STATE OF NORTH CAROLINA

UTILITIES COMMISSION

RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016

DIRECT TESTIMONY

OF

BEN JOHNSON, PH.D.

ON BEHALF OF

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

PUBLIC VERSION

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Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Consulting Economist and President of Ben Johnson Associates, Inc., a consulting firm that specializes in public utility regulation.

Q. PLEASE DISCUSS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics.

I have been actively involved in public utility regulation since 1974. Over the past four decades I have analyzed a wide range of different issues involving many types of regulated firms, participated in more than 400 regulatory dockets, and provided expert testimony on more than 300 occasions before state and federal courts and utility regulatory commissions in 35 states, two Canadian provinces, and the District of Columbia.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. The first time I recall was in 1983, when I testified in Docket No. P-55 Sub 834, a Southern Bell rate case. Since that time, my firm has participated in more than a dozen other proceedings before the North Carolina Utilities Commission ("NCUC" or the "Commission"). I testified in most, but not all, of these proceedings. In most of these cases I testified on behalf of the Public Staff. However, on some occasions, as in this case, our firm provided assistance to other parties, instead.

Our firm's past consulting engagements in North Carolina include: Docket No. E-100, Sub 53, a 1986 proceeding concerning avoided costs; Docket No. E-2 Sub 537, a 1986 Carolina Power & Light rate case in which we assisted Public Staff with reviewing the prudence of the Shearon Harris nuclear plant; Docket Number E-100, Sub 57, a 1988 proceeding concerning avoided costs; Docket No. E-100, Sub 66, a 1993 proceeding concerning avoided costs; Docket No. E-100, Sub 74, a 1995 proceeding concerning avoided costs; Docket No. E-100, Sub 75, a 1995 proceeding concerning Least Cost Integrated Resource

Planning; Docket No. E-7, Sub 1013 a 2001 proceeding in which Duke Energy Corp requested permission to issue stock in connection with its proposed acquisition of Westcoast Energy, Inc.; Docket Number E-2, Sub 760, the 2000 proceeding in which CP&L Holdings, Inc. requested permission to acquire Florida Progress Corporation; Docket Nos. E-7, Sub 828 & 829 E-100, Sub 112, a 2007 Duke Energy Carolinas case; Docket Nos. E-7, Sub 909, a 2009 Duke Energy Carolinas rate case; Docket No. E-2, Sub 966, an avoided cost arbitration between Capital Power Corporation and Progress Energy Carolina, Inc.; Docket No. E-22, Sub 459 a 2010 Dominion North Carolina Power rate case; Docket No. E-2, Sub 1023 a 2012 Progress Energy rate case; Docket No. E-22, Sub 479, a 2012 Dominion North Carolina Power rate case; Docket No. E-100, Sub 136 the 2012 proceeding concerning avoided costs and Docket No. E-100, Sub 140 the 2014 proceeding concerning avoided costs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My firm has been retained by the North Carolina Sustainable Energy Association ("NCSEA") to evaluate the concerns expressed by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") ("Duke") and Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP") (all three collectively, the "Utilities") in their November 15, 2016 filings (the "initial filings") and in their testimony with respect to alleged problems related to growth in solar generation and the Commission's long-standing approach to implementing the Public Utility Regulatory Policies Act of 1978 ("PURPA"). In addition, I have reviewed the Utilities' proposed changes to the peaker methodology and input parameters and assumptions used in developing the new rates they are proposing to pay to Qualifying Facilities ("QFs").[1] I have also developed recommendations for how the Commission can resolve the concerns identified by the Utilities, protect the interests of the using and consuming public in North Carolina, and encourage continued investment in the state by small power producers.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following these introductory remarks, there are seven major sections to my testimony.

In the first section, I discuss North Carolina's implementation of PURPA, as compared with other states.

In the second section, I discuss recent growth in solar production and related concerns that have been identified by the Utilities. I also briefly discuss a few of the proposals offered by the Utilities in response to these concerns. However, most of my detailed discussion of the Utilities' proposals is reserved for later sections, where I offer some alternatives which I believe would be at

1 16 U.S.C. § 824a-3.

least as effective in resolving the Utilities' stated concerns, while better serving the interests of the using and consuming public in North Carolina.

In the third section, I compare the avoided cost rates approved by the Commission in Docket No. E-100, Sub 140 ("2014 QF rates") and the proposed QF rates. This portion of my testimony includes a discussion of marginal and average energy costs and some comparisons between the QF rates and some benchmark long run avoided cost estimates.

In the fourth section, I discuss the "indifference" standard under PURPA, the concept of avoided costs, and the three standard methods for estimating avoided costs. I also explain my estimates of long run avoided capacity and energy costs, which I use at various points in my testimony. These cost estimates are not intended to be used in establishing the tariff rates in this proceeding – which I assume will continue to be developed in accordance with the same methodology which the Commission has historically used, including the refinements adopted by the Commission in its December 31, 2014 Order Setting Avoided Cost Input Parameters ("Order Setting Parameters").[2] Instead, these cost estimates are offered as a benchmark for comparison, and to help illustrate and clarify various points in my testimony, particularly with respect to different technologies, fuel prices and scenarios.

2 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014.

Generally, in the remaining sections I respond to specific proposals offered by the Utilities and offer some alternatives, which I believe will be at least as effective as the Utilities' proposals in resolving the Utilities' stated concerns, while better serving the interests of ratepayers.

Specifically, in the fifth section, I discuss the proposed QF energy rates, including the proposal to no longer offer fixed long-term rates. From the perspective of both QFs and ratepayers, this is a "lose-lose" proposition. It would significantly increase the risks borne by QFs, and make it more difficult to finance QF projects, while simultaneously increasing (not decreasing) the risks borne by ratepayers. In this section I also discuss the use of forward market data and fundamental forecasts, with a particular focus on Duke's proposal to exclusively rely on forward market data in developing their proposed QF energy rates. I also discuss some geography-related issues, including DNCP's proposal to reduce its avoided cost energy rates based on the historical energy price differences between the DOM Zone and the North Carolina service area.

In the sixth section I discuss the proposed QF capacity rates, including the proposal to value capacity at zero during some years, as well as the proposal to reduce the Performance Adjustment Factor from 1.20 to 1.05 based upon the availability of a new combustion turbine, rather than the performance of the Utilities' entire fleet of generating units, including baseload units, as the Commission has historically required.

In the seventh section, I discuss various issues related to seasonality and time of day, including Duke's proposal to no longer give 60% weight to the summer season and 40% weight to the winter season, and to instead give 20% weight to the summer and 80% weight to the winter. In this section I also discuss Duke's proposals to modify their standard QF contract terms and conditions to allow them to curtail QF energy output and discontinue QF purchases during loosely defined emergency periods. I also offer two alternative suggestions which would be much less heavy-handed and damaging to the financial viability of QFs, while still resolving the Utilities' stated concerns, thereby better advancing the interests of North Carolina ratepayers.

Section 1: PURPA Implementation in North Carolina and Other States

Q. HAS INCREASED DEVELOPMENT OF RENEWABLE ENERGY SOURCES BEEN A LONGSTANDING GOAL OF PUBLIC POLICY MAKERS?

A. Yes. Since the Energy Crisis of the mid-1970s, many steps have been taken at both the state and federal level in an effort to reduce our reliance on traditional energy sources – particularly imported oil – to encourage greater energy independence and diversity. While many different tools have been used at various levels of government, including tax policies and incentives, some of the earliest steps were taken by the United States Congress in 1978 when it adopted PURPA.

Looking at the relevant portions of this law from my perspective as an economist, it appears to advance at least two distinct goals. First, it encourages expanded use of targeted technologies and energy sources which had been neglected by the electric utility industry. Second, it encourages investment in small power producers – new firms that enter the market to develop these targeted technologies and energy sources.

Q. DID PURPA ENCOURAGE SOLAR PRODUCTION BY NON-UTILITY GENERATORS?

A. Yes. PURPA advanced an "all of the above" energy strategy, which was intended to encourage greater energy independence and increased supply diversity in the United States. PURPA requires electric utilities to purchase electrical energy from a special category of independent power producers, known as QFs that was established by Congress for this purpose, including ones that specialize in solar energy production.[3]

3 16 U.S.C. § 824a-3.

More specifically, PURPA requires the Federal Energy Regulatory Commission ("FERC") to prescribe rules necessary to "encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity."[4] The scope of this portion of PURPA was narrowly focused. Utilities were exempted from any requirement to purchase from independent power producers that used the energy sources that had been historically been favored by electric utilities, like coal, residual oil, nuclear, and natural gas. Instead, Congress focused on certain unconventional energy sources, including cogeneration, which had not been aggressively pursued by utilities.

Although they do not typically involve renewable energy sources, cogeneration facilities (which are specialized installations that produce electric power in conjunction with another form of energy, like the production of heat or steam for use in a manufacturing process) were also a good match for both goals. Congress apparently was convinced this was a cost-effective and energy-efficient technology which had the potential for more widespread deployment than had been observed up to that time. By prohibiting utilities from discriminating against this efficient energy source, the goals of increased, targeted competition and increased energy independence and diversity would both be advanced.

4 16 U.S.C. § 824a-3(a).

Other targeted technologies include electricity produced from biomass and waste, as well as renewable resources like wind, small hydro, and geothermal energy. The primary purpose in encouraging investment in these specialized energy sources was similar to the reason why cogeneration was targeted: if PURPA were successful in encouraging new entry, supply diversity would be improved, and the country would reduce its dependence on scarce and nonrenewable resources like coal and oil.

Q. CAN YOU ELABORATE ON THE SECOND GOAL YOU MENTIONED – ENCOURAGING TARGETED COMPETITION FROM SMALL POWER PRODUCERS?

A. Yes. By requiring utilities to purchase from QFs, Congress was not only encouraging diversity of energy supply sources, but it was also pursuing a strategy of encouraging narrowly targeted competition in electric power production. PURPA was adopted at a time when public policy makers were trying to scale back unnecessary regulations, improve regulatory structures, and rely more on competition to advance the public interest – particularly in industries, like the electric power industry, where competition had been (intentionally or unintentionally) effectively suppressed by government policy.

Perhaps the most memorable and visible example of this new market-oriented policy approach was the deregulation of airlines, which occurred around the same time. In that industry, safety continued to be tightly regulated, but other rules were changed to remove barriers to entry, encourage new airlines to challenge incumbent firms and to deregulate prices, which had previously been tightly controlled. The resulting increase in competition successfully unleashed a tidal wave of innovations, cost cutting, and price reductions.

Although PURPA was not as visible or dramatic, it reflected much the same pro-competitive philosophy underpinning airline deregulation. Congress sought to gain some of the benefits of increased competition without foregoing the benefits of traditional rate base regulation. The idea was to retain existing constraints on monopoly power in retail markets, while introducing new, carefully thought-through constraints on monopsony power in wholesale markets. The key to this strategy was encouraging increased investment and new entry by small, independent power producers, who had the potential to unleash downward pressures on the incumbents' costs and retail prices, without taking the risk of fully deregulating an industry which had many of the characteristics of a natural monopoly.

Thus, it is fair to say that one of the fundamental goals of this portion of PURPA was to encourage, on a narrowly targeted basis, increased competition in the market for electrical generation without jeopardizing continued regulation of other aspects of the industry. The strategy was straightforward: encourage investment in small firms that would use unconventional technologies to produce electricity in competition with the existing, vertically integrated electric utilities.

Q. WHY WAS THIS SORT OF ENCOURAGEMENT NEEDED?

A. Prior to the adoption of PURPA, most electric utilities obtained all, or nearly all, of their power from large centralized generating plants that they owned and constructed themselves, or from similar plants operated by a nearby utility. Congress made a conscious decision in 1978 to deviate from this historical pattern by encouraging investment in small power producers (80 MW or less at any single site) that would compete with the vertically integrated utilities, provided they focused on the targeted generation technologies.

Before PURPA, the monopoly power enjoyed by electric utilities in the transmission and distribution of electricity and the regulatory apparatus designed to constrain that monopoly power combined to discourage competition. This was true even for parts of the electric industry – like generation – which did not seem to exhibit the characteristics of a natural monopoly.

For example, before PURPA, few industrial firms would consider generating their own power, even where this would be economically efficient (e.g. utilizing waste heat from the manufacturing process), because there was not a ready market for power produced in excess of the firm's own needs. Practical constraints, as well as legal barriers associated with monopoly regulation, made it difficult or impossible for industrial firms to sell power to anyone other than the local utility, and most utilities weren't interested in buying power from new entrants. Rather, electric utilities generally preferred obtaining power from conventional generating plants – particularly ones they owned and operated themselves.

Before PURPA changed the regulatory landscape, the utility's preference for owning and operating its own generating plants using conventional energy sources nearly always prevailed over what might otherwise have been commercially viable transactions to purchase from independent power producers that would have ultimately benefited the utilities' customers. The utility was largely immune from pressures to pursue unfamiliar technologies or to buy from independent power producers, because it was effectively both a monopolist (single seller) and a monopsonist (single buyer), within its particular service territory.

Thus, for example, unless an industrial firm was willing to pull up stakes and move to another state, it was forced to pay whatever price the utility charged for whatever power it used, and it was forced to accept whatever price (typically much lower) the utility was willing to pay for any extra power the industrial firm produced. Before PURPA, if the gap between the price charged by the utility for power supplied to the industrial firm and the price paid by the utility for power received from the industrial firm seemed unduly large, the industrial firm could in theory complain to the state regulator about the magnitude of the gap, and ask the regulator to require the utility to pay a higher price. In practice, however, this option was generally too costly and risky to be worth pursuing. Accordingly, before PURPA, most industrial firms ignored the potential for cogeneration, regardless of how attractive the underlying economics might be, rather than risk undertaking an investment that would be subject to the utility's unconstrained monopsony power, or the uncertain outcome of future regulatory decisions.

This problem was not limited to cogeneration by industrial firms – it also affected the viability of investments in power production by small run-of-river hydro plants and other opportunities that existed for generating electrical power on a small scale. The utility was typically the sole buyer of power in the local market, and it controlled interconnection to the power grid, thereby largely determining the viability of small power production by other firms. Absent a well-defined system of constraints on the utility's monopsony power, small power production was an enormously risky proposition that few investors were willing to seriously contemplate.

Q. CAN YOU BRIEFLY ELABORATE ON THE DISTINCTION BETWEEN MONOPOLY POWER AND MONOPSONY POWER, AS IT RELATES TO UTILITY REGULATION?

A. Yes. By the early 1900s in most jurisdictions, a comprehensive system of regulation to control monopoly power had evolved, which severely limited the ability of electric utilities to impose unreasonable prices, terms, and conditions on their sales transactions with most retail customers. In contrast, prior to the adoption of PURPA, relatively little thought was given to monopsony power (which exists when a single buyer dominates the market). In most jurisdictions, no comparable comprehensive regulatory mechanisms existed to constrain monopsony power, or prevent electric utilities from using this power to suppress competition from independent power producers.

As the primary or exclusive potential buyer of electrical energy within their respective market areas, the incumbent electric utilities enjoyed as much "monopsony power" when buying electricity as the "monopoly power" they had when selling energy. Taking advantage of their market power, utilities generally decided to construct, own and operate their own generating units, or to purchase power from neighboring utilities, rather than buying from independent firms.

In general, incumbent utilities prevented, or at least discouraged, competitive entry by other firms, even in situations where those firms had a clear efficiency advantage (e.g. the ability to generate electricity less expensively, by taking advantage of waste heat involved in industrial processes), or they were willing to take greater risks in trying new, less familiar technologies.

Whether or not it was intentional, the result was that electric utilities prevented the consuming public from seeing the benefits of competition by independent power producers, who could potentially bring down costs and bring long term societal benefits by increasing supply source diversity, experimenting with innovative technologies, reducing costs, increasing efficiency, or accepting lower profit margins.

In sum, the potential benefits from imposing regulatory constraints on monopsony power are conceptually similar to the reasons why the monopoly power of the incumbent utilities have long been constrained. However, the existence of monopsony power, and the benefits from constraining it, have not been as widely understood or effectively dealt with.

Q. WHY DO UTILITIES PREFER THEIR OWN GENERATING FACILITIES?

A. There are multiple factors which help explain why electric utilities have historically resisted purchasing from competing firms. First, there is a natural tendency for utility company management to want to retain maximum direct control over system reliability and other outcomes for which they are ultimately accountable. Second, management operates within the context of a growth-oriented U.S. corporate culture, which favors expansion of a firm's staff, assets, income, and earnings per share. Third, management is expected to maximize profits and value for its stockholders, which leads to a strong bias in favor of expanding the rate base, due to the Averch-Johnson effect.[5]

With PURPA, Congress attempted to overcome this resistance by reducing barriers to competitive entry into the electric utility industry without disrupting the more successful aspects of traditional rate base regulation. It did this by providing an overarching federal regulatory structure for implementing state regulatory oversight of transactions between electric utilities and QFs, with a view toward encouraging QF investment.

However, PURPA did not change the attitudes or preferences of the incumbent utilities. These firms continue to prefer owning and operating their own generating resources for perfectly rational reasons. If the benefits of competitive entry are going to fully emerge, it is necessary for state and federal

5 Named after the authors of a famous article published in 1962 in the American Economic Review, which demonstrated that under typical conditions, rational rate base regulated firms will tend to expand their capital investment beyond the optimal point of maximum economic efficiency. This tendency occurs whenever the allowed rate of return exceeds the utility's actual cost of capital by even a small margin. Theoretically the Averch-Johnson effect could be avoided if the allowed rate of return were set precisely equal to the cost of capital. However, this degree of precision isn't achievable in practice. As well, an allowed return which exceeds a barebones estimate of the cost of capital can be viewed as preferable, since it helps maintain the utility's financial integrity, strengthens its financial ratios and protects its bond rating.

regulators to actively implement the provisions of PURPA in a way that fulfills the goal of encouraging competitive entry, and placing greater reliance on market forces to advance the interests of ratepayers and the public good.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMMISSION'S ROLE IN IMPLEMENTING PURPA?

A. State commissions have an important role in implementing PURPA, together with FERC and the courts.

> Questions about the actual avoided-cost determinations are litigated before the state commissions or the state courts with applicable jurisdiction for non-regulated utilities. Questions regarding whether a method of avoided-cost determination is consistent with PURPA and FERC implementation rules are litigated before FERC or an applicable federal court. [6]

State commissions have been provided with extensive guidance for how they are to carry out their responsibilities, both in the text of the underlying statute, and in rules adopted by FERC which were subsequently upheld by the United States Supreme Court.[7]

6 PURPA Title II Compliance Manual, p. 15. The PURPA Title II Compliance Manual was jointly published by the American Public Power Association ("APPA"), Edison Electric Institute ("EEI"), National Association of Regulatory Commissioners ("NARUC") and National Rural Electric Cooperative Association ("NRECA") on March 2014, with the intended purpose of being used as an aid to state commissions and utilities as they deal with issues related to PURPA.

7 American Paper Institute, Inc. v. American Electric Power Service. Corp., 461 U.S. 402, 103 S.Ct. 1921 (1983).

Rates for purchases from QFs ("QF rates") must: (a) be just and reasonable to the electric consumers of the electric utility and in the public interest; (b) not discriminate against qualifying cogenerators or qualifying small power producers; and (c) cannot exceed "the incremental cost to the electric utility of alternative electric energy."[8]

While I am not an attorney, it is my understanding as an economist that under PURPA the Commission is expected to (a) require utilities to purchase energy and capacity from QFs on terms consistent with all applicable FERC regulations; (b) treat avoided costs as the pricing floor for those purchases; (c) enforce the legal right for QFs to sell power to utilities on either an as-available basis, or pursuant to a "Legally Enforceable Obligation" ("LEO") at the QF's option; (d) enforce the legal right for QFs to sell power to utilities pursuant to long-term contracts; and (e) ensure utilities provide nondiscriminatory interconnection and/or transmission service to QFs that they sell power to QFs on request.

Q. HAS THIS COMMISSION'S EXPERIENCE WITH IMPLEMENTING PURPA BEEN TYPICAL?

A. For more than 30 years this Commission and the Public Staff have invested a high level of effort studying the issues involved with PURPA, endeavoring to

8 16 U.S.C. § 824a-3(a).

strike the appropriate balance by encouraging small power production while protecting ratepayers. These efforts are evidenced by the long series of actively litigated biennial rate proceedings where the Utilities' proposals related to implementation of PURPA were subjected to a high degree of scrutiny by the Public Staff and other interested parties.

The Commission has also occasionally probed even more deeply into specific issues – a notable example being the nearly year-long investigation into input parameters and methods for calculating avoided costs which recently occurred in the 2014 biennial avoided cost proceeding. In contrast, in many other states there simply has not been as much interest in QF development, and the incumbent utilities' implementation of their PURPA obligations have not been subjected to a comparable level of intense scrutiny.

Q. WHY HAS NORTH CAROLINA'S EXPERIENCE WITH PURPA BEEN DIFFERENT THAN IN OTHER STATES?

A. There are many factors involved, including the fact that in some other states PURPA issues remain largely unfamiliar and because these issues arise in the context of highly specialized tariff filings which have an immediate, direct effect on very few people.

In fact, unless and until independent power producers actually enter a given market to compete with the state's utilities, there may not be anyone in that state for whom accurate QF rates are a top priority, or who can justify expending the effort required to intervene into the regulatory process in order to challenge the utility's QF rate calculations.

Q. CAN YOU PROVIDE SOME EXAMPLES OF HOW PURPA HAS BEEN IMPLEMENTED DIFFERENTLY IN OTHER STATES?

A. Yes. For one thing, some states have adopted regulatory systems that rely on broader forms of competition, which tend to supplant or suppress the more narrowly focused forms of competition envisioned in PURPA. Even where broader forms of competition have not been introduced, the utilities have sometimes been successful in avoiding long term fixed rate standard offer QF tariffs, or limiting the scope of these tariffs to very small QFs. As a result, in some states potential entrants are largely forced to negotiate rates and other terms and conditions, because the standard offer tariff is only available for extremely small projects, or it only provides high risk variable rates, which make it difficult (or impossible) to finance a QF project.

At least theoretically, these limitations could be overcome through negotiations and, if necessary, arbitration. However, from a potential entrant's perspective, this process is much more difficult, time consuming and costly than simply choosing to accept the published tariff or choosing to pursue better investment opportunities elsewhere.

In states with QF tariffs that do not offer certain critical elements (like long term contracts with fixed rates and reasonable terms and conditions), potential entrants may be reluctant to invest the time and effort required to negotiate with the local utility, since the outcome this investment is so unpredictable, with a high risk of failure. Since negotiations are time consuming, risky and costly, firms may be discouraged from entering a state unless and until <u>after</u> acceptable standard offer rates and terms have been published. Thus, a "chicken and egg" phenomenon can arise, in which few, if any, firms with QF experience become active in a state, and no one already in the state is willing to expend the effort required to deeply investigate the issues and advocate the sorts of changes that are needed to make QF investment more attractive.

While continued resistance to QF entry on the part of the incumbent utilities is readily predicted and explained as a matter of economic theory, it is important to realize this is not a merely speculative or theoretical concern, but a fundamental aspect of the industry. Succinctly stated, in a typical retail rate proceeding, the utility will often seek rates that are higher than necessary or appropriate, but in a QF rate proceeding the reverse is true: the utility will often seek rates that are lower than necessary or appropriate.

In my experience, utility companies have consistently preferred setting QF rates at relatively low levels, and have advocated proposals that have the effect of discouraging QF investment and justifying continued expansion of their own rate base instead. In some states, QF tariffs have sometimes been adopted with little or no change from the way they were initially proposed. The Commission should keep this in mind, when comparing the situation in North Carolina with that in other states.

Q. CAN YOU ELABORATE ON DIFFERENCES BETWEEN THE WAY PURPA HAS BEEN IMPLEMENTED IN NORTH CAROLINA COMPARED TO SOME OTHER STATES?

