BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1089

In the Matter of:	)	
Application of Duke Energy	)	
Progress, LLC for a Certificate of	)	**COMMENTS**
Public Convenience and Necessity to	)	**OF BRAD ROUSE**
Construct a 752 Megawatt Natural	)	
Gas-Fueled Electric Generation	)	
Facility in Buncombe County Near	)	
the City of Asheville	)	

Brad Rouse's Comments

Having intervened in this proceeding, I Brad Rouse am submitting these comments so that they may be considered by the North Carolina Utilities Commission (Commission) as it reviews the Application for Certificate of Public Convenience and Necessity and Motion for Partial Waiver of Commission Rule R8-61("Application") filed by Duke Energy Progress, LLC (DEP) on January 15, 2016.

OVERVIEW

I have reviewed the Duke Energy Progress (DEP) application for a certificate of need and necessity for construction of a plant predominantly fired by natural gas in Arden, NC to replace the existing 376 MW coal plant there. My conclusion is that this application is flawed. The Commission should either pause the proceedings to request DEP to present an alternative strategy, or the Commission should deny the request. Instead of the plan filed in the application, DEP should go for a smaller plant footprint and should move more slowly than the application indicates.

Small and slow is better than big and fast because the energy and electric utility industries are in a tumultuous time. Twin tsunamis are headed their way.

The first tsunami is the growing clamor to end the fossil fuel era. Greenhouse gases from fossil fuel burning and natural gas leakage are the primary causes of climate change. The world scientific community has concluded that we must ramp down fossil fuel use 80% or more by 2050, to avoid dangerously destabilizing the climate. Over 190 nations agreed to this goal in Paris late last year. As governments take action to meet these goals, either through regulation or carbon pricing, the new DEP plant will be increasingly uneconomic not that long after its 2020 completion.

The second tsunami is technological - much like the waves of change that swept land lines, cable TV, cellphones, computers, the music industry, book publishing and the newspaper industry, etc. Technological alternatives to fossil fuels are coming on fast and furious. A blend of solar, wind, and energy efficiency resources is already less expensive than the proposed plant. Solar and wind costs declined by 81% and 50% respectively from 2009-2015, with no sign of slowing. LED lights reduce electric use by 90% at reasonable cost. Battery storage costs continue declining. As we gain experience, we keep realizing that we can use more and more of these technologies while providing reliable electricity. According to Stanford university scientists, the National Renewable Energy Laboratory, and others, we can see a clear path to produce 80-100% of our electricity with renewables, storage, efficiency and a better and smarter electric grid in the next few decades.

These twin tsunamis may make the Arden plant economically obsolete on its first day of operation. The fuel used by the plant, natural gas, is likely to be seen as so undesirable that it is sharply constrained through regulation or priced through taxation. Since DEP is guaranteed recovery on investments "made on our behalf", ratepayers will bear the burden of these "stranded investments".

It is with the backdrop of these two trends that DEP is asking the Commission to approve a $1.1 billion investment. This investment will end the use of coal but double the fossil fuel generating capacity there.

My detailed comments will show that this project, as configured, is unnecessary because the region could get by for now on a smaller plant configuration. The project increases the size of the largest power generation unit in the region from 186 MW to 280 MW. Such a larger plant size does nothing to improve reliability according to the industry rules that DEP is attempting to comply with

Building a plant that is bigger than the absolute minimum needed, given the "twin tsunamis" will subject DEP and its ratepayers to unnecessary risks. Already, alternatives to the proposed plant – a blend of solar, wind, energy efficiency, and demand management – can be deployed at lower cost than the plant. As climate concerns mount, it is very likely that a price on carbon and an adder for methane leakage will be added to the fuel cost for natural gas. This will lead to a lifecycle plant cost that could be as high as triple the cost of the alternative. To take such a risk is foolhardy.

The Commission should deny DEP's request and ask them to work with the community to come up with a plan that gives the region the maximum opportunity to take advantage of the lower cost options coming full steam ahead and to avoid the pitfalls of an overreliance on fuels that have a great risk of much higher cost.

There is a reasonable long term solution that does not rely on fossil fuels. I know from personal experience that there are many opportunities to reduce our extreme energy waste. DEP's current programs are underutilized and just scratch the surface. The rush DEP feels to add capacity is in large part based on high power demands in recent winters. Focusing intensely on reducing energy use at system peak, 7:00 AM on bitterly cold mornings, would bring down that peak. There are off the shelf solutions available now to do this. By mobilizing the cooperative efforts of DEP, and local civic, political, and faith leaders this can happen, and happen in a way that also helps our low income residents save on energy costs.

Building a plant that is bigger than the absolute minimum and sooner than really needed is risky. To take such a risk when better options are readily available is foolhardy.

DETAILED COMMENTS

The following are my detailed comments, posed in a question and answer style.

Mr. Rouse, what are your qualifications in this matter?

My career has been spent in the fields of economic and financial analysis, with special focus on energy system planning. I received my BA in Economics from Yale in 1974, graduating cum laude. I then received an MBA from the University of North Carolina at Chapel Hill (Kenan Flagler) in 1976, graduating Beta Gamm Sigma, with a focus on finance. After graduate school I was employed as an Economics Consultant for Data Resources Inc., advancing to manager of DRI's utility economics practice. My primary effort at DRI was to develop energy and demand forecasting systems for electric utilities in the Southeast. I led the development of DEP Progress's (then Carolina Power and Light) first long range econometric load forecasting system. In reading DEP's description of their load forecasting approach, I see that it still bears much similarity to the system I helped develop.

My career also includes a long period of time developing systems and performing analysis for utility long - range strategic planning. As a Vice President for Energy Management Associates, Inc. (EMA) in Atlanta, GA, I led the development of two premiere systems used to perform integrated resource plans – Proview and Strategist. Both Duke Energy and Carolina Power and Light used these systems as part of their development of integrated resource plans and I consulted extensively with Duke Energy system planning and financial departments for this purpose. At one time over 100 utilities were using these products worldwide, and there are still many users of one or more of these products today.

In addition to overseeing the development of these systems, I worked extensively with EMA consultants and utility planners, including at Duke Energy, to help apply these systems in the Integrated Resource Planning process. Usually working in the background on these efforts, I did present expert witness testimony in Montana and Pennsylvania, and more recently have testified as a member of the public before the Georgia Public Service Commission and the US Environmental Protection Agency.

After working with EMA, I worked for a number of years advising individuals and businesses on financial planning strategy. I received the Certified Financial Planner designation in 2002. I sold my financial planning advisory practice in 2013 to focus again on energy planning issues.

Why should the Commission deny the application?

DEP has not submitted information demonstrating that a plant of the requested size is needed at its 2020 projected in service date, nor has DEP demonstrated that this plant is the lowest cost and lowest risk option to meeting the need for power. I have performed an evaluation, which I review below, that demonstrates that a plan relying on substantially less gas fired capacity and more renewable energy, demand management and energy efficiency is very likely to have sufficient reliability to meet NERC standards and be lower cost than the one envisioned in the documents supporting DEP's application.

Because of the sustained decline in the cost of renewable alternatives and storage, DEP should reduce the size and delay the timing of new gas capacity to take advantage of these escalating cost advantages. With a downsizing and or a delay, DEP would have additional time to add more renewables, efficiency, and storage, possibly delaying the plants even further.

