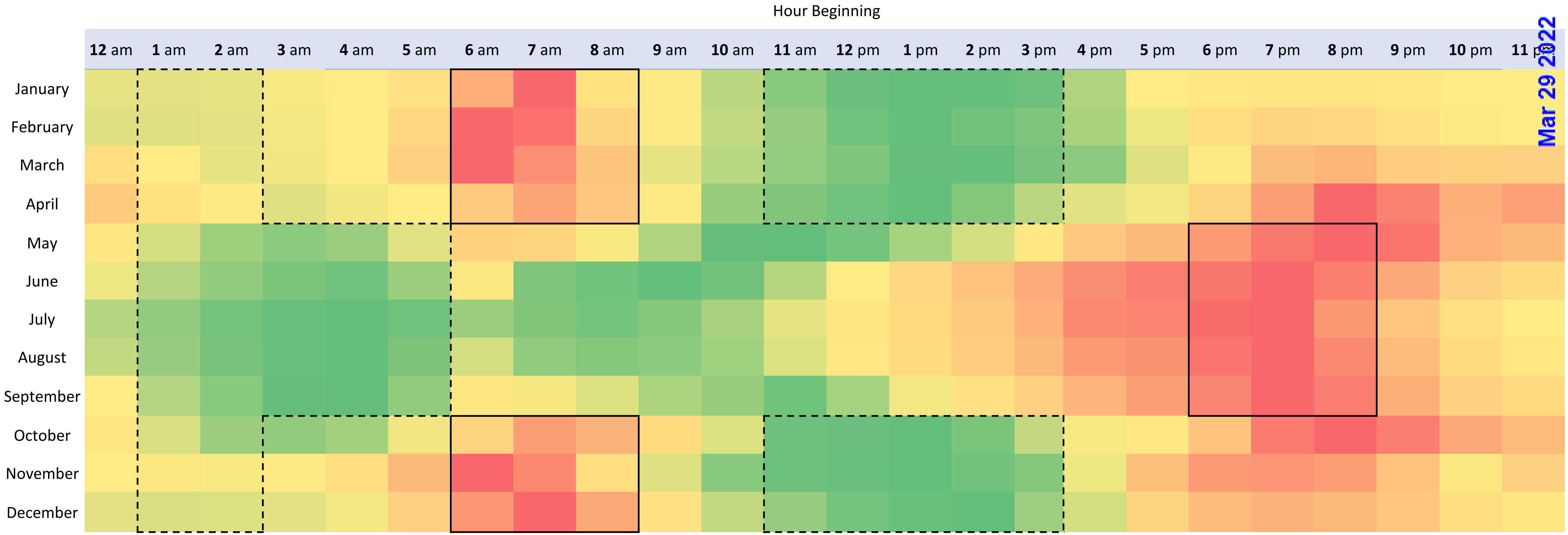
- Should drive price responsive behavior
- New structures needed to enable more broad and diverse participation
- Can apply to existing load if price responsive

System Beneficial Electrification

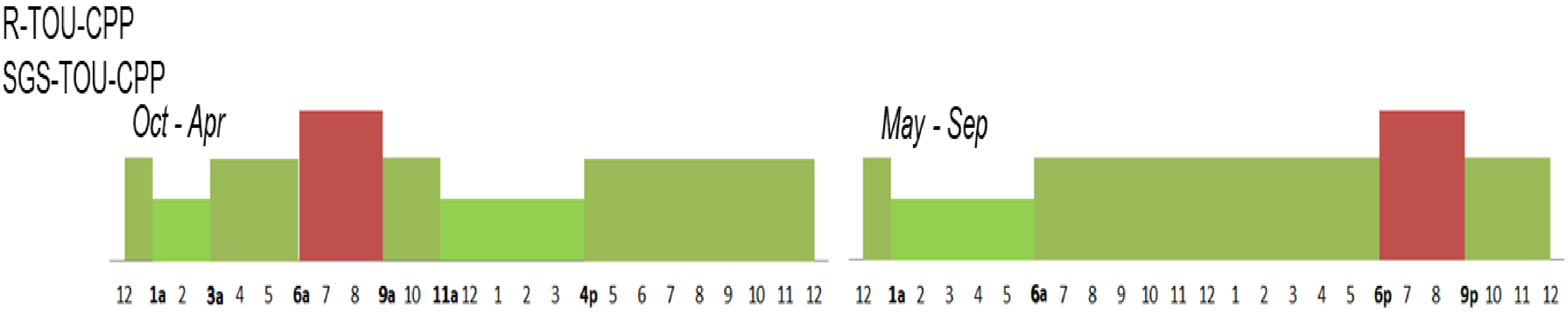
- Customer adoption of Electric Vehicles
- System benefits unlocked with TOU/dynamic pricing and smart device bundles
- On tariff financing
- Vehicle to home or grid (future state)

System Driven Time of Use Periods – Cost Duration Model 2030

- Summer peak aligns with proposed peak period beyond 2025
- Mid-day costs in winter continue to drop in later years due to solar, but costs remain low for overnight discount period



System Driven Time of Use Periods



- On-Peak 6-9 am in Winter, 6-9 pm in Summer
- Discount periods 1-3 am and 11 am – 4 pm in Winter and 1-6 am in Summer

Distributed Energy Technologies (DETs)

Distributed Solar

- Solar Choice– TOU CPP rate (future state)
- TOU monthly netting for energy export (future state)
- Smart Saver Solar EE Program (future state)

Storage Technology

- Batteries
- Bring your own battery (BYOB)
- Subscription with battery management

Smart Thermostats

- Residential load management through TOU & CPP
- Bring your own thermostat (BYOT)
- Subscription with T-stat management

Electric Vehicles

- Beneficial Charging
- Vehicle to Home
- Vehicle to Grid
- Fleet Electrification
- Hourly Pricing for flexible loads

What is a Regulatory Sandbox?

- Creating space for innovation
- A concept developed to address regulatory uncertainty
- Innovation requires testing new potentially unproven concepts and technologies
- Sandbox concept provides leeway from normal regulations and requirements for a limited period of time
- Allows new products and services to be rolled out in a limited environment to gain clarity

QUESTIONS?

Lunch Break

Please return at 1:00PM.

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Carbon Plan Transmission Cost Estimates

SAMMY ROBERTS
GENERAL MANAGER, TRANSMISSION PLANNING AND OPERATIONS

MARCH 22, 2022

DUKE ENERGY®

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Transmission Cost Estimates in Carbon Plan

INTENT

Estimate transmission costs of various pathways/portfolio.

Similar to Integrated Resource Planning, transmission costs in the Carbon Plan **serve as a proxy** for actual costs that will be developed during the execution phase.

Development of Carbon Plan

Specific location of new generation are **unknown**

Transmission costs are **estimated**

Execution of Carbon Plan

Specific location of new generation are **known**

Actual transmission costs developed

Carbon Plan Associated Transmission Considerations

- Factors Impacting Transmission Needs and Cost Determinants
  - Generation Size
  - Location
    - For example:
      - Constrained vs. unconstrained area
      - Greenfield site vs. Brownfield site
    - At best, we know mere generalities about some resource types (i.e., Offshore wind or PJM Capacity Purchase)
  - Sequence of Resource Interconnection
  - Generating Resource Retirements
  - Load projection
  - Long-term Transmission Planning Considerations

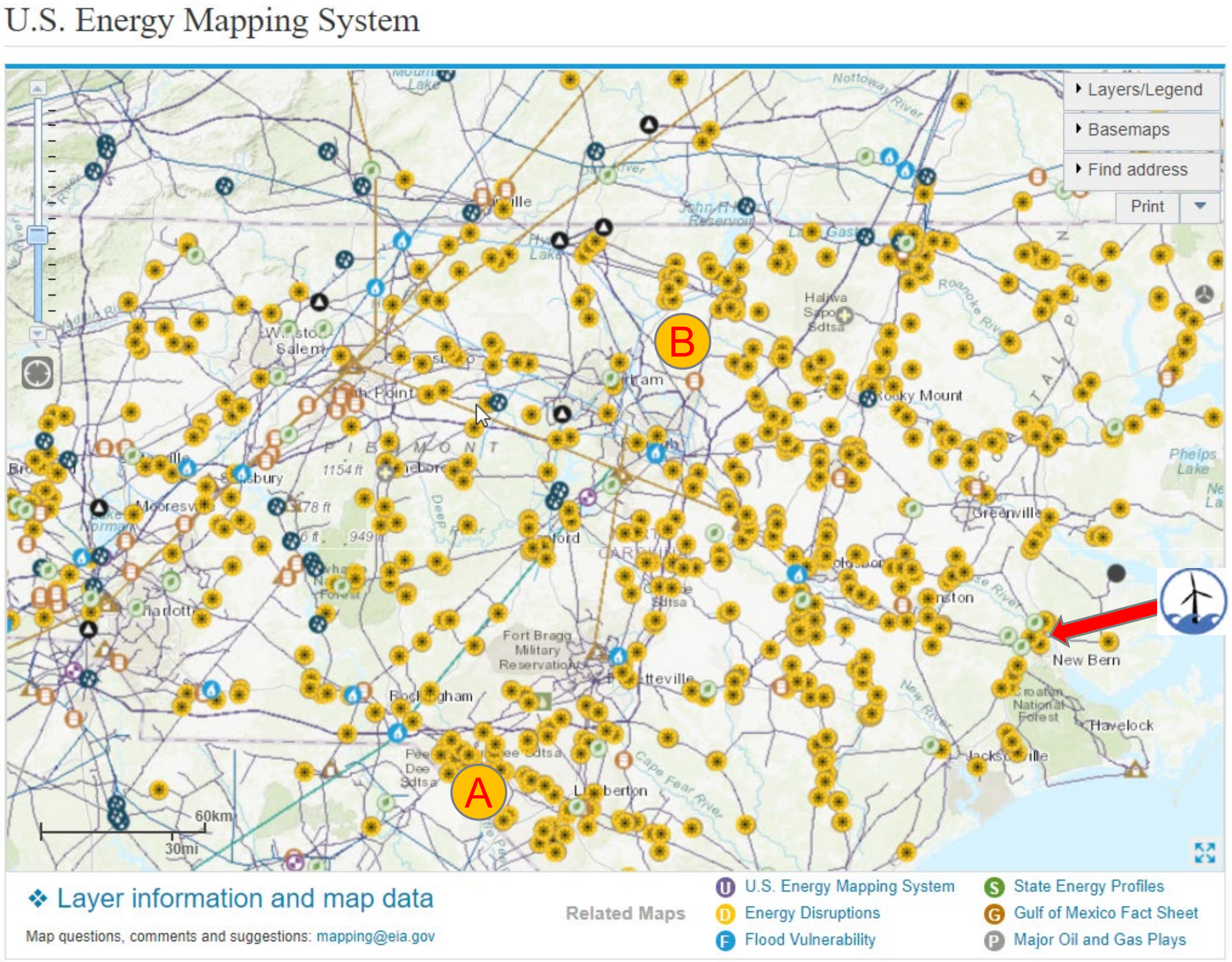
NCUC 2020 IRP Order

The Commission concludes that in developing their Carbon Plan for 2022 and for future IRPs DEC and DEP should:

1. Continue to follow the directive contained in the Commission's August 27, 2019, Order in Docket No. E-100 sub 157 that the IRPs contain an analysis of anticipated or likely grid impacts associated with each alternative resource portfolio modeled in the IRPs and continue to refine transmission network upgrade cost estimates for incremental resources to take into account the most recent system impact study results;
2. Determine the feasibility of providing a timeline for necessary critical transmission network upgrades required to enable interconnection of incremental resources identified in each alternative resource portfolio modeled in the IRPs;
3. Incorporate the results of the North Carolina Transmission Planning Cooperative (NCTPC) offshore wind study results and associated cost estimates;
4. Incorporate applicable results from the 2021 NCTPC Future Resource Scenario Study, as was referred to and discussed at the Second Technical Conference;
5. Refine import capability studies specifically for capacity purchase from PJM; and
6. Continue to assess costs, risks, and reliability aspects of potential off-system purchases.

Examples of Why Size, Location, and Sequence Matter

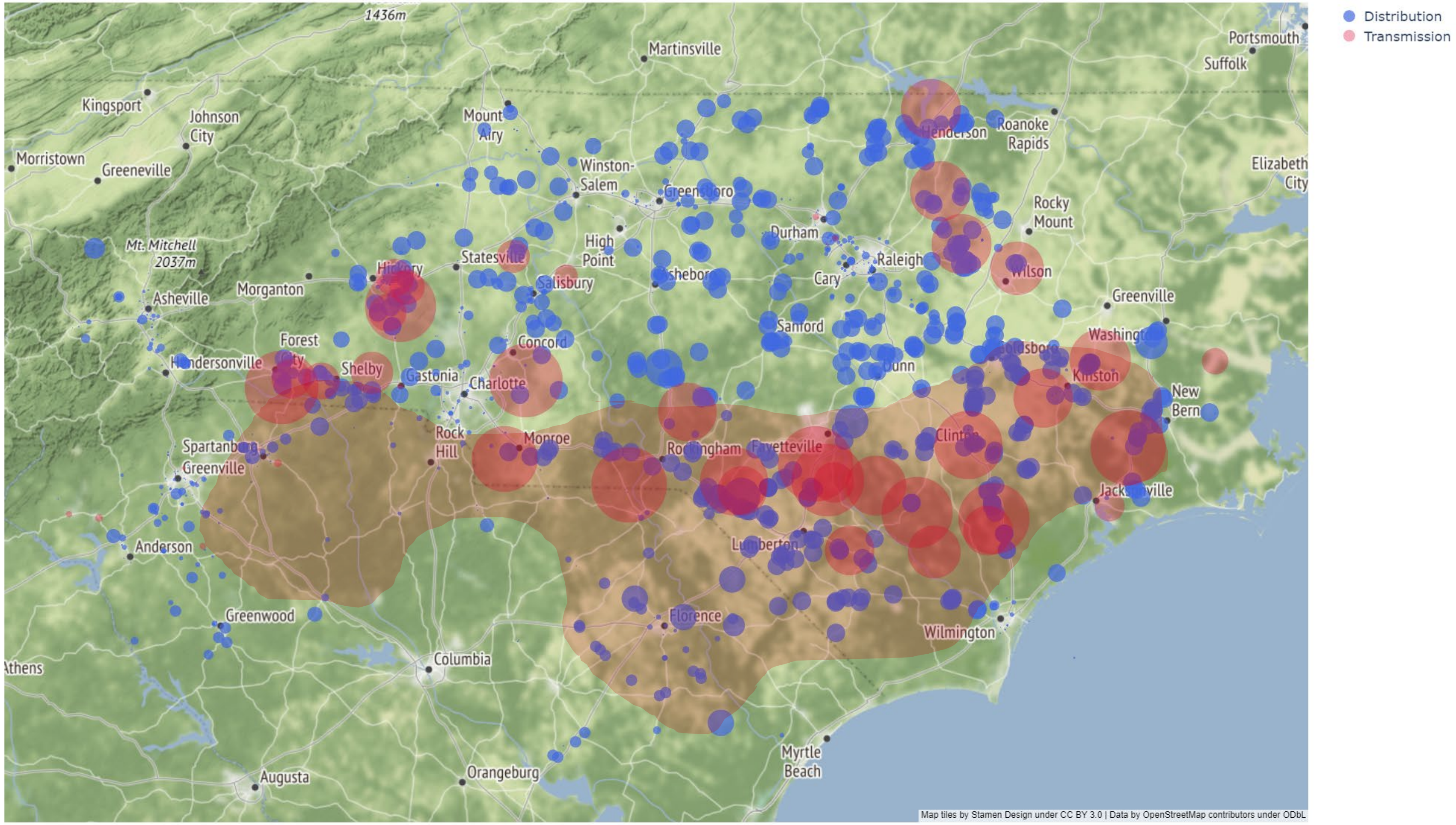
- **Location** - for interconnecting a 200 MW solar facility
  - A – several significant network upgrades needed
  - B – small network upgrades needed
- **Size** - for injecting offshore wind into New Bern
  - 800 MW – likely no new 500kV line network upgrade needed
  - 1600 MW – a new 500kV line network upgrade is needed and additional 230kV line upgrades needed
- **Sequence** – likely to interconnect significant amounts of solar prior to any offshore wind