A. Yes. In response to discovery, Duke provided some valuable information concerning implementation of PURPA in some nearby states – and in most cases the differences are stark. For instance, Alabama, Arkansas, Florida, Kentucky, Louisiana Maryland, and Virginia offer variable, rather than fixed long term rates. This is a hugely important difference, since variable rates greatly increase the riskiness of solar projects, which have high fixed costs and low variable costs.[9]

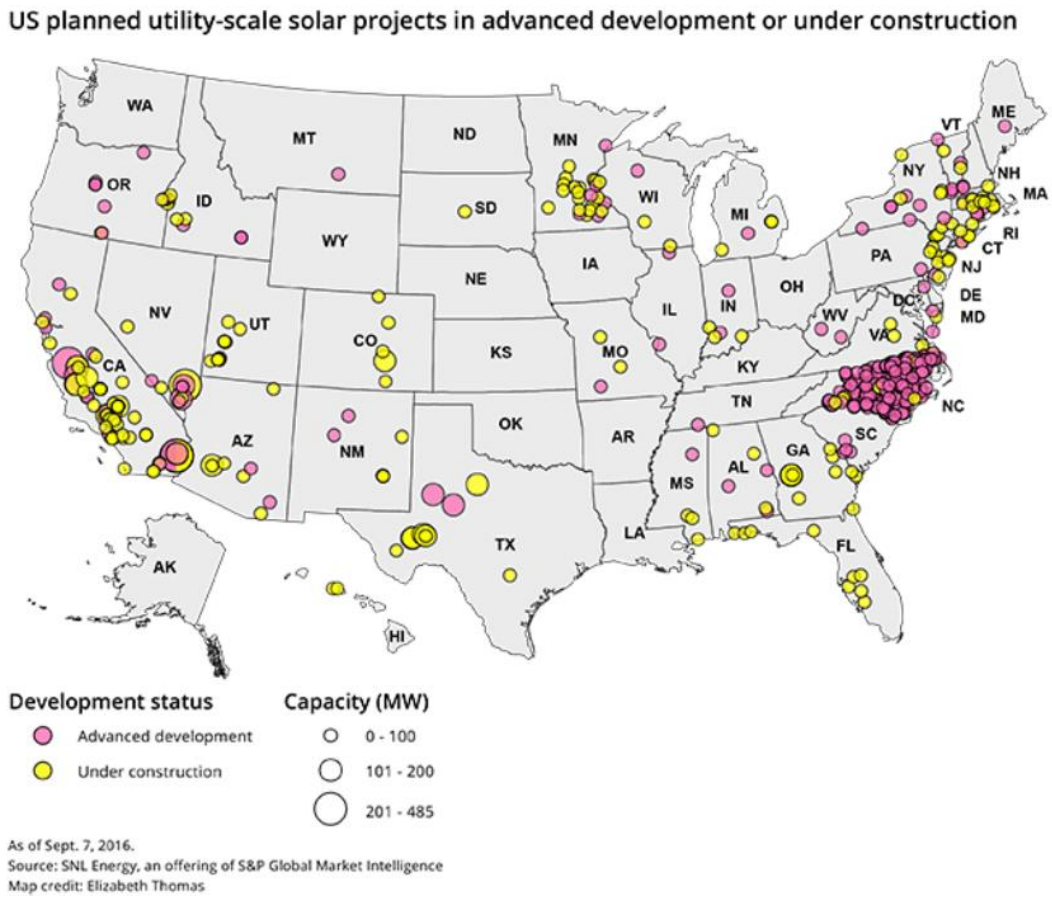
9 Duke's Response to NCSEA's first data request ("NCSEADR1"), request 9 ("NCSEADR1-9").

Similarly, QFs are forced to negotiate rates, terms and conditions in Alabama, Georgia, Maryland, Mississippi, and West Virginia, because the standard offer tariff is only available to QFs with nameplate capacity of 100 kW (one-tenth of 1 MW). In fact, aside from Tennessee, the only state cited by Duke which offers fixed long-term rates to QFs larger than 100 kW is South Carolina – where Duke's QF tariffs are largely identical to those approved by this Commission.

Q. HAS THERE BEEN MORE QF DEVELOPMENT IN NORTH CAROLINA THAN IN MOST OTHER STATES?

A. Yes. The following map demonstrates that solar investment in North Carolina has been different than in most other states.[10] More specifically, it confirms my impression that North Carolina has more solar generating projects than most nearby states, including states like Alabama, Florida, Georgia, Louisiana, and Mississippi, which continue to regulate utilities in the traditional manner. As, it appears North Carolina has more geographically dispersed projects than in most other states.

[10] An earlier version of this map appears on page 17 of the Joint Initial Statement Proposed Standard Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC filed in N.C.U.C. Docket No. E-100, Sub 148, November 15, 2016 and on page 36 the Direct Testimony of Kendal C. Bowman on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Bowman Direct").



The contrast with states like Arkansas, Kentucky, Louisiana, Oklahoma and Tennessee, which have very little solar activity, is particularly striking. However, these states are not alone in lagging behind their potential. Even Florida – despite its branding as the "Sunshine State" – has far fewer solar projects compared to North Carolina – relative to the size of the land mass and population of each state.

Of course, the way one views this map can be reminiscent of whether one sees a glass that is half empty, or one that is half full. What this map does not tell us is whether North Carolina is doing something right, and states like Florida and Louisiana could benefit from emulating it, or whether North Carolina it is doing something wrong, and should change its approach to implementing PURPA, in order to achieve outcomes that are more like these other states.

Q. ARE THESE DIFFERENCES ENTIRELY NEW?

A. No. My impression is that some differences have existed for many years, and can be traced all the way back to the availability of small hydro development opportunities in North Carolina that simply did not exist in most other states. In part due to the desire to take better advantage of this hydro potential, beginning in the 1980's the Public Staff invested a large amount of effort investigating the best way to fulfill the purpose of PURPA, while protecting the interests of the using and consuming public. This effort helped overcome the typical "chicken and egg" phenomenon I alluded to earlier, since small QFs were no longer forced to engage in time consuming, risky and costly negotiations.

Q. ARE THERE ANY OTHER NOTABLE DIFFERENCES BETWEEN NORTH CAROLINA AND OTHER STATES?

A. Yes. In some states, growth in renewables has been almost entirely driven by mechanisms like state renewable portfolio standards and government mandated procurement obligations.[11] While these approaches have increased the use of sustainable energy sources, there are some important differences. Realizing that the size of the yellow and red circles on the map indicate the size of each project, it is apparent that states like California, Texas and Florida are being developed with relatively large projects.

When comparing North Carolina with other states, it is reasonable to conclude that differences in PURPA implementation contribute to differences in the outcomes – but it should be acknowledged other explanatory factors are also relevant. Some of North Carolina's success in attracting solar investment could be attributable to some of the same factors which explain why the Research Triangle has attracted high-tech firms, Charlotte has become a major banking hub, and so many other businesses have been drawn to the state in recent years. Additionally, and increasingly, many large customers in the state, including the military, some new industrials, and some high-tech firms, are increasingly interested in obtaining energy that is sourced from renewable resources. Duke's Green Source Rider Program is evidence of this fact.

However, when looking at the state's success in attracting investment in solar energy in particular, three important considerations have greatly added to the state's appeal. First, the state has a favorable meteorological climate, with

11 GTM Research, The Next Wave of U.S. Utility Solar, Procurement Beyond the RPS (Feb.2016), accessible at https://www.greentechmedia.com/research/report/the-next-wave-of-us-utility-solar.

more solar radiation and less winter cloud cover than many other states. Second, the state has had a favorable legislative climate, with tax incentives, Renewable Energy Portfolio Standards, and other policies intended to encourage investment in renewable energy. Third, the state has had a favorable regulatory climate, with a long history of closely scrutinizing QF tariffs to ensure they are fully consistent with the requirements of PURPA, while also protecting the interests of the state's ratepayers. Fourth, the incumbent utilities have carefully complied with REPS and their PURPA obligations, including (for example) negotiating in good faith with QFs that were interested in pursuing arrangements that differ from the standard offer tariff.

Q. ARE THERE BENEFITS TO NUMEROUS SMALL QFs, RATHER THAN MOSTLY LARGER UTILITY-CONTROLLED PROJECTS?

A. Yes. There are significant public policy, economic efficiency, energy security, price stability, and economic development benefits to small, independently owned power production. While all energy projects share some benefits, there are additional benefits to QF projects which are not readily achieved with development of large, central generating stations by utilities.

First and foremost, competition from small power producers provides additional long-term benefits to consumers and the state economy as a whole, because it provides a healthy check on the monopoly power of the utilities, helping to constrain costs and keep rates at more affordable levels over the long term. Competition can bring long term societal benefits that are not readily achieved through other mechanisms, like a utility-controlled procurement process.

Supply source diversity can be greatly increased when market opportunities are not limited to an administratively constrained and managed RFP process. Some firms might not be successful at writing proposals or jumping through all the administrative hoops required by an RFP process, yet succeed as a QF. The difference in business models is subtle, but important. QFs have the opportunity to sell the utility as much power as they want, at a published tariffed rate. Hence, the keys to success are raising capital, developing innovative technologies, driving down costs, and increasing efficiency – or being willing to accept lower profit margins in return for the greater freedom and long-term upside potential that is inherent to the QF business model.

Second, QF development tends to reduce the risks posed to the state's economy by widely fluctuating coal and natural gas prices. From the perspective of retail ratepayers, QF energy is particularly attractive when it is purchased at fixed prices pursuant to long-term contracts, because these contracts provide a stabilizing element in the utilities' cost structure, thereby reducing volatility in retail prices. This reduced volatility also helps strengthen the state's economy and provides a more stable and attractive business environment.

Third, QF development helps diversify the state's energy mix and reduces the state's exposure to future uncertainties related to overseas geo-political events and the price of crude oil (which influence gas and coal prices), as well as the state's exposure to future political uncertainties related to coal and other traditional fuel sources. In most cases utilities continue to favor traditional technologies like coal, gas, and nuclear. While renewable energy development is being achieved in some other states, much of this investment is limited to, and being channeled through, government mandated or controlled procurement processes. While government quotas and mandates can be effective in jump-starting the use of alternative technologies, over the long haul its much more effective to set up a system that encourages market-driven investment decisions, rather than relying exclusively on administrative decision-making processes.

Fourth, QF investment provides widespread economic benefits to the local communities where these facilities are located – including substantial enhancements to the local tax base and property tax collections, without burdening local infrastructure or creating a corresponding need for additional government services. The net impact is a clear and significant benefit for local communities where these facilities are sited and installed – benefits that will not be achieved if solar, biomass, and other types of QFs are discouraged from investing in the state, and the focus is on developing much larger, more centralized generating units.

Fifth, when QF investment is encouraged on a widely-dispersed basis, the state's growing energy needs can be met with less need for costly expansion of the state's high voltage transmission systems – expansion that is all but inevitable if the state relies exclusively on construction of very large central generating units by the utilities in a small number of remote locations.

Section 2: Uncontrolled Growth in Solar Production

Q. HAS NORTH CAROLINA BEEN EXPERIENCING SIGNIFICANT GROWTH IN SOLAR PRODUCTION?

A. Yes. Witnesses for all three Utilities have described what they refer to as "unprecedented" growth in solar energy within the state:

> As a result of regulatory and legislative policies, strong support by DEC and DEP, and aggressive construction and deployment of solar facilities by developers, North Carolina is second only to California in interconnected solar capacity. As of December 31, 2016, there are more than 1,600 MW of third-party developed solar connected to DEC's and DEP's grid in North Carolina, with another

> 4,900 MW progressing through the interconnection queue.[12]

> ...as of February 1, 2017, DNCP has 72 effective PPAs for approximately 500 MW of solar QF capacity in North Carolina. (The Company has executed 9 PPAs totaling 45 MW even since the Initial Comments were filed just three months ago.) Of these 500 MW, approximately 350 MW have already commenced commercial operation, while the remaining 150 MW is under various stages of development. This is a mere three years since February 2014, when the Company had only 58 MW of distributed solar capacity under contract, with one project operational.[13]

Q. IS THIS DIFFERENT THAN WHAT IS HAPPENING IN NEIGHBORING STATES?

A. Yes. The growth North Carolina is experiencing is both substantial and more rapid than the relatively leisurely pace at which solar activity is occurring in nearby states like Alabama, Florida, Georgia, Indiana, Kentucky, Louisiana, Mississippi, and Virginia. Mr. Yates describes Duke Energy Corporation as a "national leader in renewable energy"[14] and points to massive investments it has made in North Carolina and elsewhere:

> Since 2007, Duke Energy has invested approximately $5.8 billion in renewable generation projects, including nearly

12 Direct Testimony of Lloyd M. Yates on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Yates Direct"), p. 6.

13 Direct Testimony of J. Scott Gaskill on behalf of Dominion North Carolina Power, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Gaskill Direct"), p.8

14 Yates Direct, p. 5.

> $300 million by DEP and $175 million by DEC in North Carolina.[15]

Yet, it is important to put this investment into context. In fact, all forms of renewable energy remain a very small share of Duke Energy Corporation's total electrical production. Duke Energy Corporation reported that its Hydroelectric and Solar facilities <u>combined</u> provided just 0.7% of its total generation during 2016 – and this was actually down from the 0.8% which was achieved in 2015 and 0.8% in 2014.[16]

When comparisons are made between solar nameplate capacity and other types of capacity, growth in solar generation can appear to be more significant than it really is. For instance, in its 2015 Annual Report to Stockholders, Duke Energy Corporation reported that Hydro and Solar represented 7.0% of its "owned capacity" while simultaneously reporting that Hydro and Solar generated just 1% of its total net output in gigawatt-hours ("Gwh").[17] While both statistics are interesting, the latter statistic is far more relevant and provides a better perspective on where things actually stand.

For more than 30 years, state and federal policy makers have been seeking to reduce dependence on imported energy sources, and increase the use of renewable energy sources. The focus of these efforts has always been on

15 <u>Id</u>.

16 Duke Energy Corporation, 2016 Form 10-K, p. 12.

17 Duke Energy Corporation, 2015 Annual Report, p. 11.

energy – not their share of nameplate capacity. Nevertheless, some data sources only show nameplate capacity, which is often cited when discussing progress toward adding renewable energy sources to the grid.

Q. HOW DOES DUKE'S PROGRESS IN CONNECTING SOLAR IN OTHER STATES COMPARE TO NORTH CAROLINA?

A. The following table[18] compares pending solar projects (as of March 2017) including both utility-owned projects and independent power producers: **BEGIN CONFIDENTIAL**

[redacted]

18 Duke's response to NCSEADR2-9(f), PURPA Solar Penetration as of 03.13.17.xlsx.

[redacted] **END CONFIDENTIAL** in North and South Carolina (both have adopted similar standard offer QF tariffs) compared with the other states, where solar projects are more likely to be utility-owned or negotiated.

The following table[19] shows analogous data for the size of the pending projects:

BEGIN CONFIDENTIAL

[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			

END CONFIDENTIAL

19 Duke's response to NCSEADR2-9(f), PURPA Solar Penetration as of 03.13.17.xlsx.

Q. HOW SIGNIFICANT IS THE EXISTING AND PENDING SOLAR CAPACITY RELATIVE TO OTHER ENERGY SOURCES?

A. Solar is still a relatively minor source of energy, and is expected to remain so for the near term. The summer nameplate capacity of DEC's non-solar generating units in North Carolina (including Nantahala Power & Light hydroelectric generation) totaled 20,270 MW as of March 30, 2016.[20] On the same date, DEP's analogous summer nameplate capacity totaled 12,873 MW,[21] bringing the combined total for both systems to 33,247 MW of non-solar capacity. The capacity is even higher during the winter months: 21,028 for DEC and 13,971 for DEP, with a combined total of 35,104, due to cooler temperatures. About half of this capacity relies on fossil fuels (coal and natural gas), while approximately 30% is nuclear. Approximately 10% is hydro (including pumped storage units, which require electrical energy from other fuel sources in order to function).

In contrast, in its 2016 IRP, DEC estimated it will have just 735 MW of solar nameplate capacity connected to its system in 2017, growing to 2,168 MW in

20 DEC response to NCSEADR1-d, N.C.U.C. Docket No. E-100, Sub 147.

21 DEP response to NCSEADR1-d, N.C.U.C. Docket No. E-100, Sub 147.

2031.[22] Similarly, DEP estimated it would have 1,710 MW of solar nameplate capacity connected to its system in 2017, growing to 3,270 MW in 2031.[23]

Duke also developed "High Renewables" scenarios, which considered the potential impact of high carbon prices, increased renewable mandates, and other factors.[24] In the "High Renewables" scenarios, by the year 2031 connected solar nameplate capacity was projected to increase to 5,062 (DEP) plus 2,957 (DEC) for a total of 8,019.[25] Duke also developed "Low Renewables" scenarios, which considered the potential impact of "lower avoided costs and/or less favorable PURPA terms.[26] Under this scenario, by the year 2031 solar nameplate capacity would grow to just 2,618 MW (DEP) plus 1,932 MW (DEC) for a total of 4,550 MW of solar connected to the system.[27]

However, none of these solar nameplate figures, or the 1,600 MW of third-party developed solar connected to DEC's and DEP's grid in North Carolina, or the 4,900 MW of potential projects progressing through the interconnection

22 Duke Energy Carolinas, LLC, 2016 Integrated Resource Plan, N.C.U.C. Docket No. E-100, Sub 147 ("DEC 2016 IRP"), Table 5-A.

23 Duke Energy Progress, LLC, 2016 Integrated Resource Plan, N.C.U.C. Docket No. E-100, Sub 147 ("DEP 2016 IRP"), Table 5-A.

24 DEC 2016 IRP, p. 26.

25 DEC 2016 IRP, Table 5-B; DEP 2016 IRP, Table 5-B.

26 DEC 2016 IRP, p. 26.

27 DEC 2016 IRP, Table 5-C; DEP 2016 IRP, Table 5-C.

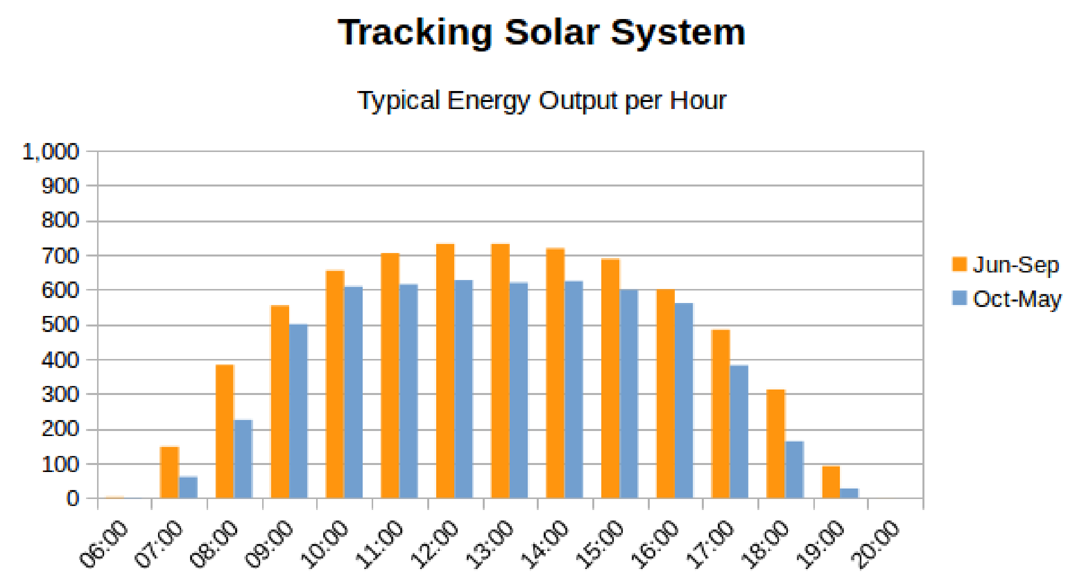
queue[28] can be directly compared to the nameplate capacity of other types of generation.

Q. WHY CAN SOLAR NAMEPLATE CAPACITY NOT BE DIRECTLY COMPARED TO OTHER TYPES OF GENERATING UNITS?

A. Solar energy output is almost never equal to the nameplate capacity. Output varies with the sun's movement, which varies in a predictable manner with the time of day and time of year. However, solar output is also affected by cloud cover, which is less predictable. In general, solar facilities have less capacity during the winter, because the sun is lower in the sky, and because cloud cover tends to be heavier and more frequent.

The following graph illustrates this pattern, using a data set in which the maximum hourly output of 1,000 MWh only occurred during a few hours of the year.

28 Yates Direct, p. 6.



The orange bars show the average hourly output during June through September, and the blue bars show the analogous average hourly output during October through May. As this graph illustrates, the electrical output follows a smooth and predictable pattern once the data is averaged across multiple days. However, it is also tends to be significantly less than its nominal nameplate capacity. The extent of the discrepancy varies depending on the technology (tracking versus fixed) as well as the time of day and day of the year.

The QF is only paid for actual energy sent to the grid and is only paid for capacity to the extent it provides energy during the limited "On Peak" hours which the utility specifies in its tariff. The theoretical nameplate capacity has no direct relevance to the amount paid by ratepayers, or the amount received by solar QFs for the use of their generating capacity; these are strictly a function of the energy provided to the utility during the On Peak hours specified in the utility's tariff.

Q. HAS DUKE PROVIDED SOME ESTIMATES OF SOLAR CAPACITY THAT CAN BE MORE DIRECTLY AND MEANINGFULLY COMPARED TO OTHER TYPES OF GENERATION?

A. Yes. Duke developed some projections for its IRP which can be very helpful in understanding the complications involved with using nameplate capacity, and drawing conclusions about the relative significance of solar capacity compared to nuclear, fossil and hydro capacity. In these projections, Duke used on 5% of nameplate capacity for the winter season, which it estimates is the fraction of solar nameplate capacity that would be generated "in the early morning hours around 7:00 a.m, when solar basically has little to no output."[29] It developed analogous data for the summer using a 46% factor, which it explained as follows:

> Solar resources contribute approximately 45% (46% for DEC and 44% for DEP) of their nameplate rating at the

29 Direct Testimony of Glen Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Snider Direct"), p. 27.

> time of the summer peak, which occurs in afternoon hours.[30]

In the following tables, I present Duke's solar capacity estimates, although I think the 5% figure for the winter might be too low. Solar facilities produce rapidly increasing amounts of energy from the moment the sun rises over the horizon, and solar output often averages more than 5% of nameplate capacity during the two-hour block from 7 a.m. until 9 a.m. – which is when the greatest need for peak capacity exists in the winter season. I will discuss this time period in greater detail later my testimony, in the context of the peak and off peak QF rates.

As shown below, Duke projects that solar capacity connected to the grid in 2017 will be less than 3% of its total 2016 nuclear, fossil, and hydro capacity.

2017 Net Solar Capacity
Compared to 2016 Total Capacity[31]

	Low Solar	Base	High Solar
Winter – 2017	0.35 %	0.35 %	0.77 %
Summer – 2017	3.28 %	3.28 %	3.46 %
Average – 2017	2.69 %	2.69 %	2.84 %

30 Snider Direct, p. 29.

31 Solar MW Contribution to Peak from DEC and DEP 2016 IRPs, Tables 5-A, 5-B, 5-C, divided by Coal, Nuclear, Combined Cycle, Combustion Turbine, Duke Hydro and NP&L Hydro capacity from DEC and DEP Responses to NCSEA DR1-d, Docket No. E-100, Sub 147.

As more solar QFs are completed and connected to the grid, solar energy is expected to become an increasingly important part of DEC and DEP's energy mix. This is reflected in the fact that Duke projects net solar capacity to roughly double or triple by 2031, as shown below:

2031 Net Solar Capacity Compared to 2016 Total Capacity[32]			
	Low Solar	**Base**	**High Solar**
Winter – 2031	0.65 %	0.77 %	1.14 %
Summer – 2031	6.14 %	7.33 %	10.79 %
Average – 2031	5.04 %	6.02 %	8.86 %

However, even under the fastest growth scenario, in 2031 solar will still be less than 9% of Duke's existing nuclear, fossil and hydro capacity.