Of particular note is the recent extension of tax credits for solar and wind. DEP has not published a reassessment of the least cost plan after these extensions, but others have. The result of a study by The Rhodium Group Consultancy entitled "Renewable Tax Extenders: The Bridge to the Clean Power Plan", concluded:

> "Without the tax extenders, the least-cost CPP compliance pathway would be a shift from coal generation to Natural Gas Combined Cycle (NGCC) generation. The tax extenders fundamentally change the game. We expect wind and solar to cut off the surge of NGCC generation and become the technology of choice for the entire CPP compliance period."[1]

So just as the Commission is being asked to make a decision on this plant, the game is changing. This alone should lead DEP to seriously consider the idea of a smaller footprint for the combined cycle units at the plant.

As important as the cost and reliability comparisons are, the degree of risk to ratepayers in relying on excess gas fired capacity is the primary reason the Commission should deny DEPs request to continue expanding its fossil fuel "business as usual" strategy. Indeed, there is a heightened chance that any major commitment to fossil fuel resource is likely to subject ratepayers to grave risks.

How does DEP's "business as usual" plan to build two natural gas fired Combined Cycle (CC) units and one Combustion Turbine (CT) expose them to grave risks?

Perhaps the biggest dramatic change on the horizon is climate change and our actions to mitigate it. Momentum is building for climate action on a national and global scale. Pope Francis' recent encyclical has opened a new chapter in that many faith communities are now strongly supportive of reducing fossil fuel emissions. A recent poll from USA Today illustrates very strong support for transitioning to a clean energy economy among voters under age 35: "By an overwhelming 80%-10%, those surveyed say the United States should transition to mostly clean or renewable energy by 2030"[2].

The accord reached in Paris illustrates this momentum and the implications for power system planning. The 196 nations who signed the accord all agreed on a goal of keeping global average temperature well below a climate destabilizing limit of 2 degrees C. Andrew P Jones,[3] co-founder of "Climate Interactive"

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[1] "Renewable Tax Extenders: The Bridge to the Clean Power Plan" by John Larsen and Whitney Herndon, January 27, 2016. http://rhg.com/notes/renewable-tax-extenders-the-bridge-to-the-clean-power-plan

[2] USA Today, 1/11/2016 http://www.usatoday.com/story/news/politics/elections/2016/01/11/poll-millennials-agenda-president-rock-the-vote-republican-trump-sanders-democrat/78556154/

[3] "With Improved Pledges Every Five Years, Paris Agreement Could Limit Warming Below 2°C" By Andrew Jones, John Sterman, Ellie Johnston, and Lori Siegel, December 14, 2015 blog post. https://www.climateinteractive.org/blog/press-release-with-an-ambitious-review-cycle-offers-to-paris-climate-talks-could-limit-warming-below-2c/

in Asheville, has developed a model to illustrate how fast emissions need to come down in each country to meet that goal. The implications of his work are clear: global net fossil fuel emissions need to be 46% below 2005 by 2030 and 80% below 2005 by 2050. In the US they need to begin declining almost immediately, and be in sharp decline in the time frame from 2025 to 2050. Emissions in the power sector need to begin declining even sooner than that, since the hardest economic sector to convert to renewables is transportation, especially air travel, and that will take longer. Indeed, the Paris accord calls for ongoing consideration of an even more ambitious goal of stabilizing the climate below 1.5 degrees C.

The diplomats in Paris agreed that this is the magnitude of change needed. If that happens, the useful life of this plant would end essentially by 2040 or sooner, when the plant was only 20 years old. Well before 2040, the introduction of measures to constrain carbon emissions would reduce the capacity factors of this plant, increasing its average cost. If these events occur, which I deem likely, then this plant will have been a terrible decision. Delaying the plant now for further study and searching for alternatives is a prudent strategy. DEP's plan doesn't consider this risk and should be rejected in favor of more extensive planning and questioning, leading hopefully to a better plan with lower risk.

It's interesting that DEP is already anticipating climate change. They are using a higher planning reserve margin based on greater load variability observed due to the "polar vortex". This greater variability is an expected result of climate change. Also, DEP already assumes a cost of carbon of $29.00 a ton in the filing.

In my assessment, however, DEP's assumed cost of carbon of $29.00 per ton is far too low, because it is not likely to be high enough to promote the changes needed to reach the Paris goals. In my opinion, the biggest risk from building units bigger than the minimum possible is economic. The price on carbon will most likely need to be much higher in order to meet a US reduction of 45% of greenhouse gas emissions by 2030 and 80% by 2050. Such a price could be as high as $300 a ton by 2050. I will provide more detail on the implications of such a high price in my discussion of the cost of DEP's plan versus alternatives, below.

Is carbon pricing gaining support?

Yes, it is gaining a large amount of support and is highly likely. There are several bills in Congress to introduce a carbon fee. The idea has received tremendous amount of support from the public both conservative and liberal thought leaders, governments, and major corporations. I review some of the elements of that support in more detail in Appendix A. I will also quantify the carbon price risk when I discuss the details of the cost comparisons below.

While enacting a national carbon tax or fee is the simplest approach to pricing carbon, it is not the only approach. Such approaches as "cap and trade" or the RECs trading in EPA's "Clean Power Plan" will effectively lead to a price on carbon or a comparable subsidy of renewable alternatives. Of course, the "Clean Power Plan" does not satisfy the goals of the Paris Accords and something stronger is likely.

An action by EPA under Section 115 of the Clean Air Act ("International Pollution") is gaining legal support as a mechanism for enforcing economy wide reductions in carbon dioxide and methane emissions from fossil fuels.[4] Even if our federal legislative process is hopelessly deadlocked, and will never enact carbon legislation, there is direct language in the Clean Air Act that could allow a future President and EPA to enforce sweeping reductions in the burning of fossil fuels. A future price on carbon does NOT depend on legislative action.

DEP is prudent to include carbon pricing in their planning. However, DEP and this Commission need to put increased emphasis on understanding the growing movement for climate action and the political risk that this imposes on the price of gas. Approving DEP's application will burden customers with those costs if it turns out you made the wrong choice.

This is not about a moral choice for the future of our grandchildren or whether the Commission is convinced that global warming is real and caused by man or not. Instead, the question that should be asked is "What should a reasonable person know or logically conclude about the risk of political or administrative action to reduce fossil fuel emissions?" And based on what I see, a reasonable person should conclude that there is **very substantial risk** that the global scientific community is right, that there is broad global consensus that something should be done, that there is growing US consensus, and that when it happens, directly or indirectly, the result will be a significant price on carbon. In my opinion, DEP is seriously understating the potential size of that future price. DEP, in its plans, and the Commission, in its review of DEP plans, must quantify and seek alternatives to mitigate carbon price risk.

And due to that risk as well as the ongoing technological change, the Commission should deny DEPs application because it exposes ratepayers to a larger risk than is needed.

Mr. Rouse, why do you say that DEP has not demonstrated that this plant is needed at its 2020 projected in service data?

DEP's need for power in this case is based on two separate needs: (1) The need for power in Western North Carolina (WNC) and (2) the need for power in the DEP system overall.

DEP's current system is transmission constrained in WNC, which means that DEP is only able to bring a limited amount of power from the rest of the system into WNC, and is also only able to supply the rest of the system with a limited amount of power from WNC. And if you look at recent history, it would appear that DEP is barely using the existing power resources in the region. In 2014 the existing 379 MW coal plant only operated at a 44% capacity factor. In 2013 it operated at a 39% capacity factor. The existing additional 2 unit 370 MW capacity gas turbines together operated at a 2.0% capacity factor in 2014 and at 2.3% in 2013. The combined capacity factor for the 4 units was 26% capacity factor in 2014 and 22% in 2013[5].With such a low utilization rate for the existing resources, it is hard to understand why DEP would need even more capacity in the region.