Current and Future Carolinas Solar

- Map represents over 4.5GW of connected solar (>20kW)
  - Red – Transmission
  - Blue - Distribution
- Does not reflect 270MW additional solar connected to Wholesale within DEC and DEP
- Shaded region provides an example of solar-preferred siting based on past queue information, land availability and lease prices

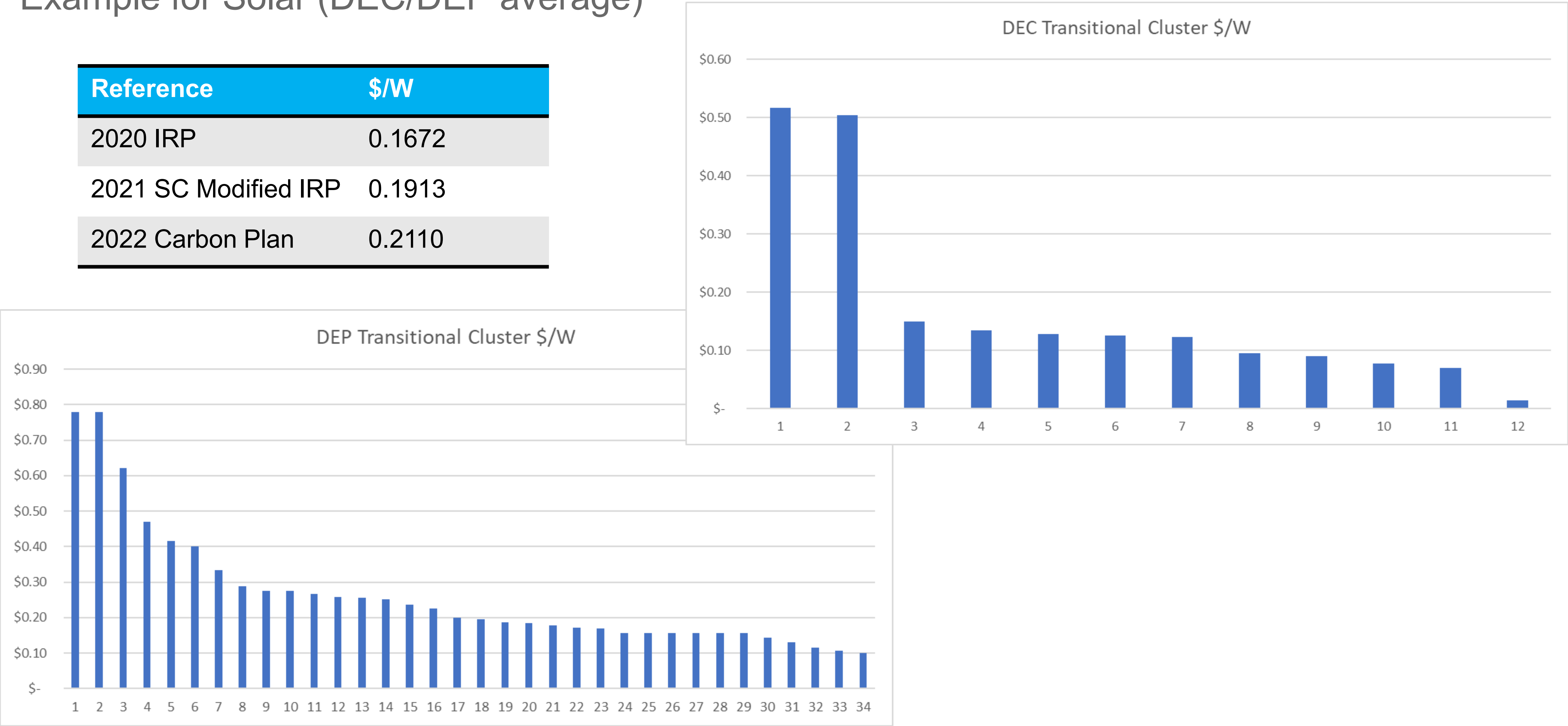
Solar by Connection Type



Network Upgrade Cost Estimates

Example for Solar (DEC/DEP average)

Reference	$/W
2020 IRP	0.1672
2021 SC Modified IRP	0.1913
2022 Carbon Plan	0.2110



Offshore Wind Transmission Considerations

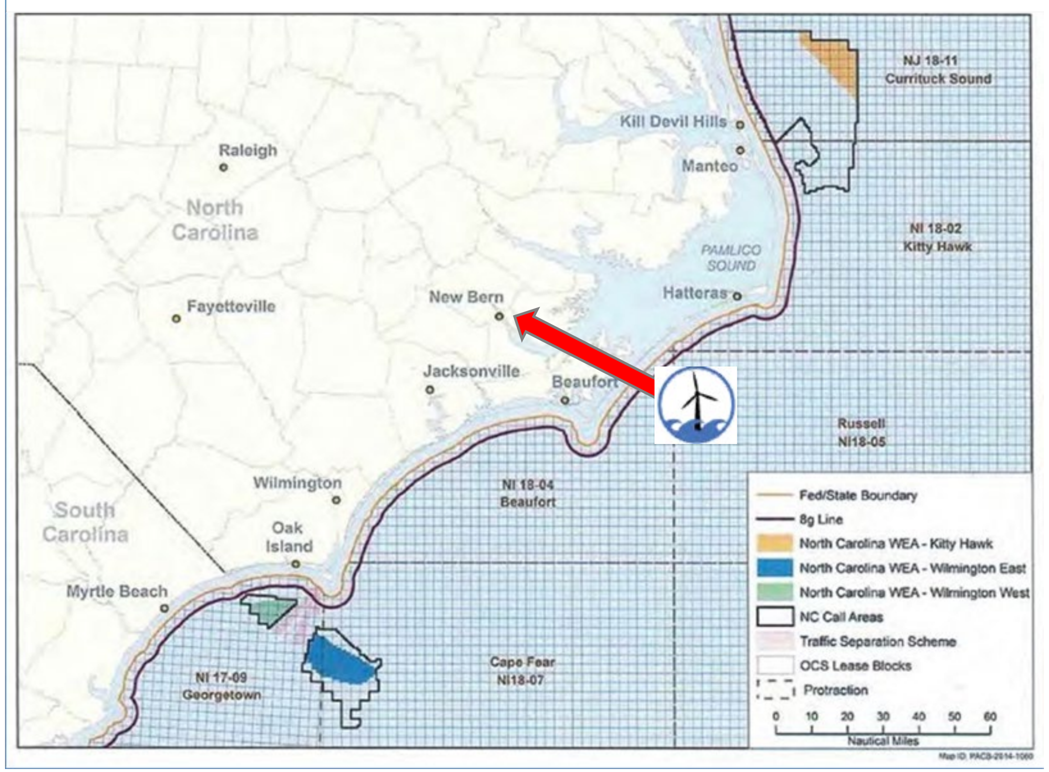
2020 NCTPC Offshore Wind Study Report

- New Bern would be one of the better sites to inject up to 3.2 GW of offshore wind.
- A formal generation interconnection study will be needed to assess the upgrades and estimated cost to interconnect offshore wind.

Schedule for Transmission

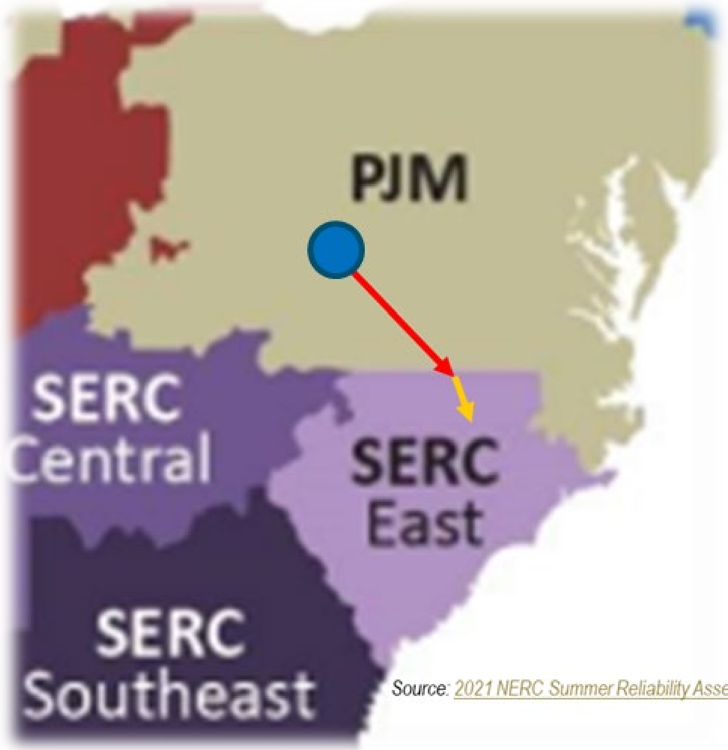
- Leverage existing ROW as much as possible
- New ROW, Public Engagement, Scoping, Routing, Permitting, CPCN processes, Construction
  - 800MW – estimated 7 to 8 years
  - 1600MW – 2400MW - estimated 9 to 11 years

NC Wind Energy Areas (WEAS) (Developed in Joint Venture by Duke Energy and NREL)



PJM Capacity Purchase Transmission Considerations

- Cost of Transmission Reservation for Firm Capacity Purchase – PJM Border Rate is currently $67,625/MW-yr and has increased 21.5% since 2020.
    - A transmission reservation for a 1500 MW purchase from PJM would cost $100M/yr
- For example: 300MW PJM Transmission Service Reservation request was submitted by DEC in 2019.
    - Allocated $411M in upgrade costs
    - 84 months estimate to get upgrades in-service
- Duke Energy's Assessment
    - Reveals significant upgrades needed – schedule and cost concerns
    - Concerned with potential impacts from PJM Queue Reform
- Validation of cost and schedule through TSR request



Source: 2021 NERC Summer Reliability Assessment

Risk Assessment for Off-system Purchases

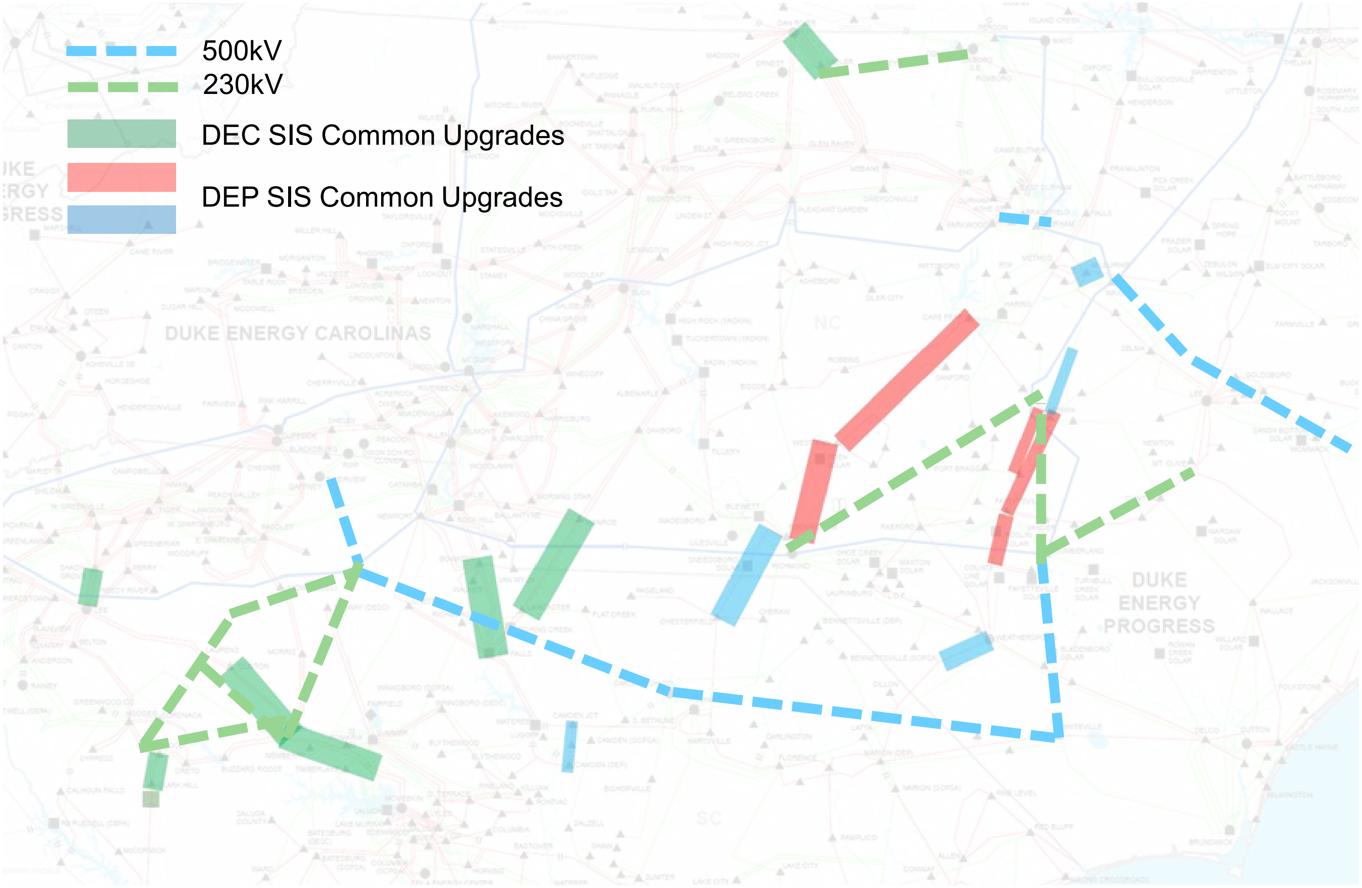
System risks with relying on significant off-system capacity purchases for Carbon Plan resource needs include, but are not limited to:

- **Delay in resource availability –** delays in transmission network upgrades on the DEC/DEP transmission systems or neighboring transmission systems due to sitting, permitting, or construction issues
- **Impact on system ancillary needs –** Voltage/Reactive Support, Inertia/Frequency Response, AGC/Regulation for balancing renewable output
- **Vulnerability to neighboring system congestion issues** – TLR curtailment due to transmission constraints in neighboring areas
- **Transmission system stability** – stability concerns due to added distance between the capacity resource and load.