32 Solar MW Contribution to Peak from DEC and DEP 2016 IRPs, Tables 5-A, 5-B, 5-C, divided by Coal, Nuclear, Combined Cycle, Combustion Turbine, Duke Hydro and NP&L Hydro capacity from DEC and DEP Responses to NCSEA DR1-d, Docket No. E-100, Sub 147.

Q. SHOULD THE COMMISSION ADOPT LESS FAVORABLE PURPA TERMS IN ORDER TO SLOW THE GROWTH IN SOLAR?

A. No, although this seems to be the Utilities' preference. Duke describes the recent growth in solar as both "unprecedented" and "unconstrained." Both Utilities' witnesses expressed concerns about challenges they face in trying to adapt to having more solar in their generation mix:

> This unprecedented growth in interconnected and proposed solar generation in just the past few years has ...created challenges that put our State at a crossroads.[33]

However, it is important to keep things in perspective: growth in solar production has long been the goal of public policy makers in North Carolina and elsewhere. One of the dilemmas policy makers in the state and elsewhere have long been confronted with is the reality that – absent tax incentives – solar and other sustainable technologies appeared to have higher life cycle costs than traditional energy sources like coal and oil. This perception of high costs created a vicious circle, which made it difficult for society to gain the benefits of reducing reliance on fossil fuels, and increasing the use of renewable energy sources.

High costs often limited sustainable technologies to "niche" status and blocked them from achieving mass commercial scale. In turn, the lack of

33 Yates Direct, p. 6.

commercial activity kept costs high, because (1) economies of scale in the manufacturing process were not being fully achieved, (2) too few firms were moving down the learning curve gaining the experience and skills needed to squeeze precious dollars out of the installation process, and (3) there was a general lack of opportunity (industry-wide) to observe and learn from experience, to identify "best practices" and to find solutions to difficulties.

The need to break this vicious circle was one of the fundamental reasons why Renewable Portfolio Standards, tax incentives, and other government policies have been widely adopted. In the case of solar energy in particular, it is obvious the sun provides an incredibly abundant energy source, so there is widespread agreement that we need to figure out how to commercialize the process of converting solar energy into electricity so that it will cost no more than (and eventually much less than) other energy sources. This rationale lies at the core of PURPA, as well as the many tax incentives and other policies which have been adopted by government policy makers in an attempt to break out of the vicious circle and initiate the process of bringing costs down below the level of other traditional energy sources.

In North Carolina, the solar industry is starting to break out of this vicious circle. QFs are delivering more and more solar energy at prices that have been set equal to the incremental cost of natural gas and coal fueled energy. It would be a mistake to slam on the brakes just as commercial mass scale is beginning to be achieved, because this growth is bringing new "challenges."

The challenges faced by the Utilities are real, and the care should be taken to investigate these challenges, and develop appropriate policy responses to ensure they do not become more serious. But, fundamental changes like the shift toward renewable energy normally bring with them many different technical, economic and other challenges. There is no reason to let these challenges slow the growth of solar – which could block the emergence of a virtuous circle of rapid growth, rapid movement down the learning curve, and rapid improvements in economic efficiency.

Q. HAVE THE UTILITIES RECOGNIZED THE BENEFITS TO SOCIETY FROM "UNCONSTRAINED" GROWTH IN SOLAR PRODUCTION?

A. No. The focus of their testimony seems to be almost entirely on the technical difficulties and operational challenges they are facing as a result of having more and more solar energy injected onto their systems, rather than the benefits to society that result from this rapid growth.

In response to these challenges, all three Utilities are asking the Commission to reverse long-standing Commission policies concerning PURPA, impose higher risks on QFs and lower QF rates below long run incremental costs. This is at least tacitly acknowledged in this passage from DNCP's testimony:

> It is true that several proposals similar to those that the Company has proposed in this proceeding were not accepted by the Commission in the 2014 Avoided Cost Case. However, as I will explain further in this testimony, since the 2014 Avoided Cost Case, the landscape of QF development in the Company's North Carolina service area has changed significantly. Given these changes, [DNCP] believes that it is imperative that the Commission reconsider these issues on a prospective basis for new solar QF development, and evaluate the Company's proposed revisions to its standard avoided cost rate schedules and contracts to adapt to those changing circumstances.[34]

If the Commission adopts these proposed responses to the challenges the Utilities are facing, it will create a more leisurely pace of solar expansion (more like what is happening in Louisiana or Mississippi), and it will lessen the chances of moving from a vicious circle of high costs and little experience gained, to a virtuous circle of rapid growth, swift movement down the learning curve, and larger cost reductions.

Q. HOW DO THE UTILITIES DESCRIBE THE POLICY CHOICES IN FRONT OF THE COMMISSION?

A. Mr. Yates conveyed the essence of Duke's position in his testimony:

> North Carolina is at a critical crossroads regarding the integration, development, and customer costs of renewable

34 Gaskill Direct, p. 5.

> generation. This crossroads is particularly critical for solar generation. [35]

> ...current regulatory and economic drivers necessitate a comprehensive review of the Commission's PURPA policies to ensure the long-term viability and integration of additional solar and other renewable resources for the benefit of our State and our customers.[36]

In general, I think it's fair to say DEC, DEP, and DNCP see the disparity between solar growth in North Carolina and in other states rather negatively, rather than positively:

> Existing policies, which have resulted in unconstrained growth in solar generation, have created a distorted marketplace for solar projects that have resulted in artificially high costs that are inevitably passed onto North Carolina residents, businesses, and industries, while potentially degrading operation of the Companies' electric systems. These policies have created a larger and more rapid utility-scale solar growth and now need to be reevaluated to allow for a smarter, more sustainable and economic approach. [37]

DNCP does not describe the situation in quite such stark terms, but nevertheless much of its testimony focuses on negative aspects of the growth, rather than its societal benefits. These passages from DNCP witness Gaskill's testimony capture the general tenor:

35 Yates Direct, p. 4.

36 Yates Direct, p. 10.

37 Yates Direct, p. 6.

> The influx of distributed solar generation onto DNCP's North Carolina system is now adversely impacting our system operations in this State.[38]

I will discuss many of these concerns, and I will respond to specific proposals offered by the Utilities in reaction to these concerns, at various points throughout the remainder of my testimony.

Section 3: Rate Comparisons

Q. HAVE YOU COMPARED THE QF RATES PROPOSED IN THIS CASE TO THE RATES THAT WERE APPROVED AT THE END OF THE LAST BIENNIAL PROCEEDING?

A. Yes. Duke's most recently approved QF rates were developed pursuant to a settlement agreement amongst the Utilities, the Public Staff, NCSEA, and the Southern Alliance for Clean Energy ("SACE").[39] Analogous rates were submitted by DNCP on February 2, 2016 as a compliance filing. Before presenting my numerical comparisons, it is helpful to mention some structural differences between those tariffs ("2014 tariffs") and the ones that have been submitted in this proceeding.

38 Direct Testimony of J. Scott Gaskill on behalf of Dominion North Carolina Power, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Gaskill Direct"), p. 7.

39 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 140, March 10, 2016.

First, the Utilities' 2014 tariffs offer QFs four different rate options: a variable rate, a 5-year levelized rate, a 10-year levelized rate, and a 15-year levelized rate. DEC and DEP proposed to eliminate half of these options, forcing the QF to choose between a variable rate that does not include any payment for capacity and a 10-year rate that does. DNCP proposes to eliminate the 15-year option, limiting QFs to rates that do not extend beyond 10 years.

Second, the DEC and DEP proposed tariffs do not specify the rates that will be paid each year during the 10-year term, unlike the 2014 tariff which provides a fixed rate for the entire 10- or 15-year term. Instead, the energy component is subject to change every two years. Furthermore, the tariff does not include a formula or index, or any other information which would limit the magnitude of future rate changes, or which could be used by lenders and investors to estimate the actual rate that will be paid (what revenue the QF will receive) after the first two years.

Third, the Utilities' 2014 tariffs are available to certain QFs up to 5 MW in size; DEC, DEP, and DNCP's proposed tariffs are limited to QFs up to 1 MW.

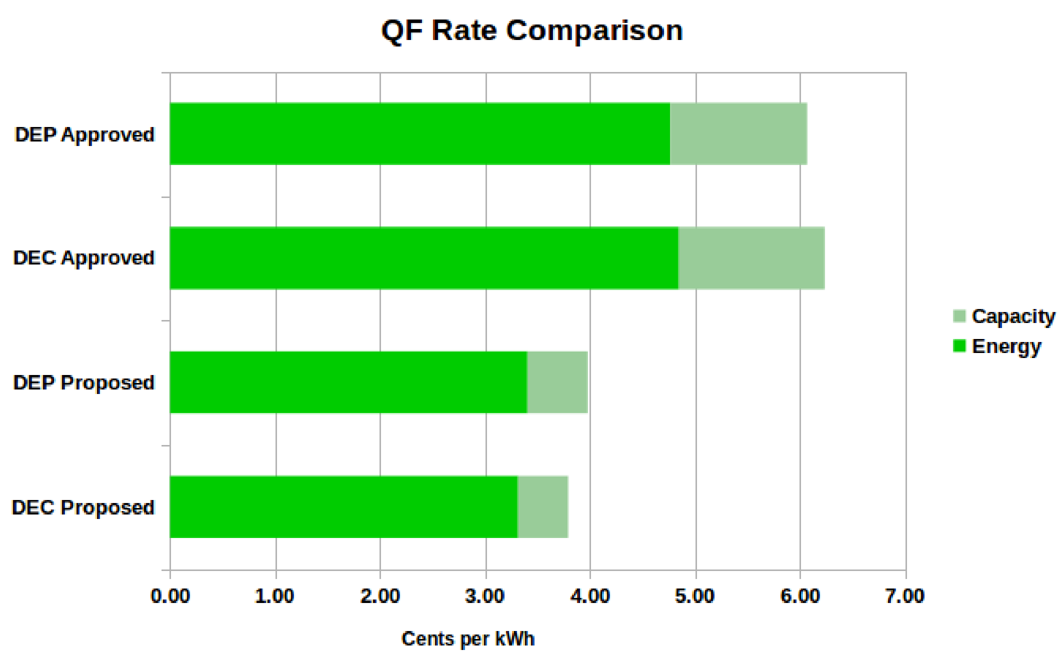
All of these proposals have the effect of increasing the risks faced by QFs, and making it more difficult to finance QF projects. They also make it harder to provide the Commission with meaningful comparisons between the current and proposed rates, since any comparison will necessarily involve some degree of mismatching.

I have tried to deal with this problem by comparing the current 15-year rates to the proposed 10-year rates. Of course, this is not a perfect match, since the proposed rates are only available to a 1 MW QF, while the current rates can be used with projects of up to 5 MW, and the PPA terms and durations are not identical. However, this provides the closest, most realistic comparison that is feasible, since it compares the least risky option which also generates the highest "bankable" revenue under the current tariff to the least risky option which generates the highest "bankable" revenue under the proposed tariff. To further simplify and improve the comparisons, I compared the rates on a composite or weighted average basis, as they apply to a typical solar facility.

More specifically, I looked at the rates applicable during each hour of each day of the year, and applied them to the volume of energy which can reasonably be expected from a typical QF solar facility to determine the total payments that would be received by the QF. The total payments were then divided by the total kWh which were expected to be produced by the QF, in order to calculate an overall composite rate per kWh. This procedure took into account how the Summer and Non-Summer seasons are defined, as well as how the peak and non-peak time periods are defined in each of the tariffs.

Q. WHAT IS REVEALED BY THIS COMPARISON?

A. This composite analysis demonstrates that the proposed QF rates are far lower than the current rates. If the proposed tariffs are approved, it will be much more difficult to finance QF projects, as shown in the following graph:



The current DEP and DEC rates differ just slightly, primarily due to differences in their generating facilities and load patterns. In contrast, both sets of proposed rates are significantly lower, as shown in the following tables:

Difference in QF Rates: DEP Current versus Proposed			
	Energy	Capacity	Total

DEP – Current	4.767 cents	1.303 cents	6.070 cents
DEP – Proposed	3.406 cents	0.573 cents	3.979 cents
Difference	-1.360 cents	-0.730 cents	-2.091 cents
Percent Difference	-28.5%	-56.0 %	-34.4 %

Difference in QF Rates: DEC Current versus Proposed			
	Energy	Capacity	Total
DEC – Current	4.850 cents	1.386 cents	6.236 cents
DEC – Proposed	3.315 cents	0.478 cents	3.793 cents
Difference	-1.535 cents	-0.908 cents	-2.443 cents
Percent Difference	-31.6 %	-65.5 %	-39.2 %

As shown in the above tables, under the proposed tariff, QFs will receive 34.4% (DEC) or 39.2% (DEP) less revenue than if the project were eligible for the 2014 rates. These are very substantial revenue reductions, which would make it harder for them to obtain financing. Along with structural changes to the standard offer which increase the risks facing QF projects, these rates will have a substantial, negative impact on QF investment in the state.

Q. HOW DO THE CURRENT QF ENERGY RATES COMPARE TO DUKE'S AVERAGE FOSSIL FUEL COSTS?

A. The QF energy rates in the 2014 tariff are about a penny higher per kWh than Duke's average fossil fuel costs during the 12 months ending December 2015,[40] as shown in the following table:

Duke 2014 – 2028 QF Energy Rates versus 2015 Average Fuel Costs		
	DEP	**DEC**
2014 – 2028 QF Rate	4.767 cents	4.850 cents
2015 Average Fuel Cost	3.670 cents	3.444 cents
Difference	1.097 cents	1.406 cents

Q. IS A DIFFERENCE OF THIS TYPE TO BE EXPECTED?

A. Yes. There are at least two reasons to expect QF rates to be higher than average fossil fuel costs.

First, the QF rates are levelized, so they are based upon fuel prices that are forecasted into the future. In other words, the QF energy rates reflect a combination of lower fuel costs in the early years of the contract and higher fuel costs in the later years of the contract. Any comparison that only looks

40 DEC and DEP Monthly Fuel Reports pursuant to NCUC Rule R8-52, February 3, 2016.

at average fossil fuel costs in the early years will necessarily be lower than the levelized QF rates. By the same token, analogous comparisons that are performed during the latter part of the 15-year period can be expected to show the opposite pattern: the levelized rates will be less than fossil fuel costs incurred in those years.

Second, under the Peaker Method, the QF rates are based upon marginal, not average fuel costs. The Peaker Method assumes marginal fuel costs will be higher than average fuel costs, and it assumes the difference will be sufficient to compensate for the higher cost of building and operating baseload generating units compared to the capacity-related costs of a peaker.

Q. CAN YOU EXPLAIN IN MORE DEPTH WHY THE QF ENERGY RATES DEVELOPED USING THE PEAKER METHOD ARE SUPPOSED TO BE HIGHER THAN AVERAGE FUEL COSTS?

A. Yes. This goes all the way back to the historical roots and theoretical underpinnings of the Peaker Method. In its 1994 Biennial Avoided Cost Order, the North Carolina Utilities Commission explained the Peaker Method as follows:

> The peaker approach to avoided costs used by both Duke and Progress Energy in the biennial proceedings, is based on a method developed by National Economic Research Associates, Inc. (NERA) and described in detail in the "Grey" series of publications jointly sponsored by the

> National Association of Regulatory Utility Commissioners, the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association and the National Rural Electric Cooperative Association. It is one of four marginal costing methodologies developed in the "Electric Utility Rate Design Study" part of the series (topics 1.3 and 4).

According to the theory underlying the Peaker Method, the capital cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system should produce the utility's full avoided cost of building and operating a new baseload generating plant, assuming the utility's generating system is operating at equilibrium with an efficient mix of baseload, intermediate and peaking plants. This result is supposed to be achieved by using relatively high energy costs from the most costly unit operated during any given hour. In essence, the avoided energy cost estimates used in creating the QF rates are based on decreasing the output of whatever unit is operating "at the top of the stack" by 100 MW during any given hour.

The premise behind the Peaker Method is that the cost of operating the unit at the top of the stack will generally be higher than the cost of operating units farther down the stack (because, in theory, those have lower heat rates and lower fuel costs). If combustion turbines with poor heat rates are operating at the top of the stack during enough hours of the year, this difference in fuel costs will be sufficient to compensate for the additional capital costs of a baseload unit relative to a peaker.

Stated another way, the Peaker Method does not provide explicit recovery of the higher fixed costs of a combined cycle or other baseload plant, relative to a peaker. However, those higher fixed costs are supposed to be implicitly recovered by calculating higher avoided energy costs that are derived exclusively from the "top of the stack." By combining higher energy costs with lower capital costs, the results of the Peaker Method are supposed to be equivalent to the results of using the Proxy Unit method to estimate the full avoided cost of building and operating a new baseload unit.

> According to the theory underlying the Peaker Method, if the utility's generating system is operating at equilibrium (i.e., at the optimal point), the cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost. It will also equal the avoided cost of a baseload plant, despite the fact that the capital costs of a peaker are less than those of a baseload plant. This is because the lower capital costs of the CT are offset by the fuel and other operation and maintenance expenses included in system marginal running costs, which are higher for a peaker than for a new baseload plant. Thus, the summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker.[41]

This aspect of the Peaker Method can lead to confusion when comparing the cost of QF power, particularly when compared to the cost of nuclear power,

41 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 100, September 29, 2005, p. 17.

but it also is relevant to comparisons with coal and natural gas fired baseload units. Although it can lead to confusion, this additional complexity is one of the main advantages of the Peaker Method: it allows costs to be computed on an hour-by-hour basis.

In fact, the original purpose of the Peaker Method was specifically to help develop time-differentiated prices based upon "marginal cost." This is clear from both the titles, and the contents of NERA's Grey Books. One of the books, covering Topic 1.3, was called A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States. The other book, covering Topic 4, was called How to Quantify Marginal Costs.

Hour-by-hour granularity was achieved by combining the levelized cost of building and owning a new peaking plant (rather baseload) with the marginal running costs of the entire system, separately calculated for each hour of the day and each day of the year. As explained in the Grey Books:

> During the day, the marginal cost will generally be the running cost of an intermediate machine, and at peak it will be the running cost of a peaking machine. This is the familiar dispatch cost which is routinely calculated for interutility sales. At peak, however, we also encounter the need to expand capacity, and each hour at peak should also be charged the cost of expanding capacity. The appropriate cost is, however, the marginal cost of capacity, the

> machine that will meet loads of shortest duration in the least cost way. It will generally be a peaking plant.[42]

> [T]he price of running cost and capital cost of a peaker at the peak will exactly recover the total costs of adding and running the peaking plant.[43]

> In the long run, after capacity has been adjusted, the marginal cost is the cost of energy plus the cost of capacity at peak.[44]

Q. WILL THE DIFFERENCE BETWEEN AVERAGE AND MARGINAL FUEL COSTS ALWAYS FULLY COMPENSATE FOR THE HIGHER CAPITAL COST OF A BASELOAD PLANT?

A. No. While this is the intent of the Peaker Method, there is no guarantee that QFs will be paid the full avoided cost of a baseload plant. In practice, it depends on how often the utility's combustion turbines are actually dispatched and other real-life factors which do not necessarily precisely match the assumptions used in developing the theory. As a result, in practice the difference between average and marginal cost may not be sufficient to achieve this intended result. While the avoided energy cost estimates and avoided capacity cost estimates are supposed to provide total compensation that is

42 A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States, p. 57.

43 A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States, p. 63.

44 How to Quantify Marginal Costs, p.37.

equivalent to the full avoided cost of building and operating a new baseload generating plant – this does not necessarily happen every time.

In fact, because of the "lumpiness" of baseload capacity additions, changes in relative price levels for different types of fuel and other factors, marginal fuel costs may not always exceed average fuel costs by a wide enough margin to fully compensate for the cost of building and operating a new baseload generating plant.

Q. HAVE YOU COMPARED DUKE'S MARGINAL FUEL COSTS TO ITS AVERAGE FOSSIL FUEL COSTS?

A. Yes. I compared the same average fossil fuel data discussed earlier, with DEC and DEP's hourly marginal costs during 2015.[45] To make a direct comparison, I weighted the marginal cost in each hour by the volume of energy during that hour. Thus, the higher marginal costs that are incurred during daytime hours were given more weight than the lower costs that are incurred at night. This is the most relevant comparison, since the average fuel cost data is conceptually similar. The data can be seen below:

Duke Marginal Fuel Costs versus Average Fuel Costs

45 Duke's response to NCSEADR1-11, 2015 hourly marginal costs.xlsx.

	DEP	DEC
2015 Marginal Fuel Cost	3.494 cents	3.493 cents
2015 Average Fuel Cost	3.670 cents	3.444 cents
Difference	-0.176 cents	0.049 cents

I then analyzed the marginal cost data using the On Peak and Off Peak time periods used in the QF tariffs. That comparison is summarized below:

Duke Marginal Fuel Costs versus Average Fuel Costs		
	DEP	**DEC**
2015 Marginal Fuel Cost – On Peak	3.724 cents	3.723 cents
2015 Marginal Fuel Cost – Off Peak	3.264 cents	3.263 cents
2015 Average Fuel Cost	3.670 cents	3.444 cents
Difference – On Peak	0.054 cents	0.279 cents
Difference – Off Peak	-0.406 cents	-0.181 cents

In general, this analysis suggests Duke's marginal fuel costs are currently very similar to its average fossil fuel costs. Since this is a snapshot of a single year, no definitive conclusions can be reached, but these comparisons suggest Duke's marginal fuel costs may not, in actual practice, be far enough above its average fuel costs to cover the full incremental cost of a natural gas or coal-fired baseload plant. In other words, this data suggests the Peaker Method is providing low-end estimates of avoided costs, since the marginal fuel costs are so close to the system average fossil fuel costs.

Q. WHY IS THIS?

A. Although Duke owns many peaking plants, they are rarely operated. As discussed earlier, the theory underpinning the Peaker Method assumes combustion turbines will be operating at the "top of the stack" during many hours of the year. The more hours there are when high marginal fuel costs are being incurred, the more opportunity there is for the gap between marginal and average fuel costs to be large enough to be equivalent to the difference between the capacity cost of a new baseload plant and a new peaker.

In Duke's case, there are many hours of the year when the generating unit that is actually operating at the "top of the stack" is not a combustion turbine with high fuel costs, but instead it is a baseload coal or combined cycle unit, that has significantly lower fuel costs.

This can be confirmed by analyzing the Prosym output that was used to develop the proposed rates. For instance, DEC's Proysm runs show a combustion turbine operating at the "top of the stack" during less than **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** in 2017.[46] While combustion turbines operate a little more frequently during some other years, in none of the years are they operated anywhere near the theoretical "cross-over" point that was used to support the Peaker Method.[47]

Q. IF PEAKERS ARE RARELY ON THE MARGIN, WHAT IS ACTUALLY OPERATING AT THE "TOP OF THE STACK"?

A. Coal units are expected to be operating at the margin during **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** hours during 2017.[48] In fact, coal units are expected to be operating at the top of the stack during **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** of the on-peak hours and an even higher percentage of the off-peak hours throughout 2018 – 2026.[49]

The following graphic shows the generation sources that Proysm shows operating at the margin during on-peak hours:[50] **BEGIN CONFIDENTIAL**

46 DEC response to the second data request of the Public Staff ("PSDR2"), request 18 ("PSDR2-18), StationGroup Hours.xlsx.

47 The breakeven or "cross-over" point (where fuel cost savings justify building a combined cycle unit instead of a peaker) depends on the heat rate of the combined cycle and combustion turbine units, fuel prices and other factors. The benchmark cost analysis described in detail later in my testimony indicates a cross-over point in the vicinity of 4 to 5 hours per day. For shorter duration loads, the higher fixed cost of the combined cycle unit outweighs the higher variable fuel cost of the combustion turbine.

48 DEC response to PSDR2-18, StationGroup Hours.xlsx.

49 DEC response to PSDR2-18, StationGroup Hours.xlsx.

50 DEC response to PSDR2-18, StationGroup Hours.xlsx.

[redacted]

END CONFIDENTIAL Since at present baseload units, rather than peaking units, are expected to be operating at the "top of the stack" during so many hours, there is reason to question whether the marginal energy costs developed by Prosym actually exceed the fuel cost of a new baseload plant to the degree initially envisioned by the theoreticians who developed the Peaker Method, many years ago.