[4] "Legal Pathways to Reducing Greenhouse Gas Emissions Under Section 115 of the Clean Air Act", January 2016, © 2016 Sabin Center for Climate Change Law, Columbia Law School; Emmett Institute for Climate Change and the Environment, University of California-Los Angeles School of Law; Institute for Policy Integrity, New York University School of Law, Michael Burger, Columbia Law School, Coordinating Lead Author.
[5] Source: Energy Information Administration, http://www.eia.gov/electricity/data/browser/#/plant/2706

But doesn't DEP's application, specifically Table 1 of Exhibit 1B, show that DEP will not have enough capacity to meet NERC guidelines when the coal plants are retired unless they have the new CC units in 2020 and the contingency unit in 2024?

Yes, that is what Table 1 seems to show. But the two 280 MW units are excessive versus what is needed. The extra capacity actually does nothing to support DEP's satisfaction of reliability regulations. DEP's own statements and data support this conclusion. I refer you to Exhibit 1B: Statement of Need, Table 1. This table calculates the "NERC compliance reserves after single contingency". I have included the exact numbers from this Exhibit 1B as Table 1. You can see from Table 1 that the NERC compliance reserves are at 90 in 2020, the year the coal plant is retired and the new capacity comes on line. DEP implies that the only way to keep these reserves from going below zero is to install two 280 MW CC units. But there's more to this story.

Exhibit A, Table 1

DEP Case

Table 1: DEP-Western Region Demand/Load Balance (Winter) and NERC Compliance Post-WCMP

Duplicate data from Exhibit 1A

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand Forecast	1,146	1,170	1,187	1,199	1,214	1,243	1,259	1,278	1,297	1,310	1,333
Total Generating Capacity:											
Existing Company-Owned Resources	486	486	486	486	486	486	486	486	486	486	486
CC	280	280	280	280	280	280	280	280	280	280	280
CC	280	280	280	280	280	280	280	280	280	280	280
Contingent CT					186	186	186	186	186	186	186
Total Generating Capacity	1,046	1,046	1,046	1,046	1,232	1,232	1,232	1,232	1,232	1,232	1,232
Total Transmission Import Capability	750	750	750	750	750	750	750	750	750	750	750
Transmission Reliability Margin (TRM)	280	280	280	280	280	280	280	280	280	280	280
Useable Transmission	470	470	470	470	470	470	470	470	470	470	470
Total Generation and Usable Transmission	1,516	1,516	1,516	1,516	1,702	1,702	1,702	1,702	1,702	1,702	1,702
Total Reserves (Generation + Usable Transn - Peak Load)	370	346	329	317	488	459	443	424	405	392	369
TRM Requirements after Single Contingency	280	280	280	280	280	280	280	280	280	280	280
NERC Compliance reserves After Single Contingency	**90**	**66**	**49**	**37**	**208**	**179**	**163**	**144**	**125**	**112**	**89**

I developed a spreadsheet that duplicated all the results of Table 1, shown here as Table 2. My analysis shows that DEP could just as easily satisfy that need with two 188 MW units, either CC or CT or one of each. This makes sense when you consider that a system with given capacity and larger units is less reliable than a system with the same capacity but composed of smaller units. The impact of one of the units having a forced outage is much greater when the system has a few large units. To achieve the stated reliability goal, DEP doesn't need 560 MW in two units. They could just as easily build 376 MW in two gas units, essentially replacing the coal megawatt for megawatt. In addition to cutting the capacity of the two 280 MW CC units to 188 MW each, DEP could delay the Contingent CT one year while maintaining sufficient required reserves. With these changes, the compliance reserves are still above zero in every year. Since this lower level of capacity still meets the minimum reserve levels, I conclude that DEP could easily get by with a smaller unit size (CC or CT) and a delay of the Contingent CT. Since a smaller capacity is sufficient, the larger unit size is not needed to meet reliability standards.

Table 2: DEP-Western Region Demand/Load Balance (Winter) and NERC Compliance Post-WCMP 185 MW CT or CC Case with Contingent CT delayed until 2025

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand Forecast	1,146	1,170	1,187	1,199	1,214	1,243	1,259	1,278	1,297	1,310	1,333
Total Generating Capacity:											
Existing Company-Owned Resources	486	486	486	486	486	486	486	486	486	486	486
CC	188	188	188	188	188	188	188	188	188	188	188
CC	188	188	188	188	188	188	188	188	188	188	188
Contingent CT					0	186	186	186	186	186	186
Total Generating Capacity	862	862	862	862	862	1,048	1,048	1,048	1,048	1,048	1,048
Total Transmission Import Capability	750	750	750	750	750	750	750	750	750	750	750
Transmission Reliability Margin (TRM)	188	188	188	188	188	188	188	188	188	188	188
Useable Transmission	562	562	562	562	562	562	562	562	562	562	562
Total Generation and Usable Transmission	1,424	1,424	1,424	1,424	1,424	1,610	1,610	1,610	1,610	1,610	1,610
Total Reserves (Generation + Usable Transmission less Peak Load)	278	254	237	225	210	367	351	332	313	300	277
TRM Requirements after Single Contingency	188	188	188	188	188	188	188	188	188	188	188
NERC Compliance reserves After Single Contingency	**90**	**66**	**49**	**37**	**22**	**179**	**163**	**144**	**125**	**112**	**89**

Could you simply scale the units down to 188 MW? Is there something magical about the 280MW that makes that a better unit size?

I have spoken with several experts in the industry who concur that CC units are scalable and various unit sizes are available. In any case, you could build 2 CT units at 186 MW each because that is the size of the third unit in DEPs proposal. There may be some minor scale advantages to the larger size units, are likely outweighed by the benefit of not overinvesting in the WNC electric system at such a momentous time in the industry. I'm surprised that DEP didn't at least show a smaller unit size as an option. The Commission should deny this application in favor of a new assessment by DEP of a smaller configuration at the plant.

Would there be a way for DEP to eliminate the need for the plant altogether?

Unless alternate capacity or transmission can be found the plant could not be eliminated completely by 2020 if the coal units are retired. Instead, I propose DEP seriously consider is a series of 188 MW units that can allow for the capacity to be either phased in or partially eliminated over time, depending on conditions as they change. A total of 376 MW could be added to replace the coal plant and then alternatives explored to see how the additional planned capacity of another 376 MW could be avoided or deferred.

How might DEP defer the capacity of the Contingent CT unit?

DEP should seek to make the region a test case of transitioning to a renewable energy electric system. This would involve combining additional renewable resources such as wind, hydro and solar with additional demand management, and efficiency to obtain the needed reliability. Over time the region will need new transmission capability to take advantage of emerging renewable energy opportunities elsewhere. Perhaps a new intertie to TVA or to Duke Carolina's service territory in far Western NC (DEC-WNC) with its connections to TVA and the 373 MW Brookfield Hydro could be developed. Perhaps the coal units could remain available on a seasonal basis to give the region time to fully support the alternatives. I recommend that the Commission instruct DEP to fully evaluate these alternatives before committing to such a large expansion of fossil fuel resources in the region. DEP could eliminate the need for expansion beyond the 376 MW coal with such a strategy. The Commission should request that DEP develop, with local input, one or more such strategies before the Commission approves new fossil infrastructure in WNC beyond a smaller configuration gas plant.

As a starting point for this thought process, I have provided in Table 3 a hypothetical expansion of the system over time that illustrates how needs of the region could be met with two 188 MW CC units and not the contingent CT. In this hypothetical scenario, the region's needs are more than met by one or two wind turbines a year added from 2020 on, a significant improvement in energy efficiency focused on the winter peak, additional load control, a small contribution of solar energy with storage to winter peak, and modest expansion transmission. This is an example of the sort of alternative that DEP should explore before committing to the contingent CT.