Long-term Transmission Expansion Planning - Example

Moving toward net-zero (2050)

- Hypothetical example of significant greenfield transmission (represented by the dashed lines) that will be needed as we go beyond 2030 toward net zero CO2 emissions
- Most likely over $7B of greenfield and SIS identified common upgrades transmission represented on the map needed for interconnecting Carbon Plan resources
- Greenfield transmission project schedules are up to 10 – 15 years



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Carbon Plan Meeting
March 22, 2022

NCTPC Process Overview

Rich Wodyka

Prior to Establishment of NCTPC

- **Transmission plans were developed independently by each IOU for their own control areas**
- **Limited involvement from municipally owned electric utilities, electric cooperatives, and other transmission-dependent utilities**
- **Emphasis on reliability**

North Carolina Transmission Planning Collaborative

Fundamental Purpose of the NCTPC

- **Improve and continue to improve transmission planning in North Carolina in collaborative process with increased involvement by all stakeholders**
- **The NCTPC is the local transmission planning process included in the Duke OATT that covers the DEC and DEP transmission systems**

North Carolina Transmission Planning Collaborative

NCTPC Participation Agreement

Agreement executed on May 20, 2005 by:

- **Duke Power**
- **Progress Energy**
- **ElectriCities of NC – representing municipally owned electric utilities**
- **North Carolina Electric Membership Corporation (NCEMC) – representing NC electric cooperatives**

NCTPC Goals

- Provide Participants and other stakeholders the opportunity to participate in the NC Transmission Planning Collaborative (NCTPC) process
- Preserve integrity of the current reliability and least cost planning process
- Provide analysis of increased access to resources inside and outside Progress and Duke control areas
- Develop a single Collaborative Transmission Plan that includes reliability and local enhanced access solutions while appropriately balancing costs, benefits and risks

NCTPC Organizational Structure

➢ Oversight / Steering Committee (OSC)

- **Reviews and approves the Reliability and Local Economic Planning criteria, critical assumptions and scenarios to be used by the PWG**
- **Oversee the study process and approves the final Coordinated Transmission Plan**

➢ Planning Working Group (PWG)

- **Provides expertise in model development, running the transmission models, problem identification, solution development and overall plan development**
- **Performs study analysis and reports results to the OSC**

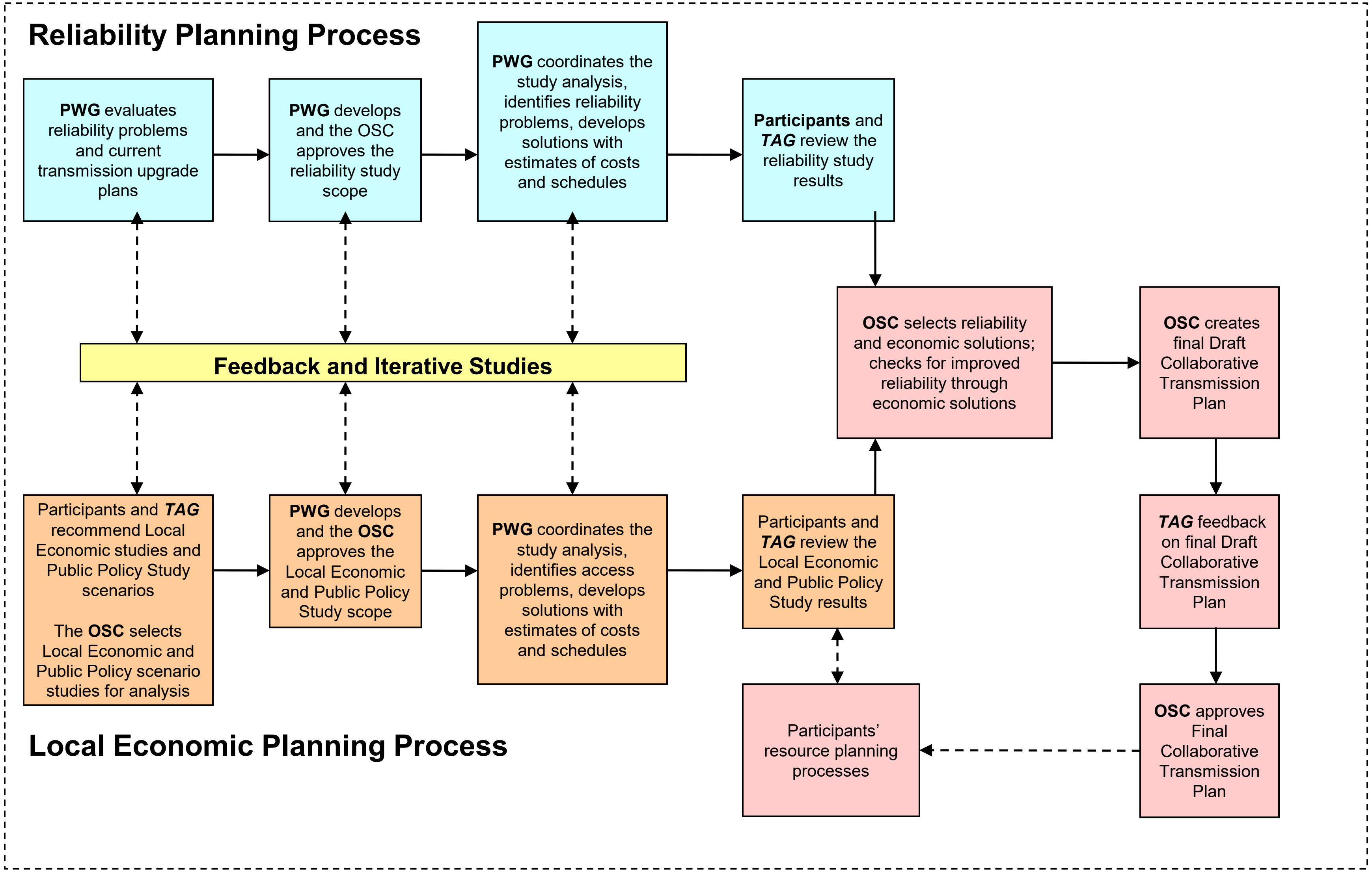
➢ Transmission Advisory Group (TAG)

- **Provides advice and recommendations to the OSC which will aid in the development of a Coordinated Transmission Plan**
- **Membership open to all stakeholders**

➢ Independent Third Party (ITP)

- **Independent advisor to the OSC and PWG and will vote to break a tie in the OSC**
- **Facilitates the TAG activities and advises on the entire NCTPC process**

NCTPC Process Flow Chart



Reliability Planning Process

PWG evaluates reliability problems and current transmission upgrade plans

PWG develops and the OSC approves the reliability study scope

PWG coordinates the study analysis, identifies reliability problems, develops solutions with estimates of costs and schedules

Participants and ***TAG*** review the reliability study results

Feedback and Iterative Studies

OSC selects reliability and economic solutions; checks for improved reliability through economic solutions

OSC creates final Draft Collaborative Transmission Plan

Participants and ***TAG*** recommend Local Economic studies and Public Policy Study scenarios

The **OSC** selects Local Economic and Public Policy scenario studies for analysis

PWG develops and the **OSC** approves the Local Economic and Public Policy Study scope

PWG coordinates the study analysis, identifies access problems, develops solutions with estimates of costs and schedules

Participants and ***TAG*** review the Local Economic and Public Policy Study results

TAG feedback on final Draft Collaborative Transmission Plan

Participants' resource planning processes

OSC approves Final Collaborative Transmission Plan

Local Economic Planning Process

Annual Local Economic and Public Policy Study Requests

- Participants and TAG can propose local economic hypothetical scenarios to be studied
- Requests can include in, out and through transmission service
- Participants and TAG can propose study scenarios related to public policies that are driving the need for local transmission
- TAG request is distributed annually in January

Annual Study Scope of Work

Reliability Planning Process

- Analyze forecasted transmission system conditions out in the next 5 and 10 years
- Identify transmission problems and develop solutions

Local Economic Study Process

- TAG, as well as Participants, provide input on proposed Local Economic Study scenarios and interfaces for study
- TAG, as well as Participants, provide input in identifying any public policies that are driving the need for local transmission

Development of Annual Study Scope

- PWG prepares a proposed annual study scope of work for both the Reliability and Local Economic Study Process
- TAG has an opportunity to review and comment on the proposed study scope of work
- OSC approves the final Annual Study Scope of Work

Past and Current Local Economic Study Scenarios

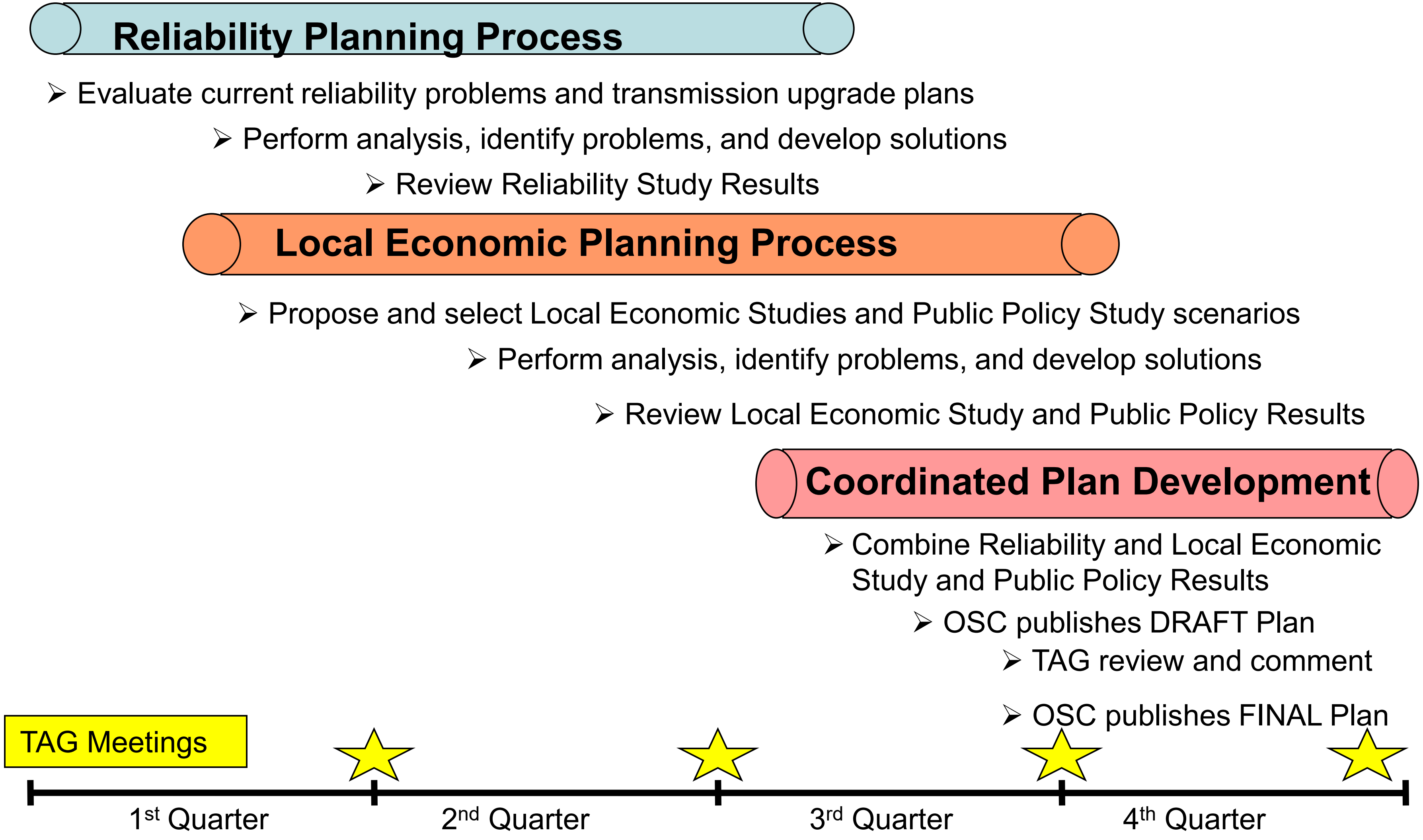
- Hypothetical Imports/Exports re-evaluated every other year (last performed in 2019)
  - 1000 MW transfers
- Hypothetical NC Generation
  - Fossil Fuel
  - Wind Energy – On-shore and Off-shore
    NCTPC only and NCTPC-PJM Joint Study
- Retirement of Coal Units
- 2022 - 4 Requests being considered

Past and Current Public Policy Study Scenarios

- 2020 - Study of Possible Offshore Wind Interconnection Points
- 2021 - High Renewables Study (1 scenario)
  - Preliminary results March 28th TAG meeting
- 2022 - 2 Requests being considered