> According to the theory underlying the Peaker Method ...the cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system will ...equal the avoided cost of a baseload plant, despite the fact that the

> capital costs of a peaker are less than those of a baseload plant.[51]

In essence, when the Peaker Method was developed, it was assumed the marginal units would have high fuel costs, and as a result the system running costs would be much higher than the fuel costs of a new baseload plant:

> Thus, the summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker[52]

In this proceeding, however, DEC and DEP's Prosym model runs show baseload coal and combined cycle plants being operated at the margin during **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** during 2017-2026.[53] Consequently, there is reason to doubt whether the marginal energy costs produced by Prosym are high enough to be fully consistent with the theory underlying the Peaker Method. In other words, we can't be confident that the Prosym output, when combined with the capital cost of a combustion turbine, will equal the full long run incremental cost of a new baseload plant – as it should be.

51 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 100, September 29, 2005, p. 17.

52 Id.

53 DEC response to PSDR2-18, StationGroup Hours.xlsx.

Q. HAVE YOU DEVELOPED SOME DATA THAT FURTHER CLARIFIES THIS ISSUE?

A. Yes. I developed some benchmark avoided cost estimates using the Proxy Unit method that can shed further light on this issue. I provide a more detailed discussion of these cost estimates in the next section of my testimony, including an explanation of my methodology and assumptions. For the moment, it is sufficient to briefly mention a few issues.

When thinking about energy costs, maintenance, fuel and other operating costs that vary with energy output are what immediately come to mind. However, it is important to note that, under the Peaker Method, avoided energy costs are also supposed to include some fixed capital-related costs. Thus, the distinction between capacity-related costs and energy-related costs is not identical to the distinction between fixed costs and variable costs, nor is it identical to the distinction between capital-related and operating expense-related costs.

Q. HOW DID YOU SPLIT FIXED COSTS BETWEEN THE ENERGY AND CAPACITY RELATED CATEGORIES?

A. I assumed the "capacity-related" portion was limited to the annual fixed cost of building and owning the combustion turbine. The remainder of the fixed costs of building and operating the nuclear plant and combined cycle plant were treated as "energy-related." This disaggregation is widely accepted – as I mentioned earlier, it is fundamental to the theoretical underpinnings of the Peaker Method.

Disaggregating fixed costs in this manner is particularly useful in understanding the economics of a nuclear unit. The great majority of the capital investment in a nuclear plant is not attributable to the goal of meeting peak capacity (although a nuclear plant also provides capacity for achieving that goal). Rather, the bulk of the investment in a nuclear plant is attributable to the goal of safely producing energy with low fuel costs. The uranium used to fuel a nuclear plant tends to be less costly than coal, oil or natural gas – and this cost advantage is a key motivation for using this technology. No one would invest in a nuclear unit just to provide capacity during peak hours.

In general, the added investment expended on baseload plants is only justified by the potential for minimizing fuel and other variable costs over the operating life of the plant. Consequently, any investment in excess of that required for a peaking plant is appropriately categorized as energy-related. The same logic applies to disaggregating the costs of the combined cycle plant, although the impact is not as significant.

Q. WHAT IS THE ANNUAL FIXED COST PER KW FOR EACH OF THESE TECHNOLOGIES?

A. The benchmark levelized annual cost estimates in 2017 dollars are summarized in the following table:

Cost per kW/Year	**Nuclear**	**Combined Cycle**	**CT**
Capacity Related	$ 87.12	$ 87.12	$ 87.12
Energy Related	605.61	51.78	0.00
Total	$ 692.72	$ 138.90	$ 87.12

Q. CAN THESE NUMBERS BE CONVERTED INTO CENTS PER KWH?

A. Yes. However, annual fixed costs per kWh vary widely, depending on how many hours a unit is assumed to operate. For instance, I have assumed a nuclear unit will be dispatched at the bottom of the generating stack, and its energy-related costs will be recovered during all 8,760 hours per year. With this assumption, the capacity-related fixed costs of the nuclear unit are approximately one cent per kWh ($87.12/8760), and the energy-related fixed costs are 6.91 cents per kWh.

I assumed the combined cycle unit would be dispatched after the nuclear unit, and would not be operated as many hours, while the combustion turbine would be dispatched last, and operate the fewest hours. For certain purposes, I assumed annual fixed costs of the combined cycle unit would be recovered over 5,110 hours per year[54] but I also looked at other assumptions.

Similarly, I assumed the combustion turbine would be dispatched last, since it has the highest variable costs. For some comparative purposes, I assumed the CT would be dispatched approximately 4 hours per day, or 1,460 hours per year, but I also considered other assumptions.

Q. CAN YOU EXPLAIN WHY DISPATCH HOURS ARE IMPORTANT AND CAN VARY?

A. Yes. Historically, coal plants were built with the expectation of being dispatched after nuclear plants and before combined cycle plants, which primarily thought of as intermediate or mid-range plants. Combustion turbines were classified as peakers and dispatched last.

Generating plants tend to be dispatched more frequently when they are first added to the system and less frequently as they get older, as newer, more fuel-efficient units are introduced to the resource stack. Hence, the actual dispatch

54 Spreading the energy-related fixed costs over 5,110 kWh per KW of capacity is similar to assuming the combined cycle unit will be dispatched approximately 58% of the time. I recognize this is less than the actual dispatch factor that would be anticipated for a new combined cycle plant under current conditions. Natural gas prices are currently very low, while the system includes many coal fired plants that are being dispatched after combined cycle units, which was not anticipated at the time the coal plants were built. Nevertheless, a 58% dispatch factor is an appropriate assumption in this particular context, since this is similar to a typical overall system load factor.

sequence will vary depending on the age (and heat rate) of each specific plant. Changes in relative fuel prices can also cause the dispatch order to change.

For instance, during 2015 and 2016 natural gas prices were very low. This led to coal plants being dispatched higher in the generation stack (after newly built gas-fired combined cycle plants), even though they have higher capital costs. Some coal plants would never have been built, if the planners had known that natural gas prices were going to be as low as they have been recently. Ratepayers continue to pay the full cost of these baseload plants, even though they are being dispatched later in the stack, and their fixed costs are therefore being spread over relatively few hours. As a result, their effective cost per kWh is higher than was originally anticipated when their construction was planned. Since the actual number of hours any given plant will be dispatched can vary as fuel prices change, and may decline as newer, more efficient units are added to the system, it can be useful to see how the fixed costs per kWh will vary, depending on how many hours the unit is assumed to operate.

Q. WHAT IS THE FIXED COST PER KWH OF THESE TECHNOLOGIES?

A. The combined cycle plant has a capacity-related costs could theoretically be as low as .99 cents per kWh for capacity and .59 cents per kWh for energy, totaling 1.58 cents per kWh if it were dispatched 100% of the time it is available. The capacity-related cost would likely be around 1.70 cents per kWh and the energy-related costs around 1.01 cents per kWh, for a total of 2.71 cents per kWh if it were dispatched at roughly the same rate as a typical overall system load factor (58%), as shown in the table below:

Levelized Fixed Costs per kWh

Annual Dispatch Rate	**CC - Capacity**	**CC - Energy**	**CT - Capacity**
100%	0.99 cents	0.59 cents	0.99 cents
90%	1.10 cents	0.66 cents	1.10 cents
75%	1.33 cents	0.74 cents	1.33 cents
58.3%	1.70 cents	1.01 cents	1.70 cents
29.2%	3.41 cents	2.03 cents	3.41 cents
16.7%	5.97 cents	3.55 cents	5.97 cents
5%	19.89 cents	11.82 cents	19.89 cents

The CT and CC capacity-related costs are identical by definition (the portion of the combined cycle unit's total fixed costs that is categorized as capacity-related is derived from the CT's capacity related costs).

The difference between the fixed cost of a combined cycle plant and the fixed cost of a combustion turbine will be at least .66 cents per kWh (if the plant is dispatched 90% of the time throughout its entire economic life), and more likely it will be around 1.01 cents per kWh. These figures provide some useful perspective in judging the reasonableness of the QF rates.

These fixed costs are paid by retail customers when power is generated by the utility using generating units that are included in its rate base. These types of costs can be avoided when power is purchased from a QF instead, and they should therefore also be encompassed within the QF rates, as part of the avoided energy costs. Under the Peaker Method, the implicit assumption is that marginal energy costs will exceed average fuel costs by an amount sufficient to recover this additional penny. Considering that marginal fuel costs have recently been much closer to the system average fossil fuel costs, it is doubtful this intended result is being achieved.

Q. WILL YOU PLEASE RESTATE THE CONCLUSION YOU REACHED FROM ALL THIS DATA?

A. Given the theory behind the Peaker Method, the calculated marginal cost-based avoided energy rates should be approximately .66 to 1.01 cents per kWh higher than the system average fossil fuel costs. Since the recently observed gap between marginal and average costs is much narrower than this, the Peaker Method is currently yielding relatively low avoided energy cost estimates which do not fully compensate for the full cost of building and operating a combined cycle plant. This is an important piece of evidence the Commission should keep in mind when deciding how to resolve the issues in this proceeding.

Q. DID YOU ALSO LOOK AT FUEL AND OTHER VARIABLE ENERGY-RELATED COSTS?

A. Yes. Before presenting this data, it is important to keep in mind that variable costs can be difficult to deal with, because they are largely determined by future fuel prices, which are not knowable with much precision. For that reason, I developed cost estimates using several different fuel price scenarios. I will be discussing each of these scenarios, and other issues related to fuel costs, later in my testimony.

Q. HOW DO THE PER KWH ENERGY COSTS COMPARE FOR THESE THREE TECHNOLOGIES?

A. The costs vary fairly widely, depending upon the technology and long-term natural gas price scenario. Looking first at the combustion turbine, the levelized avoided energy costs (including fuel and variable operations and maintenance costs, but excluding capacity-related costs) range from less than 4 cents per kWh to more than 11 cents per kWh, as shown below:

Combustion Turbine Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.76 ¢	5.14 ¢	4.76 ¢	5.76 ¢
2022 - 2026 Levelized	5.13 ¢	6.39 ¢	6.72 ¢	8.80 ¢

Combustion Turbine Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2027 - 2031 Levelized	6.09 ¢	7.79 ¢	8.31 ¢	11.16 ¢

With the combined cycle plant, the sensitivity to fuel prices isn't quite as extreme, since the unit has a better heat rate (burns less fuel) and because the avoided energy costs include energy-related fixed costs, which do not vary with fuel prices, but do vary with the assumed capacity factor, as was just discussed. This greater stability can be seen in the following table, which assumes a 58% dispatch factor:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	2.94 ¢	3.83 ¢	3.59 ¢	4.23 ¢
2022 - 2026 Levelized	3.78 ¢	4.59 ¢	4.80 ¢	6.13 ¢
2027 - 2031 Levelized	4.33 ¢	5.43 ¢	5.76 ¢	7.60 ¢

The Nuclear plant is not sensitive to gas prices and the cost is largely stable over time, because most of the costs are fixed and levelized:

Nuclear Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	8.22 ¢	8.22 ¢	8.22 ¢	8.22 ¢
2022 - 2026 Levelized	8.35 ¢	8.35 ¢	8.35 ¢	8.35 ¢
2027 - 2031 Levelized	8.50 ¢	8.50 ¢	8.50 ¢	8.50 ¢

The combined cycle unit generally has the lowest costs and therefore in the remainder of my testimony I have primarily focused on these cost estimates. However, each technology has advantages and disadvantages. The combustion turbine tends to be more cost effective in meeting loads of short duration[55] while nuclear technology provides the greatest price stability over the very long term. This greater stability has historically proven to be an advantage for nuclear plants – even ones that encountered major schedule delays and cost over-runs ultimately became more cost effective in the latter part of their life cycle. Even troubled nuclear plants, with high construction costs, have looked better and better over time, because their construction cost was largely fixed, and the cost of alternative fuels increased greatly over the 40- to 60-year life of the plant.

55 If a generating unit is going to be dispatched less than approximately 1,700 hours a year, the benefit of the lower installed cost of the CT outweighs the burden of its higher heat rate and fuel costs.

Q. HAVE YOU COMPARED THESE BENCHMARK COST ESTIMATES TO THE CURRENT AND PROPOSED RATES?

A. Yes. This table compares the QF rates in the standard offer tariff approved in the 2014 biennial proceeding to the 2017-2021 levelized cost of the combined cycle unit:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.76 ¢	5.14 ¢	4.76 ¢	5.76 ¢
DEP – 2014 Rates	4.77 ¢	4.77 ¢	4.77 ¢	4.77 ¢
DEC – 2014 Rates	4.85 ¢	4.85 ¢	4.85 ¢	4.85 ¢

The amount ratepayers will pay for obtaining power from QFs under the current QF energy rates will be approximately 1 cent per kWh more than the cost of obtaining power from a new combined cycle plant, assuming the "Low" fuel prices occur. If fuel prices match the most recent EIA projection during this five-year period, or if they return to the historical trend, the amount paid for QF power at the current rates will be very similar to (or slightly lower than) the cost of using the combined cycle plant. If "High" fuel prices were to occur, the combined cycle plant will be about 1 cent costlier than the current QF rates.

In contrast, under every scenario the proposed QF rates are below the estimated long run cost of generating electricity using a combined cycle plant, and the discrepancy will be quite extreme if "High" fuel prices prevail:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2017 - 2021 Levelized	3.76 ¢	5.14 ¢	4.76 ¢	5.76 ¢
DEP – Proposed	3.41 ¢	3.41 ¢	3.41 ¢	3.41 ¢
DEC – Proposed	3.32 ¢	3.32 ¢	3.32 ¢	3.32 ¢

This next table compares the current QF rates to the 2022-2026 levelized cost of the combined cycle unit:

Combined Cycle Energy-Related Cost per kWh	**Natural Gas Price Scenario**			
	Low	EIA 2017	Return to Trend	High
2022 - 2026 Levelized	5.13 ¢	6.39 ¢	6.72 ¢	8.80 ¢
DEP – 2014 Rates	4.77 ¢	4.77 ¢	4.77 ¢	4.77 ¢
DEC – 2014 Rates	4.85 ¢	4.85 ¢	4.85 ¢	4.85 ¢

The 2014 QF energy rates are lower than the cost of obtaining power from a new combined cycle plant under every scenario, with the discrepancy increasing the more fuel prices increase. Under the "High" fuel price scenario, ratepayers will be paying less than 5 cents per kWh for power obtained from

QFs while paying nearly 9 cents per kWh for power generated by a new combined cycle plant.

Needless to say, the discrepancy would be even larger if the proposed QF rates were accepted:

Combined Cycle Energy-Related Cost per kWh	Natural Gas Price Scenario			
	Low	EIA 2017	Return to Trend	High
2022 - 2026 Levelized	5.13 ¢	6.39 ¢	6.72 ¢	8.80 ¢
DEP – Proposed	3.41 ¢	3.41 ¢	3.41 ¢	3.41 ¢
DEC – Proposed	3.32 ¢	3.32 ¢	3.32 ¢	3.32 ¢

Q. WILL RETAIL CUSTOMERS BENEFIT IF THE COMMISSION REDUCES QF RATES TO A LEVEL FAR BELOW WHAT IT COSTS TO OBTAIN POWER FROM A NEW COMBINED CYCLE PLANT?

A. No. Although low QF rates may be superficially appealing (on the assumption that lower QF rates will translate into lower retail rates through a fuel adjustment and purchased power mechanism), artificially suppressing QF rates does not benefit ratepayers. Any short-term benefit from low QF rates is of limited value, because low QF rates discourage QF investment, thereby reducing the amount of energy that the utility will actually obtain at the lower rates. Taken to the extreme, if QF rates are so low that no further QF investment occurs, no purchases would be made at the artificially low rates, and there would be no further savings available to flow through to retail customers.

Even if some QFs end up selling some power at the artificially low rate (e.g. they are already committed to their projects before the low rates are established), the potential benefit to retail customers will be limited, because future QF investment will be discouraged and the potential for increased pressure on the utility to operate efficiently will be lost. Instead, customers will be forced to buy more costly power generated by the utility itself. Simply stated, over the long run, retail customers are harmed by artificially low QF rates, because low rates shield utilities from competition, reducing pressures for them to minimize their costs.

Furthermore, low QF rates encourage unnecessary expansion of the regulated rate base, thereby shifting risks onto retail customers that could have been borne by QF investors instead. For example, when a new combined cycle plant is built by DEC or DEP, their customers bear nearly all of the risks associated with scheduled delays, construction cost overruns, or unexpectedly high fuel costs. Absent an extraordinary finding of imprudence, which rarely occurs, all of the risks associated with construction and operation of a utility-owned generating plant are ultimately borne by ratepayers. Even in cases where a plant is retired early, or construction is never completed, ratepayers will normally shoulder the burden of any resulting stranded costs.

In contrast, when independent power producers build plants, customers are shielded from these risks, because they only pay for power that is actually generated, and the price remains the same regardless of what delays or cost over-runs occur during construction. In sum, it is not in the public interest for the Commission to endorse unrealistically low avoided cost estimates, or to adopt excessively low QF rates. To the contrary, the public interest is best served by encouraging competition, by accurately and fairly implementing the provisions of PURPA and the associated FERC rules.

Q. ARE YOU ADVOCATING SETTING QF RATES AT THE HIGHEST ALLOWABLE LEVEL?

A. No. A middle course is preferable. Retail customers are better served by regulatory decisions that set QF rates away from these extremes, at a point that is closer to the long run incremental costs that are incurred by utilities when they build and operate their own generating plants. I believe this long-run incremental cost standard is also more consistent with the requirements of federal law. It encourages competitive entry by small power producers, without imposing a cost burden on customers, and without subsidizing QF development or running the risk of encouraging economically inefficient levels of QF investment.

Stated a little differently, the public interest is best achieved by establishing rates that leave ratepayers indifferent as to whether energy and capacity is obtained from QFs or from the utility itself under traditional rate base regulation. By setting QF rates equal to the cost of having the utility build and operate its own generating units, PURPA creates a level competitive playing field between utility-owned generation and QF power purchases. This encourages investment by QFs to the extent they believe they can operate more efficiently or at lower cost, or they are more willing to experiment with new technologies, or they are willing to accept a lower return on their investment than the one paid on comparable investments put into the utility's rate base. This creates healthy competition, which exerts downward pressures on retail rates, pressures the incumbent utilities to minimize their own costs, and benefits retail customers over the long term.

Q. YOU HAVE DEVELOPED LONG RUN COST ESTIMATES. WOULD IT BE BETTER TO FOCUS ON SHORT-TERM COSTS?

A. No. I believe the purpose of PURPA can best be accomplished by taking a long-term view of the choice between QF and utility-provided power. More specifically, I believe the concept of “indifference” and the calculation of avoided costs should generally be consistent with the full incremental cost of building and operating generating facilities over their entire economic life cycle. This is the type of cost data I have presented above, and I think it is the most appropriate standard for evaluating the ultimate impact on ratepayers.

In the electric utility industry, short-run costs are sometimes less than long-run costs, due to lumpiness of capital additions among other factors. However, ratepayers are required to bear the full long-run cost of plants that are put into the rate base. If QF rates only considered a short-run measure of costs, like variable operating costs, while ignoring other costs the utilities incur (and customers pay) in the long run, a mismatch occurs, and indifference is not achieved. Stated another way, using a short-run view of avoided costs that fails to consider the full cost of building and operating new generating plants over their economic life cycle will discriminate against QFs and discourage QF investment.

Accordingly, it has often been recognized that the appropriate measure of avoided costs is one that is equivalent to the total costs incurred when a utility builds, owns and operates new generating plants over their life cycle. Properly implemented, a long-run measure of costs ensures that QFs receive the same amount for their power as the utilities receive for power produced using their own generating plants – no more and no less.

It should also be noted that QFs typically sign long-term contracts to sell their output at "fixed or pre-specified prices" and this is type of contract is needed for them to obtain debt financing. For logical consistency, long-term contracts generally require the use of "long-term estimates of avoided cost."[56] Furthermore, FERC has clarified that under PURPA QF's are entitled to sell electricity pursuant long-term contracts with forecasted avoided cost rates.[57]

Q. WHAT CONCLUSION DID YOU REACH FROM THESE BENCHMARK COST COMPARISONS?

A. The most significant conclusion is that the long run costs the Utilities are incurring when they build and operate new combined cycle plants is in the same general range as what ratepayers have been paying for power obtained from QFs over the next five to ten years pursuant to the current approved QF tariffs. Beyond that length of time, the QF power actually costs ratepayers less than the cost of power from a new combined cycle plant – with the greatest potential savings to customers occurring in the "High" fuel price scenario.

56 Edison Electric Institute, PURPA: Making the Sequel Better than the Original, December 2006, Page 9.

57 Hydrodynamics Inc., 146 FERC ¶ 61,193 (Mar. 20, 2014) at P 34; 18 C.F.R. Sec. 292.304(d)(2).

This benchmark cost data also provides support for my conclusion that the current approved QF rates were consistent with the PURPA indifference standard, and that customers are not being burdened by rapid growth in the amount of QF power that is being purchased by the Utilities under the 2014 tariffs.

Q. HAVE THE UTILITIES REACHED THE SAME CONCLUSIONS?

A. Apparently not. Their witnesses apparently believe the current QF rates are too high, and they worry their ratepayers are being adversely affected by the rates currently being paid for QF power under existing PPAs.

Mr. Yates explained Duke's concern this way:

> As discussed in more detail by Witness Glen Snider, because of the trend in declining energy markets over the past several years, actual incremental energy costs have been significantly lower than prior forecasts in earlier avoided cost filings.
>
> DEC and DEP have long-term PPAs with Commission-set avoided cost rates ranging from $55 to $85 per MWh, while the Companies' current actual system incremental "avoided" costs are approximately $35 per MWh. As Mr. Snider details in his testimony, the Companies and our customers are paying approximately $80 million annually, or nearly $1 billion in total, more to solar developers than

> their actual avoided costs over the remaining life of the existing contracts.[58]

DNCP witness Petrie expressed a similar concern:

> The forward prices of fuel and power have dropped substantially over the last several years, causing the current payments to QFs under these contracts to be uneconomic. ...the current estimate of avoided costs, based on [recent] ICF and PJM data as discussed above, is substantially below the contractual rates paid to small QFs that signed agreements under the two prior avoided cost dockets.[59]

Q. HAVE THE UTILITIES COMPARED THEIR QF RATES TO THE FULL LIFE CYCLE COST OF THEIR OWN GENERATORS?

A. No. To my knowledge, they have not compared the cost of QF power to the cost of power produced by any of the new coal-fired or natural-gas fired generating plants they have added to their rate base in recent years. I believe an analysis of their recently added combined cycle plants would yield similar conclusions to the ones I have drawn from my benchmark cost comparisons.

58 Yates Direct, p. 7.

59 Direct Testimony of Bruce E. Petrie on behalf of Dominion North Carolina Power, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Petrie Direct"), p. 4.

Q. WHAT IS THE BASIS FOR THEIR CONCERN THAT RATEPAYERS MAY BE PAYING TOO MUCH FOR QF POWER?

A. Duke witness Snider explained in his testimony how he derived the $1 billion figure he used to quantify his understanding of the adverse impact of QF rates on Duke's ratepayers:

> ...changing economic and market conditions have caused a potential long-term overpayment of approximately $1.0 billion by customers compared to the Companies' current calculation of its avoided cost rates proposed in this proceeding.[60]

> DEC's and DEP's current estimated combined financial obligation for previously contracted solar QFs as of December 31, 2016, is approximately $2.9 billion, which ultimately will be paid for by our customers. If those contracts were valued at the most recently filed avoided cost rates, they would have a value of only $1.9 billion. This results in a gap of approximately $1.0 billion, representing the level of potential overpayment by customers as compared to the Companies' current proposed avoided cost rates filed in this proceeding.[61]

Before explaining my understanding of how he arrived at $1 billion, let me make clear what this number does <u>not</u> represent.