Table 3: DEP-Western Region Demand/Load Balance (Winter) and NERC Compliance Post-WCMP WNC IRP higher efficiency, more renewable energy and no contingent CT before 2030

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand Forecast	1,146	1,170	1,187	1,199	1,214	1,243	1,259	1,278	1,297	1,310	1,333
Additional Energy Efficiency	11	17	23	29	35	41	47	54	60	66	73
Peak Demand	1,135	1,153	1,164	1,170	1,179	1,202	1,212	1,224	1,237	1,244	1,260
Total Generating Capacity:											
Existing Comp.-Owned Resources	486	486	486	486	486	486	486	486	486	486	486
CC	188	188	188	188	188	188	188	188	188	188	188
CC	188	188	188	188	188	188	188	188	188	188	188
Contingent CT					0	0	0	0	0	0	0
Wind	0	2	4	6	8	10	12	14	16	18	20
Solar on winter peak w. storage	1	1.2	1.4	1.6	1.8	2	2.2	2.4	2.6	2.8	3
Load Control	5	6	7	8	9	10	11	12	13	14	15
Total Generating Capacity	868	871	874	878	881	884	887	890	894	897	900
Transm. Imp. Capability - Existing	750	750	750	750	750	750	750	750	750	750	750
Transm. Imp. Capability - New	0	0	0	0	0	50	50	50	50	50	50
Total Transm. Imp. Capability	750	750	750	750	750	800	800	800	800	800	800
Total Capacity	1,618	1,621	1,624	1,628	1,631	1,684	1,687	1,690	1,694	1,697	1,700
Transm. Reliability Margin (TRM)	188	188	188	188	188	188	188	188	188	188	188
Useable Transmission	562	562	562	562	562	612	612	612	612	612	612
Total Gen. and Usable Transm.	1,430	1,433	1,436	1,440	1,443	1,496	1,499	1,502	1,506	1,509	1,512
Total Reserves (Gen + Usable Transm. less Peak Load)	295	280	272	270	264	294	287	278	269	265	252
TRM Requirements after Single Contingency	188	188	188	188	188	188	188	188	188	188	188
NERC Compliance reserves After Single Contingency	**107**	**92**	**84**	**82**	**76**	**106**	**99**	**90**	**81**	**77**	**64**

Assumptions:

Efficiency gains of .5% per year from 2019 above DEP initial projections.
One wind turbine per year on average from 2021 - 2030
Continuing build out of solar with storage for winter peak.
Additional Load Control program.
Single transmission upgrade 50 MW.

Note that the largest contributor in the plan presented in Table 3 is energy efficiency. The assumption in this case is that DEP would work with the community and partially fund a collaborative effort with the goal of reducing electric demand in the system .5% per year versus what it would otherwise have been.

There is great support in the region for a more sustainable future that relies less on fossil fuels. This support is growing as evidenced by the number of people at the public hearing on September 26. I would ask that the Commission and DEP consider the particular desires of the region and adopt a plan that relies on the combined commitment and ingenuity of DEP along with the citizens of WNC to meet their goals with a smaller footprint plant and no additional CT.

Has DEP addressed the root cause of their reliability concerns in WNC?

Not that I can see from the application. It's interesting that DEP says that a much greater electric capacity is needed to respond to the severe winter weather conditions of recent years. But these conditions are very rare, every few years or so, and last only a few days to a week. Since these conditions are so rare, DEP should look to addressing the problem directly instead of looking only at adding electric capacity. It's almost as if, DEP only has a hammer, so every problem looks like a nail. If they thought about using a screwdriver they would get a better solution.

DEP, in collaboration with the community, should develop contingency plans to deal with these rare severe weather conditions. Perhaps a major program to weatherize homes and to replace strip heat with high efficiency heat pumps would be a more cost effective way to solve this problem. It would certainly help those who participate, especially low income residents. Perhaps DEP should more aggressively pursue its demand management programs in the region. Perhaps industry could be engaged and agree to load shedding measures they would be willing to engage in when those severe conditions occur. Perhaps DEP could encourage more people to participate in Time of Use Rate programs, and could file for a "winter load emergency rate schedule" which would be revenue neutral for the rate class over a year but would marry very high rates during the emergency period with lower rates at other times.

Also, I would like to see DEP customize its energy efficiency and demand management programs for the WNC service territory. The focus in WNC is surely different because it is a transmission constrained winter peaking area versus the rest of DEP which is relatively unconstrained summer peaking area. Also, any time of use rate programs should take the regional differences into account. Programs should be targeted to WNC's specific conditions. The Commission should ask DEP to further investigate such options before this plan is approved.

Also, DEP is not considering solar energy at all in its evaluation of capacity at winter peak. But some solar energy could be made available through battery storage sized to allow all winter peak day solar to be stored and then dedicated to peak shaving on those extreme days. Are those days typically cloudy or sunny, which would allow solar output to be stored during these peak conditions?

There are many ways to address these occasional severe peak conditions which do not involve overinvesting in risky gas fired generation.

You mentioned enhancement of transmission. Are you aware of particular options?

DEP has presented only one alternative transmission option, the link to South Carolina that was discarded in favor of the current plan. I have not had access to detailed transmission planning information, but I was able to examine many of the links from DEP because they are visible from space and thus can be followed using Google Maps satellite function. Certainly DEP should make available some of their transmission data because it must be public record given it is so easily seen on Google Maps.

There are two connections of interest. One is the connection from DEC-WNC's Nantahala dam to TVA's Fontana Dam and the 373 MW Brookfield Hydro units and also to a substation near Sylva, NC which is very close to DEP territory in Haywood County. Also, DEP's Walter's Dam which serves WNC is also connected to a substation in Tennessee. Either of these links or similar ones could be candidates for interconnection and thus make available power coming from the DEC-WNC, TVA, and Brookfield.

Would connecting to the dams in Western NC and other power sources further west through TVA make sense for WNC?

It would make "common sense" and I would hope the Commission would ask DEP to evaluate such an alternative. The reason is two factors. First, there is an explosion of very inexpensive wind power coming on line in the Midwest and Great Plains. The Plains and Eastern project of Clean Line Power is in the final stages of approval and will bring almost 4000 MW of low cost wind power from Oklahoma to the Southeast[6] . For example, recent news reports showed the City of Tallahassee Florida purchasing 50 MW of Oklahoma wind power via Plains and Eastern[7].

These sources of power from the west will compete with the hydro power near the NC / TVA border. Most of the hydro power now flows west into Tennessee, but with the influx of cheap wind, it would make sense that the hydro power would find better markets to the east into WNC, if transmission were available. Thus, additional transmission creating and strengthening ties to TVA would be very beneficial to WNC by giving greater access to these wind and hydro resources. As will show below, other than energy efficiency, on shore wind is less expensive than any other source of energy at the current time. Secondly, the TVA area is not experiencing rapid load growth[8] so they may have excess capacity given the influx of wind power. Connections to TVA would help reliability and it would provide better access to cheap renewable power. It's an idea worth exploring in detail before committing to expensive fossil fuel power in WNC.

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[6] Clean Line Power web site: http://www.plainsandeasterncleanline.com/site/page/project-description

[7] News report in "Electric Light and Power", 1/25/2016. http://www.elp.com/articles/2016/01/florida-city-to-buy-wind-power-from-clean-line-transmission-project.html

[8] TVA 2015 Integrated Resource Plan. The TVA peak forecast does not eclipse its' 2007 record peak until 2027, and is forecast to grow at 1% overall. https://tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf .

What other WNC specific actions should DEP undertake?

WNC should have its own IRP as a supplement to the annual IRP process. WNC is its own service territory with its own specific needs. DEP's strategy to meet those needs should be fully transparent for all to see, and that can be done best with an IRP supplement with demand and energy history and forecasts and capacity and import forecasts for the region as a separate entity.

You mentioned that DEP also says that the need for power is based on the DEP system as a whole. What will be the impact on the larger DEP system if we don't build as much capacity in WNC?

DEP system reliability does not need the larger size of the DEP plants in WNC nor the contingent CT. According to the IRP, DEP is going from a planning reserve margin on summer peak of 14.5% to a 17% reserve margin. The IRP tells us they will build more fossil capacity to meet those needs, thus adding an asset exposed to climate risk and not exploring other options to achieve the same reliability.

A cursory evaluation of the IRP suggests they are understating solar energy contribution to the summer capacity as well. My assessment is that DEP will be able to reliably serve the full DEP territory with a smaller expansion in WNC. Please see Appendix B for a fuller discussion of this topic.

Turning from the need for the power from the plant, you mentioned that the plant, even if needed, would not be the least cost option. How did you evaluate the cost effectiveness of the plant?

I evaluated this plant versus other alternatives using "Levelized Cost of Energy" (LCOE) analysis. The LCOE of a particular electric generation technology is a single value of the cost to produce one MWH of energy from the technology over a period of future years. The advantage of this approach is that you can examine each technology against the other and vary assumptions to see how relative cost changes as you vary the assumptions. The LCOE is composed of a capital component and an operating component. The capital component is very similar to a mortgage payment, or the annualized value which will completely pay off the investor who makes the investment up front. The operating component is based on an expected cost per MWH for fuel and operation and maintenance, with the future payments "levelized" into a single value for comparison. This is a standard analysis technique which is likely used in the DEP IRP process during the "screening" phase of technology evaluation.

Where did you get the data for your analysis?

Well, unfortunately the data DEP uses for each technology is not publicly available, so I obtained data from public sources. Luckily, the Lazard organization annually gathers data on LCOE for different generation technologies. The latest report is the Lazard 9.0 study, produced in September 2015[9]. But instead of directly using Lazard's LCOE estimates, I mostly used the assumptions from the Lazard analysis to compute the LCOE myself. This allows me to vary some of the key assumptions around each technology.

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[9]"Lazard's Levelized Cost of Energy Analysis – Version 9.0, November 2015, Lazard, LTD. https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

What are the key assumptions?

There are many key assumptions used in these calculations. The price of fuel, the upfront capital cost of the plant, the heat rate (efficiency in converting fuel to electricity), the life of the plant, the cost of financing, and the capacity factor are the most important assumptions.

Capacity factor is the percent of the possible energy from the plant (operating full speed 24 hours a day, 365 days a year) that is actually generated. For renewable technologies, the capacity factor depends upon things like how much the sun shines or the wind blows in a year. For solar, I used a capacity factor of 19%, based on the Lazard information for NC, for example. For gas CC or CT plants, the capacity factor depends on the extent to which the technology is to be utilized based on the demand for energy and where the technology sits in terms of relative cost effectiveness in operating cost. Nuclear tends to have a very high capacity factor because its operating cost means it is almost always the lowest way to meet the load. The capacity factor for gas CC units like the ones in DEP's plan may vary dramatically depending on the cost of gas relative to other fuels. Thus the expected capacity factor greatly affects the relative comparison.

Were you able to measure the likely capacity factor of the units in question?

Yes, I made what you might call an "informed approximation". I was able to determine that, under DEPs current assumptions, the CC units are likely to run at a very high capacity factor. This is because of the low price of gas and because these units will be dispatched ahead of coal and make coal run at a lower capacity factor. DEP states in the application that these plants will be used to satisfy base load needs on the system as a whole, and not just WNC. I developed a simplified production dispatch model to compute the likely capacity factor of the CC units. Based on this simplified production dispatch, I conclude these units will run at around an 80% capacity factor, at least until carbon legislation of some sort leads to a lower utilization in favor of more renewables, efficiency gains, and nuclear. For the CT I developed LCOE estimates assuming 5% or 10% capacity factor.

Based on your reasoning, does the high capacity factor for the CC units lead you to conclude that these units were the most cost effective?

No. Using the Lazard data as a source, I estimated the LCOE for CC units to be $51.00 per MWH. I then compared that cost to alternatives for solar, wind, and energy efficiency. In the case of solar and wind, where I used averages of the output ranges computed by Lazard to develop the LCOE. With the latest data and tax extenders, utility scale solar had an LCOE of $61.00 per MWH, onshore wind came in at $27.00 per MWH, and Lazard estimates that energy efficiency comes in between $0.00 and $50.00 per MWH. For efficiency I used the average cost from Lazard of $25. If I assume replacement power that is 1/3 each from efficiency, wind and utility solar, I derive a blended cost of $38.00 per MWH, compared to a cost of $51.00 for the planned CC expansion. So actually these other options, for this blend, would lower than using gas. Unfortunately, if DEP overbuilds on a gas unit, money will have been spent that could have gone to lower cost options. The results of these calculations are presented as Table 4.

Table 4
Levelized Cost of Energy (LCOE) by technology
Duke Case

Technology	Utility Solar	Wind Power	Efficiency	Gas CT CF =5%	Gas CT CF=105	Gas CC
Discount Rate	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Technology Lifetime	30	30	30	30	30	30
Capacity Factor	19%	44%	100%	5%	10%	80%
Kwh per year	1664	3854	8760	438	876	7008
Installed Cost before Tax Credit	$1,600	$1,475	$0	$950	$950	$1,150
Investment Tax Credit Percent	30.00%	0.00%	0.00%	10.00%	10.00%	10.00%
Installed Cost after tax credit ($/KW)	1120	1475	0	855	855	1035
Levelized Annual Capital Cost ($/KW)	$89.77	$118.23	$0.00	$68.53	$68.53	$82.96
Fixed O&M ($/kw/yr)	11.5	37.5	0	15	15	15
Fixed O&M ($/MWH)	$6.91	$9.73	$25.00	$34.25	$17.12	$2.14
Variable O&M ($/MWH)	$0.00	$0.00	$0.00	$6.10	$6.10	$2.75
Fuel Price ($ per MMBTU)	$0.00	$0.00	$0.00	$3.45	$3.45	$3.45
Heat Rate (BTU per KWH)	0	0	0	9600	9600	6800
Fuel Cost ($/MWH)	$0.00	$0.00	$0.00	$33.12	$33.12	$23.46
Carbon Content (lbs/MBTU)	0.00	0.00	0.00	117.00	117.00	117.00
Carbon Content (lbs/KWH)	0.00	0.00	0.00	1.12	1.12	0.80
Carbon Content (tons/MWH)	0.00	0.00	0.00	0.56	0.56	0.40
Carbon Fee $/ton	$29	$29	$29	$29	$29	$29
Carbon fee (30 year levelized, $/MWH)	$0.00	$0.00	$0.00	$16.29	$16.29	$11.54
Dispatch Cost (levelized $/MWH)	$0.00	$0.00	$0.00	$55.51	$55.51	$37.75
Prod. tax credit ($/MWH) for 10 years	$0.00	$23.00	$0.00	$0.00	$0.00	$0.00
Value of Production Tax Credit ($/MWH)	$0.00	($13.50)	$0.00	$0.00	$0.00	$0.00
LCOE - Capital Component ($/MWH)	$53.94	$17.17	$0.00	$156.46	$78.23	$11.84
LCOE - Operating Component ($/MWH)	$6.91	$9.73	$25.00	$89.75	$72.63	$39.89
LCOE - Total ($/MWH)	**$60.85**	**$26.90**	**$25.00**	**$246.22**	**$150.86**	**$51.72**

So with the tax extenders, renewables and efficiency are less expensive than gas. Is that likely to continue to be the case?

