NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

March 30, 2020

Kimberley Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-100, Sub 157

Dear Ms. Campbell:

On March 9, 2020, the Commission held a public hearing on the 2019 Integrated Resource Plan updates of the electric investor-owned utility providers in North Carolina. At the hearing, Ms. Anne Lazarides provided testimony and indicated that she would provide additional information for the Commission's consideration. On her behalf, I am attaching her additional comments on the following pages.

Regards,
/s/ Lucy E. Edmondson
Staff Attorney
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March 9, 2020, DEC IRP Hearing
Speaker: A. Lazarides

Thank you for taking on the responsibility that comes with regulatory oversight at a time when the challenges are so great. Those of us who are concerned about the energy transition appreciate the magnitude of the task in which you are engaged.

I would like to voice concerns about the latest Duke Energy Carolinas (DEC) Integrated Resource Plan (IRP). I share with the previous speakers a deep concern about the climate crisis, our increasing use of gas, and our inattentiveness to the dangers of methane. However, here I will focus on the resource selection process. My perspective reflects my professional interests. I have extensive experience in developing models of physical systems, including models that deal responsibly with uncertainty, i.e. are not deterministic. I have done this work in industrial, academic, and consulting settings.

<u>Problem Statement</u>

The 2019 update to the 2018 IRP characterizes our electricity needs as growing and identifies gas plants as the majority component in meeting growth and plant retirement needs. The resource plan was developed using a legacy process originally designed to compare several types of central power stations. The process is not appropriate in a time when there are competitive distributed resource options. On both climate and economic grounds, we cannot afford to wait for the utility to voluntarily incorporate clean distributed resources in their planning *on an equal footing* with central, thermal stations.

More specifically,

1. The utility identifies load growth as 1.1%/year for residential and commercial sectors, and 0.4%/year for industry and proposes to meet resource needs in the coming 15 years largely (>50%) through construction of gas plants powered by simple cycle combustion turbines (CTs). For the 'base case' which presumes that emissions will be constrained according to the clean power plan, generation additions would include combined cycle (CC) plants (also gas) in lieu of several CTs.

2. The utility's rational for gas is that combustion facilities more readily provide the flexibility needed to meet variable load and will continue to be needed as renewables come online because of the variability of the renewable supply. Their concern comes partly from the existing generation mix and the availability of solar supply, as:

(a) 55% of DEC generation is from nuclear plants that run non-stop, as opposed to following load as nuclear plants do in France, and

(b) under low load conditions, nuclear output (and a component from 'must-run' coal plants) is close to or as large as load, such that, under current operational procedures, following load is already a challenge.

Thus, we have insufficient flexibility to follow load under low load conditions or whenever solar power without storage is the only other source.

3. The reason we are seeing renewables presented as solutions throughout the country is that there exist cost effective methods of balancing supply and demand through solutions that rely upon renewable souces, operational changes, energy storage, energy efficiency, and demand response.

So, how do we do planning when

1. least cost solutions are highly likely to be comprised of distributed generation (DG), energy efficiency (EE), and demand response (DR),

2. models that incorporate distributed components at the individual device level, as is done in older models designed for systems with central stations and exclusively centralized control, are too cumbersome to develop and execute as would be required to produce a single least cost solution,

3. new planning methods are being developed, but the modeling tools that could yield low cost solutions from the palette of distributed, clean choices are not yet in steady-state; thus, their use involves extensive exercise of judgment and/or preference, and new tool adoption cannot be done without debate, and

4. the utility is governed by a corporate board as well as by us under a business model that incentivizes choices misaligned with our goals, such as choices designed to achieve earnings growth?

Some steps we can take to enable better planning

We need to acknowledge that central planning approaches to resource planning can, at best, do approximate cost minimization when available resources are resources of all sizes in an infinite number of locations throughout the distribution as well as transmission system. In complex systems, such as the electrical system with distributed resources, planning tool selection and implementation relies upon judgments made by the planners; outcomes necessarily will reflect these choices. Once we accept that a single least cost solution can no longer be found, we can step up to the job of guiding planning to facilitate consideration of contemporary clean solutions. Toward this end, I request that the commission

(1) issue an order that requires utilities to submit resource plans that include a case that excludes new gas plants. This would be consistent with the precedent of requiring the resource plan to include carbon-constrained and carbon-unconstrained cases as was done for the current IRP.

We further need to be vigilant about gas infrastructure build-out that happens outside the resource planning process. In particular, we need to

(2) close loopholes that allow the utility to make commitments to gas use through dual fuel conversions for which regulatory approval is sought after the fact, at the time when the utility seeks cost recovery.

We need to step outside the debate of what load growth may or may not be by

(3) requiring that the utility include in the resource plan a case in which load growth is met by energy efficiency (EE). A number of states that are seeking to reduce costs and emissions are raising the EE resource component in their resource mix by mandating annual increments of several percent in EE savings.[1] Others mandate pegging EE increments to a fraction of load growth.[2] While setting an EE mandate to the full amount of load growth would be novel, it could serve to motivate aggressive action in reducing both heating and cooling load and bring our EE level closer to the levels accomplished in high EE states.