Mr. Snider is not comparing what Duke's customers pay for QF power to what those customers pay for power supplied by generating units in DEC or DEP's rate base. He is not comparing the cost of QF power to the projected life cycle

60 Snider Direct, p. 4.

61 Snider Direct, p. 13.

cost of power that would be generated by the nuclear units Duke still has under consideration. He is not comparing the QF rates to the estimated life cycle cost of power generated by one of the combined cycle or combustion turbine units which DEC and DEP has included in their Integrated Resource Plans, which are expected to be added to their rate base during the next 10 to 15 years.

Q. THEN WHAT IS THE BASIS FOR THESE STATEMENTS?

A. Duke witness Yates describes the $1 billion figure as being derived from:

> the Companies' current actual system incremental "avoided" costs [of] approximately $35 per MWh[.][62]

Duke witness Snider discussed the same $1 billion number, but he describes it a little differently, saying it represents

> ...the level of potential overpayment by customers as compared to the Companies' current proposed avoided cost rates filed in this proceeding.[63]

The latter explanation appears to be similar to one provided by DNCP witness Petrie, who described his analogous calculations as a comparison between the rates included in existing QF contracts and the ones being proposed in this

62 Yates Direct, p. 7.

63 Snider Direct, p. 13.

proceeding – which he describes as "the most recently filed avoided cost rates.".[64]

In discovery, Duke was asked to explain the $1 billion figure, as well as the underlying comparison between "$55 to $85 per MWh" for QF power and the estimated "current actual system incremental "avoided" costs" of approximately "$35 per Mwh".[65] With respect to the range of $55 to $85 per MWh, Duke explained this was based upon its review of existing contracts for:

> PURPA projects that are already connected or in construction, including both standard offer < or equal to 5 MW and negotiated agreements of greater than 5 MW. The $85/MWH and $55/MWH values reflect the high and low points of the calculated levelized rate for each contract in DEC's and DEP's database.[66]

Thus, the QF side of the comparison reflects levelized rates from the current standard offer tariff as well earlier vintage QF tariffs, which were based upon the higher fuel prices that prevailed at the time, and negotiated QF rates.

Importantly, the other side of the comparison – $35 per MWh – is a single point estimate or snapshot of Duke's current short run marginal costs:

> The single point estimate for current incremental hourly costs represents the weighted average hourly cost observed during 2015. 2015 was the last full year of hourly

64 Petrie Direct, p. 4.

65 Duke response to NCSEADR1-11.

66 Duke response to NCSEADR1-11.

> information available at the time the analysis was completed.

This is the same data I used earlier to compare Duke's marginal fuel costs during 2015 to its average fuel costs. However, rather than comparing two different numbers for the same year, Duke is comparing marginal fuel costs taken from a snapshot of a single year (2015) to levelized fixed QF prices that have been averaged across a large group of long term contracts (typically for 15 years), including ones that were signed when fuel prices were higher than they are currently, as well as ones that will remain in effect for years into the future.

Q. IS THIS A FAIR WAY OF COMPARING THE COST OF QF POWER TO POWER THAT DUKE GENERATES?

A. No. It greatly exaggerates the impact of the recent dip in fuel prices, and it creates an incorrect impression that the existing QF contracts are costlier than power produced by generating units Duke owns and operates. There are at least four fundamental problems with this comparison, which render it completely invalid.

First, no one knows what prices ratepayers will ultimately have to pay for the fuel Duke will burn in its fossil-fired generating units over the duration of these QF contracts. Duke is comparing a snapshot of fluctuating fuel prices taken at a time when fuel prices happened to be relatively low. When fuel prices move higher, the arithmetic will change – potentially rather drastically – and the comparison will look less favorable for Duke's fossil-fueled units. The gap between the QF fixed contract price and Duke's marginal cost of fuel could entirely disappear during the remaining years of these contracts, if fuel prices return to their historical trend line.

Second, the $1 billion estimate ignores differences in risk. A long-term contract with fixed prices is less risky for ratepayers, compared with the cost of burning fossil fuels, whose price can fluctuate widely over the course of just a few months or years. A fair comparison between a fixed price and a fluctuating one needs to acknowledge this difference – just as many people are willing to pay more for a fixed rate mortgage, and will only accept a floating rate mortgage if the interest rate is significantly lower.

Third, the $1 billion estimate is based upon a fundamental mismatch: the $35 per MWh figure only includes fuel costs. It does not include any of the fixed operating and maintenance expenses, property taxes, depreciation, income taxes, debt service or other fixed costs incurred by Duke, which ratepayers reimburse. In contrast, the QF contract sets forth an "All In" price which encompasses everything ratepayers pay for power obtained from the QF. Ratepayers are not required to pay anything else toward the QF's operating and maintenance costs, depreciation or other fixed costs.

Fourth, nearly all of the QF power is being generated during the daytime hours, when power is more valuable to ratepayers. In contrast, the $35 figure referenced by Duke witness Snider includes the lower fuel costs incurred late at night, when power is less valuable to ratepayers, and Duke's fuel costs are lower.

In effect, he is comparing the cost of a less valuable power, which is mostly produced during off-peak hours, with the cost of more valuable QF power, which is almost entirely produced during peak hours. The difference is reflected in the following table, using the same data discussed earlier in my testimony:

Duke Marginal Fuel Costs versus Average Fuel Costs[67]		
	DEP	**DEC**
2015 Marginal Fuel Cost – On Peak	3.724 cents	3.723 cents
2015 Marginal Fuel Cost – Off Peak	3.264 cents	3.263 cents
2015 Marginal Fuel Cost – All Hours	3.494 cents	3.493 cents

67 Duke response to NCSEADR1-11, 2015 hourly marginal costs.xlsx; DEC and DEP Monthly Fuel Reports pursuant to NCUC Rule R8-52, February 3, 2016.

Q. DO YOU HAVE ANY OTHER COMMENTS CONCERNING THE IMPACT OF CHANGES TO FUEL PRICES ON THESE SORTS OF COMPARISONS?

A. Yes. The Utilities have emphasized the impact of falling fuel prices in drawing comparisons between QF contracts that were signed in earlier years with costs that are estimated currently, based on the lower fuel prices that are currently prevailing.

> In general, 10-year (2017 to 2026) levelized natural gas prices have fallen approximately 40%, while coal prices have fallen approximately 16% for that same time period as compared to those used in calculating the Companies' avoided cost of energy in the 2014 biennial Sub 140 proceeding. Compared to the 2012 Sub 136 avoided energy costs, fuel costs have fallen even further with natural gas declining approximately 48% and coal, 33%. [68]

A valid comparison of QF generation to fossil fueled generation will recognize and take into account this downward shift in fuel prices (as I did when developing my benchmark cost comparisons). And, it is important to understand that any such comparison will inevitably look less favorable when looking at existing QF contracts that were based on the higher fuel prices that prevailed when the current and earlier vintages of QF rates were approved by the Commission.

68 Snider Direct, p. 16.

However, this sort of comparison should be kept in the proper perspective. For instance, ratepayers are paying the full life cycle cost of the Cliffside 6 coal fired generating unit, which was planned and constructed based upon fuel forecasts that have subsequently proven to be inaccurate. With changes in the relative price of coal and natural gas, the technology used at the Cliffside plant no longer appears to be as attractive as it must have seemed when this technology was chosen in lieu of natural gas-fired combined cycle units.

My point in using this example is not to criticize Duke for committing to a coal fired unit with a 40-year life right before natural gas prices plunged. I am simply trying to point out that <u>all</u> sources of electricity involve economic uncertainties and risks that may seem less attractive in hindsight than they did at the time the decisions were made. It is fundamentally unfair to criticize the solar industry for building facilities that made economic sense based on projections of high gas prices, when Duke itself made a similar decision to build a high technology coal plant based on projections of high gas prices.

Just because some of the earliest solar projects now appear to be costlier than they did before gas prices dropped does not mean those contracts are unfair or burdensome to ratepayers. Nor does it indicate the decision to purchase QF power was unreasonable at the time the contract was signed. Similarly, it would not be reasonable to conclude from comparisons based upon older vintage contracts that QF power is an inherently costly or risky way of obtaining power, or that fundamental changes need to be made in the way the Commission implements PURPA.

Section 4: PURPA and the Indifference Standard

Q. BEFORE EXPLAINING YOUR BENCHMARK AVOIDED COST DATA, CAN YOU PLEASE EXPLAIN YOUR UNDERSTANDING OF THE FEDERAL STANDARDS WHICH YOU CONSIDERED IN DEVELOPING THIS DATA?

A. Yes. PURPA requires the FERC to prescribe rules necessary to "encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity."[69]

A key theme running through the FERC’s rules implementing PURPA and related caselaw on this guidance is that QF rates should be based upon incremental or avoided costs, which should leave ratepayers indifferent as to whether their power is generated by the incumbent utility, or purchased from a QF.

69 16 U.S.C. § 824a-3.

Q. CAN YOU EXPLAIN THE "INDIFFERENCE" STANDARD AND THE "AVOIDED COST" CONCEPT?

A. Yes. As the FERC has stated on several occasions, the intention of Congress in enacting PURPA "was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives" of PURPA.[70] As explained more recently by the North Carolina Utilities Commission, "the goal is to make ratepayers indifferent between purchases of QF power versus construction and rate basing of utility-built resources."[71] Although PURPA is designed to encourage QF development, it does not accomplish this by subsidizing QFs, or by requiring customers to pay more for their power. To the contrary, if PURPA is correctly implemented, ratepayers are "held harmless," leaving them indifferent to whether they receive power from a QF or from new generating units added to the utility's rate base.

The FERC rules implementing PURPA generally require electric utilities to purchase any energy and capacity which is made available to the utility from a QF.[72] Rates for purchases from Qualifying Facilities built after 1978 must be based upon the electric utility's "avoided costs."[73] Although the term

70 Southern Cal. Edison, San Diego Gas & Elec., 71 FERC ¶ 61,269 at p. 62,080 (1995).

71 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 21.

72 18 C.F.R. § 292.303(a).

73 18 C.F.R. § 292.101(b).

"avoided cost" is not used in the text of PURPA, it is consistent with the statutory language referencing the "incremental cost of alternative electric energy," which is defined in PURPA as: "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." More specifically, FERC defines avoided costs as:

> [T]he incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[74]

Among other things, the FERC rules require state commissions, to the extent practicable, to consider these factors when determining avoided costs:

> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> > (i) The ability of the utility to dispatch the qualifying facility;
> >
> > (ii) The expected or demonstrated reliability of the qualifying facility;
> >
> > (iii) The terms of any contract or other legally enforceable obligation, including the duration of the

74 18 CFR § 292.101(b)(6).

> > obligation, termination notice requirement and sanctions for non-compliance;
> >
> > (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
> >
> > (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
> >
> > (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
> >
> > (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
>
> (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
>
> (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy

> itself or purchased an equivalent amount of electric energy or capacity.[75]

Q. CAN YOU EXPLAIN WHAT INFORMATION IS REQUIRED BY SECTION 292.302(b) OF TITLE 18 OF THE CODE OF FEDERAL REGULATIONS?

A. Yes. Under part C of Section 210 of PURPA, electric utilities like Duke and DNCP are required not less often than every two years to provide to their state regulatory commission the following information, and to make it available for public inspection:

> (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
>
> (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and
>
> (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of

75 18 CFR § 292.304(e).

> individual generating units and of individual planned firm purchases.

Q. HOW CAN "AVOIDED COSTS" BE ESTIMATED?

A. There are just three major methods that have historically been used to develop avoided cost estimates. These are (a) the Proxy Unit method (also sometimes referred to as the Proxy Resource or Committed Unit method), (b) the Differential Revenue Requirement ("DRR") method, and (c) the Peaker method.[76]

All three of these methods are intended to measure the same thing (long run incremental costs), so all three methods can (and should) yield approximately the same total cost per kWh (assuming each one is properly performed using similar inputs and assumptions).

Q. CAN YOU BRIEFLY EXPLAIN THE PROXY UNIT METHOD?

A. Yes. The Proxy Unit (or Proxy Resource) method is described in the PURPA Title II Compliance Manual as follows:

> This method bases the avoided cost on the cost of the host utility's next planned addition, typically a combined cycle/gas turbine (CCGT) generating unit. This approach essentially assumes that the QF substitutes for a planned utility generating unit, or what is assumed to be the next

76 PURPA: Making the Sequel Better than the Original, p. 9. See also PURPA Title II Compliance Manual, p. 35; Reviving PURPA's Purpose, Carolyn Elefant, p. 13.

> generating unit. The proxy unit's estimated fixed cost (annualized over the expected life of the unit) determines the avoided capacity cost and the estimated variable cost sets the avoided energy cost. The type and size of the unit or units is determined in an Integrated Resource Process (IRP) or from the utility's planning process, where the planning process, for regulated utilities, follows a state commission-approved procedure. Because this is a relatively simple method to use, the proxy method is very common, although the results largely depend on the type of unit or units chosen as the proxy.[77]

This methodology has many advantages, including the fact that it is relatively straightforward and easily understood. Its flexibility is also an advantage: It can be implemented using data for a generating unit that is currently under construction, or has recently been constructed by the utility, a unit that has been identified for future construction in the utility's Integrated Resource Plan, a hypothetical or surrogate unit, or some combination or variant of these data sources.

I have used the Proxy Unit method to develop my benchmark estimates of avoided costs, which I have used to evaluate the current and proposed QF rates, and for other illustrative purposes.

77 PURPA Title II Compliance Manual, p. 35.

Q. ARE YOU ASKING THE COMMISSION TO ADOPT THE PROXY UNIT METHOD IN LIEU OF THE PEAKER METHOD?

A. No, not at all. The Commission has a long history of using the Peaker Method to develop QF rates, and I am not in any way suggesting it should abandon that long-standing practice. All three of the standard methods for estimating avoided costs are intended to measure the same thing, and the choice of a specific method in a specific context is largely a matter of administrative or calculational convenience.

In this instance, it was convenient for me to use the Proxy Unit method to illustrate and clarify various of points in my testimony. The Proxy Unit method was ideal for this purpose because: First, it is a relatively straightforward, simple method which is relatively easy to explain, implement and understand. Second, it can be developed using publicly available information, thereby improving transparency and reliability. Third, it is well suited for consideration of the information that must be provided by utilities pursuant to 18 C.F.R. Section 292.302(b) as I mentioned earlier in my testimony.[78] This is significant, since the FERC rules specifically require state regulators to consider this information in setting avoided-cost based rates, to

78 All of the information submitted by utilities pursuant to this regulation tends to be useful, including the cost of planned capacity additions and firm purchases on the basis of dollars per kilowatt, and the associated costs of each unit, expressed in cents per kilowatt hour.

the extent practicable.[79] Moreover, this avoided cost data is available for many different utilities, potentially facilitating comparisons with data submitted by other utilities. Fourth, the proxy unit method offers great flexibility, which made it easier to develop multiple different calculations using a wide variety of different assumptions (e.g. fuel choices and cost scenarios).

None of the conclusions I have reached in my testimony are contingent on the use of the Proxy Unit method, nor am I suggesting the Commission, should use the Proxy Unit method to determine the QF rates that are established in this proceeding.

Q. CAN YOU BRIEFLY EXPLAIN THE DIFFERENTIAL REVENUE REQUIREMENT METHOD?

A. Yes. The DRR method is described in the PURPA Title II Compliance Manual as follows:

79 18 CFR § 292.304(e).

> Under a revenue requirement differential method, the system revenue requirement without the QF is subtracted from the system revenue requirement with the QF.[80]

The DRR method, as typically discussed, is a fairly complex approach, requiring the use of two different computer models.

> A planning expansion model is used to develop generation expansion plans both with and without the estimated QF output. The resulting two expansion plans then are used as inputs to a financial planning model that yields the utility's projected revenue requirement both with and without the QF output (assuming that the QFs are a "free" resource). The difference in the present value revenue requirements of these two expansion plans is the avoided revenue requirement made possible by the expected QF output. This avoided revenue requirement includes avoided energy and capacity costs as well as other factors (e.g., taxes)[81]

Q. CAN YOU BRIEFLY EXPLAIN THE PEAKER METHOD?

A. This is the method which Duke has historically used in both South and North Carolina. The Peaker Method is described in the PURPA Title II Compliance Manual as follows:

> Under the peaker method, the value of the QF's capacity is determined by assuming that the QF will be operating as a utility peaking unit. If the utility requires capacity, this method sets the avoided capacity at the lowest-cost capacity option available to the utility, for example, a combustion turbine (CT). Avoided energy cost may be based on the utility's system-wide avoided energy cost, not the peaking unit's energy cost. This requires production cost modeling to determine the system-wide avoided

80 PURPA Title II Compliance Manual, p. 35.

81 PURPA: Making the Sequel Better than the Original, December 2006, p. 11.

> energy cost, which increases the complexity of this method over the "proxy" unit approach.[82]

The Peaker method has at least one significant advantage: it develops energy cost estimates on an hour-by-hour, year-by-year basis. However, some of this advantage can be lost when the calculations are averaged and levelized across broad, potentially arbitrary "Peak" and "Non-Peak" categories and seasons (groups of months). The Peaker Method also has at least one significant disadvantage: it is not especially well-suited to fully utilize the information provided pursuant to 18 CFR Section 292.302(b), particularly with regard to the incremental cost of nuclear and other baseload generating units, since this data isn't used in the Peaker Method.

Q. DO ALL THREE METHODS ESTIMATE THE INCREMENTAL COST OF BUILDING AND OPERATING NEW GENERATING FACILITIES OVER THEIR ECONOMIC LIFE CYCLE?

A. They can, and in my opinion they should. Incremental life cycle cost is an appropriate benchmark, which can be estimated using any of these methods, if they are correctly implemented with appropriate assumptions and inputs.

It is easiest to see this with the Proxy Unit method, which specifically focuses on the life cycle cost of owning and operating a specific unit. Like any

82 PURPA Title II Compliance Manual, p. 35.

method, however, the costs that are calculated will vary – particularly on a per kWh basis – depending on the assumptions and inputs which are selected, and how they are used. For instance, if avoided costs are being calculated for use in paying QFs for power that will be generated during many hours of the year, the primary focus should be on a proxy unit that is cost-effective in serving long duration loads, like a combined cycle or nuclear unit. If the analysis were limited to a peaking unit instead, the resulting cost per kWh could be higher than the full life cycle cost of owning and operating a baseload plant, because a combustion turbine has very high fuel costs, which outweigh its low construction costs if power is going to be provided during many hours of a typical day.

The Peaker Method will also achieve this benchmark when appropriately implemented, although it is not intuitively obvious how it can accomplish this, since it focuses on the capital cost of a peaker (combustion turbine or CT) rather than a base load plant. As I explained earlier in my testimony, the Peaker Method, assumes combustion turbines with poor heat rates will be operated at the top of the dispatch stack during enough hours of the year to ensure that the difference in fuel costs (e.g. between a new peaking unit and a new nuclear generating unit) will compensate for the additional capital costs of the baseload unit.

Stated another way, the Peaker Method does not provide recovery of the high fixed costs of a baseload plant like a combined cycle unit or nuclear plant in the avoided capacity cost results. Instead, the capacity costs are limited to those of a CT, while the remainder of the fixed costs of owning and operating a baseload plant are supposed to show up in the energy costs. The avoided energy costs are based upon the "top of the stack" (typically, the least fuel-efficient generating unit that is running during any given hour), which are expected to exceed the cost of fuel for baseload units by an amount that should be large enough to recover the portion of the baseload plant investment that exceeds the investment in a peaking unit.

Q. CAN YOU BRIEFLY HIGHLIGHT SOME PRACTICAL ISSUES WITH RESPECT TO PRODUCTION COST MODELS, LIKE PROSYM?

A. Yes. The Peaker method takes advantage of computerized production cost modeling to estimate avoided energy costs on an hour-by-hour, year-by-year basis. The great advantage of these models is that they produce cost estimates in extreme granular detail (literally 8,760 different cost numbers are generated for each year), and they can easily accomplish this level of granular detail for many different scenarios – simply by adjusting the inputs used in running the model for each scenario.

For instance, a production cost model can easily develop precise estimates of how costs will be affected during various time periods and seasons, depending on what happens to fuel prices in future years. Unfortunately, neither Duke nor DNCP took full advantage of the ability of programs like Prosym to produce detailed, hourly output that make it feasible to understand and compare the impact of different scenarios. For instance, they did not provide hourly cost estimates showing the impact of different scenarios that vary based upon the rate of growth in solar energy being added to the grid in future years.

Furthermore, the Utilities did not use the granular output from their production cost models to support their proposed peak and off peak rate periods, or to support their position concerning the impact of solar growth on their operations. Instead, the simply summarized or aggregated this data across the existing peak and off peak time periods. This reduces or eliminates some of the potential benefits of using Prosym to develop energy costs on a detailed, hour-by-hour, year-by-year basis. Similarly, the Utilities did not take full advantage of their production cost model's inherent “What if” capabilities to provide the Commission and other interested parties with energy cost estimates under multiple different scenarios (e.g. higher or lower fuel prices in future years).

This highlights one of the most significant disadvantages of using a production cost model: they are data-intensive and costly to license. Furthermore, extensive training is required before these models can be operated reliably. Because of these licensing and training barriers, the model effectively becomes a "black box" for most other parties, which cannot easily be penetrated by the Commission, the Public Staff, or other parties. Due to licensing costs and other barriers, it is difficult or impractical for most other parties to probe the underlying inputs and assumptions that drive the avoided energy cost estimates produced by a model like Prosym. This is a significant consideration, since the inputs largely control the outputs of these types of computer models.

Q. PLEASE BRIEFLY EXPLAIN YOUR AVOIDED COSTS ESTIMATES.

A. I started by estimating the cost of constructing and owning a hypothetical nuclear plant, a hypothetical combined cycle plant, and a hypothetical combustion turbine. I then combined this data with estimates of the cost of fueling and operating these plants, and converted this data into per-kWh cost estimates.

Q. CAN YOU BRIEFLY EXPLAIN HOW YOU ESTIMATED THE COST OF CONSTRUCTION FOR A NEW NUCLEAR GENERATING UNIT?

A. In my avoided cost analysis I assumed an installed cost of $5,350 per kW for a newly constructed nuclear unit. I developed this number by looking at publicly available information concerning construction costs, including the cost of the V.C. Summer nuclear plants which SCE&G currently has under construction, since I recently had occasion to study those costs.[83] I started with the $7.6 billion cost estimate for the V.C. Summer units, which was provided in SCE&G's June 2016 PURPA filing. However, I recognized that the actual cost of construction will not be known until the units are completed. (The analogous estimate in the 2014 PURPA filing was $5.76 billion.)[84]

Also, I recognize there is a learning curve involved with nuclear units, and thus future units might be less costly than the ones that are currently under development. Hence, I also considered the most recent available cost estimate published by the Energy Information Administration ("EIA") for new nuclear

83 SCE&G's June 30, 2016 avoided cost filing in compliance with Subpart C, Section 210 of PURPA indicates the first planned unit is V.C. Summer #2, which is projected to add 625 MW of capacity in 2020, 22 MW of capacity in 2021, and 23 MW in 2022. V.C. Summer #3 is expected to add 648 MW of additional nuclear capacity in 2021 and another 22 MW of capacity in 2022, for a grand total of 1,340 MW. SCE&G's 2016 avoided cost filing is available at: https://dms.psc.sc.gov/Attachments/Matter/47629bd9-e607-47ba-a766-fd93412ce610 (last accessed March 27, 2017).

84 SCE&G's 2014 avoided cost filing is available at: https://dms.psc.sc.gov/attachments/matter/5180191F-155D-141F-239A12DA68A40511 (last accessed March 27, 2017).

construction, which I adjusted to 2017 dollars using an annual inflation rate of 2.0% and to reflect local cost conditions using their state-specific cost adjustment factor:

Nuclear	Cost per KW in 2017 Dollars
Proxy Unit	**$ 5,350**
EIA – Advanced Nuclear [85]	$ 5,712
SCE&G – Summer June 2016 Estimate	$ 5,307

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBINED CYCLE UNIT?