Yes, and the cost differential will continue to grow. A review of these trends, as shown in Lazard page 10 shows that from 2009 to 2015 the costs for wind energy declined 61%. Over that same period of time, the costs of solar energy declined by 82%. These cost declines go even further back in time. Even if these cost declines are cut in half as we go forward, the result in a few years will be that solar and wind will be still even more competitive. This will be true even after the tax extenders expire, so that the advantage of solar and wind will become permanent. When you have a declining cost of a technology like this, versus the long term increase of a limited resource, it pays to wait a while to take advantage of the declining costs. This is another reason for DEP to start small and go slow with expansion in WNC.

So why didn't DEP come to this same answer in their 2014 IRP?

DEP should answer that question, but I'll give you my thoughts.

First, a lot has changed over the last year or so and that has probably not been brought into the evaluation. As I discussed above, before December 15, 2015 we didn't know that the investment tax credits for solar and wind were going to be extended. I have taken those credits into account. Also, we have had continued years of sustained cost declines in wind and solar which is apparent from the Lazard data, and which has likely not been fully considered by DEP. Also, there is new information continually being brought forward regarding the benefit of wind energy in the Southeast, and perhaps had not then considered purchase of Oklahoma wind power available through the Clean Line Partners project. Finally, DEP does take very seriously their mission to provide extremely reliable electricity, and they may have ruled out some technologies because they had greater comfort with the more established technologies.

Shouldn't DEP take seriously the reliability problems associated with renewable energy?

Certainly, but they shouldn't be overly cautious either. New reports continue to come in, based on experience and on simulations, that ever higher blends of renewable energy can be incorporated into system operations without sacrificing reliability. Several countries are now reliably providing electricity with far higher penetration than DEP's highest forecast year in their IRP.

The National Renewable Energy Laboratory performed a major study in 2014 entitled: "Renewable Energy (RE) Futures Study".[10] Their executive summary report states:

> "RE Futures results indicate that a future U.S. electricity system that is largely powered by renewable sources is possible and that further work is warranted to investigate this clean generation pathway. The central conclusion of the analysis is that renewable electricity generation from technologies that are commercially available today, in combination with a more flexible electric system, is more than adequate to supply 80% of total U.S. electricity generation in 2050 while meeting electricity demand on an hourly basis in every region of the United States."

I would also point the Commission to a study on the potential for renewable energy in the Northeast and Midwest performed by General Electric Company and funded by the Pennsylvania, New Jersey, Maryland Interconnection (PJM), released on March 31, 2014. This study concludes that the PJM system would be able to accommodate 30% renewable energy penetration without significant strain. [11]

[10] NREL: "Renewable Energy Futures Study", http://www.nrel.gov/docs/fy13osti/52409-ES.pdf

[11] GE Consulting, "PJM Renewable Integration Study", http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx

DEP should also continue to pursue opportunities to improve access to transmission. When viewed across a large enough area, renewable intermittency declines or goes away. This is due to "offsetting downtimes". When the sun is behind a cloud in one area, it is shining in another. While solar produces more in summer, wind produces more in winter. This improves the reliability situation with renewables even without storage.

I understand that the idea of a transmission line from the south into the DEP territory was a stumbling block, even though it would have been an improvement from the perspective of integrating renewables. Perhaps if DEP had positioned that transmission line as a necessary step in the widespread adoption of renewables, and if they had shown a large penetration of renewables in the IRP, then it would have been more readily accepted.

DEP should still consider adding wind in the region as well as pushing solar and energy efficiency programs very aggressively. But in the end, the lack of a readily available transmission alternative probably means that some new gas fired generation in the region is needed when the coal unit is retired.

In all of these cases, building a smaller CC plant in Asheville or delaying construction would make it easier for DEP to benefit from the ongoing cost declines in renewable energy, energy efficiency, and solar. Delaying or downsizing would give DEP time to become more comfortable integrating renewable power and efficiency in a manner that maintains reliability. The "business as usual" path that DEP is pursuing is becoming technologically obsolete and subjects DEP ratepayers to grave risks. In such a situation, DEP's best strategy is to try to avoid spending funds pursuing the business as usual strategy as much as possible and to spend time and effort to exploit the new, less risky technologies as much as possible.

You mentioned in the Overview that carbon pricing might make the plant uneconomic. Could you elaborate?

First we should consider how high a carbon price might go. One way to look at this would be to consider the cost to society of using fossil fuels. This would base the price for each fossil fuel on an assessment of the damages caused by their use. Many conservative economists advocate for this strategy. Considering the social cost is only fair and is necessary for the utility system in the state to be developed in a way that minimizes the overall cost, not just the direct cost. The Commission should demand that all costs to society be considered in determining what is least cost. In a very real sense, we are subsidizing fossil fuel use by NOT requiring such use to bear the cost of the damages they cause. Such subsidies would be ended if we imposed a price on carbon. One way to price carbon is to add a fee that reflected this social cost.

What would be a reasonable estimate of the social cost of using natural gas?

One good source would be to look at a recent study from Duke University, "The Social Cost of Atmospheric Release",[12] authored by Drew T. Shindell of the Duke University School of the Environment. This study looked at many estimates and found that there were a range of social costs with midpoints of

[12] "The Social Cost of Atmospheric Release", Drew T Shindell, Feb 15, 2015 . http://paperity.org/p/59074595/the-social-cost-of-atmospheric-release

$110 per MWH for gas and $240 per MWH for coal. The obvious conclusion from this comparison is that DEP is making the right move to get off coal, but it doesn't just follow that they should move to gas. A $110 per MWH social cost would bring the total cost to the $150 range, or more than **triple the cost** of the renewable and efficiency blend cost.

Is the social cost approach the only way to place a price on carbon?

No. Another way is to estimate the price we might need to lead private investment to decarbonize the energy system. Consider the implications of the recently assigned Paris accord on climate.

To evaluate this option, we can look at one of the current proposals. George P Shultz (Secretary of State under President Ronald Reagan), promotes a plan referred to as "Carbon Fee and Dividend". This plan envisions a cost per ton of $15 increasing gradually by $10 per ton per year until US carbon emissions decline 90%. The revenue from this program is recirculated through the economy, so it does not become an overall economic drag. George Shultz is Advisory Chair of the organization that is building grassroots support, Citizens Climate Lobby [13]. I volunteer with that organization and can attest that it is rapidly building momentum for a fee on carbon.

W**hat would the impact of Carbon Fee and Dividend be on the economics of the DEP CC proposal?**

If this plan were adopted nationally in the year that this plant is placed in service in 2020, then the levelized cost per ton would be $108 over 30 years. The fee by 2050 would be $305 per ton if emissions had not reached the target level by then. This would translate to a LCOE of $43 for the CC unit and $60 per MWH of the CT unit, just for the carbon fee component. The resulting total LCOE would be $87 for the CC unit at 80% capacity factor and higher as its capacity factor declines. For the CT unit the LCOE would be $190 at 10% capacity factor. This is more than double the blended LCOE of solar, wind, and efficiency of under $38 for the CC unit, and 4 times the blended LCOE of the CT.(see Table 5 below.)