North Carolina Transmission Planning Collaborative

NCTPC Overview Schedule



Reliability Planning Process

- Evaluate current reliability problems and transmission upgrade plans
- Perform analysis, identify problems, and develop solutions
- Review Reliability Study Results

Local Economic Planning Process

- Propose and select Local Economic Studies and Public Policy Study scenarios
- Perform analysis, identify problems, and develop solutions
- Review Local Economic Study and Public Policy Results

Coordinated Plan Development

- Combine Reliability and Local Economic Study and Public Policy Results
- OSC publishes DRAFT Plan
- TAG review and comment
- OSC publishes FINAL Plan

North Carolina Transmission Planning Collaborative

NCTPC Study Process Overview

1. Assumptions Selected
2. Study Criteria Established
3. Study Methodologies Selected
4. Models and Cases Developed
5. Technical Analysis Performed
6. Problems Identified and Solutions Developed
7. Collaborative Plan Projects Selected
8. Study Report Prepared

Study Assumptions Selected

- **Study Year's for Reliability analyses:**
  - **Near-term: 5 years from current year**
    - **Analyze both summer and winter cases**
  - **Longer-term: 10 years from current year**
    - **Alternately analyzed summer and winter cases**
- **Study Year's Local Economic Study analyses:**
  - **Longer-term: 10 years from current year**
    - **Use same cases as Reliability analysis**
- **LSEs provide:**
  - **Input for load forecasts and resource supply assumptions**
  - **Dispatch order for their resources**
- **Adjustments may be made based on additional coordination with neighboring systems**

Study Criteria Established

- **NERC Reliability Standards**
  - **Current standards for base study screening**
  - **Current SERC and NERC Requirements**
- **Individual company transmission criteria**

Study Methodologies Selected

- **Thermal Power Flow Analysis**
- **Each system (DEC and DEP) will be tested for impact of other system's contingencies**

Models and Cases Developed

- Start with latest series of NERC MMWG cases
- Latest updates to detailed models for DEC and DEP systems will be included
- Planned transmission additions from latest updated Transmission Plan included in models

Technical Analysis

- Conduct thermal screenings and analysis of the cases based on approved study criteria and methodologies

Problems Identified and Solutions Developed

- **Identify limitations and develop potential alternative solutions for further testing and evaluation**
- **Estimate project costs and schedule**

Collaborative Plan Projects Selected

- **Compare all alternatives and select preferred transmission solutions**

Transmission Plan Report Prepared, Reviewed & Published

- Prepare Draft report and distribute to TAG for review and comment
- TAG provided OSC feedback on Draft report
- OSC incorporates any TAG feedback received, if applicable
- OSC publishes Final Collaborative Transmission Plan Report

NCTPC Process Results

Since NCTPC inception in 2005

- **Transmission projects totaling more than *$2.123 billion* have been identified in the NCTPC plans**
- **More than *$1.13 billion* in projects have been placed in service through the end of 2021**
- ***$664 million* are still in the planning stage**
- **Another *$329 million* were deferred until after 2031 or cancelled as a result of changing transmission system requirements**
- **Collaborative Transmission Plan is updated annually**

NCTPC Website - nctpc.org/nctpc/home.jsp

Break

Please return at 2:45PM.

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Duke Energy Resource Mix to Meet 70% GHG Reduction by 2030 in NC

PREPARED BY
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PREPARED FOR
CLEAN POWER SUPPLIERS ASSOCIATION

MARCH 22, 2022

Disclaimer

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Key Takeaways

Based on our analysis of Duke Energy's options to achieve 70% reduction in GHG emissions, at least 8 GW of additional solar capacity (beyond the HB589 baseline) is necessary to meet the 2030 target, even under conservative solar cost assumptions

This will be the case unless one or more of the following occurs:

- Emissions leakage is allowed via imported gas generation (from SC or beyond Duke's system)
- Higher cost offshore wind is selected by Duke
- Large-scale renewable imports occur via Midwest wind or other resources

Duke's proposed limits on annual solar installations results in the selection of offshore wind as the next least cost solution, but is likely to increase compliance costs of H951 or prevent achieving the 2030 target

Introduction

Objective: Analyze least-cost future resource mix that achieves 70% reduction in emissions from Duke Energy's North Carolina power generation plants by 2030

Scope: Model Duke Energy system in North Carolina and South Carolina under updated assumptions through 2035

Approach:

- Update internal GridSIM model of Duke Energy system to incorporate GHG limits, new resource costs, and current natural gas prices
- Identify the least-cost resource mix to meet GHG goals
- Estimate annual solar additions from 2026 to 2030 to achieve the GHG goals

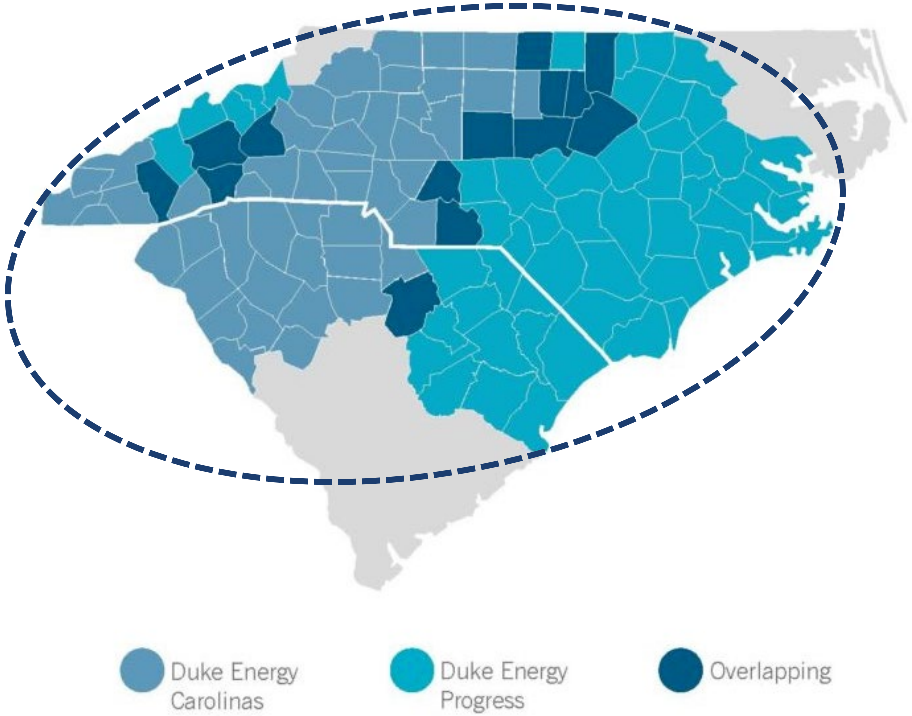
Modeling Approach

Analyzed the combined Duke Energy system using Brattle's internal capacity expansion model GridSIM

- Simulates dispatch of generation and storage resources to meet demand and cost-effective resource expansion
- Captures chronological dynamics of a future power system that relies more heavily on renewable resources by analyzing 49 representative days
(4 days in each month plus the peak demand day)

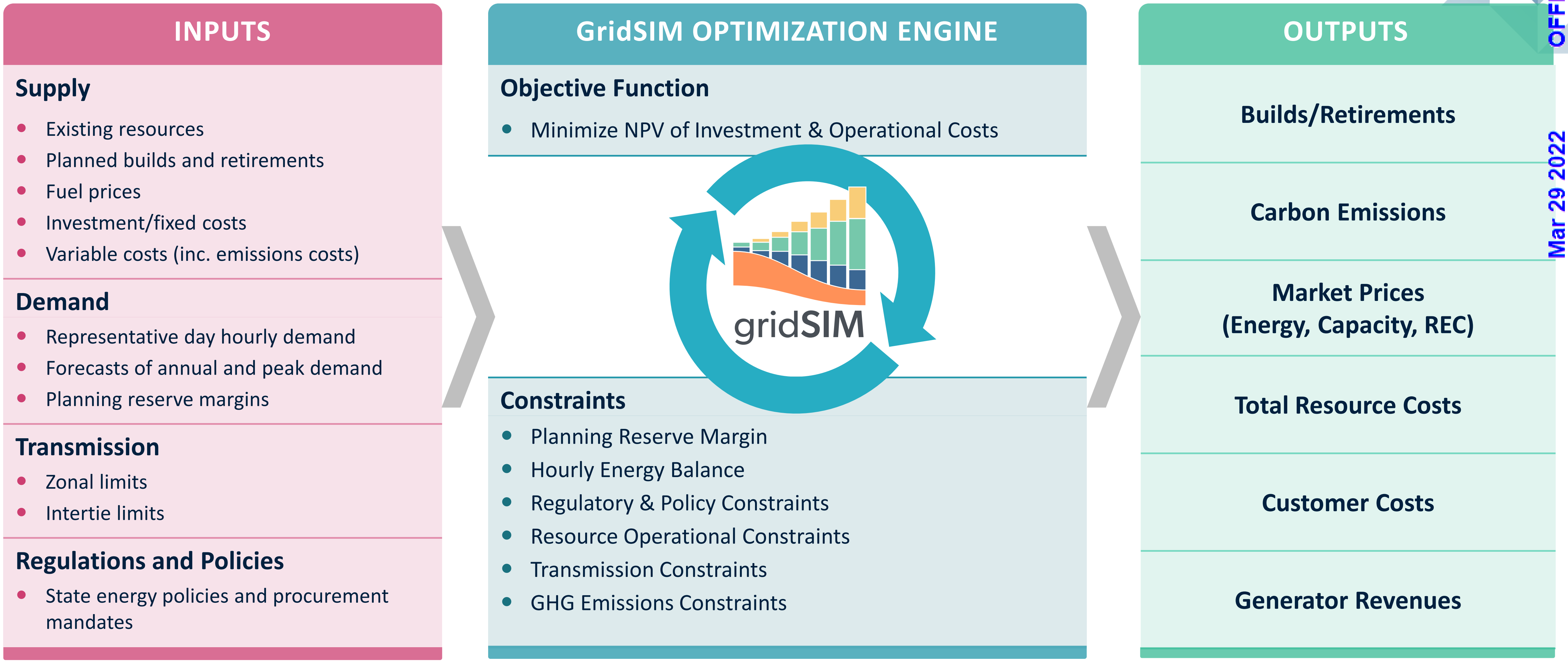
Modeled the Duke service territory as an island with limited transactions with neighboring markets, similar to the approach in Duke 2020 IRP

Duke Service Territory Modeled



Source: https://www.hannonlaw.com/wp-content/uploads/2017/12/Duke-Energy-Carolinas-Territory-Map-768x768.jpg

GridSIM Overview



INPUTS

Supply

- Existing resources
- Planned builds and retirements
- Fuel prices
- Investment/fixed costs
- Variable costs (inc. emissions costs)

Demand

- Representative day hourly demand
- Forecasts of annual and peak demand
- Planning reserve margins

Transmission

- Zonal limits
- Intertie limits

Regulations and Policies

- State energy policies and procurement mandates

GridSIM OPTIMIZATION ENGINE

Objective Function

- Minimize NPV of Investment & Operational Costs

Constraints

- Planning Reserve Margin
- Hourly Energy Balance
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints
- GHG Emissions Constraints

OUTPUTS

Builds/Retirements

Carbon Emissions

Market Prices (Energy, Capacity, REC)

Total Resource Costs

Customer Costs

Generator Revenues

Key Assumptions

Legend:
Data that Duke has made publicly available
Data that Duke may make publicly available but hasn't yet
Data that Duke will not make publicly available

Assumption	Brattle	Duke (understanding based on discussions thru 3/21)
Generation Capital Costs	- NREL 2021 ATB Conservative Case: solar, storage, onshore wind (Class 9), and offshore wind (Class 5), Gas CC - 2022 PJM CONE Study: Gas CT	- Guidehouse: solar, offshore wind, storage - Burns & McDonnell: onshore wind - Unknown: other resources
Transmission Cost Adder	- NC Transmission Planning Collaborative: Offshore wind - Internal experience: Other technologies	- Unknown: all resources
O&M Costs	- NREL 2021 ATB Conservative Case: solar, storage, onshore wind (Class 9), and offshore wind (Class 5), Gas CC - 2022 PJM CONE Study: Gas CT	- Duke internal: solar - Guidehouse: storage & offshore wind - Burns & McDonnell: onshore wind
Fuel Prices	- Natural gas prices: near-term forwards blended with average of EIA and Woodmac - Coal prices: delivered prices escalated based on AEO2021	- Natural gas prices: near-term forwards blended with average of EIA, EVA, IHS, and Woodmac - Coal prices: unknown
Fossil Heat Rates	- Existing resources: Historical heat rates of Duke resources - New resources: AEO assumptions	- Unknown
Renewable Capacity Factors	- Solar: 28% - Onshore Wind: 30% - Offshore Wind: 42%	- Solar: 26%-28% - Onshore Wind: 20%-30% - Offshore Wind: 40%-45%
Capacity Credit/ELCCs	- Duke 2020 IRP: 1% solar; 33% onshore wind; 45% offshore wind; 100% storage; 100% gas CC and CT	- New ELCC Study
Generation Ownership	- Solar: 45% IPP/55% Duke - All Other Resources: 100% Duke	- All Resources: 100% Duke

Key inputs for the dispatch of existing resources and selection of new resources

Key Assumptions (2)

Legend:
Data that Duke has made publicly available
Data that Duke may make publicly available but hasn't yet
Data that Duke will not make publicly available

Assumption	Brattle	Duke (understanding based on discussions thru 3/21)
Renewable Capacity Addition Constraints	- Solar: uncapped (sensitivity based on Duke cap) - Onshore wind: 300 MW/yr, 2028-2030 - Offshore wind: 2,250 MW (Wilmington West/East WEA capacity) - Imports: No renewable imports	- Solar: 750 MW in 2026; 1,000 MW in 2027; 1,360 MW in 2028-2030 = 4,470 MW by start-2030 - Onshore wind: 300 MW/yr, 2028-2030 - Offshore wind: 1,400 MW - Imports: Unknown
Carbon Methodology	- NC emissions constrained in 2030 at 70% of 2005 - SC emissions constrained based on historical levels (2019-2021 avg.), increased for exp. load growth	- Unclear; Duke indicated they would goal-seek a carbon price (applied to both SC & NC units) that achieves NC target with no constraint on SC emissions

Constrains Duke's tools for meeting targets

Determine Duke's ability to export GHG emissions outside of NC

STUDY ASSUMPTIONS

NC and SC GHG Emissions Caps

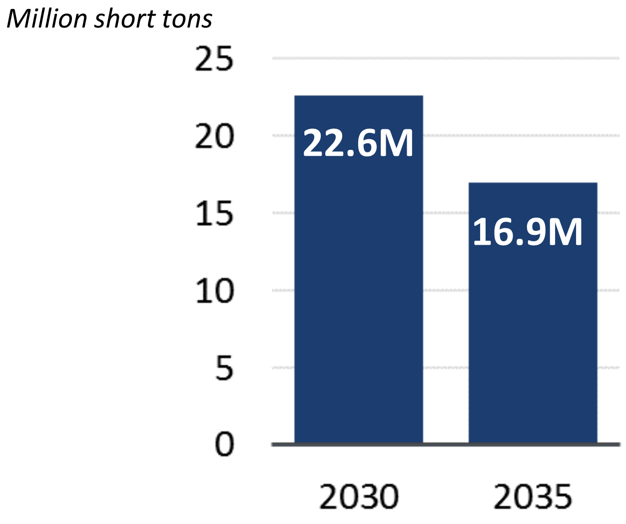
Duke North Carolina 2030 emissions cap of 22.6 million short tons is calculated as a 70% reduction from 2005 emissions levels (75.4 million short tons)

- Interpolate emissions linearly between 2030 and 2050 assuming NC reaches net zero emissions by 2050.
- Results in a 2035 emissions limit for Duke NC plants of 16.9 million short tons.