A. I started with an installed cost per KW in 2017 dollars of $1,050. This is consistent with these publicly available data sources:

Combined Cycle	Cost per KW in 2017 Dollars
Proxy Unit	**$ 1,050**
EIA – Advanced CC[86]	$ 1,023
DEC – Dan River CC[87]	$ 1,077

85 Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016 ("2016 EIA Report"), p. 7. My calculations apply EIA's location adjustment factor for North Carolina (Page A-20) and adjust for inflation at 2% per year.

86 2016 EIA Report, p. A-14.

87 DEC completed its Dan River combined cycle plant in 2012. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $912, which is equivalent to approximately $1,077 in 2017 dollars.

DEC – Buck CC[88]	$ 1,060
Brattle – Dominion [89]	$ 1,041

Q. HOW DID YOU ESTIMATE THE COST OF BUILDING A NEW COMBUSTION TURBINE?

A. I used an installed cost of $650 per KW in 2017. This is primarily based upon the most recent cost information published by the EIA, but I also considered other publicly available data sources:

Combustion Turbine	Cost per KW in 2017 Dollars
Proxy Unit	**$ 650**
EIA – Advanced CT [90]	$ 639
Brattle – Dominion [91]	$ 885
Pasteris SOM – EMACC [92]	$ 763

88 DEC completed its Buck combined cycle plant in 2011. According to DEC's 2014 FERC Form 1, the cost per KW of installed capacity was $941 per KW, which is equivalent to approximately $1,060 per KW in 2017 dollars.

89 The Brattle Group and Sargent & Lundy, Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, May 2014 ("Brattle Report"), p. 43, available at: http://www.brattle.com/system/publications/pdfs/000/005/010/original/Cost_of_New_Entry_Estimates_for_Combustion_Turbine_and_Combined_Cycle_Plants_in_PJM.pdf?1400252453 (last accessed March 27, 2017).

90 2016 EIA Report, p. A-18.

91 Brattle's estimate of the overnight cost of constructing an Advanced Combustion Turbine in Dominion's service area was $931 per KW in 2018/19. Brattle Report, p. 41.

92 Pasteris Energy, Inc., Brattle CONE Combustion Turbine Revenue Requirements Review, July 25, 2014, p. 12, available at: http://www.pjm.com/~/media/committees-groups/task-forces/cstf/20140725/20140725-brattle-vs-ma-som-cone-ct-revenue-requirements-comparison-final-report.ashx (last accessed March 27, 2017).

SCE&G – 2023 CT [93]	$ 734

Q. HOW DID YOU TRANSLATE THE INSTALLED COST INTO ANNUAL EQUIVALENTS?

A. First, I added an allowance for the cost of construction financing. I then developed an allowance for depreciation based on an economic life of 30 years for the combined cycle and combustion turbine units, and 70 years for the nuclear unit. I developed an estimate of income taxes using a composite state and federal tax rate of 34.93%, and I applied a weighted cost of capital of 7.36% (a pre-tax cost of capital of 10.17%), consistent with the following calculations:

Capital Source	**Ratio**	**Cost Rate**	**Weighted Cost**	**Tax Factor**	**Pre-Tax Weighted Cost**
Equity	50.00%	9.50%	4.75%	1.5367	7.30%
Debt	50.00%	4.75%	2.38%	1.0000	2.38%
Total	100.00%		7.36%		9.67%

The costs were initially developed for each individual year, then levelized across the entire economic life of the plant. The latter step is similar to the way most home mortgages are structured to provide uniform, level payments, even though the cost of the mortgage (the interest) varies from year to year.

93 SCE&G 2014 avoided cost filing.

The end result was a uniform levelized capital cost of $490.75 per kW per year for the nuclear plant, $113.04 per kW per year for the combined cycle plant and $69.97 per kW per year for the combustion turbine.

Q. DID YOU CONSIDER ANY OTHER FIXED ANNUAL COSTS?

A. Yes. Before converting these levelized amounts into per-kWh costs, it was necessary to add an allowance for fixed operating and maintenance and corporate overhead costs. I assumed annual fixed operating and maintenance expenses would be $95.00 per kW for the nuclear plant, $10.00 per kW for the combined cycle Plant and $7.00 per kW for the advanced combustion turbine (in 2016 dollars). The assumptions are consistent with estimates developed by the Energy Information Administration and data from various utilities, which I have reviewed in the course of my consulting work. Applying an annual inflation factor of 2% and levelizing each figure results in an annual cost per kW in 2017 of $136.00, $12.64 and $8.85, respectively.

I also applied a 95% availability factor, to compensate for forced outages and times when the unit is unavailable for energy production due to scheduled maintenance (and refueling in the case of a nuclear unit). An allowance for corporate overhead costs was also needed; I provided a 5% allowance for this category of costs. All of these costs were developed on a year-by-year basis, then uniformly spread across the economic life of the plant. The resulting levelized costs totaled $692.72 per kW for the nuclear plant, $138.90 per kW for the combined cycle plant and $87.12 per kW for the combustion turbine.

Q. HOW DID YOU ESTIMATE AVOIDED ENERGY COSTS?

A. I developed separate avoided energy cost estimates for the hypothetical nuclear plant, the hypothetical combined cycle plant and the hypothetical combustion turbine. When thinking about energy costs, maintenance, fuel and other operating costs that vary with energy output are what immediately come to mind, and these were a major element of this part of the cost estimation process. However, my energy-related cost estimates also include certain fixed capital-related costs, as I mentioned earlier in my testimony. To arrive at an accurate distinction between costs that are attributable to the need for capacity during peak hours and costs that are energy related, it was necessary to recognize that some of the costs of building and owning the nuclear and combined cycle units were energy-related.

Q. HOW DID YOU SPLIT FIXED COSTS BETWEEN THE ENERGY AND CAPACITY RELATED CATEGORIES?

A. I assumed the "capacity-related" portion of all three proxy units was limited to the annual fixed cost of building and owning the combustion turbine. The remainder of the fixed costs of building and operating the nuclear plant and combined cycle plant are were treated as "energy-related." This disaggregation is widely accepted – in fact, it is fundamental to the theoretical underpinnings of the Peaker Method.

The extra step involved in disaggregating fixed costs is particularly useful when examining the economics of a nuclear unit. In fact, the great majority of the capital investment in a nuclear plant is not attributable to the goal of meeting peak capacity (although a nuclear plant also provides capacity for achieving that goal). Rather, the bulk of the investment in a nuclear plant is attributable to the goal of safely producing energy with low fuel costs.

The uranium used to fuel a nuclear plant costs tends to be less costly than coal, oil or natural gas – and this cost advantage is a key motivation for using this technology. No one would invest in a nuclear unit just to provide capacity during peak hours. The added investment expended on baseload plants is only justified by the potential for minimizing fuel and other variable costs over the operating life of the plant. Consequently, any investment in excess of that required for a peaking plant is appropriately categorized as energy-related. The same logic applies to disaggregating the costs of the combined cycle plant, although the impact is not as significant.

After drawing this distinction, the levelized fixed annual cost estimates in 2017 dollars are summarized in the following table:

Cost per kW/Year	**Nuclear**	**Combined Cycle**	**CT**
Capacity Related	$ 87.12	$ 87.12	$ 87.12
Energy Related	605.61	51.78	0.00
Total	$ 692.72	$ 138.90	$ 87.12

Q. HOW DID YOU HANDLE FUEL AND OTHER VARIABLE COSTS?

A. Variable costs can be difficult to deal with, because they are highly dependent on future fuel prices, which are not knowable with any degree of precision.

For example, natural gas prices have exhibited wide fluctuations over both short and medium time frames, although they have exhibited a tendency to trend higher and higher over the long term. The problem with price instability was vividly illustrated during 2016, when natural gas prices plunged by more than 20% during a few months early in the year, and then shot upward by nearly 40% over an even shorter time period later in the year.

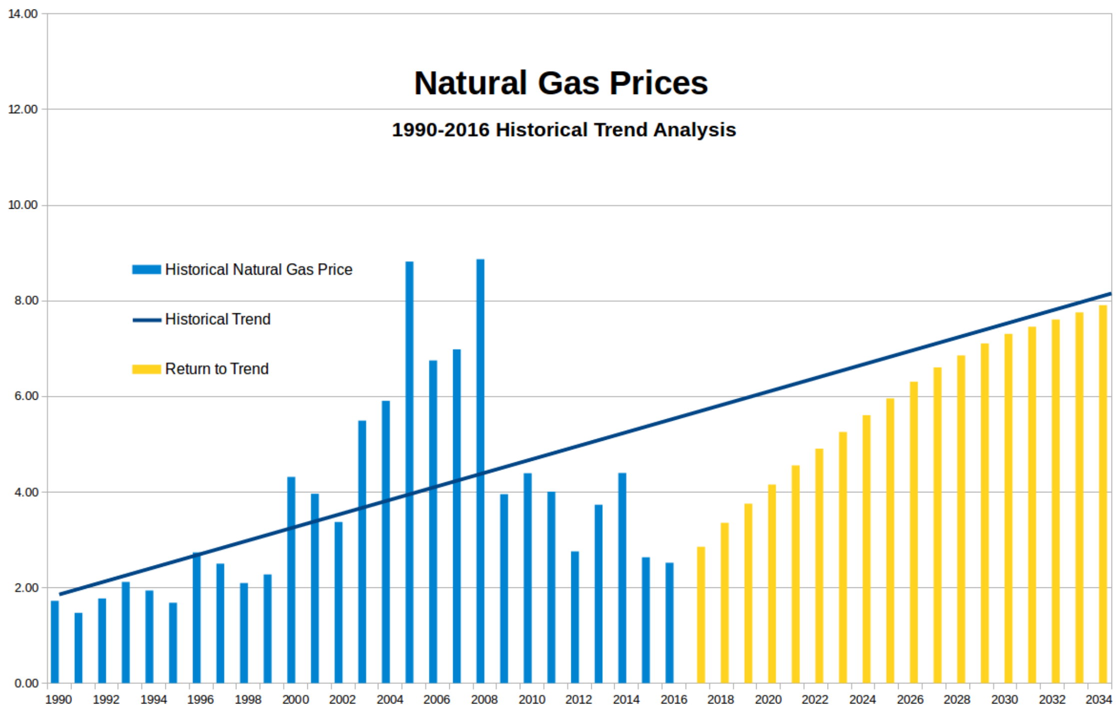
Recently, gas prices returned to very low levels – in fact, the Wall Street Journal had a headline on the front page of its March 15, 2017 edition with the headline "Natural-Gas Glut Deepens." At current prices, gas is so inexpensive it might appear that other options – like coal and nuclear – are undesirable. However, such a conclusion would be premature, since generating plants are 30+ year investments, and the relative merits of each technology need to be evaluated from a long-term perspective.

In fact, the instability of natural gas prices, and difficulties associated with predicting these prices is one of the principal disadvantages, or risks, associated with using this fuel source. These risks are important to keep in mind when evaluating the merits of long-term investments in gas-fueled generation relative to other options. Coal has some of the same risk characteristics as gas, but to a lesser degree, since coal prices tend to be more stable and because coal can be sometimes be purchased from coal mines pursuant to multi-year contracts at fixed prices.

The key point is that fuel price assumptions or projections are of critical importance when evaluating generating technologies or estimating energy costs using different fuel sources. In fact, the fuel cost assumptions will at least heavily influence, if not entirely determine, the conclusions that are drawn from an analysis of the relative cost-effectiveness of using different generating technologies.

Q. CAN YOU ELABORATE ON THESE PROBLEMS?

A. Yes. The following graph shows the long term upward trend in natural gas prices from 1990 through 2016. The light blue bars show average gas prices experienced during each of these years, using data obtained from Reuters (1990-96) and the EIA (1997-2015). The dark blue line shows the linear trend reflected in that historical data, extended into the future.



Finally, the pale yellow bars on the right side of the graph shows what future would look like, if gas prices were to smoothly return to the historical trend line and follow the slope of the historical trend line thereafter. Given the wide fluctuations observed in the historical data (light blue bars), it is apparent that fuel prices cannot be accurately predicted years in advance of when it is purchased. This greatly complicates any attempt to analyze the cost of producing electricity using different technologies or fuels.

This problem is particularly acute when comparing the cost of generating sources that burn fossil fuels with those that do not – like nuclear power, hydro, and solar. The extent to which one concludes the latter technologies are higher or lower cost options for ratepayers will be almost entirely dependent upon whatever assumptions or projections are made concerning future fuel prices. A similar problem arises when trying to analyze the impact on ratepayers of obtaining power at fixed long-term prices from a QF compared to having the utility build new generating plants that will burn fossil fuel purchased at prices that are not known in advance, and cannot be predicted with any degree of certainty.

Q. CAN YOU GIVE A REAL-WORLD EXAMPLE OF HOW UNCERTAINTIES CONCERNING FUTURE NATURAL GAS PRICES CAN BE DEALT WITH IN THIS TYPE OF ANALYSIS?

A. Yes. This example is drawn from the recent experience in South Carolina where SCE&G evaluated the economic viability of its V.C. Summer nuclear construction project. The utility considered several different scenarios concerning potential future gas prices – all of which were higher than the unusually low prices that have recently been observed.[94] SCE&G started with

> "two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration (EIA) natural gas forecast reported in their 2015 Annual Energy Outlook (AEO). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices

94 South Carolina Electric & Gas, Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy, May 26, 2015, available at: https://dms.psc.sc.gov/Attachments/Matter/4c84883e-157b-4ad4-856a-c49a3c0b1b25 (last accessed March 27, 2017).

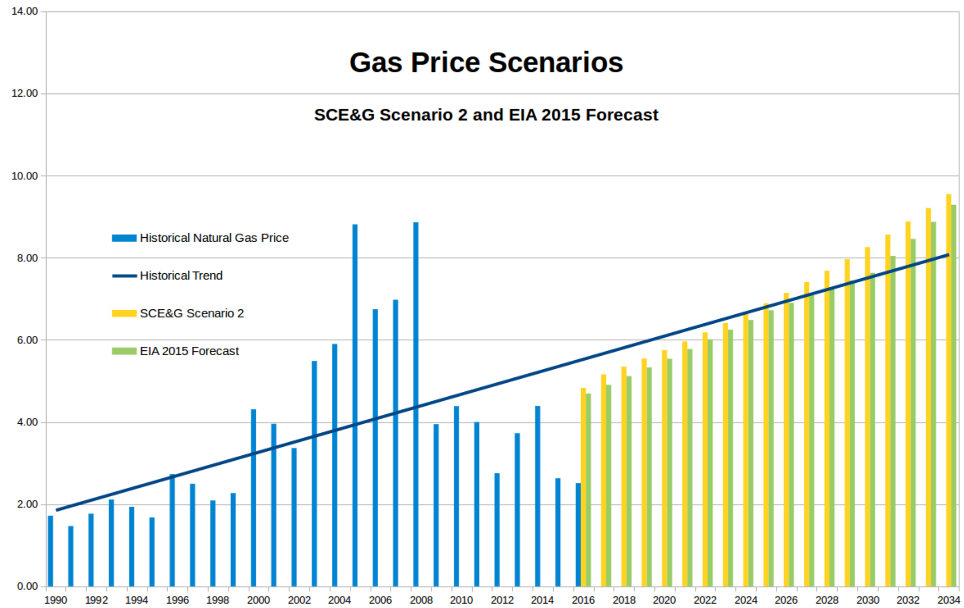
> reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor … to forecast prices beyond three years in the future."[95]

The latter forecast, which it described as its "base line forecast" of natural gas prices, was the lowest of three forecasts it developed and used for its evaluation. SCE&G also evaluated the impact of natural gas prices being 50% higher (Scenario 2) or 100% higher (Scenario 3) than this baseline.[96]

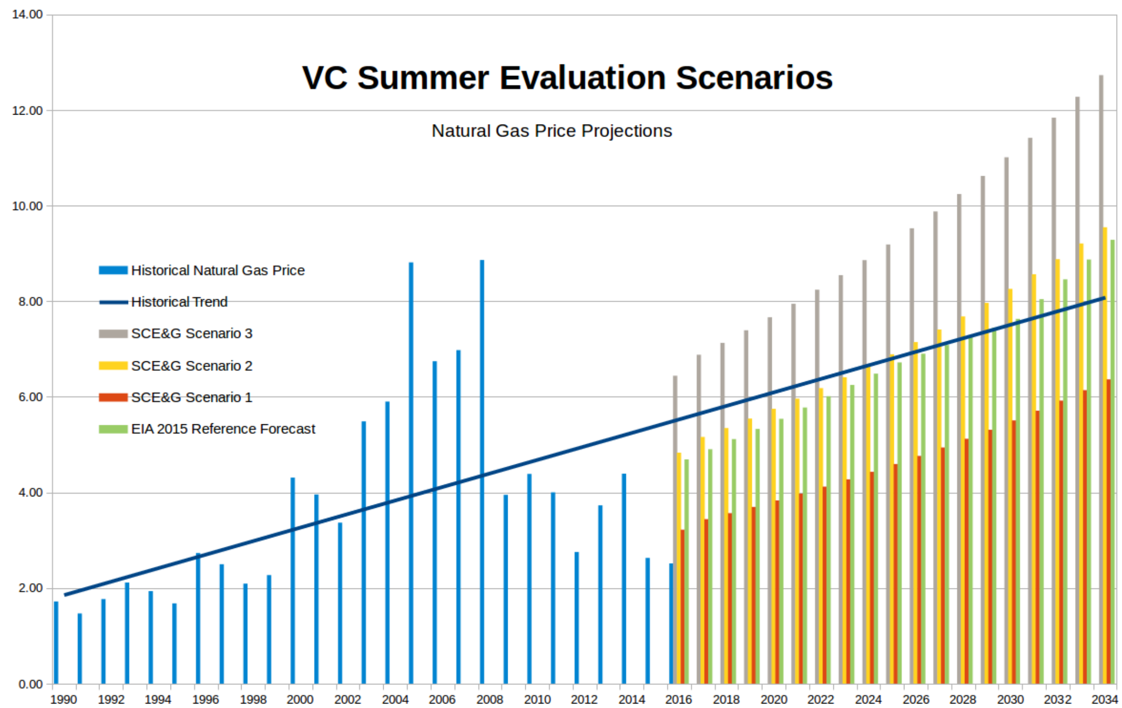
Scenario 2 and the 2015 EIA baseline forecast were both similar to the historical trend as well as each other, as shown in the following graph:

95 Id., p. 3.

96 Id., p. 3.



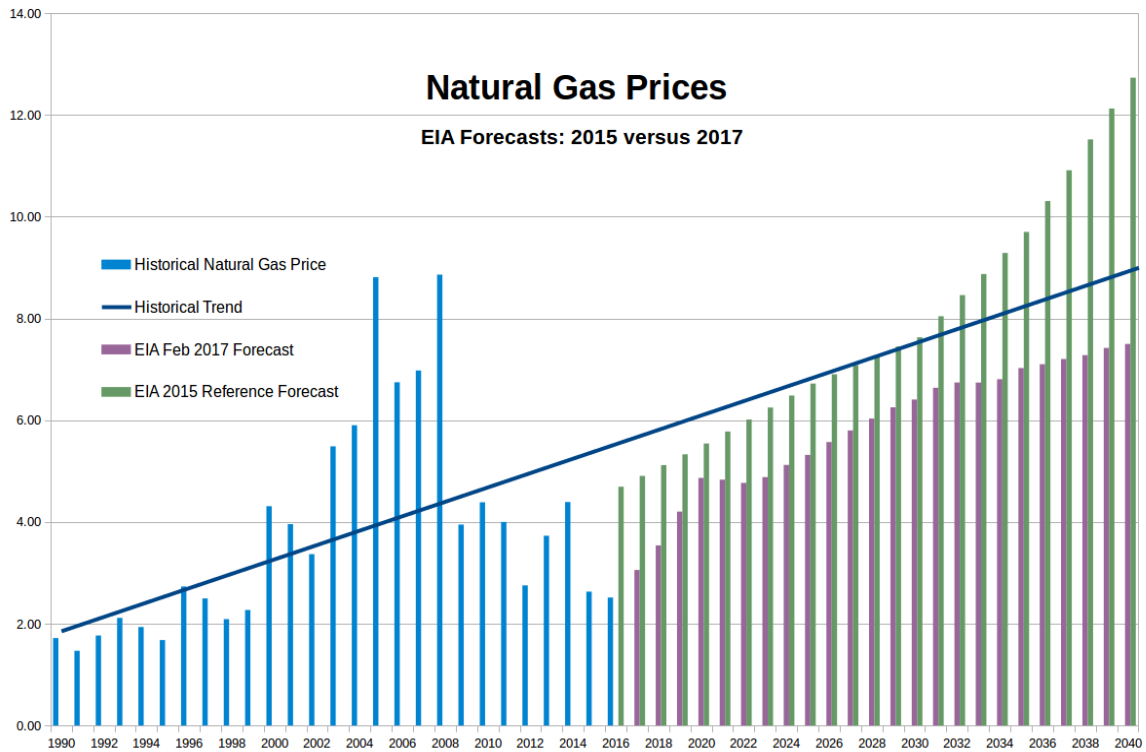
Recognizing that "all forecasts of future gas prices are subject to error" SCE&G looked at multiple scenarios, with their Baseline Scenario 1 forming the bottom of the range, Scenario 2 and the EIA's 2015 forecast falling in the middle, and Scenario 3 moving well above the others. Strictly speaking, Scenario 3 was not the highest pricing scenario SCE&G considered, since it also considered the impact of adding an estimate of the cost of carbon to natural gas prices. The three SCE&G scenarios are shown in the following graph, which also includes historical data through 2016, and the historical trend line.



When reviewing this graph, it is important to keep in mind that the V.C. Summer evaluation was completed in June 2015, before most of the 2015 prices, or any of the 2016 prices were known.

Q. HAVE FUEL PRICE FORECASTS DECLINED IN REACTION TO LOWER PRICES?

A. Yes. Many forecasters have reduced their expectations for long term future prices, as well as near-term prices. For example, the following graph compares the EIA's 2015 forecast with its 2017 forecast, which was published in March 2017:

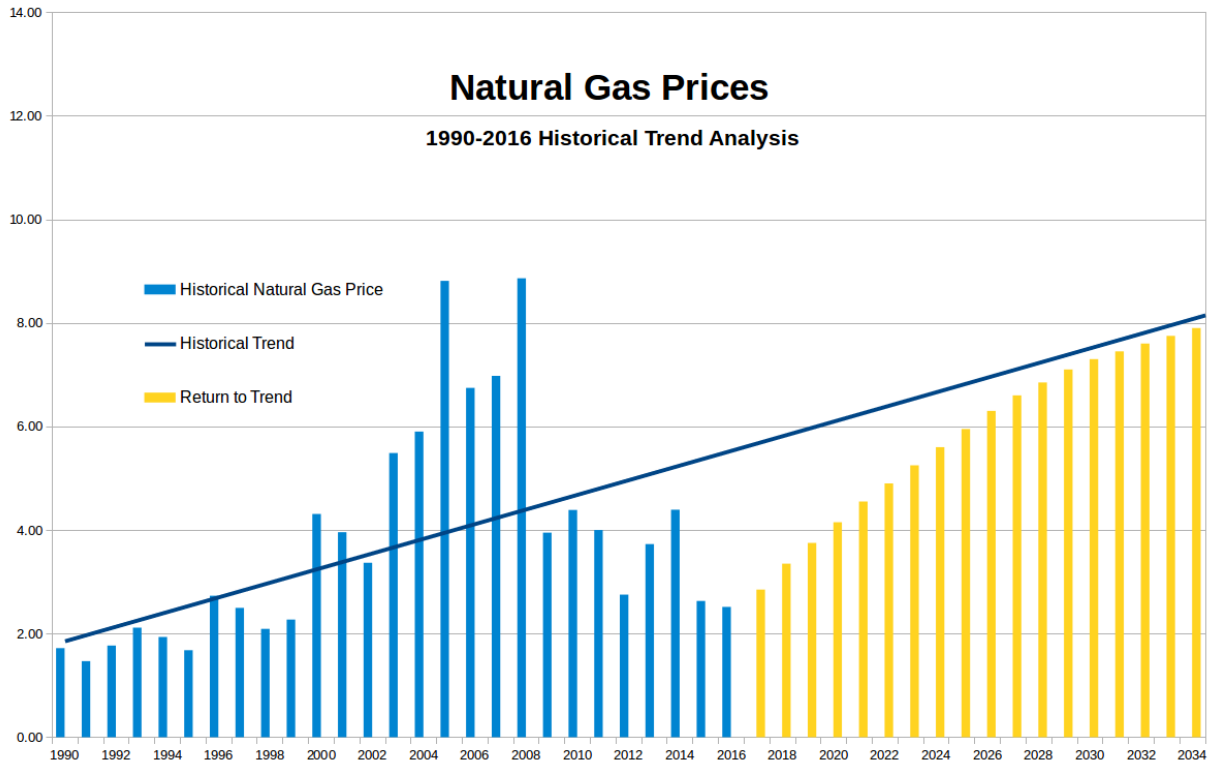


The earlier forecast (light green) is consistently higher than the most recent forecast, because that forecast takes into account the recent experience.