The CC capacity factor in a higher carbon fee case is likely to be far lower because the short term avoided cost of gas becomes greater than the long term cost (LCOE) of alternatives. When short term cost of the incumbent gas technology becomes higher than the long term cost of the alternatives, it pays developers (or DEP) to build as much of these alternatives as possible, even though the gas plant is already in place. Thus the annual capacity factor would be in continuing decline as these more economic alternatives continued to come on line. This would end up being a very bad investment for DEP ratepayers, or stockholders if the plant had to be written off because it was no longer "used and useful".

DEP could pursue renewable energy far more aggressively at roughly similar current costs with no fee on carbon, and thus avoid a probability of much higher cost under a carbon constrained or high carbon price future. Based on the momentum of the Paris accords and other factors, a high weight should be given to the likelihood of a much higher carbon price, a result which makes the DEP plan extremely uneconomic versus the alternative.

[13] http://citizensclimatelobby.org/about-ccl/

Table 5
Levelized Cost of Energy (LCOE) by technology
Carbon Fee and Dividend Case

Technology	Utility Solar	Wind Power	Efficiency	Gas CT CF =5%	Gas CT CF=105	Gas CC
Discount Rate	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Technology Lifetime	30	30	30	30	30	30
Capacity Factor	19%	44%	100%	5%	10%	80%
KWH per year	1664	3854	8760	438	876	7008
Installed Cost before Tax Credit	$1,600	$1,475	$0	$900	$900	$1,310
Investment Tax Credit Percent	30.00%	0.00%	0.00%	10.00%	10.00%	10.00%
Installed Cost after tax credit ($/KW)	1120	1475	0	810	810	1179
Levelized Annual Capital Cost ($/KW)	$89.77	$118.23	$0.00	$64.92	$64.92	$94.50
Fixed O&M ($/KW/yr)	13	37.5	37.5	15	15	15
Fixed O&M ($/MWH)	$7.81	$9.73	$25.00	$34.25	$17.12	$2.14
Variable O&M ($/MWH)	$0.00	$0.00	$0.00	$4.70	$4.70	$4.70
Fuel Price ($ per MMBTU)	$0.00	$0.00	$0.00	$3.45	$3.45	$3.45
Heat Rate (BTU per KWH)	0	0	0	9600	9600	6800
Fuel Cost ($/MWH)	$0.00	$0.00	$0.00	$33.12	$33.12	$23.46
Carbon Content (lbs/MBTU)	0.00	0.00	0.00	117.00	117.00	117.00
Carbon Content (lbs/KWH)	0.00	0.00	0.00	1.12	1.12	0.80
Carbon Content (tons/WH)	0.00	0.00	0.00	0.56	0.56	0.40
Carbon Fee $/ton	$109	$109	$109	$109	$109	$109
Carbon fee (30 year levelized, $/MWH)	$0.00	$0.00	$0.00	$60.95	$60.95	$43.18
Dispatch Cost (levelized $/MWH)	$0.00	$0.00	$0.00	$98.77	$98.77	$71.34
Production tax credit ($/MWH) for 10 yrs	$0.00	$23.00	$0.00	$0.00	$0.00	$0.00
Value of Production Tax Credit ($/MWH)	$0.00	($13.50)	$0.00	$0.00	$0.00	$0.00
LCOE - Capital Component ($/MWH)	$53.94	$17.17	$0.00	$148.23	$74.11	$13.48
LCOE - Operating Component ($/MWH)	$7.81	$9.73	$25.00	$133.02	$115.90	$73.48
LCOE - Total ($/MWH)	**$61.75**	**$26.90**	**$25.00**	**$281.25**	**$190.01**	**$86.96**

Numerous studies have shown that methane leakage from natural gas production facilities and pipelines into the atmosphere has a substantially higher climate impact than carbon dioxide. What implications does that have for the risk and economics for the plant?

Methane leakage just makes matters worse. According to the EPA web site: "Pound for pound, the comparative impact of methane on climate change is more than 25 times greater than carbon dioxide over a 100-year period". According to a 2012 paper titled "Greater Focus Needed on Leakage from Natural Gas Infrastructure", the carbon benefits from natural gas over coal are negated at a methane leakage rate of 3.2%[14]. If natural gas were indeed as bad as coal, and if a methane leakage price were assessed based on a leakage rate of 1.6%, then the effect would be to increase the LCOE for the CC plant to somewhere in the $108 range, or almost 3 times the renewables blend. There will always be some methane leakage, so accounting for it will make the CC unit suffer even more in comparison to a blend of renewable energy and energy efficiency or nuclear power.

Could you summarize your assessment?

Climate change is usually depicted as a moral issue, and indeed it may be one of the great moral issues of our time. Technological change is typically something that we all hope for and are amazed by, unless we happen to be in an industry that is threatened by something new and better. Certificates of Need and Public Convenience, (CNPC) the object of Duke's application, are usually debated on fairly mundane grounds around such issues as "reliability", "reserve margin", "transmission constraints", "pipelines", "least cost", "levelized cost of energy", "net present value of revenue requirements", etc.

In the current time, these three topics come together and must be considered as one. Climate change is a moral issue, but this Commission need not base a decision on moral grounds. Instead, the commission must consider the likelihood that climate change is real, that it is caused by humans, that this will become more and more apparent, and that political demands, both domestic and international, will increasingly demand action, and that such action will necessarily impose significant costs on fossil fuels.

Similarly, the Commission need not base a decision on a specific technological forecast, but rather with the general appreciation that the tides that have swept through so many other industries are now approaching the electric utilities. The technological information that informed an IRP in 2014, or indeed 2015, are no longer valid. With the global research and business community bringing out "climate solutions" every day, the industry regulated by the Commission in this case is on the precipice of profound change.

These "twin tsunamis" must be considered by the Commission, because all of the mundane evaluations of the CNPC depend on what assumptions are made about them. The Commission should not simply accept a set of assumptions, as is offered by DEP, of more or less business as usual**. The Commission instead should be on the lookout to make sure that DEP doesn't make the mistake of overbuilding,**

[14] : Ramón A. Alvareza, Stephen W. Pacalab, James J. Winebrakec , William L. Chameidesd , and Steven P. Hamburg, 2012. Greater focus needed on methane leakage from natural gas infrastructure. Proceedings of the National Academy of Sciences. Vol 109, No 17. P 6435-6440. http://www.pnas.org/content/109/17/6435.full.pdf

because in an environment such as the one we have today, as at so many other turning points in economic history, overbuilding can have serious negative consequences.

DEP does not need to build as much capacity as they are asking for. They certainly have not made that case in the application being considered in this docket. Closing the coal unit is a good move that will help in a variety of ways, but there is no need to build more fossil fuel capacity at this plant than is already there. The Commission should deny this application and ask Duke to consider two smaller CC units to replace the coal units. The contingent CT request should be denied outright. The remainder of the funds that would have been devoted to the larger expansion should instead be devoted to learning how to ride the wave of the technological change in renewable energy, storage, demand management, and energy efficiency. These funds should also be used to help to engage the local community in a collaborative effort to build a 21st century electric infrastructure for WNC. This is the best, lowest cost, least risk, least regret way to move forward

The Commission should deny DEP's application and ask DEP to present a new proposal along these lines.