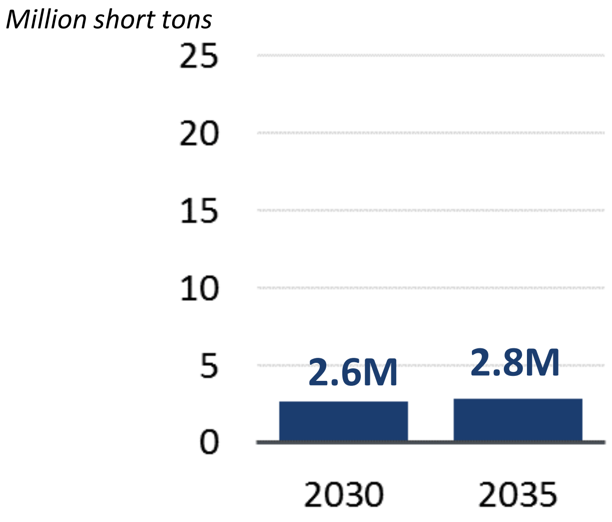
To limit GHG emissions leakage into SC, we limited Duke South Carolina emissions based on the average 2019-2021 emissions from existing plants

- We scale this value in each year according to the projected load growth by 2030 and 2035
- Historical emissions data sourced from EV data hub; load growth forecast sourced from Duke 2020 IRP.

Duke NC GHG Emissions Cap



Duke SC GHG Emissions Cap



Coal Plant Retirement and Conversion Date Assumptions

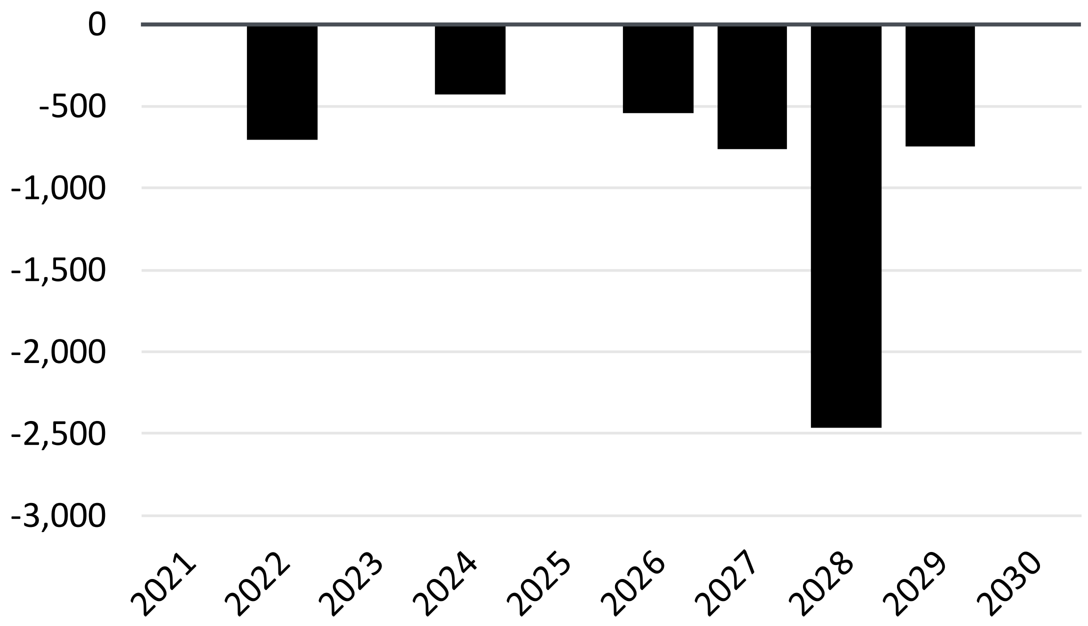
We assume that coal plants retire based on timing proposed during development of H951 legislation with retirement occurring 3 years after filing of replacement plans

- Belews Creek 1-2 and Cliffside 6 are converted to operate on natural gas

Coal Plant Retirement Dates

Plant	Owner	Carbon Policy Case	Modeled Retirement
Allen 2-4	DEC	2022	2022
Allen 1-5	DEC	2024	2024
Cliffside 5	DEC	2026	2026
Marshall 1-2	**DEC**	**2035**	**2027**
Roxboro 1-2	**DEP**	**2029**	**2028**
Roxboro 3-4	DEP	2028	2028
Mayo 1	DEP	2029	2029
Marshall 3-4	DEC	2035	2035
Belews Creek 1-2	DEC	2038	Gas-Only in 2030
Cliffside 6	DEC	2048	Gas-Only in 2030

Total Annual Coal Plant Retirements (MW)



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Mar 29 2022

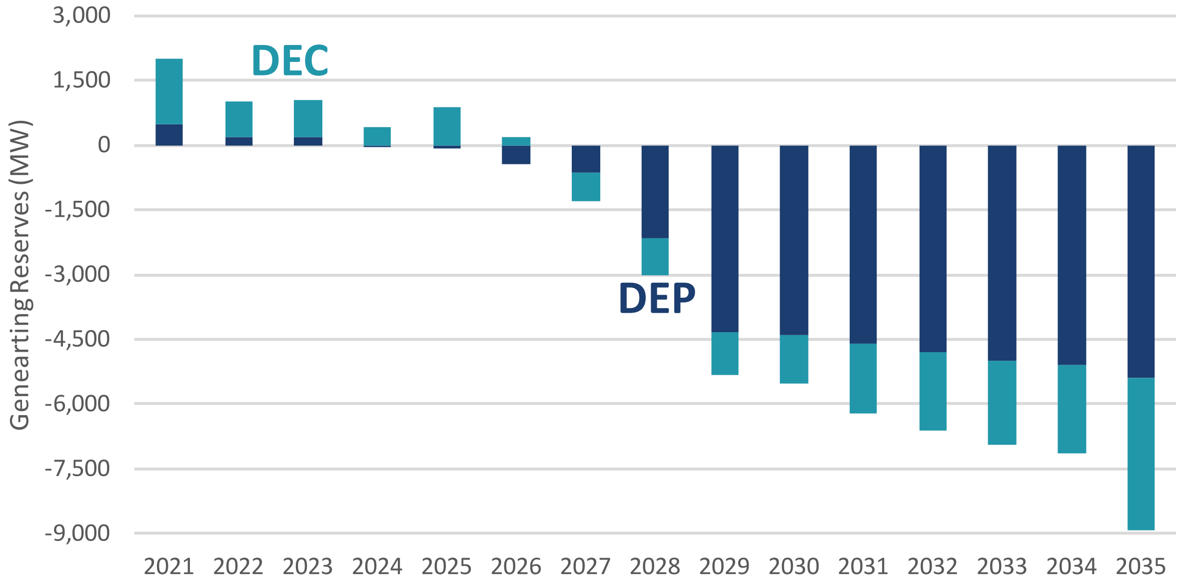
Resource Adequacy

Estimated capacity shortfall for both DEC and DEP to meet their 17% reserve margin

- Started with 2020 IRP winter capacity balance and adjusted reserve margin based on alternative assumptions for coal plant retirements and new resource additions (only added mandated solar capacity under H589)
- Assumed ELCC of solar (1%), wind (33%), and 4-hour battery storage (100%) based on Duke IRP, and 45% for offshore wind based on average output during winter mornings

Projected Capacity Shortfall in the Updated Policy Case

(prior to identifying economic new resources)



Available New Generation and BESS Resources

We allow GridSIM to select the following resources to meet capacity and energy demand and the GHG reduction target at least cost to ratepayers

Resource Type	Capacity Factor	RA Credit (% ICAP)	2035 Capacity Limit	Assumed Life
Gas CC	n.a.	100%	n.a.	20 years
Gas CT	n.a.	100%	n.a.	25 years
Solar	28%	1%	n.a.	30 years
Onshore Wind	30%	33%	900 MW	30 years
Offshore Wind	42%	45%	2,250 MW	30 years
4-Hour BESS	n.a.	100%	n.a.	15 years

Note: Due to time constraints, we did not model a separate solar+BESS hybrid resource, but do see both solar and storage entering when modeled as standalone resources.

We did not consider Gas CC with CCS or Nuclear SMR due to the limited feasibility of these resources being built by 2030

Capital Costs for New Resources

Capital cost assumptions based on 2021 ATB Conservative case

- Based on feedback from Duke, we adopted lower capital costs for Gas CT using recent PJM Cost of New Entry (CONE) study
- For new Gas CC, we added $125/kW for the costs of new gas lateral based on EPA analysis of NC plants

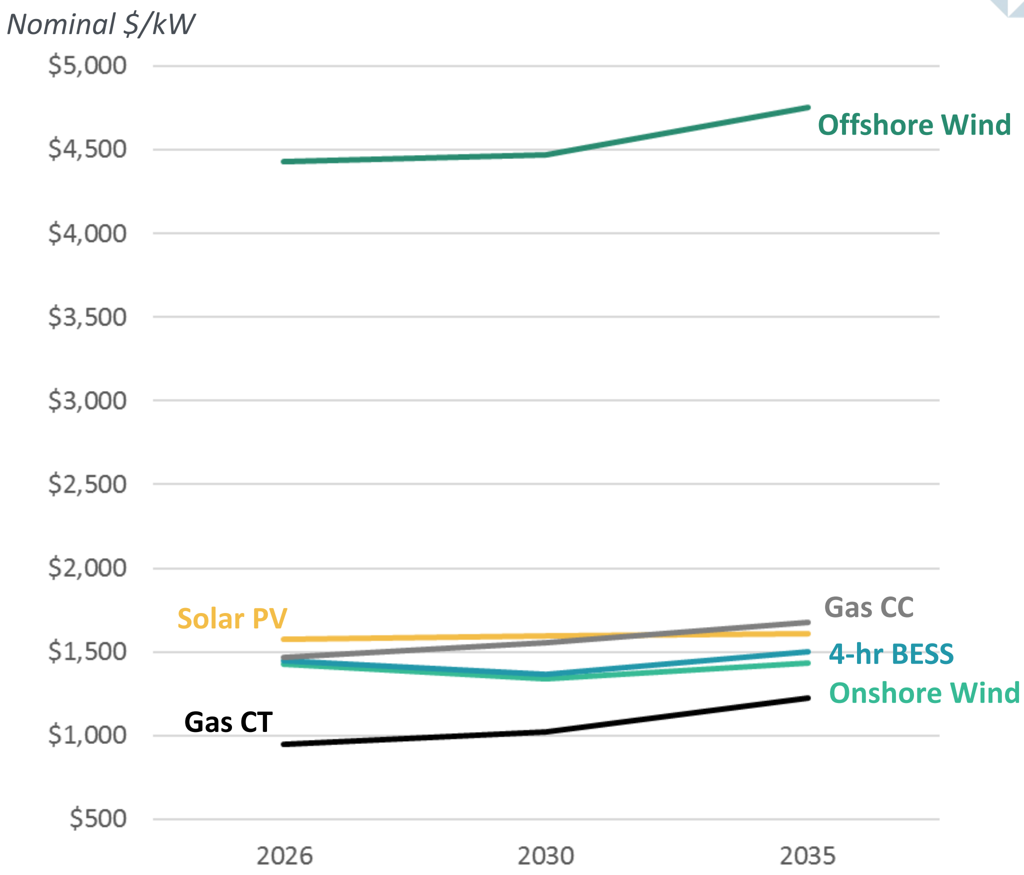
We added estimated transmission upgrades for each resource:

- Offshore wind: $441/kW in 2030 based on NCTPC study
- All other resources: $100/kW

Assume ITC and PTC phase out:

- 30% ITC for solar & storage online by Jan 1, 2024; phased down to 10% for projects online by Jan 1, 2027
- 30% ITC for offshore wind commencing construction by Jan 1, 2026 with ten years to complete (available for 2030 and 2035)
- PTC phases out for onshore wind resources entering after 2025

Overnight Capital Cost Projections

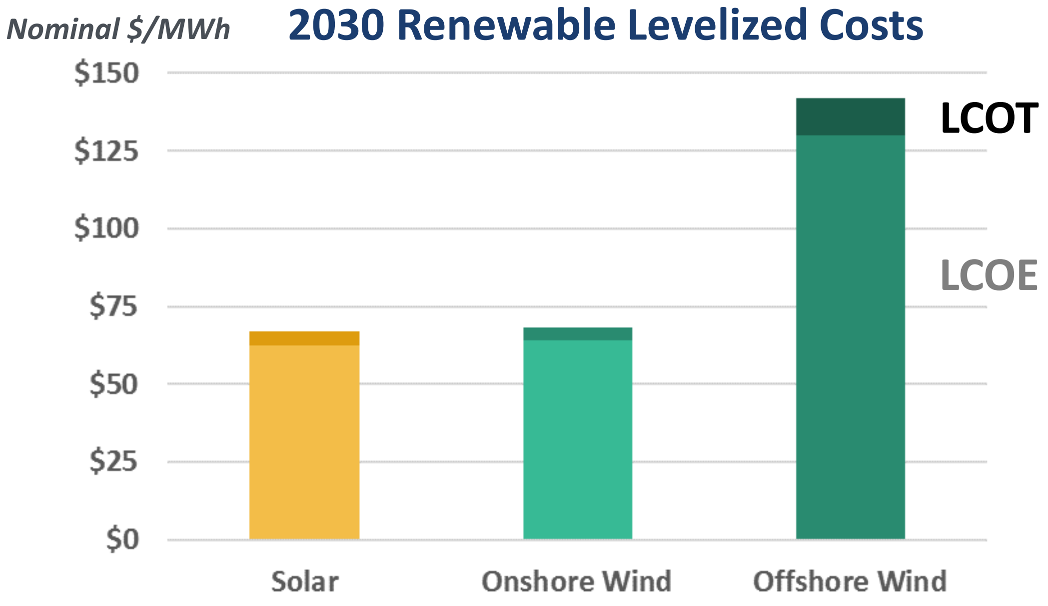


Note: Renewable capital costs are based on the NREL ATB conservative case. Offshore wind is based on Class 5 resources and onshore wind is based on Class 9 resources.