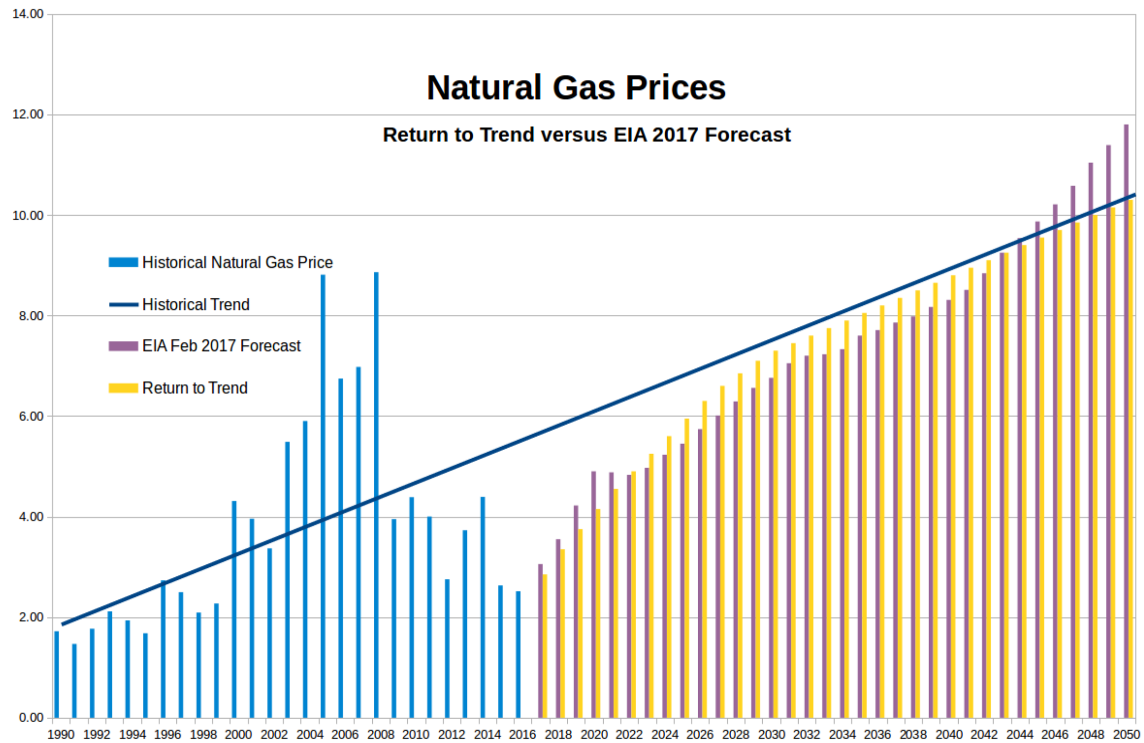
Q. WHAT FUEL PRICES DID YOU USE TO DEVELOP YOUR LONG RUN AVOIDED COST ESTIMATES?

A. I evaluated multiple scenarios, similar to the way SCE&G evaluated its V.C. Summer units. One scenario assumed natural gas prices gradually return to the historical trend line, then follow the trend line, as shown in this graph:

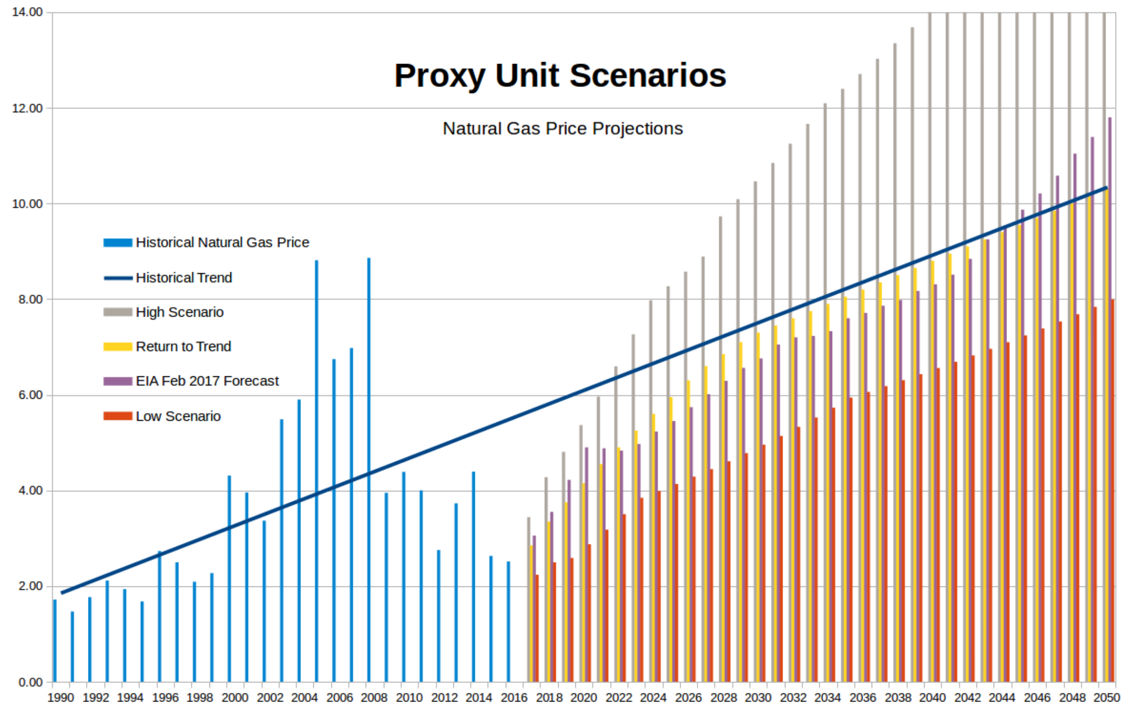
Another scenario was based upon the EIA's recently published 2017 baseline fuel price forecast, shown in the previous graph. The EIA's 2017 forecast is



similar to the trend-based scenario, but the EIA prices sometimes move a little above and sometimes a little below the smoother "Return to Trend" assumptions. This is shown in the following graph:



I also bracketed these scenarios with a lower price scenario and a higher one. The lowest scenario was derived from SCE&G's Scenario 1 while the highest price scenario was derived from SCE&G's Scenario 3. However, I lowered all of the prices in the initial years, to reflect the 2015 and 2016 historical data, which was not available when SCE&G prepared its V.C. Summer evaluation. All four scenarios are shown in the following graph:



Q. DID YOU MAKE ANY OTHER ASSUMPTIONS RELATED TO FUEL COSTS?

A. Yes. First, I assumed fuel prices would eventually grow at the overall inflation rate (2%) except in the "High" scenario, where I assumed gas prices would increase 0.5% per year faster than the overall rate of inflation. Second, I assumed a heat rate of 6,500 BTU/kWh for the combined cycle unit and 9,750 BTU/kWh for the combustion turbine unit. Third, I provided an allowance for non-fuel-related variable Operating and Maintenance costs of $2.50 per MWh for the combined cycle unit, $11.00 per MWh for the combustion turbine and $2.35 per MWh for the nuclear unit in 2016 dollars, before applying a 2% per annum inflation factor. Fourth, I assumed nuclear fuel costs of 1.00 cents per kWh in 2016 Dollars, before applying a 2% per annum inflation factor. This is consistent with, or slightly lower than, the estimates reported by SCE&G in their June 2016 FERC avoided cost report under Subpart C, Section 210 of PURPA.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING RECOVERY OF FIXED COSTS OVER DIFFERENT TIME PERIODS AND SEASONS?

A. Capacity-related fixed costs are appropriately attributed to peak hours and seasons. To some extent, the same logic holds for energy-related fixed costs, which should also be recovered disproportionately during daytime hours, when energy usage is relatively high.

In the Peaker Method, this can be accomplished by disaggregating the production modeling output during different time periods and seasons, and by focusing on marginal energy costs, rather than average energy costs. Since marginal costs tend to be high during hours when energy usage is high, the Peaker Method allows fixed energy-related capital costs to be recovered on a granular, hour-by-hour basis, following the hourly variation in marginal energy costs. It should be noted, however, this procedure does not necessarily ensure that fixed costs are recovered in their entirety.[97]

I used a similar approach in applying the proxy unit method to achieve a reasonable degree of granularity and ensure all of the fixed costs are taken into account. I first classified fixed costs in excess of the fixed costs of the combustion turbine as energy-related, and then took steps to ensure that energy-related fixed costs were largely recovered during times when energy usage is high, rather than at night, when energy usage tends to be lower.

Q. WHAT ASSUMPTIONS DID YOU MAKE CONCERNING HOURS OF OPERATION?

A. I assumed the nuclear unit would be dispatched at the bottom of the generating stack, and its energy-related costs would be recovered during all 8,760 hours per year. I assumed the combined cycle unit would be dispatched in the middle of the stack (below the combustion turbine) and its energy-related fixed costs would be recovered over 5,110 hours per year. [98] Finally, the combustion turbine would be dispatched last, since it has the highest variable

97 In practice, the results of the Peaker Method can sometimes understate costs, since there is no guarantee the energy cost estimates and capacity cost components will be internally consistent, or sum to the full incremental cost of building and operating a new generating plant – as they are theoretically supposed to.

98 Spreading the energy-related fixed costs over 5,110 kWh per KW of capacity is similar to assuming the combined cycle unit will be dispatched approximately 58% of the time, which is reasonably consistent with the overall system load factor.

costs. As discussed earlier in my testimony, I studied multiple dispatch factors; the most interesting and relevant ones assumed the CT was dispatched somewhere in the vicinity of 4 to 5 hours per day, which the proxy unit cost model indicates is near the "cross-over" or breakeven point.[99] Above that point it is cheaper to use a combined cycle plant.

Although somewhat simplified, the approach I used is consistent with the way these different technologies are typically used over their economic life cycle, and it provides a straightforward way of comparing the cost of these different proxy units. However, it is helpful to realize the actual number of hours any given plant will be dispatched will vary as fuel prices change, and it will tend to decline as the plant ages.

Section 5: QF Energy Rates

Q. ARE THERE SPECIFIC ASPECTS OF THE PROPOSED QF ENERGY RATES YOU WOULD LIKE TO DISCUSS?

A. Yes. First, I would like to discuss the Utilities' fuel forecasts, especially Duke's proposal exclusively to use forward market data in developing its proposed QF energy rates. Second, I would like to discuss the Utilities'

99 The exact cross-over point varies slightly, depending on the heat rate of the combined cycle and combustion turbine units, fuel prices and other factors.

proposals to no longer offer fixed long-term energy rates, forcing both QFs and ratepayers to bear the additional risks associated with variable energy rates. Third, I would like to discuss some geography-related issues, including DNCP's proposal to reduce its energy rates based on the historical energy price differences between the DOM Zone and the North Carolina service area.

Q. DID DUKE AND DNCP FOLLOW HANDLE THEIR FUEL PRICE FORECASTS IN THE SAME MANNER?

A. No. There is an important difference in the way DNCP and Duke developed the fuel prices they input into their production cost models to develop their proposed avoided energy costs and QF rates.

In developing its Promod model inputs, DNCP relied on forward market prices for 18 months, followed by an 18-month transition to a fundamental price forecast, which it used for all remaining years.

> For the first 18 months of the forecast period, the fuel, PJM power, and emission allowance prices are based on estimated market prices as of September 29, 2016. For the next 18 months, the prices are a blend of the market prices and the ICF commodity price forecast as of early October 2016. For the remainder of the term (starting October

> 2019), the prices are based exclusively on ICF's commodity price forecast.[100]

DNCP explained this is the same approach to blending market and fundamental data it used in developing the compliance rates in the 2014 biennial avoided cost proceeding.[101]

In contrast, to develop its Prosym inputs, Duke used fuel price data from futures markets for the first 10 years (through 2026), followed by a four-year transition to a fundamental forecast. Beginning in 2031 it exclusively used its Fall 2016 fundamental forecast assuming Clean Power Plan compliance.

Q. WHAT IS A FUNDAMENTAL FORECAST?

A. This is simply the name given to a price forecast that is developed from an analysis of the underlying factors which help explain prices, including supply and demand, technological changes, government policies and other "fundamental" factors.

100 DNCP response to NCSEADR1-13 (d).

101 DNCP response to NCSEADR1-13 (f).

Q. HOW DOES THAT DIFFER FROM FORWARD MARKET PRICES?

A. Forward market data are typically taken from futures markets, where traders are buying and selling specialized legal rights which typically involve the right to purchase or the right to sell a specified volume of a commodity on a specific future date.

These market transactions do not typically result in the actual physical delivery of the commodity, although this is theoretically a possibility. Instead, the market provides opportunities for firms to hedge risks, and for traders to make speculative bets. Market participants are typically largely focused on short term phenomena, like how they think the market will move in response to upcoming market conditions, weather, political events, market psychology, and other factors that influence prices in the short term. The market also tends to be more active, or liquid, for contracts in the relative near future. While price quotes can be obtained for dates farther into the future, that data is not as meaningful or reliable as the market data for the immediate near term.

Q. HAS THE QUESTION OF HOW MUCH WEIGHT TO GIVE MARKET DATA AND FUNDAMENTAL FORECASTS BEEN CONSIDERED BEFORE?

A. Yes. This issue also arose in the 2014 biennial proceeding, and in the 2016 IRP proceeding. NCSEA has consistently expressed concerns about placing too much emphasis on forward market data, particularly over lengthy time periods, and expressed its concerns in the comments it recently submitted in the 2016 IRP proceeding:

> ...it is NCSEA's position that fundamentals-based forecasts in future years are more representative of a utility's avoided cost and that it is not appropriate to rely on ten years of "forward prices" in estimating future avoided cost.
>
> ...The appropriate reliance on fundamental forecast and futures prices, and the appropriate time periods over which these data sources should be used, are issues that are best resolved in the context of the avoided cost proceeding. [102]

In that same proceeding, the Public Staff succinctly restated the history of this controversy, and expressed some concerns with the impact of Duke's approach in the context of avoided cost development:

> In the 2014 avoided cost proceeding in Docket No. E-100, Sub 140, the Public Staff and other parties advocated that the Company return to its previous use of forward prices for the early years of the forecast and then transition to a fundamental forecast developed by energy economists and gas analysts that estimate the future demand and supply of natural gas.
>
> ...DEC and DEP are proposing to use ten years of forwards prices and transitioning to a fundamental forecast for the rest of the 15-year term. The Public Staff notes that DNCP continues to follow the method of using three years of forward prices and then in the 30th month of the forecast, beginning a transition to reliance on the fundamental natural gas forecast developed by ICF. By the 36 th month

102 NCSEA Comments, N.C.U.C. Docket No. E-100, Sub 147, p. 4.

> of the forecast, DNCP has fully transitioned to a fundamental gas price forecast.
>
> The Public Staff further notes that the use of an excessively conservative natural gas price forecast is unlikely to alter DEC or DEP's generation expansion plan; however, the use of a low gas price forecast will depress the avoided energy costs that are paid to qualifying facilities, and also reduce the avoided energy costs that are used to evaluate the cost-effectiveness of DSM and EE programs.
>
> ...the proposed use of forward natural gas prices for ten years by DEP and DEC leads to natural gas prices that the Public Staff believes are overly conservative and inappropriate for planning purposes. Instead, the Public Staff finds more reasonable DNCP's approach of using forward price data for the short term before transitioning to its long-term fundamental natural gas price forecast. [103]

Q. SINCE DNCP AND DUKE ARE USING DIFFERENT APPROACHES, IS THIS A MATTER OF LONG-STANDING CORPORATE ATTITUDES TOWARD FUNDAMENTAL FORECASTS?

A. No. In fact, Duke's recent proposals to minimize or completely avoid using their fundamental forecast is particularly striking because it is inconsistent with the substantial level of effort Duke Energy Corporation has historically investing in developing its fundamental forecast data, and because it is inconsistent with its long-standing corporate practice of relying on fundamental forecasts for its internal investment decisions and long term plans.

103 Public Staff Comments, N.C.U.C. Docket No. E-100, Sub 147, pp 82-85.

Furthermore, Duke's recent proposals are even inconsistent with DEC's past practice in developing avoided cost calculations. For instance, in the 2012 biennial proceeding Duke used two years of forward price data combined with 24 months of transitional data that it merged with its long-term fundamental natural gas price forecast, and all subsequent years were based entirely on its fundamental forecast.[104]

104 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 140, December 17, 2015, p. 24.

Q. HAVE YOU LOOKED AT THE FUNDAMENTAL FORECAST DUKE USED IN ITS 2016 IRP FILING?

A. Yes. The fundamental forecast included in Duke's 2016 IRP is shown in light purple in the following graph:

BEGIN CONFIDENTIAL

[redacted]

[redacted]

END CONFIDENTIAL Both are fundamental forecasts are very similar. The Duke forecast is a little higher from after 2035 and it is a little lower between 2020 and approximately 2034.

Q. HOW DOES DUKE'S FUNDAMENTAL FORECAST COMPARE TO THE FUEL PRICES IT USED FOR ITS PROPOSED QF RATES?

A. Duke used much lower prices to develop its proposed QF rates in this proceeding. The difference can be seen in the following graph, where the light purple lines show its fundamental forecast, and the darker purple lines show the forward market and "blended" prices it used in this proceeding.

BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL

These lower fuel prices concentrated in the 10-year period which Duke used to calculate its avoided costs, and this resulted in correspondingly lower QF energy rates being proposed in this proceeding.

Q. IS THIS INCONSISTENCY APPROPRIATE?

A. No. Duke Energy Corporation goes to considerable effort and expense to develop its own, comprehensive fundamental forecast of the entire US energy sector, which it updates periodically for use by both the parent and its subsidiaries. This proprietary forecast reflects Duke Energy's view of the long-term outlook for the energy sector, which it uses to make long-term investment decisions by all of its electric utilities.[105]

Forward market data is useful for short term forecasts, because it can easily and frequently be updated, as commodities traders respond to changes in the weather and minute-by-minute and day-to-day changes in supply and demand conditions in the commodities markets. In essence, forward market data is particularly useful for dealing with, and hedging against, fluctuations in commodity prices over the near-term future. But, it is not as useful, nor as appropriate, to use it for long-term planning purposes.

105 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 6.

In practice, while Duke Energy Corporation's utility operating subsidiaries use forward market data for hedging and other near-term operational purposes, they typically rely on Duke Energy Corporation's fundamental forecast for longer term decisions. This was explained by a witness for Duke Energy Florida in a recent proceeding before the Florida Public Service Commission. He explained the fundamental forecast is provided to the fuels procurement group, which uses futures market quotes from the NYMEX to estimate fuel price for the first three years, followed by a two-year transition period of blended prices to the long-term fundamentals.[106] The fundamental forecast is relied upon exclusively for the balance of the planning process. He also explained that the short-term fuels forecast is based on observed market prices, and is used mainly for operational purposes.[107] He also made clear that long-term investment decisions are made by Duke Energy Corporation and its electric utilities based on the fundamental forecast.[108]

Considering the pivotal importance of fuel prices to its internal decision-making process, it's not surprising that Duke Energy Corporation goes to considerable effort to develop and periodically update its Fundamental Forecast. In fact, an outside consulting firm that specializes in fuel price

106 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 12.

107 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 6.

108 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, Exhibit KED-1, p. 6.

forecast modeling and analysis is retained to assist with this process, and these outside experts are required to work with assumptions that are approved by Duke Energy Corporation. Moreover, all of their work is carefully reviewed by internal corporate subject matter experts, to ensure consistency with Duke Energy's own internal planning assumptions and views concerning future changes in environmental policies, load growth, and other variables.[109] Considering how much effort Duke Energy Corporation puts into developing the fundamental forecast, and the magnitude of the investment decisions it makes in reliance on this information, it isn't surprising this witness described the Fundamental Forecast as reflecting both "industry expertise and Duke Energy's expertise and professional judgment of future fuel costs.[110] Nor is it surprising he repeatedly testified on behalf of Duke Energy Florida that the fundamental forecast "reasonably represents future fuel commodity prices."[111]

I am not aware of any instance in which an analogous claim has been made by forecasting experts or authoritative representative of Duke Energy Corporation, or any of its operating utilities, suggesting that forward market prices are superior to their internally developed fundamental forecast for long term investment decisions. To the contrary, this witness warned that futures

109 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, pp 8-9.

110 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, p. 5.

111 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, 14.

market "prices are illiquid after the first few years and often do not reflect the impacts of proposed environmental rulemaking, retirements of existing generation, or changes in technology."[112]

Q. DID YOU ALSO LOOK AT DNCP'S FUEL PRICES?

A. Yes. The following graph shows the natural gas prices DNCP used in its Spring 2016 IRP filing in light purple. **BEGIN CONFIDENTIAL**

[redacted] **ND CONFIDENTIAL** The two forecasts are quite similar for the first several years, but DNCP's forecast is quite a bit higher in the latter part of the forecast period. It's important to

112 Direct Testimony of Kevin E. Delehanty, Duke Energy Florida, Inc., F.P.S.C. Docket No. 150043-EI, January 30, 2015, Exhibit KED-1, p. 7.

note, however, that DNCP did not actually use this forecast in preparing its QF avoided energy rates. Instead, it used a significantly lower set of fuel prices, as shown in darker purple in the following graph.

BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL

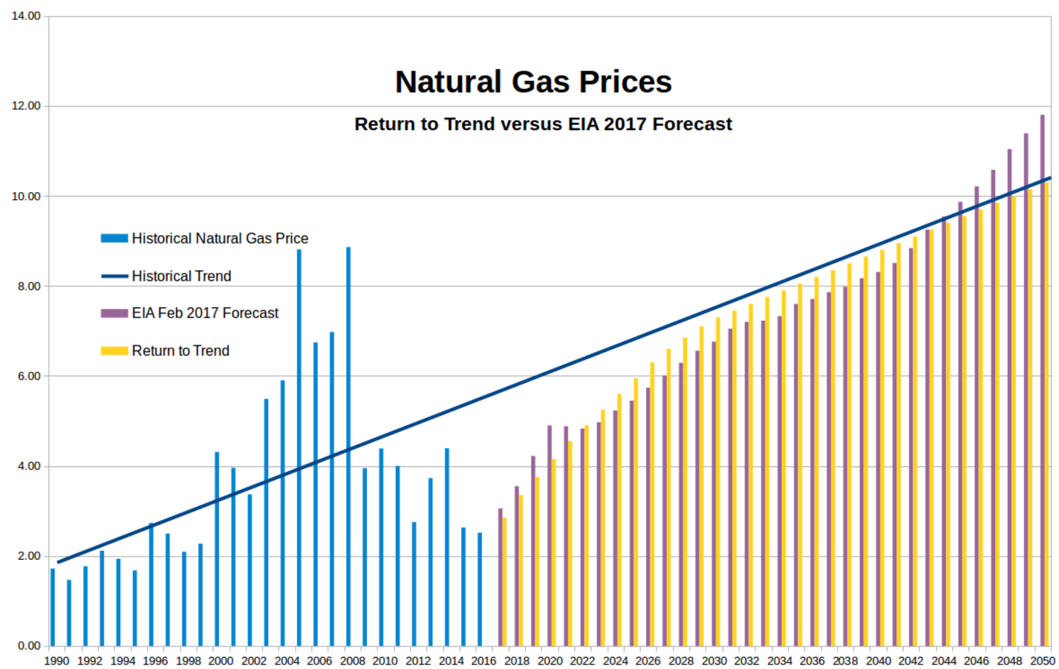
Q. WHAT CONCLUSIONS DID YOU REACH CONCERNING FUEL FORECASTS?