Respectfully submitted,

Brad Rouse

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CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Comments of Brad Rouse as filed today in Docket No. E-2, Sub 1089 has been served on all parties of record by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.
This 9th day of February, 2016.

s/ Brad Rouse

Appendix A

Support for a Carbon Fee or Tax

As an example of support for pricing carbon, especially among conservatives, Henry Paulson, Secretary of Treasury under George W. Bush wrote an editorial in the New York Times supporting a price on carbon[15]. Here is a quote from that article:

> "This is a crisis we can't afford to ignore. I feel as if I'm watching as we fly in slow motion on a collision course toward a giant mountain. We can see the crash coming, and yet we're sitting on our hands rather than altering course.
>
> We need to act now, even though there is much disagreement, including from members of my own Republican Party, on how to address this issue while remaining economically competitive. They're right to consider the economic implications. But we must not lose sight of the profound economic risks of doing nothing.
>
> The solution can be a fundamentally conservative one that will empower the marketplace to find the most efficient response. We can do this by putting a price on emissions of carbon dioxide — a carbon tax."

George P Shultz, Secretary of State under Ronald Reagan, wrote an in the Washington Post [16]Here is a little of what he had to say:

> "We all know there are those who have doubts about the problems presented by climate change. But if these doubters are wrong, the evidence is clear that the consequences, while varied, will be mostly bad, some catastrophic. So why don't we follow Reagan's example and take out an insurance policy?
>
> … let's level the playing field for competing sources of energy so that costs imposed on the community are borne by the sources of energy that create them, most particularly carbon dioxide. A carbon tax, starting small and escalating to a significant level on a legislated schedule, would do the trick."

Conservatives like the idea of explicitly pricing carbon because it is a market based approach that minimizes the intrusiveness of government regulation and maximizes business flexibility.

Major corporations are supporting and anticipating a price on carbon. Even DEP, in its 2015 IRP, no longer includes carbon pricing as an alternative "scenario", but instead includes it in its base case. Other examples include:

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[15] "The Coming Climate Crash", Henry M Paulson, NYTIMES, June 21, 2014 , http://www.nytimes.com/2014/06/22/opinion/sunday/lessons-for-climate-change-in-the-2008-recession.html?module=Search&mabReward=relbias&

[16] " A Reagan Approach to Climate Change", George P Shultz, Washington Post, March 3, 2015. https://www.washingtonpost.com/opinions/a-reagan-model-on-climate-change/2015/03/13/4f4182e2-c6a8-11e4-b2a1-bed1aaea2816_story.html

- The World Bank produced a statement, “Putting a Price on Carbon” and have called on governments, companies and other stakeholders (e.g. industry associations) to sign up to it.
- International Monetary Fund (IMF) Chief Christine Lagarde advocates introducing a carbon tax to generate more funds to sponsor poorer countries' climate goals.
- Bill Gates supports “a rapid expansion of carbon pricing policies”
- Six of the largest European oil companies (Shell, BP, BG Group, ENI, Statoil, Total) – put out an open letter to United Nations requesting a carbon fee because it is less costly than regulation, allows for more predictability in the market and their projections, and allows them to move away from carbon fuels into renewables.
- Shell and Exxon have incorporated a carbon fee in their budget projections.
- Six major U.S. banks (Bank of America, Citi, Goldman Sachs, JPMorgan Chase, Morgan Stanley and Wells Fargo) – wrote a letter in support of climate change solutions stating:”Policy frameworks that recognize the costs of carbon are among many important instruments needed to provide greater market certainty, accelerate investment, drive innovation in low carbon energy, and create jobs.”

Appendix B

Does DEP need larger expansion in WNC to meet system summer peak?

DEP relies on the 2015 Integrated Resource Plan(IRP), Exhibit 1A to demonstrate the system wide need. While the need for WNC is based on the winter peak, the need for DEP as a whole is based on the summer peak. The 2015 IRP, Table 6A, shows that with designated upgrades of 1013 MW and retirements of 782 MW the system just reaches the target reserve margin of 17.0% in 2020. With load growth as assumed, additional capacity appears to be needed in 2021 in the amount of the 359 MW growth in peak plus 17% reserve margin, or 420 MW.

But an inconsistency in Table 6A suggests that DEP's reserve margin is not going to be that tight in 2020. DEP's IRP, Table 6A, only refers to 438 MW of renewable capacity in 2020 and only 348 MW in 2021. But the IRP also states that DEP is currently processing a backlog of over 3800 MW of solar energy applications at the current time. This doesn't count the solar that has been added to date and the additional solar that *will* come on between now and 2020. It doesn't consider the declining cost of solar or the recent extension of the 30% solar investment tax credit that was approved December 15, 2015.

Summer peak occurs when there is a good deal of solar output, so it is hard to square 438 MW credit for renewables with likely more than 10 times that amount of solar on the system. In fact, a recent study undertaken for the California Public Service Commission[17] estimates that a given capacity of solar is as good as 60% of that capacity for a perfectly reliable fossil unit. So if DEP builds say 2000 MW by 2020, which is conservative given the 3800 MW backlog, then 1200 MW would be available on peak, not 438 MW. Taking all of these factors into account, and assuming solar grows by 30 MW a year on peak, Table 6 shows the DEP summer reserve margin will be at 23.3% in 2020 with the smaller 370 MW plant profile at Lake Julian.

[17] Energy Division Draft Staff Paper, Effective Load Carrying Capability of Wind and Solar Resources in the CAISO Balancing Authority, California Utilities Commission, July 15, 2015

Table 6 Load, Capacity and Reserves Table, with Reasonable solar
Shows Duke Case Versus adjusted case with solar and smaller WNC capacity

	IRP				Adj. for smaller units and solar			
Year	2020	2021	2022	2023	2020	2021	2022	2023
Adusted Duke Peak	13916	14146	14355	14595	13916	14146	14355	14595
Generating Capacity	12963	13194	12844	12844	12963	13004	12654	12654
Additions	1013	0	0	0	823	0	0	0
Retirements	-782	-350	0	0	-782	-350	0	0
Cumulative Generating Capacity(existing plus designated)	13194	12844	12844	12844	13004	12654	12654	12654
Purchased Contracts	1616	861	528	528	1616	861	528	528
Undesignated Future Resources	0	1743	895	0	0	1743	895	0
Cumulative Undesignated Resource	20	1763	2658	2658	20	1763	2658	2658
Renewables	437	348	347	619	1200	1230	1260	1290
Cumulative Production Capacity	15267	15816	16377	16649	15840	16508	17100	17130
DSM	1021	1029	1032	1034	1021	1029	1032	1034
Cumulative Capacity w DSM	16288	16845	17409	17683	16861	17537	18132	18164
Generating Reserves	2372	2699	3054	3088	2945	3391	3777	3569
% Reserve Margin	**17.0%**	**19.1%**	**21.3%**	**21.2%**	**21.2%**	**24.0%**	**26.3%**	**24.5%**

The 17% stated reserve margin is also new. In the 2014 IRP DEP stated that they needed a 14.5% reserve margin. Given the climate and technology risks, I question whether the move to a higher reserve margin makes economic sense at the current time. What DEP is saying is that they need more fossil capacity to achieve a higher reserve margin to account for increased load variability. I haven't seen anything to show that more fossil capacity is the best solution to this higher variability. They haven't made the case.

Also, remember, DEP is still a summer peaking utility, so from a SYSTEM perspective, why does the existence of the polar vortex and winter related events matter at all, at least until DEP becomes a winter peaking company? The resources that are added from WNC, combined with other resource additions in the winter of 2021/20212, bring the winter reserve margin to 28%.

Finally, such a momentous time in the industry is the time to be cautious with overinvesting in incumbent technologies like natural gas generation, not the time to be speeding up such investment with a higher reserve margin.

In summary, there are a number of holes in DEP's assertion that this new plant is needed by the projected in service date, either from the system or from the WNC perspective.