Comparison of Levelized Costs

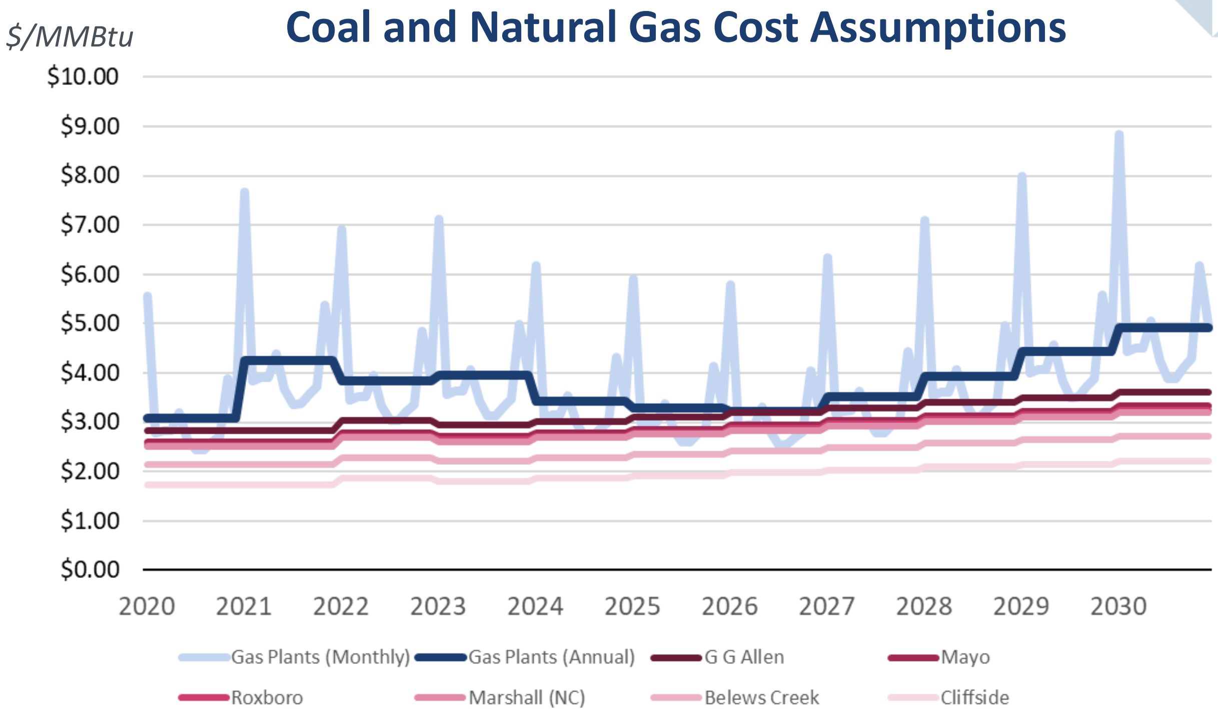
The estimated 2030 LCOE for solar and onshore wind are similar ($65-70/MWh), while offshore wind is more than 2x higher ($140/MWh)

- We estimated the LCOE assuming the levelized costs remain constant in nominal terms over its economic life and assuming Duke's most recent cost of capital of about 6.5% ATWACC
- LCOE values shown here are higher than ATB due to use of nominal 2030 dollars (instead of real 2019 dollars), assumption that levelized costs are constant in nominal terms (instead of real terms), and higher cost of capital

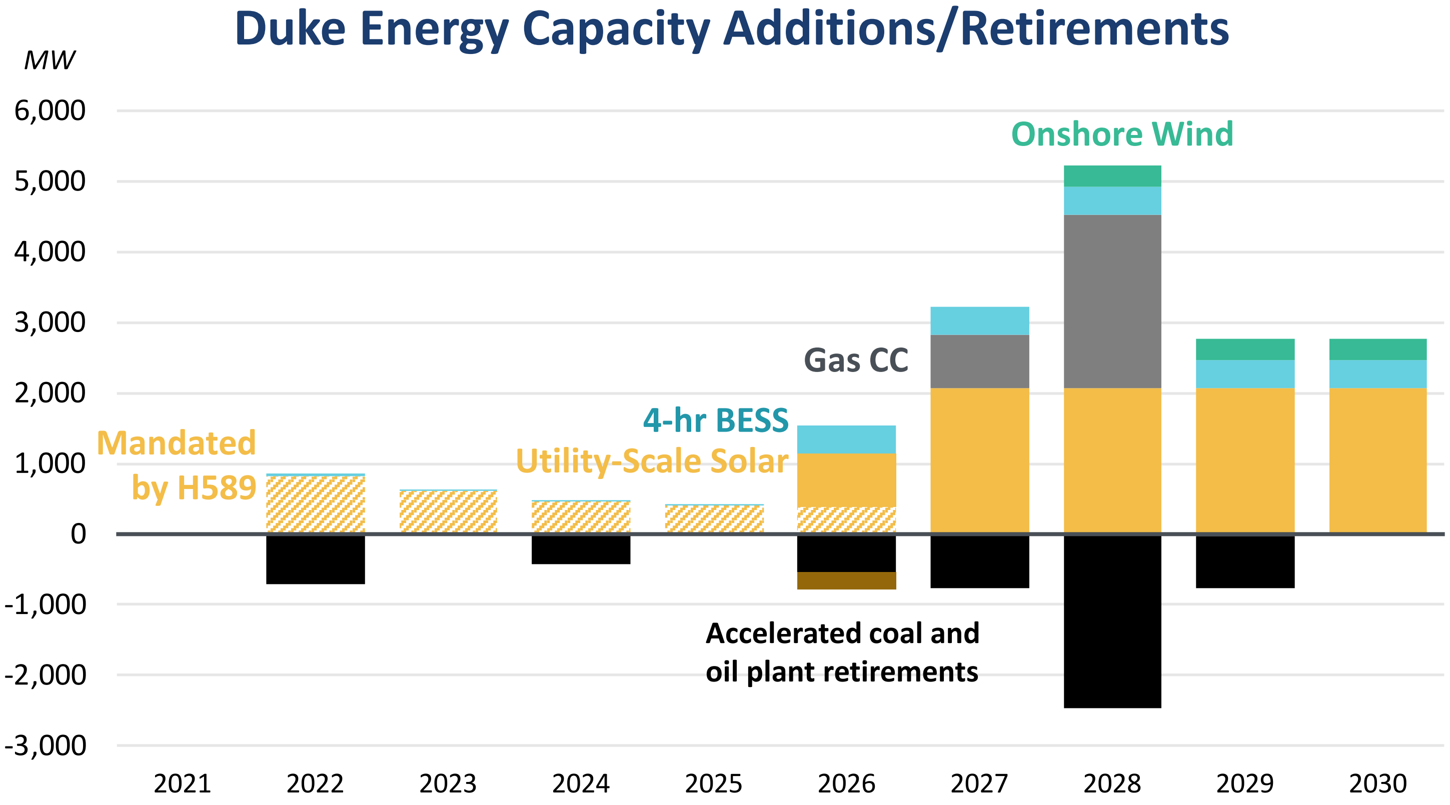


Delivered Fuel Price Projections

- Delivered gas price forecast from recent forwards (first 5 years), then blend for 3 years with fundamentals-based forecasts (average of AEO2021 SERC and WoodMac TranscoZ6), then 100% fundamentals-based forecasts
  - Monthly shapes based on average historical shape from 2018-2020 to account for commodity price and variable delivery charges
- Coal price by plant based on delivered coal prices in 2020 and escalated based on AEO2021 forecast for delivered cost of coal into SRCA region



Projected 2030 Generation and Storage Resource Mix



Total New Resources by 2030

Utility-Scale Solar: +11,690 MW

- 2,690 MW due to H589 by 2026
- Additional 9,000 MW by 2030

Onshore Wind: +900 MW

4-Hour BESS: +2,000 MW

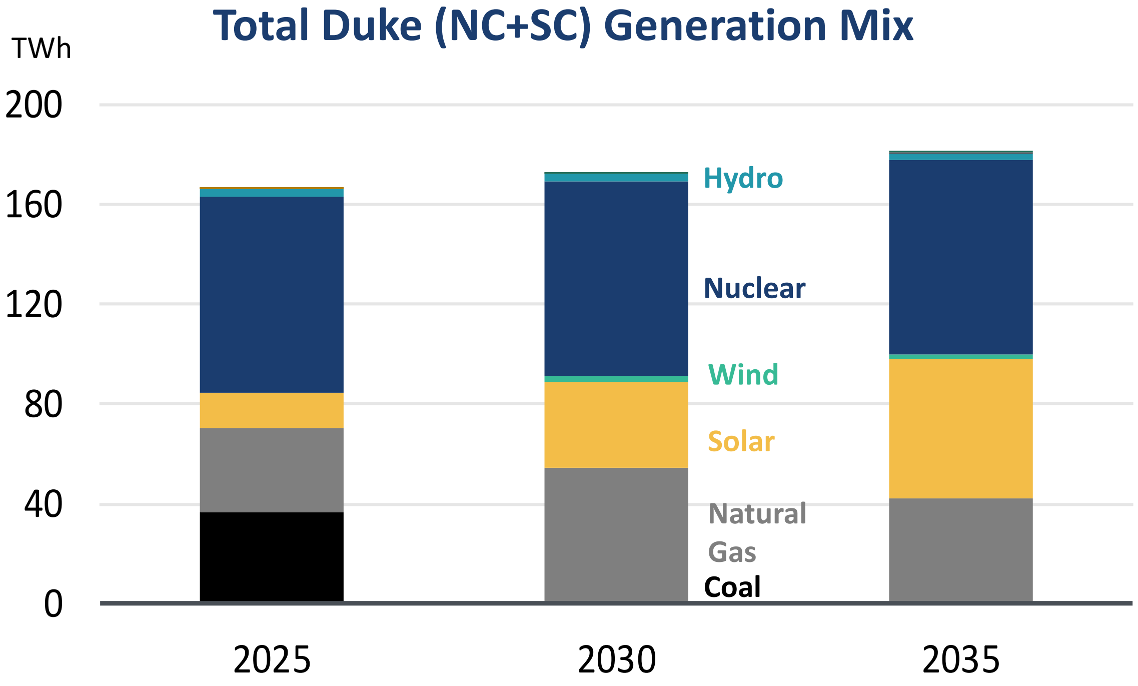
Gas CC: +3,200 MW

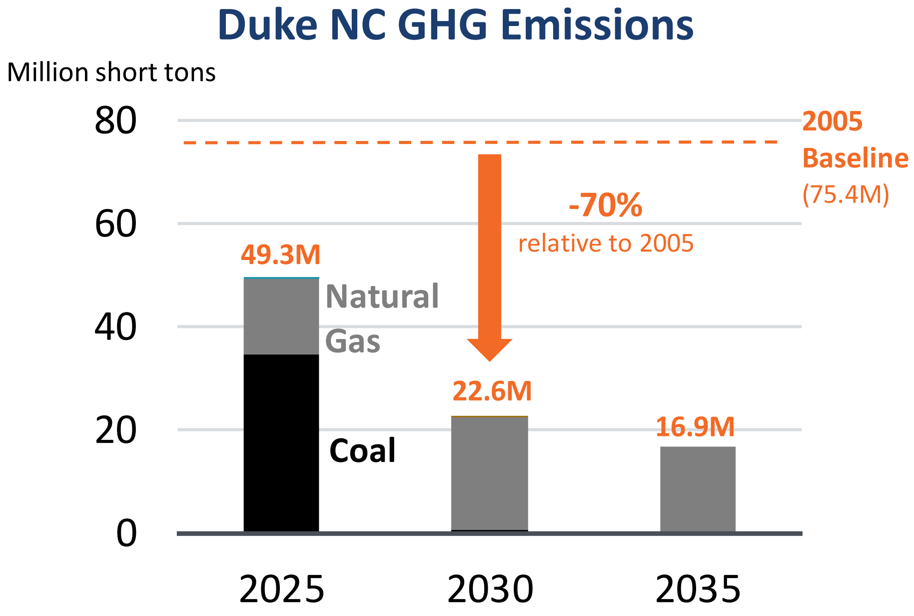
Offshore wind generation selected if solar capacity additions limited based on Duke Energy’s proposed limits

Duke Energy Generation Mix and GHG Emissions

Solar and wind generation increase from 9% of total generation in 2025 to 22% in 2030

- Non-emitting resources (i.e., solar, wind, hydro and nuclear) account for 69% of total 2030 generation
- Coal generation decreases to nearly zero
- Natural gas generation increases in 2030 due to new Gas CC additions





Impacts of Limiting Solar Additions by 2030

Limiting solar additions from 2026 to 2030 to the capacity Duke identified in its Enhanced Transmission Policy Case will result in the following:

- Require alternative clean sources of generation to meet the 2030 GHG goal
- One approach: add about 5,300 GWh of wind generation (1.4 GW offshore or 2.0 GW onshore)
- Increases 2030 costs by about $400 million

Gas CC Entry Likely Overestimated

1. Modeling timeframe only extends to 2035, which does not consider that the value of generation from Gas CC will decrease after 2035 to achieve deeper GHG reductions
2. Low ELCC for solar increases demand for other resources to meet reserve margin requirements
3. Normalized hourly demand and renewable generation conditions does not capture value of fast-start Gas CT and BESS to serve unexpected, sub-hourly market conditions