We need to develop familiarity with the economic benefits of making more extensive use of distributed resources. One approach to facilitating comparison between clean distributed solutions and new gas plants is to define clean energy portfolios (CEPs) comprised of distributed resources that

[1] For example, Massachusetts and Rhode Island, see the ACEEE's State Energy Efficiency Resource Standard (EERS) Activity database at https://www.aceee.org/content/state-energy-efficiency-resource-standard-eers-activity

[2] In Tennessee the mandate to tie the EE requirement to load growth is mandated by the TVA, i.e. through regulation. In Texas, where utilities are deregulated, the tie is established through a legislated Energy Efficiency Resource Standards (EERS), see above reference to the ACEEE database.

can substitute for specific types of plants.[3] Notably, the cost minimization process that defines the clean portfolios that can substitute for CT or CC plants is much more tractable than the problem of minimizing cost of the full electricity system. While constraining collections of distributed resources to have the properties of central plants leaves out some benefits of distributed resources and, thus, undervalues them, the clean energy portfolios could be incorporated into central planning processes. However, the key benefit of determining least cost clean energy portfolios is that it allows the portfolio costs to be compared with the costs of thermal generators. Determinations then can be made as to when the thermal plants will become uneconomic under conservative assumptions. The compositions of the clean energy portfolios are themselves illuminating, as they describe which clean resources could substitute for which types of thermal plants. [See Rocky Mountain Instititute report at rmi.org/insight/clean-energy-portfolios-pipelines-and-plants and the Portland General Electric 2019 IRP at portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning]

Whereas energy efficiency and renewable generation form major components of portfolios that substitute for combined cycle (CC) plants, clean portfolios that substitute for combustion turbines (CT) require more demand response and storage. While over time, these components will work their way into new planning tools, in the near term we need to form an understanding of the state's potential for the least expensive CT clean portfolio component, demand response (DR). The groundwork for characterizing DR potential for the state and for local regions, or even on a circuit-by-circuit basis within the distribution system, has been laid by national lab studies of DR potential in the Western Interconnect. These studies characterized DR potential on a sector by sector basis, and further analyzed the DR potential of individual processes within specific industries. DR supply curves developed for individual industrial processes can be used to develop facility-specific curves following an inventory of each industrial facility's process mix. A region's DR supply potential can then be characterized by combining residential, commercial, and industrial components. This type of knowledge will enable us to quantify the extent to which DR can be substituted for more capital-intensive energy storage when designing portfolios that combine renewable supply with complimentary components that allow renewably-powered resources to perform the functions performed by gas plants in the past. Thus we need to

(4) initiate a collaboration with NREL or LBNL that will produce a description of North Carolina's demand response potential of importance in developing low cost flexibility resources.

As we move to develop the flexibility resources that will lower the cost of translating renewable supply into high capacity as well as energy sources, simultaneously we need to speed the interconnection of solar resources already present or proposed by

(5) removing all barriers to coupling storage with existing solar farms and solar projects in the interconnection queue.

[3] Dyson, M. et al, "The Economics of Clean Energy Portfolios", Rocky Mountain Institute, 2018. https://rmi.org/insight/the-economics-of-clean-energy-portfolios/

Questions, Answers, and Supporting References

1. What are the types of energy consumption that offer the greatest benefit if made more energy efficient?
   a. American Council for an Energy Efficient Economy (ACEEE)
   b. Energy Efficiency (EE) Roadmap: Heat pump water heater program
   c. Powers, B, 'North Carolina Clean Path 2025 – Achieving an Economical Clean Energy Future,' highlights heating and cooling. Note that because heating and cooling are such large components of our load peaks, increased efficiency addresses capacity as well as energy needs (at both seasonal peaks.) In regions with capacity markets governed by RTOs, aggregated EE bids into the capacity markets, for example in NY-ISO and PJM.

2. What are potential sources of large scale demand response?

   a. Municipal lighting and commercial heating and cooling are among the top resources identified in the LBNL/NREL/DOE 2013 report, LBNL-6417E.[4]

   b. Note also that traditional direct load control (DLC) of residential HVAC systems can be a large resource if properly implemented. High participation is required to generate a large resource. Highly successful DLC programs include Baltimore Gas & Electric's Smart Energy Rewards program and Xcel Energy's Savers Switch Program in Minnesota, both of which have achieved over 50 percent enrollment among eligible customers.[5]

   c. A series of national lab reports have developed demand response potential characterization methods so that DR could be included in production cost models used to inform utility resource planning. Demand response potential of manufacturing facilities was investigated by Starke et al and reported in ORNL/TM-2013/407.[6] Demand response potential of a key group of commercial, residential, and municipal loads was investigated by Olsen et al and reported in LBNL-6417E.[7] The load availability hourly profiles developed in the LBNL report were used in production cost modeling along with traditional resources and reported in Hummon et al in NREL/TP-6A20-58492.[8] Various states and/or utility commissions have solicited engineering and economic studies to use these or other methods to characterize DR potential in their balancing areas. Demand response potential has been characterized also by FERC.[9,10]

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[4] Olsen et al., "Grid Integration of Aggregated Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection."
[5] Shavel and Fox-Penner, "Exploring Natural Gas and Renewables in ERCOT, Part III: The Role of Demand Response, Energy Efficiency, and Combined Heat & Power."
[6] Starke, Alkadl, and Ma, "Assessment of Industrial Load for Demand Response across U.S. Regions of the Western Interconnect."
[7] Olsen et al., "Grid Integration of Aggregated Demand Response, Part I: Load Availability Profiles and Constraints for the Western Interconnection."
[8] Hummon et al., "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model."
[9] Brattle Group, Freeman, Sullivan, and Global Energy Partners, "A National Assessment of Demand Response Potential."
[10] "2019 Assessment of Demand Response and Advanced Metering."

3. What are references for increasing flexibility of central power stations run as baseload plants?
    a. The national lab report I had seen was for fossil fuel combustion plants[11]
    b. Will compile other references for nuclear plants

[11] Cochran, "Flexible Coal: Evolution from Baseload to Peaking Plant." NREL/BR6A20-60575