The Honorable Fred Upton
Chairman, Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Bobby Rush
Ranking Member, Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515

August 17, 2017

Dear Chairman Upton and Ranking Member Rush:

Thank you for inviting me to appear before the Subcommittee on Energy on Tuesday, July 18, 2017 to testify at the hearing entitled "Powering America: Examining the State of the Electric Industry through Market Participant Perspectives."

Per your request, I have attached my responses to the questions for the record prior to the August 18, 2017 deadline.

Please let me know if you have any questions or would like additional information.

Sincerely,

Alex Glenn
SVP State & Fed Regulatory Legal Support
Duke Energy

The Honorable Fred Upton

Question:

1. You testified that it may be time to update PURPA as a result of the changes in the market, notably substantial growth in renewable energy due to federal and state incentives and policies. Can you describe what circumstances are causing utilities to pay above-market costs for electricity under a PURPA contract?

    a. Do you have an example of how much more ratepayers are paying because of PURPA contracts?

    b. Do you have specific suggestions on how PURPA should be revised?

2. You testified that Qualifying Facilities (QFs) under PURPA contract at higher costs due to mandatory purchase obligations set out in law. However, the power they sell to the wholesale markets play an important role in fuel diversity and resiliency – do those added benefits to the grid outweigh slightly higher costs?

    a. How could avoided-cost calculations be changed to better integrate QFs into wholesale markets at more cost-effective price points?

Response:

1. The circumstances that are causing utilities to pay above-market costs for electricity under a PURPA contract are two-fold: 1) the interpretation of "incremental cost" (PURPA Section 210) has diverged from both wholesale market price and cost-based pricing in a number of jurisdictions and 2) neither the 1978 PURPA statute nor the 2005 PURPA amendments anticipated that there would be material costs associated with integrating large amounts of PURPA power into electric systems and thus, PURPA statute is silent on who bears the costs associated with integrating variable, intermittent energy deliveries from PURPA facilities into the electric system. As a result, utilities and utility customers bear those costs.

    "Incremental Cost" has diverged from actual cost
    Interpretation of PURPA Section 210, at both the FERC and state commission level, has led to a situation in which the "incremental cost" or "avoided cost rate" that a utility must offer to a PURPA facility for its energy can be markedly higher than the utility's cost-based price and/or the wholesale energy price available in a market today.

    While there are a number of examples of how "incremental cost" has diverged from actual energy prices across the nation, a well-documented example is in North Carolina, where the utility is required to offer to a PURPA facility a price that includes a capacity payment, *even when the utility has demonstrated that it does not have a new generation capacity need.* (When a utility does not have a need for new energy generation capacity, the value of new capacity is zero.)

    As a result of this divergence from actual energy prices, in North Carolina, the utility must offer a rate of approximately $50 per megawatt-hour to a PURPA facility when, in actuality, the value should be approximately $35 per megawatt-hour (a price that reflects a $35 value of energy and a $0 value of capacity). The effect of this $15 difference becomes very material when amplified by the hundreds of thousands of megawatt-hours per year that some utilities must buy from PURPA facilities.

To better align “incremental cost” with market prices, we recommend a simple remedy: Congress should specify, in a PURPA modernization amendment, “no such rule prescribed under PURPA Section 210 (a) shall provide for a rate which exceeds the lower of actual cost-based or wholesale market prices available to the electric utility (as indicated by market clearing prices, prices set through an RFP process, short contract prices, published indices, or other such indicia).”

PURPA fails to address integration cost

The second reason why some utilities have been forced to pay above-market costs for electricity under a PURPA contract is because there is no requirement that the PURPA facility (i.e., the solar or wind generator) bear any of the cost for integrating its variable, intermittent energy deliveries into the electric system operator.

As more and more PURPA solar and wind facilities deliver energy, the cost of integration has become a material burden to utility customers in a number of regions of the country. At significant levels of wind and/or solar penetration, an electric system operator will dispatch its generation and operate its transmission facilities differently – often in a more costly manner – to accommodate the weather-dependent deliveries of wind solar facilities.

The National Renewable Energy Laboratory estimates that solar and wind integration cost range from $1.00 per megawatt-hour to $7.00 per megawatt-hour, depending on amount of PURPA capacity, the type of renewable energy, and the size and capabilities of the electric system operator who must take the PURPA power. Amplified across hundreds of thousands of megawatt-hours from PURPA solar facilities and millions of megawatt-hours from PURPA wind facilities, the aggregate cost of integration becomes material.