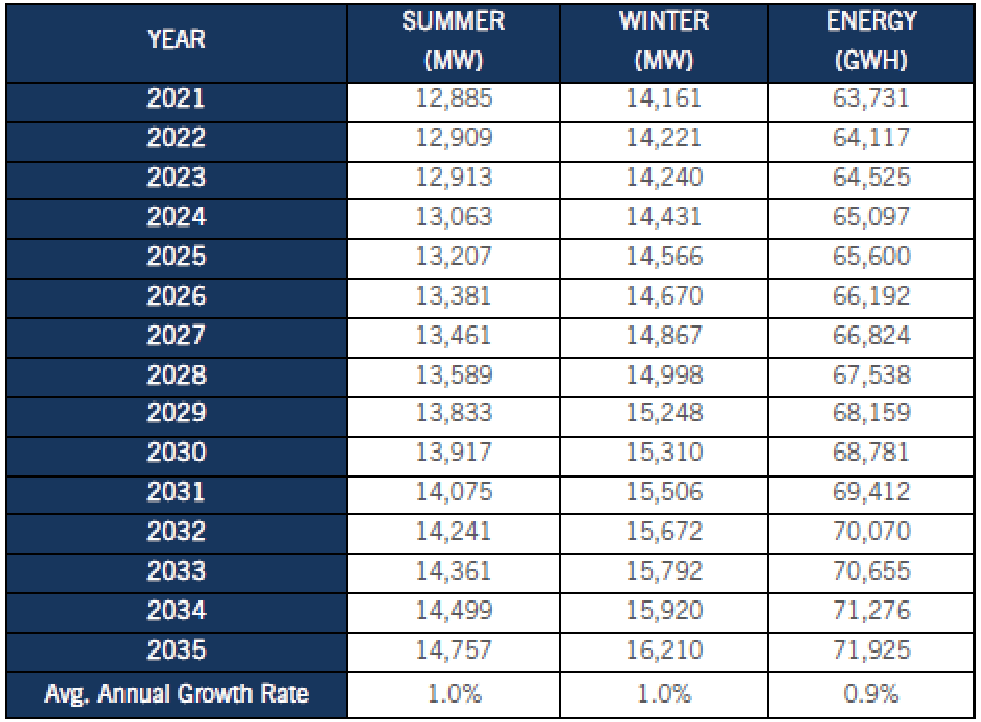
Key Resource Dynamics

- **Gas vs BESS costs:**
  - Currently selecting a mix of Gas CC and BESS resources such that shifts in costs will have a significant impact on capacity additions of each resource type by 2030
  - Modeling only to 2035 limits the long-term considerations of GHG limits and will tend to build more gas capacity
  - Reducing CT costs would tend to (1) reduce new CC entry, (2) increase coal generation, and (3) increase addition of renewable resources
- **Solar vs Offshore wind costs:**
  - Solar costs are sufficiently low to be selected with 4-hour BESS instead of higher cost offshore wind
  - Even at 25% lower offshore wind costs, no offshore wind is built
- **Slower coal plant retirements will increase need for solar/wind additions**
  - With a GHG limit, the amount of combined gas/coal generation will depend on the average emissions rates from those resources
  - Earlier coal plant retirements will decrease the average emissions rate, increase gas/coal MWhs, and decrease need for wind/solar

Appendix:
Study Assumptions

Projected Energy Demand

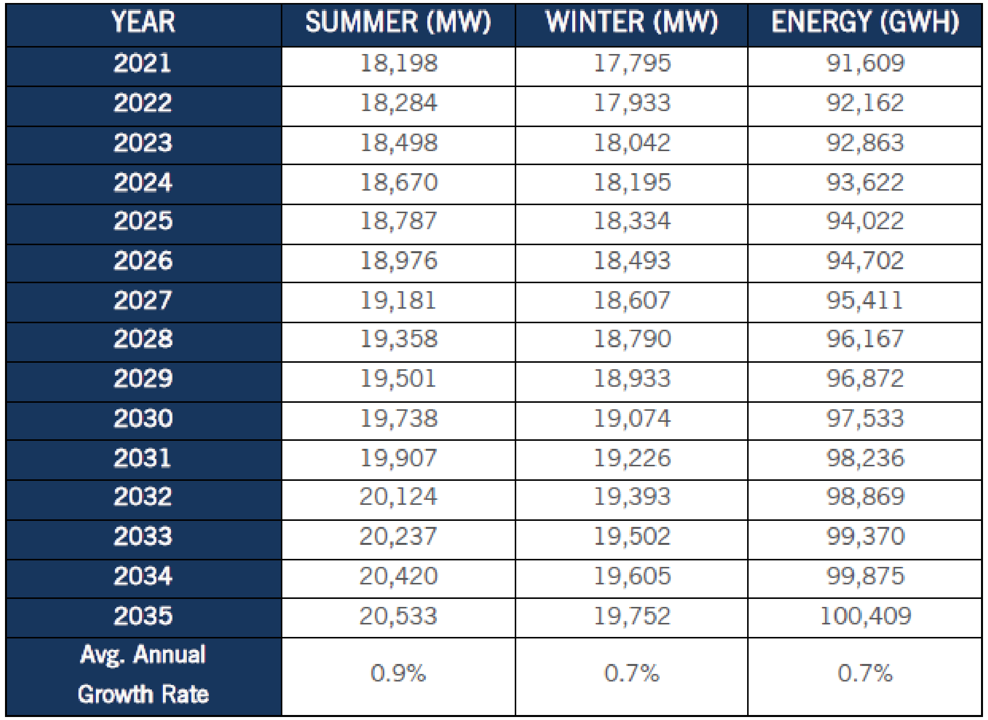
DEP Projected Demand



YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	12,885	14,161	63,731
2022	12,909	14,221	64,117
2023	12,913	14,240	64,525
2024	13,063	14,431	65,097
2025	13,207	14,566	65,600
2026	13,381	14,670	66,192
2027	13,461	14,867	66,824
2028	13,589	14,998	67,538
2029	13,833	15,248	68,159
2030	13,917	15,310	68,781
2031	14,075	15,506	69,412
2032	14,241	15,672	70,070
2033	14,361	15,792	70,655
2034	14,499	15,920	71,276
2035	14,757	16,210	71,925
Avg. Annual Growth Rate	1.0%	1.0%	0.9%

Source: DEP IRP (2020), Table C-11.

DEC Projected Demand



YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	18,198	17,795	91,609
2022	18,284	17,933	92,162
2023	18,498	18,042	92,863
2024	18,670	18,195	93,622
2025	18,787	18,334	94,022
2026	18,976	18,493	94,702
2027	19,181	18,607	95,411
2028	19,358	18,790	96,167
2029	19,501	18,933	96,872
2030	19,738	19,074	97,533
2031	19,907	19,226	98,236
2032	20,124	19,393	98,869
2033	20,237	19,502	99,370
2034	20,420	19,605	99,875
2035	20,533	19,752	100,409
Avg. Annual Growth Rate	0.9%	0.7%	0.7%

Source: DEC IRP (2020), Table C-11.

Generation and Storage Operating Characteristics

Generation and Storage Resource Attributes

	Heat Rate (MMBtu/MWh)	Variable O&M ($/MWh)	Fixed O&M ($/ICAP MW-yr)
Existing			
Coal (Range)	8.87 - 10.61	$1.38 - $4.11	$21,337 - $33,673
Gas CC	7.07	$0.71	$16,249
Gas CT	11.26	$0.59	$7,573
Nuclear	10.43	$3.35	$86,083
Hydro	0.00	$1.55	$20,359
Pumped Hydro	0.00	$1.58	$6,816
Solar	0.00	$0.61	$6,906
New			
Gas CC	6.60	$1.39	$13,383
Gas CT	9.88	$4.50	$11,855
Solar	0.00	$0.00	$16,328
Wind Onshore	0.00	$0.00	$43,421
Storage	0.00	$5.00	$31,279
CHP	7.59	$1.39	$13,383

Notes: We assume $5/MWh for storage VOM based on assumed round-trip efficiency losses of ~15% on average energy prices of $35/MWh.

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Modeling Update and Preliminary Portfolio Development

GLEN SNIDER
MANAGING DIRECTOR, CAROLINAS INTEGRATED RESOURCE PLANNING AND ANALYTICS

BUILDING A *SMARTER* ENERGY FUTURE®

MARCH 22, 2022

Key Base Assumptions for Selectable Resources

Blue text indicates resource assumptions needed to achieve 70% reduction target

EE/DR

- EE **1% of eligible retail** sales
- IVVC growing to 90% of DEC circuits
- DR programs and critical peak pricing

Solar

- Solar interconnection potential increases to **1,350**MW/yr. by start of 2029 (> 2.5X 2020 IRP)
  - **1,800**MW/yr. sensitivity
- Bifacial panels
- Additional solar + storage config
- Costs ~1% lower than moderate NREL costs

Storage

- Up to **3,000**MW standalone batteries per year
- Costs within 1% of moderate NREL costs
- Bad Creek II – long duration storage

New nuclear

- SMR – 600MW (**300**MW blocks) available 2033-2034
- Advanced reactors or additional SMR available after 2036

Wind

- Onshore wind at 30% capacity factor – **300** MW/year starting 2029 up to 1,800MW total
- Offshore wind – Two **800**MW blocks (1/1/2030, 1/1/2032)
- Additional OSW available after 2040

Gas

- Plan will count emissions as if located in NC
- Earlier and shorter transition from market-based to fundamentals-based natural gas commodity prices
- Multiple views:
  - Constrained App. gas supply (up to ~2400 MW of New CC)
  - Constrained w/ No App. gas supply (up to ~800MW of New CC)

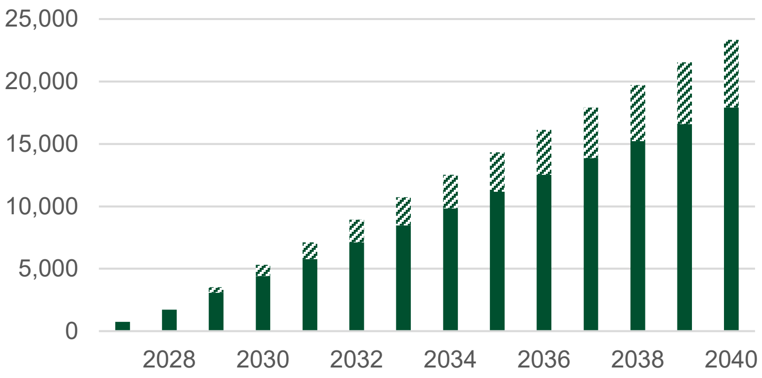
Hydrogen

- Assume H2 blending 2035+
- Incorporate H2 turbine conversion costs for existing gas and upcharge for 100% H2 capable new gas

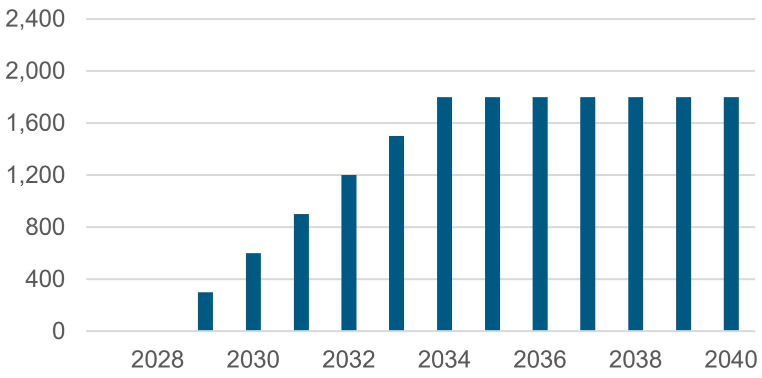
Selectable Resource Options (cumulative based on max annual potential)

CUMULATIVE LIMITS ON POTENTIAL NEW RESOURCES (MW)

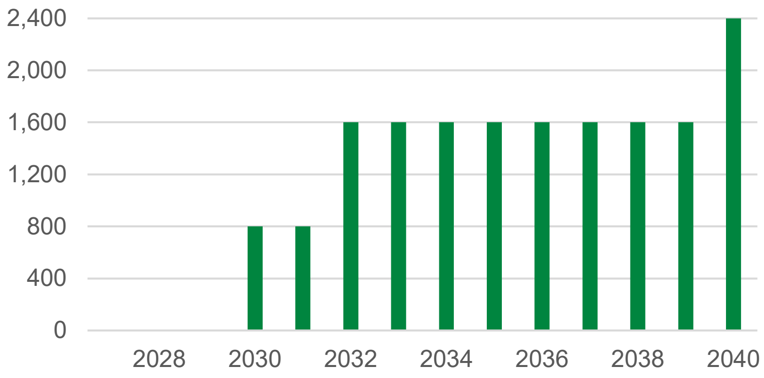
SOLAR



ONSHORE WIND



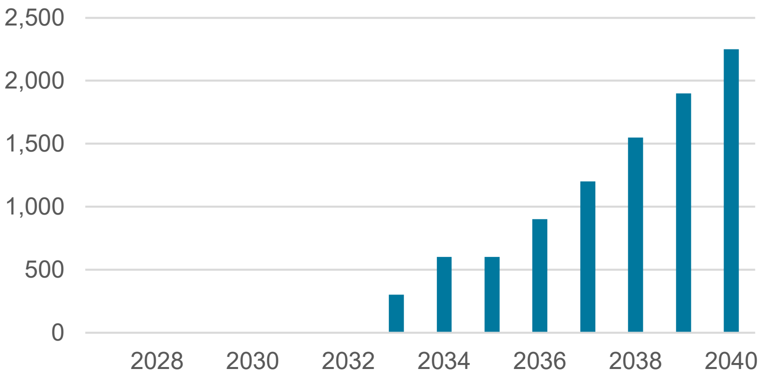
OFFSHORE WIND



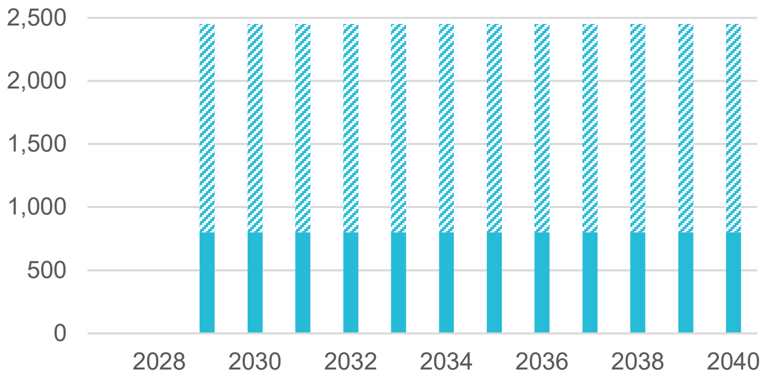
BATTERY/PEAKER

- Batteries and simple cycle CTs will enable integration of new renewable resources shown above.
- New peakers installed 2040 or beyond will be 100% hydrogen

NUCLEAR (SMR/ADV.)