An example of a situation where the utility and the utility customers are bearing the cost of integrating large volumes of solar energy is in Eastern North Carolina, where Duke Energy expects that the amount of PURPA solar capacity delivering energy at certain hours of the day during the spring and the fall, will be so high that we, Duke Energy, will be in a situation where we actually have to “dump” some amount of baseload nuclear power. That means that Duke Energy must find a neighbor utility that can accommodate that excess power and, most likely, pay him to take the excess power that Duke Energy must get rid of in order to maintain line voltages within NERC standards.

You may ask, so why not just turn off the nuclear power when the PURPA solar is delivering at such high volumes? The option of “turning off” baseload coal or nuclear is actually very costly and even dangerous, as these plants are not designed to be turned off/on daily. In addition, turning off a unit is unadvisable due to the fact that solar output varies with weather conditions. For example, if a large front of thunderstorms travels through eastern North Carolina, we can expect almost 2,000 megawatts of PURPA solar capacity (enough solar to cover 10,000 acres or 15 square miles) to cease production within seconds as the storm clouds gather and obstruct the sun. In such a situation, “turning off” baseload is not advisable because baseload energy and capacity may be necessary to serve customers when PURPA power ceases.

As a result of the nature of the PURPA must-take power, the amount of PURPA power, and the characteristics of the incumbent electric system operator, the utility consumer will likely pay two or even three times for energy: once for the nuclear power (which cannot be ramped on and off), again for the mandatory purchase of solar power, and once again for the cost of paying a neighboring utility to take excess power so that the system can safely and reliably accommodate the solar power.

To remedy this situation, Congress should amend PURPA Section 210 (b) to include the following phrase: "The rules prescribed…shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase … (*3) shall obligate the QF to operationally integrate its facility with the electric system operator*."

a. The mandatory purchase obligation, whereby a utility must buy power from PURPA facilities at specific purchase prices, for a specific term, has a measurable impact on the prices our consumers pay for electricity. Key to understanding the impact of PURPA is to recognize that when an electric utility purchases power from a PURPA facility like a solar generator or a wind generator, those costs are actually borne by the utility's consumer, in the same manner in which the cost of natural gas fuel is passed on to the customer, without mark-up.

   As for overpayment, Duke Energy calculated the degree to which its North Carolina customers were overpaying for PURPA purchase at the end of 2016. At that time, Duke Energy had an estimated 1,600 megawatts of solar interconnected to and selling back to Duke Energy. We estimated that the aggregate cost of the rates for purchase offered to PURPA facilities, extrapolated over the expected output of the facilities and across the term of the purchase agreement (12-14 years) was $2.9 billion. If the Duke Energy had not been required to offer payment for capacity when the utility's capacity need was zero, or if the utility had not been required to offer long-term, fixed price rates to PURPA facilities, and if these contracts were valued at the utility's wholesale price today, these contracts, in aggregate would have cost the utility customer base just $1.9 billion. Thus, delta between the actual wholesale price and the PURPA price, over the course of the PURPA long-term contracts, in aggregate, comes to more than $1 billion.

   For reference, sixty percent of all PURPA solar projects nationwide are in North Carolina. In 2010, North Carolina had just 20 megawatts of solar installed; enough solar to cover about one hundred acres. Today, in North Carolina, there are more than 2,000 megawatts of solar power in operation; the equivalent of 10,000 acres or 15 square miles of solar panels. Bloomberg News actually called the North Carolina a PURPA "gold rush" given the number of investors flocking to fund solar farms in North Carolina. In addition, there remain more than 5000 megawatts of PURPA facility solar awaiting interconnection; that is the equivalent of an additional five nuclear reactors' worth of solar capacity awaiting interconnection.

b. Please refer to my response to Question 1.

2. No, the added benefits of fuel diversity and "resiliency" do not justify the slightly higher prices we are obligated to offer PURPA facilities. Electric utilities constantly assess and compare the cost-effectiveness of generation resources like solar, wind, natural gas, nuclear, and coal. These calculations take into account costs and benefits of

environmental attributes as well as the long-term price of various fuels. As a result of these calculations and a tremendous amount of due diligence, Duke Energy now owns and operates a fleet of nearly 250 megawatts of solar power within our regulated utility companies. This is the amount of solar that state regulatory bodies have deemed "prudent" thus far.

The utility's ability to pay for higher cost resources is extremely limited. Utilities must prove that those resources are absolutely essential in order to meet reliability requirements, environmental requirements, and/or customer demand. While solar PV and wind are non-emitting resources with zero fuel cost, they remain weather dependent and are not reliable, dispatchable peaking resources that can be built to meet summer afternoon peaks or winter morning peaks.

As for resiliency, in order for a solar facility to supply electricity during a grid outage to a critical facility like a Red Cross evacuation site or fire station, the solar PV system would have to be designed with resiliency in mind from the beginning. That is, the solar would be combined with other technologies, such as energy storage, switches that safely isolate the circuit between the solar facility and the fire station from the rest of the grid during an outage, and additional equipment to control the flow and quality of the electricity. Today, this additional energy storage, control, and switching equipment is very expensive.

The vast majority of solar PV systems as installed today in the United States are technically incapable of providing consumer power during a grid outage; when the grid is in an outage, the solar PV systems are required to automatically shut off in accordance with IEEE 1547* protocols intended to protect the safety of utility line workers. (If solar power were to deliver energy back to the grid during an outage, that would endanger the lives of utility line workers.)

*The Energy Policy Act of 2005 established IEEE 1547 as the national standard for the interconnection of distributed generation resources [solar] in the United States of America.

a. There is a simple way to better integrate QFs into wholesale markets at more cost-effective price points: Congress should specify, in a PURPA modernization amendment, "no such rule prescribed under PURPA Section 210 (a) shall provide for a rate which exceeds the lower of actual cost-based or wholesale market prices available to the electric utility (as indicated by market clearing prices, prices set through an RFP process, short contract prices, published indices, or other such indicia)." Such an amendment will prompt FERC rule-making that will enable integration of QFs into wholesale markets at more cost-effective price points.

The Honorable Richard Hudson

<u>Question:</u>

1. In your testimony, you discuss how the timely siting and permitting of vital infrastructure projects is critical to strengthen the power grid. You also mention how the lack of quorum at FERC is preventing action on these crucial infrastructure projects, including natural gas pipelines. One such project, the Atlantic Coast Pipeline, will provide clean-burning natural gas supplies to growing markets in Virginia and North Carolina. Pipeline

construction alone will create 17,000 new jobs and $2.7 billion in economic activity across the region, and once operating, the pipeline will save consumers an estimated $377 million a year on their energy costs. Additionally, the pipeline will generate $28 million in annual property tax revenue for local governments along the route. This pipeline is one that needs a FERC Commission issued Certificate Order by the end of September in order for the company to begin physical work on clearing the right of way for the pipeline in October. If these timelines aren't met it could significantly delay the in-service date of ACP. If that happens, what will that do to Virginia and North Carolina customers?

2. You flagged that the preservation of interest deductibility in tax reform is critical for electric utilities. Can you expand on what type of capital investments Duke Energy and other electric utilities make in the communities they serve and why that is tied to interest deductibility?

Response:

1. The Atlantic Coast Pipeline needs a FERC Commission issued Certificate Order by the end of September in order for the company to begin physical work on clearing the right of way for the pipeline in October. If these timelines are not met it could significantly delay the in service date of pipeline, potentially resulting in hundreds of millions of dollars in delay-related costs to Duke and constrained natural gas supply for our customers which could result in higher prices and inability to meet demand.

2. The electric power industry is the nation's most capital-intensive industry and invests more than $100 billion annually to build a smarter energy infrastructure and to transition to even cleaner generation sources. Electric companies are significant engines of growth across the U.S. economy.

   Just this year, Duke Energy announced a $13 billion, 10-year project to modernize the state's electric system. These upgrades will harden the system against storms and outages; make it safer and more resilient against cyber-attacks and physical threats; help expand renewable energy; generate jobs and stimulate economic growth. It will also give 7 million people in North Carolina more information to manage their energy use.

   Duke Energy's 10-year modernization plan for NC will result in:

   - Additional bill-lowering tools designed to help customers reduce their energy costs
   - An average of 13,900 jobs each year
   - $10.4 billion in salaries and wages
   - Almost $800 million in state taxes and $550 million in local taxes
   - A total economic output of $21.5 billion over the 10 years

   Capital investments such as this modernization plan rely heavily on the ability to deduct interest. This is due to the highly regulated nature of our businesses as independent state public utility commissions allow electric companies to recover their costs through the rates they charge their customers for electricity service. If electric companies are unable to deduct interest costs for infrastructure projects, they would pass the higher cost of capital on to their customers. Raising electricity prices has a disproportionate impact on lower-income customers and small businesses, and hurts the global competitiveness of energy-intensive industries in this country.

Eliminating the ability to deduct interest expense would have a dramatic impact on customers' electricity bills. Raising capital through equity is currently more expensive than raising capital through debt, and removing the deduction for interest expense will not change this fact. Allowing electric companies to continue deducting interest expense provides a "win-win" for the American economy.