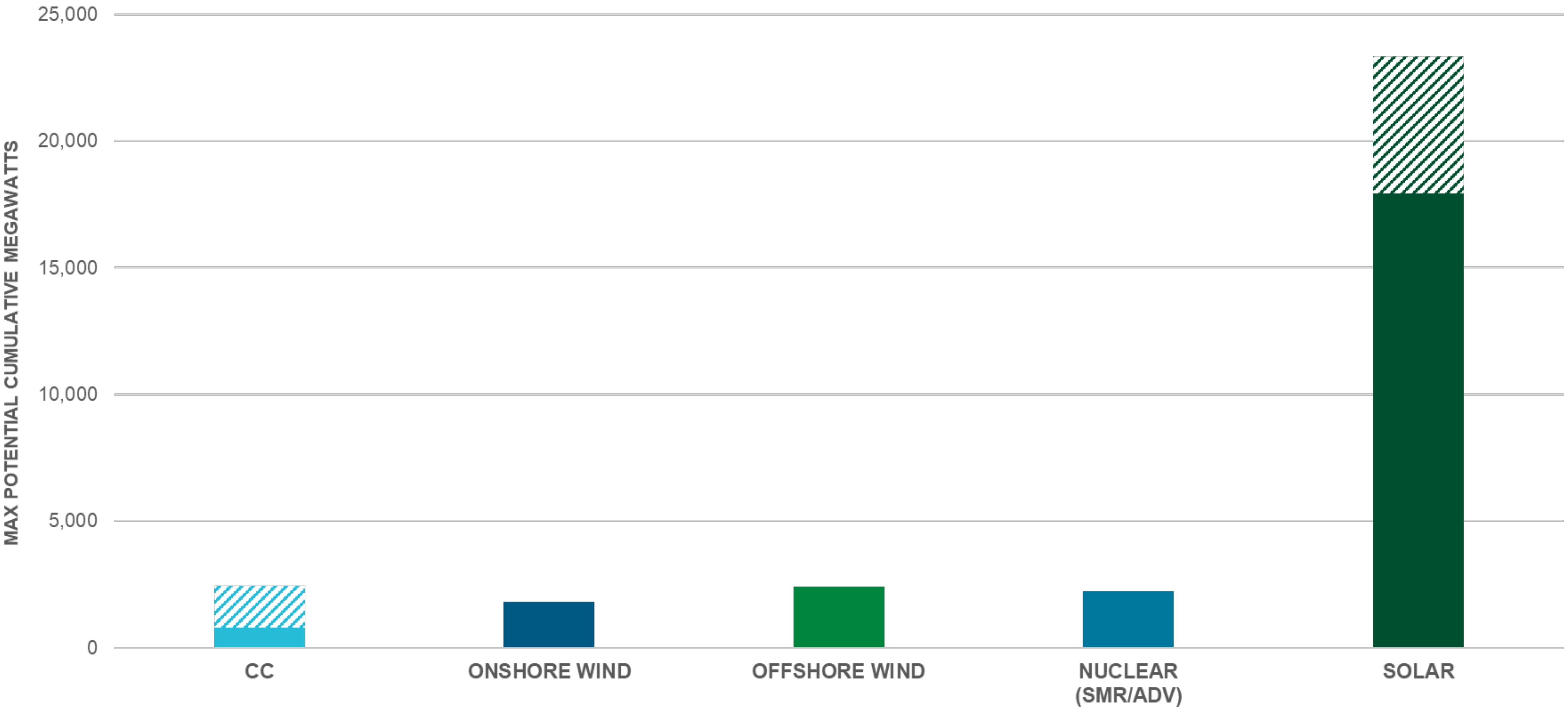
CC



Note: Dashed lines represent upper range of resource limits

Selectable Resource Options (cumulative based on max annual potential)

CUMULATIVE NEW RESOURCE LIMITS BY 2040

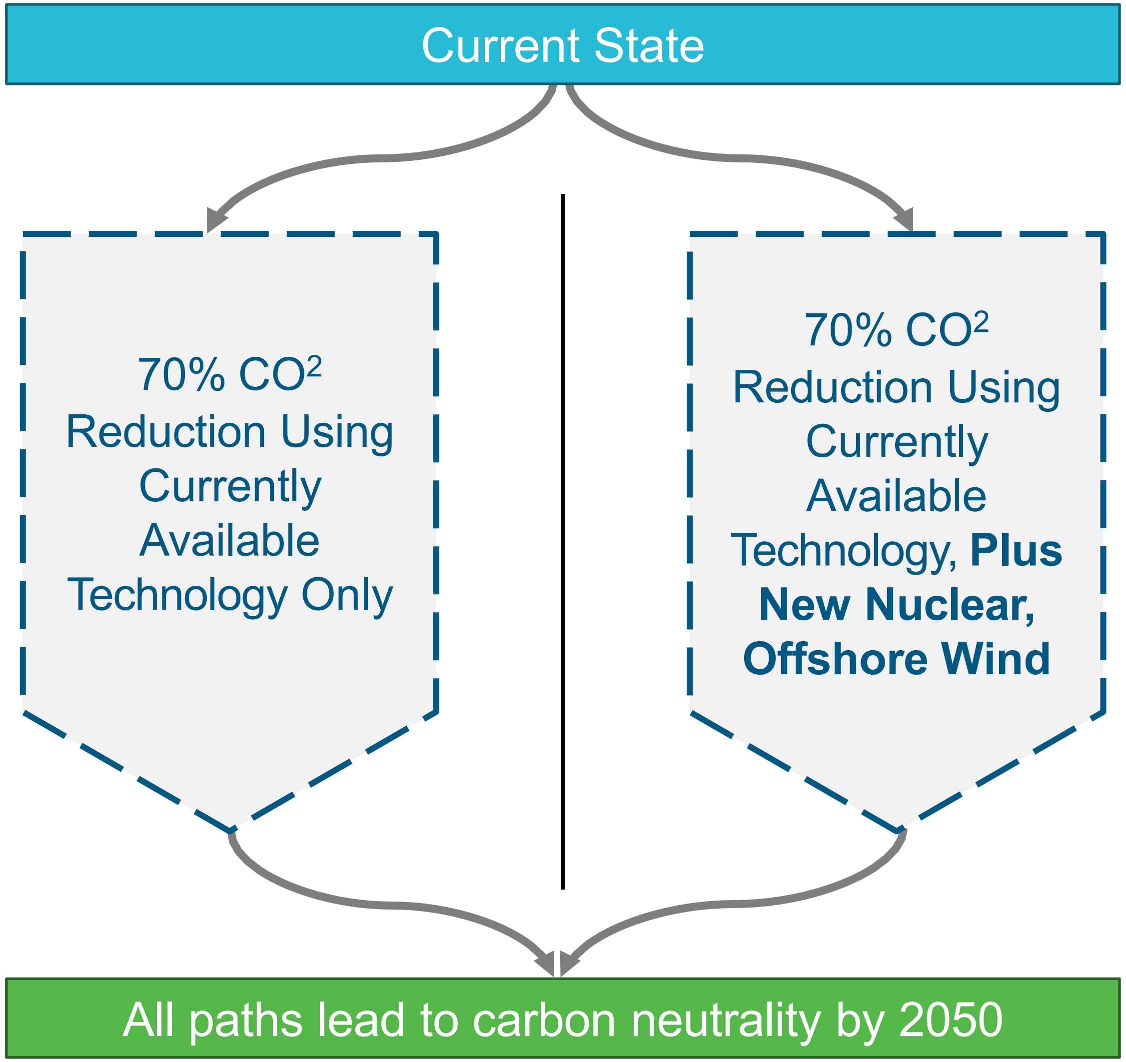


Note: Dashed lines represent upper range of resource limits

Paths on the Way to Carbon Neutrality

HB951

- "Retain discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals, including discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction; provided, however, the Commission shall not exceed the dates specified to achieve the authorized carbon reduction goals by more than two years, except in the event the Commission authorizes construction of a **nuclear** facility or **wind** energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility, or in the event necessary to maintain the adequacy and reliability of the existing grid. In making such determinations, the Utilities Commission shall receive and consider stakeholder input."



Current State

70% CO^2 Reduction Using Currently Available Technology Only

70% CO^2 Reduction Using Currently Available Technology, **Plus New Nuclear, Offshore Wind**

All paths lead to carbon neutrality by 2050

Snapshot: Potential Carbon Plan Portfolios in Year 70% is Achieved

PRELIMINARY DRAFT – MODELING ONGOING AND SUBJECT TO CHANGE

PRELIMINARY PATHWAYS	Grid Edge	Coal Ret.	New CC	Total Solar	Battery & Peaker	On. Wind	Off. Wind	New Pumped Storage	New Nuclear
70% by 2030 *with constrained App. gas*	**EE 1% of eligible retail sales** **IVVC growing to 90% circuits** **Winter DR & CPP**	**Subcritical Coal Retired by 2030**	**2,400 MW** *(2 units)*	**12.0 GW** *(includes solar paired with storage)*	**3.3 GW**	**600 MW**	**800 MW** *(1 block)*		
70% by 2030 *with no App. gas, reduced supply*			**800 MW** *(1 unit)*		**5.7 GW**				
70% by 2032 w/ Add'l OSW *and constrained App. gas*		**Subcritical Coal Retired by 2033**	**2,400 MW** *(2 units)*	**12.3 GW** *(includes sol.+stor.)*	**3.7 GW**	**1,200 MW**	**1600 MW** *(2 blocks)*		
70% by 2032 w/ Add'l OSW *and no App. gas, reduced supply*			**800 MW** *(1 unit)*	**13.9 GW** *(includes sol.+stor.)*	**4.9 GW**				
70% by 2034 w/ SMR *and constrained App. Gas*			**2,400 MW** *(2 units)*	**14.7 GW** *(includes sol.+stor.)*	**3.6 GW**			**1,600 MW** *(BCII)*	**300 MW** *(1 SMR unit)*
70% by 2034 w/ SMR *and no App. gas, reduced supply*			**800 MW** *(1 unit)*	**16.0 GW** *(includes sol.+stor.)*	**4.4 GW**				

Snapshot: Potential Carbon Plan Portfolios in 2035

PRELIMINARY DRAFT – MODELING ONGOING AND SUBJECT TO CHANGE

PRELIMINARY PATHWAYS	Grid Edge	Coal Ret.	New CC	Total Solar	Battery & Peaker	On. Wind	Off. Wind	New Pumped Storage	New Nuclear
70% by 2030 *with constrained App. gas*	**EE 1% of eligible retail sales** **IVVC growing to 90% circuits** **Winter DR & CPP**	**All Subcritical Coal and Marshall 3-4 Retired**	**2,400 MW** *(2 units)*	**19.1 GW** *(includes solar paired with storage)*	**4.8 GW**	**1,200 MW**	**800 MW** *(1 block)*	**1,600 MW** *(BCII)*	**600 MW** *(2 SMR units)*
70% by 2030 *with no App. gas, reduced supply*			**800 MW** *(1 unit)*		**6.2 GW**				
70% by 2032 w/ Add'l OSW *and constrained App. gas*			**2,400 MW** *(2 units)*	**15.2 GW** *(includes sol.+stor.)*	**3.7 GW**		**1600 MW** *(2 blocks)*		
70% by 2032 w/ Add'l OSW *and no App. gas, reduced supply*			**800 MW** *(1 unit)*	**15.6 GW** *(includes sol.+stor.)*	**4.9 GW**				
70% by 2034 w/ SMR *and constrained App. Gas*			**2,400 MW** *(2 units)*	**15.5 GW** *(includes sol.+stor.)*	**3.6 GW**				
70% by 2034 w/ SMR *and no App. gas, reduced supply*			**800 MW** *(1 unit)*	**16.3 GW** *(includes sol.+stor.)*	**4.4 GW**				

Execution Risks

DEPENDENCY	DETAIL
Transmission & Interconnection	Significant transmission needs and associated lead times for build and generator interconnection challenge connecting the magnitude of resources needed to reach 70% reduction. Assumed interconnection levels are more than double current level. Siting, permitting, build, interconnection process and capacity constraints may hinder timely addition of renewables.
Industry Resources	High industry demand for skilled labor needed to develop and interconnect resources required for fleet transformation (generation, transmission, distribution, customer programs, engineering, etc.)
Fuel Availability	Declining coal mining and transportation industry presents concerns over fuel security and flexibility to manage transition to large scale renewables. Legal challenges of pipelines may restrict ability to provide adequate gas supply needed to replace coal generation and maintain system reliability.
Regulatory Approvals	Numerous federal and state agency regulatory approvals required across various components, including regulatory approvals supportive of continued joint system planning and allocation conventions between NC and SC.
Technology Maturity	Reliance on estimated timelines for technology maturation and cost reduction, as well as development and rapid scaling of domestic and global supply chain for emerging technologies.
Supply Chain	Constraints in material (e.g., solar, storage) and labor may restrict advancement of construction.

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Wrap Up:

- Information/feedback can be sent to DukeCarbonPlan@gpisd.net

Meeting materials/recordings will be uploaded to the website:

www.duke-energy.com/CarolinasCarbonPlan

Carolinas Carbon Plan

Developing the path forward for a cleaner energy future.

Our climate strategy is our business strategy. And central to this business strategy is delivering increasingly clean energy while maintaining reliability and affordability for the communities we serve.

In the Carolinas, our target is 70% carbon reduction by 2030 and net-zero carbon emissions by 2050. Our strategy to achieve these targets will be set forth in the Carolinas Carbon Plan. **Stakeholder input will be an important contribution that shapes our initial proposal to state regulators.**

How the Carolinas Carbon Plan will be developed

Stakeholder input
January-May 2022
Duke Energy will host at least three public input sessions. Sessions will be virtual to allow participation from stakeholders

Carbon Plan proposal
May 16, 2022
Reflecting public input, a proposed Carbon Plan will be submitted to state regulators for consideration.

Stakeholder comments
Summer/Fall 2022
State regulators are likely to seek additional input from stakeholders through the regulatory process.

Carbon Plan finalized
by Dec. 31, 2022
We expect that state regulators will develop and finalize the Carbon Plan, to be reviewed every two years and adjusted as

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