A. Considering how important future fuel prices are to the outcome of these biennial proceedings, it is unfortunate the Utilties have not been more forthcoming in disclosing the assumptions and forecasts they are using. It is also unfortunate they have not provided avoided energy cost estimates using other scenarios concerning future fuel prices. This makes it more difficult for the Commission to evaluate the merits of the forecasts the Utilities used. It also makes it harder for the Commission and other parties to anticipate the impact of correcting problems with the Utilities proposals – for instance, requiring Duke to use its fundamental forecast, or requiring DNCP to use the same fundamental forecast it used in the 2016 IRP.

There are benefits to providing the Commission with avoided cost information that reflects a variety of different scenarios and forecasts obtained from multiple sources. That is one reason why I've presented so many graphs showing different forecasts, including ones taken from public sources, which are not confidential.

That said, I am particularly troubled by the fact that DNCP used significantly lower fuel prices in this proceeding than it used in the 2016 IRP proceeding. I am even more troubled by the fact that Duke essentially ignored its fundamental forecast when developing its proposed QF rates.

Duke Energy Corporation goes to great effort to develop and periodically update its fundamental forecast of energy prices, which it uses for many different long term planning purposes. Both Duke's fundamental forecast, as well as the forecast DNCP used in its 2016 IRP filing, seem reasonable, and both are reasonably consistent with the most recent long term fundamental forecast of natural gas prices that was published in March 2017 by EIA. For convenience, that forecast is shown in the following graph, although it also was discussed earlier in my testimony.



In my opinion, the 2017 EIA forecast adopts a reasonable middle ground. It is also largely consistent with the scenario (shown in yellow) in which prices gradually return to, and then follow along, the long term historical trend (the dark blue line in these graphs). Accordingly, it would be reasonable for the Commission to rely on this neutral, publicly available fundamental forecast as a benchmark for judging the reasonableness of the much lower fuel prices the Utilities used in calculating their proposed QF energy rates. In turn, this suggests it would be reasonable for the Commission to require DNCP to use either the 2017 EIA forecast, or the fundamental forecast it used in preparing its 2016 IRP.

Similarly, I recommend the Commission again reject the use of forward market data for anything more than the near-term future. To the extent some consideration is given to forward market data, I recommend using DNCP's blending approach, which is much more reasonable than Duke's approach in this proceeding. Another option would be to require Duke to use the approach that was described by Duke Energy Corporation's witness in Florida. Forward market data would be used for the first three years, followed by a brief two-year transition period of blended prices to the long-term fundamental forecast of prices, then relying entirely on the March 2017 EIA forecast, or Duke's long-term fundamental forecast, for all subsequent years.

Q. HAVE THE UTILITIES EXPRESSED ANY CONCERNS ABOUT CHANGING FUEL PRICES?

A. Yes. Duke witnesses Snider pointed out that fuel prices have fallen significantly in recent years.

> In general, 10-year (2017 to 2026) levelized natural gas prices have fallen approximately 40%, while coal prices have fallen approximately 16% for that same time period as compared to those used in calculating the Companies' avoided cost of energy in the 2014 biennial Sub 140

> proceeding. Compared to the 2012 Sub 136 avoided energy costs, fuel costs have fallen even further with natural gas declining approximately 48% and coal, 33%.[113]

Duke witnesses Bowman pointed out the resulting discrepancy that inevitably arises whenever fuel prices change – the assumptions used to establish fixed QF rates are not identical to subsequent estimates of the variable fuel costs that are avoided by QF power.

> If contracts extend for many years, the forecasted avoided cost rates become increasingly inaccurate, no longer mirroring the utility's incremental costs. Thus, long-term contracts with forecasted rates shift the risks of those rates not aligning with avoided costs to the utilities' customers.[114]

Q. DO YOU AGREE WITH THIS STATEMENT?

A. Yes. However, as I will explain later, I disagree strongly with the implication that this is problem that is so serious it needs to be "solved" by replacing fixed QF rates with ones that change every two years.

To the extent the Utilities' witnesses discussed the potential impact of forecasting risks at all, their discussion is oversimplified, and potentially misleading, as exemplified by these comments by Duke witness Bowman.

> long-term contracts with forecasted rates shift the risks of those rates not aligning with avoided costs to the utilities'

113 Snider Direct, p. 16.

114 Bowman Direct, p. 48.

> customers. This shifting of the growing risk to customers becomes increasingly unjust, unreasonable, and contrary to the public interest as greater and greater QF capacity avails itself of these longer-term rates.[115]

In my opinion, the risk of "rates not aligning with the avoided costs" is a less serious problem for ratepayers than the potential adverse consequences of the proposed solution: removing all stability from the QF rates, and adjusting rates every two years. This is a "lose-lose" modification, which increases risks for both retail ratepayers and the QFs.

Furthermore, the risk of a misalignment of QF rates and costs isn't as serious as the analogous risks incurred when the Utilities build and operate their own plants. Both methods of obtaining electricity involve uncertainties. Every time Duke builds a plant using technology A, there is a risk that technology B will turn out to have been the better, more cost-effective choice. While rarely discussed, this misalignment problem is far more significant than the misalignments involved in purchase power contracts, particularly since the latter decisions are made in smaller chunks, allowing a greater degree of cost averaging over time.

The impact of sub-optimal technology choices (in hindsight) can result in a serious misalignment between the actual costs paid by Duke's customers and the lower costs that could have been paid if a different technology or fuel

115 Bowman Direct, p. 48.

choice had been chosen. This is directly analogous to the rate/cost misalignment witness Bowman is concerned about. The difference is that the magnitude of the problem is much larger when looking at the consequences of past technology and fuel choices for the Utilities' own plants.

Q. HOW DOES FUEL PRICE INSTABILITY AFFECT UTILITIES AND THEIR CUSTOMERS?

A. For a natural gas producer, higher prices are a positive, but for the typical gas utility customer, they are a negative. The same directionality applies to electric rates. Higher coal and natural gas prices turn into higher rates and higher electric bills, which hurt consumers – particularly when the rate increase occurs suddenly, or is not fully anticipated.

Before fuel adjustment and purchased power adjustment clauses became common in public utility tariffs, unexpected fuel price increases hurt the earnings of electric utilities, while customers were initially shielded from the problem. Inevitably, however, the utility would be forced to file a general rate case, where the higher fuel costs would eventually harm customers, as well. Lower fuel prices tended to have the opposite effect – mostly benefiting utility earnings, but also helping customers in the long run, if for no other reason than by postponing the need for a general rate increase to pass through increases in other costs.

During the energy crisis of the 1970's, regulators increasingly realized that fuel price risks were not only creating serious problems for electric and gas utilities, but they were also creating problems for their customers. To solve both problems, state regulators introduced complexity into the regulatory process, in an effort to ameliorate some of the short-term risks associated with fuel prices. In many states, regulators agreed to periodically update retail electric rates on a systematic, predictable basis, using fuel adjustment and purchased power clauses or periodic, streamlined rate proceedings. Volatility in utility earnings was reduced, equity costs were reduced and bond ratings were strengthened – all of which helped both utilities and customers.

However, under this system, customers bear all of the risks associated unpredictable, volatile fuel prices over the long run. Aside from increasing reliance on hydro and nuclear power (which have high fixed costs and low variable costs), neither the utility nor regulators can do much to reduce or eliminate the downside risk of higher future fuel prices. Aside from installing more insulation or more energy-efficient appliances, there is not much individual customers can do to minimize these long-term risks, either.

Needless to say, the risks borne by customers are largely one-directional. In most cases customers are unhappy when prices are higher than expected, but they do not mind when fuel prices are lower than expected. While theoretically, a customer who invested in more insulation and installing more energy efficient appliances might be "harmed" because the return on their investment is not as high as they originally anticipated, this downside "risk" is not likely to be of major concern – particularly since they will be paying less for the remaining electricity they continue to purchase.

The fuel price risks borne by the stockholders of incumbent utilities are relatively minor and mostly bidirectional. However, that does not mean fuel price uncertainty doesn't pose major risks for customers. Since fuel price changes are entirely passed through to customers, so they are ultimately borne by customers. Stated another way, because of the fuel and purchased power rate adjustment process, fuel prices no longer have a major, direct impact on quarterly utility earnings. Absent proof of imprudence (which is extremely rare), utilities are largely impervious to even the most extreme long term fuel price related risks. When they make investments that prove to be uneconomic, the burden is borne by their customers.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW FUEL PRICE RISKS ADVERSELY AFFECT CUSTOMERS?

A. Yes. Until very recently, many utilities expected coal prices to be less volatile, and generally remain below natural gas prices (on a per-MMBTU basis). Coal prices were expected to be more stable because ample domestic supplies exist which can be readily obtained using existing mining technology, because mining costs are reasonable and are inherently stable, and because competition in both the mining and transporting of coal was expected to remain vigorous. Furthermore, coal can sometimes be purchased from mining firms under long term contracts that provide a degree of pricing stability. In contrast, natural gas prices are inherently more volatile; oil and gas are sometimes produced in tandem, and their prices are subject to significant geopolitical risks; and most forecasts projected rapidly escalating gas prices over the long term.

In fact, the instability of natural gas prices, and concerns about the potential for drastically higher gas prices over the long term, were two of the most serious disadvantages of using this fuel source to generate electricity. Earlier in my testimony, I mention that fuel price assumptions or projections are of critical importance when evaluating generating technologies or estimating energy costs using different fuel sources. In fact, the fuel cost assumptions will at least heavily influence, if not entirely determine, the conclusions that are drawn from an analysis of the relative cost-effectiveness of using different generating technologies.

Those anticipated long term fuel price savings help explain why so many utilities have seriously considered or committed to multi-billion dollar investments in advanced coal technologies. For example, according to a report published by the EIA in November 2010, a single unit Advanced Pulverized

Coal plant with 650 MW capacity was expected at that time to have a projected cost in 2010 dollars of more than $2 billion.

A utility that selected this technology would be committing billions of dollars that will end up in rate base and be borne by customers for a technology that only made economic sense under the assumption natural gas prices will be more volatile, and increase to much higher levels than coal over the 30+ year economic life cycle of the investment. This becomes clear when comparing the economics of the coal plant to the natural gas alternative given what was known at the time. The same 2010 EIA report shows the estimated cost of a 400 MW single unit advanced combined cycle natural gas plant was just $412 million. Thus, a utility could have built 5 of these combined cycle plants, with a total capacity of 2,000 MW for the same magnitude investment as a single 650 MW advanced pulverized coal plant. The natural gas option would provide more than three time the capacity (2,000 MW versus 650 MW), and it would be much more geographically diverse.

In hindsight, the coal technology is now looking very burdensome for customers, since it cost so much more than the gas plant, yet gas prices have actually declined, rather than increasing as many experts expected at that time. The technology/fuel price alignment problem is even more serious when it is realized that the natural gas option had a heat rate of 6,430 Btu/kWh compared to 8,800 Btu/kWh for the 2010 era advanced pulverized coal technology.

Q. ARE YOU SAYING IT WAS IMPRUDENT FOR UTILITIES TO BUILD ADVANCED COAL PLANTS?

A. No, not at all. The point I'm making is a simpler one. Duke witness Bowman is criticizing QF power purchases because they haven't saved customers as much money as was anticipated at the time the QF rates were set, because gas and coal prices have not increased as much as projected in past biennial proceedings. But, I don't think this "hindsight" standard is appropriate. I am using the coal technology example to illustrate why I think it is unfair to criticize the solar industry for investments and contracts that seemed reasonable at the time, merely because fossil fuel prices turned out to be lower than expected. I am simply showing the implications of this hindsight-based criticism as it would apply to past decisions between two different fossil fuels.

In fact, a similar, but very costly, problem exists with some of Duke's own coal units. In my opinion, it really is not fair to criticize them for making technology choices that turned out to be sub-optimal, merely because fuel prices have turned out to be lower were than anticipated. This sort of criticism is no more valid than criticizing a portfolio manager for buying stocks that offered diversification or other benefits, just because the price of the stock did not end up increasing as much as hoped. In making this sort of evaluation, it is important to look at how each investment fits into the overall optimization and diversification strategy. The benefits of lower volatility and counter-cyclical characteristics may make a stock a good choice for a portfolio, even if it does not turn out to be as profitable it would have been, if stock market prices had tracked closer to the portfolio manager's original price forecast.

Q. HOW DO FUEL PRICE RISKS AFFECT SOLAR AND SMALL HYDRO?

A. Solar and hydro production offer valuable diversification benefits, because they are almost entirely impervious to fuel price risk. Hence, from a purely economic perspective, the more solar and small hydro production that is introduced into the generation portfolio, the more customers will gain the benefit of a fundamentally lower degree of fuel price risk.

Both hydro and solar production require large investments per kW, but they have very low variable costs per kWh. So, from a customer's perspective, the more solar and hydro used to produce electricity, the less fuel price risk they face.

In this regard, hydro and solar are similar to nuclear generation. Nuclear plants also require large investments per kW and low variable costs, leading to relatively low fuel price risks. In fact, that favorable risk profile has long been one of the major advantages of nuclear generation, helping to explain why customers have benefited from over the long term, even when nuclear projects cost more than originally anticipated. However, it is worth noting that solar has even lower fuel related risks than nuclear production. Nuclear plants use uranium as a fuel source, which introduces a small degree of fuel cost risk when the fuel rods are acquired, and a potentially larger degree of risk when they are ultimately disposed of.

Q. IS DUKE PROPOSING CHANGES TO ITS QF TARIFFS WHICH WOULD CHANGE THE RISK PROFILE FOR SOLAR?

A. Yes. Duke witness Bowman argues that the recent experience with fuel prices and variable energy costs declining, while fixed prices in QF contracts remain the same, has resulted in a problem that needs to be solved.

> One assumption underlying FERC's statement in Order No. 69 is that "in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out" in that QF development would remain essentially constant regardless of avoided cost rates and regulatory circumstances. The enormous recent surge in QFs developments in North Carolina disproves this assumption.
>
> ...long-term fixed rate contracts, and the low threshold to obtain a LEO have resulted in large numbers of solar QFs locking in avoided cost rates in North Carolina for the next 15 years. As discussed, these rates are well in excess of the Companies' actual current avoided costs.[116]
>
> ...the 15-year maximum contract term has resulted in significant overpayment commitments by customers, now approximating $1.0 billion, which far exceed the potential

116 Bowman Direct, p. 47.

> for counterbalancing underpayments for the foreseeable future.[117]

As I explained earlier in my testimony, the $1 billion calculation greatly exaggerates the impact of the recent dip in fuel prices, and it creates a false impression that existing QF contracts will be costlier than power produced by generating units Duke owns and operates over the duration of the QF contracts, when in reality there is almost no risk of this occurring. This calculation compares a snapshot of fuel prices taken at a time when they happen to be unusually low. As fuel prices move higher, the arithmetic will change entirely, since the QF rate will remain fixed and coal and gas prices increase. Furthermore, the calculation is totally misleading, because Duke is comparing “All In” prices for QF power with only a portion of the cost of the power it generates. In addition to fuel costs, customers are paying fixed operating and maintenance expenses, property taxes, depreciation, income taxes, debt service, and other fixed costs associated with Duke's generating plants.

Having identified a perceived problem of having QF rates fixed while fuel costs having unexpectedly declined, Duke proposes to “fix” this perceived problem by fundamentally changing the QF tariff structure, by eliminating fixed tariff energy rates. Under Duke's proposed QF tariff

117 Bowman Direct, p. 48.

> The energy rates will be re-established every two years in future avoided cost proceedings based upon the Companies' then-current avoided costs, as approved by the Commission.[118]

> A structure that adjusts the energy rates at reasonable, periodic intervals throughout the duration of a long-term contract is an effective way to reduce customers' exposure to overpayments.[119]

From the perspective of the QF, this fundamentally changes the economics of solar production. Under the current tariff structure, a QF benefits from a fixed revenue stream that aligns well with its fixed costs. If this proposal is accepted, a stable, predictable revenue stream that aligns well with a cost structure of high fixed costs and low variable costs, will suddenly become highly unpredictable. Not only will the future revenue stream depend on the future course of volatile fuel prices, but it will fluctuate with those prices in ways that are fundamentally unknowable and unpredictable from the perspective of the QF and their financiers, because it will depend on the outcome of litigated proceedings every two years.

Q. IS THIS CHANGE IN RISK STRUCTURE BENEFICIAL TO RATEPAYERS?

A. No, not at all. To the contrary, this change eliminates one of the most attractive features of solar power from the perspective of the customer. Solar

118 Snider Direct, p. 7.

119 Snider Direct, p. 18.

currently brings a degree of pricing stability into electric rates; the benefits of that stability (and risk reduction) would be largely eliminated by this proposal.

In other words, this would be a "lose – lose" proposition for both QFs and ratepayers. It would significantly increase the risks borne by QF developers, making it more difficult or impossible to finance QF projects, and it would simultaneously increase (not decrease) the risks borne by ratepayers. In effect, the proposal would reshape QF purchase power contracts to make them more similar to the inherently riskier structure of most other purchased power contracts.

However, from a QF's perspective, this process of updating the energy rates would be far riskier than a typical purchased power agreement, since prices would be subject to the outcome of biennial litigation, rather than being a numerical function of a published fuel price index. The latter approach is inherently less risky and more predictable and is typical practice in the industry, as Duke witness Snider points out:

> …when contracts are negotiated to purchase power, outside of PURPA, the energy payment terms are generally linked to a real-time fuel price index, and as such, the Companies minimize the risk of the customer paying beyond market energy prices for this power. Thus, the Companies' proposed modification to the standard offer contract structure better aligns the level of risk

> imposed upon customers in PURPA contracts with non-PURPA contracts.[120]

Since most non-PURPA sellers of power are burning fuel, it makes perfect sense for them to seek a pricing structure that gives them the ability to push the risk of fuel price changes forward to the purchasing utility, who in turn pushes the risk forward to their retail customers. While this standard practice is beneficial to the buying and selling utilities, it is not particularly beneficial to the ultimate customer, who ends up bearing all of the fuel price risks. There is no logical reason to expand the scope of this pricing arrangement to encompass power production that doesn't involve burning fuel.

In sum, Duke's proposal artificially suppresses, or masks, one of the most fundamental benefits of solar power production, creating a risky revenue stream where a fixed, stable revenue stream make more sense. Both QFs and retail customers will be worse off if this “lose-lose” proposal is accepted by the Commission.

Q. WHAT ARE THE LOCATION-RELATED ISSUES YOU WANT TO DISCUSS?

A. The Utilities have identified two distinct, but conceptually similar, issues. First, DNCP expressed some concerns regarding the relative cost and value of

120 Snider Direct, p. 19.

power within Dominion's North Carolina service area relative to the DOM zone within the PJM region.

> This historical price data shows that the LMPs in the Company's North Carolina service area are consistently lower than the prices for the DOM Zone as a whole. The energy prices for Option B were 4.4% lower than the DOM Zone prices during the on-peak periods and 4.8% lower during the off-peak periods during these years. All things being equal, the LMPs in the North Carolina area are likely to be even lower in the future as more solar distributed generation ("Solar DG") is added to the Company's system.[121]

In response to this disparity, DNCP is proposing to reduce the QF energy rates by a small percentage, based on historical energy price differences between the DOM Zone and the North Carolina service area.

Second, DNCP witness Gaskill expressed some concerns about the fact that solar generation is increasingly being sent from the local area where it is generated to other neighborhoods. And, in an increasing number of cases, solar energy is flowing through the transmission system out of North Carolina to the DOM zone in PJM.

> Solar DG is a scalable resource that can be located at or near the Company's load. [...resulting] in added benefits such as reduced congestion, mitigated line losses, and, in

121 Gaskill Direct, p.10.

> some cases, improved local reliability over centrally-located generation...
>
> Because of the backflow that is occurring on the Company's system … the benefits of Solar DG – scalability, mobility – are no longer being realized.[122]

In essence, he is expressing concern that the location of solar generating facilities isn't being optimized, and thus some of the potential benefits of having numerous small, widely scattered generating units are not being fully achieved.

> When the amount of distributed generation reaches the point where it exceeds the load on its respective circuit, many benefits (and therefore avoided costs) attributed to the distributed nature of the generation are lost.[123]

This discussion is typical of the Utilities' approach to many of the issues they have identified in their testimony. DNCP witness Gaskill concedes there are significant benefits to society which can potentially be achieved when small generating facilities are distributed throughout the state, injecting energy into the grid at many more locations than in the past, but rather than dwelling on those potential benefits, he focuses on the fact that some of these benefits may not be fully achieved when individual circuits receive so much power from QFs that their energy sometimes flows back through the substation onto the transmission grid.

122 Gaskill Direct, pp 10-11.

123 Gaskill Direct, p. 10.

It is my understanding that he is not claiming this backflow is dangerous or creates any risks for either the substation or the transmission system. Rather, he is simply arguing there are potential benefits to society that are lost when energy flows in this manner.

Q. CAN YOU EXPLAIN THIS CONCERN IN MORE DETAIL?

A. Yes. The closer each retail customer is to the nearest location where power is being supplied, the less opportunity there is for energy losses to occur while the electricity is being moved from the point of generation to the point of consumption. Similarly, energy is lost whenever the voltage is changed. For example, when power is generated at a coal plant in a remote part of the state and sent over a high voltage transmission system to a different part of the state, line losses occur along the transmission path, and when the electricity is stepped down to distribution voltage. In fact, additional losses can also potentially occur when the electricity is sent from the substation over the distribution circuit to the final user.

Historically, the Utilities have provided a small allowance for line losses in the QF rates, but they have never comprehensively looked at all of these potential opportunities to avoid costs. Instead, the Utilities focused on the losses that occur when stepping down the voltage from the transmission system to the distribution system. This is why higher rates are paid to QFs at distribution voltage, rather than transmission voltage.

Many other potential benefits, including line losses that can be avoided by not sending the electricity over the transmission system, and costs of building or upgrading the transmission system itself, can also potentially be avoided. On DNCP's system, in cases where backflow is occurring, some of these potential savings (and the costs that could potentially be avoided) are not being avoided. From society's perspective, this is unfortunate – costs that could be avoided are not being avoided. But, its important to keep in mind the QF rates have never included an allowance for most of these potential avoided costs.

In the 2014 biennial proceeding, the Utilities did not necessarily dispute the existence of these potential benefits of widely distributed QF generation, but rather they offered various reasons for not including them in the QF rate development process. For instance, the DNCP witness testified that "DNCP does not reflect some asserted benefits in its rates because … the benefits are highly uncertain or speculative; and/or the benefits cannot be realized in the context of a QF, as the utility does not control the development of the facility."[124]

124 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 39.

Confronted with these objections, and having insufficient information to fully evaluate the costs and benefits associated with integrating solar generation into the grid, the Commission decided in in the 2014 biennial proceeding agreed they should not be included in the QF rates, deciding instead that "it is appropriate for the costs and/or benefits attributed to solar integration to be more fully evaluated when future studies and calculation methods have been further developed."[125]

Q. ANOTHER CONCERN IS THAT SOLAR GENERATION HAS BEEN "UNCONTROLLED" SO SOME POTENTIAL BENEFITS OF GEOGRAPHIC DIVERSITY AREN'T BEING ACHIEVED. DO YOU AGREE WITH THIS CONCERN?

A. No. DNCP witness Gaskill expressed concern about the failure to achieve maximum diversity with respect to cloud cover.

> ...for Solar DG, geographic diversity reduces the effect of intermittent cloud cover over any single location. Spreading Solar DG across the Company's service territory therefore improves reliability and minimizes integration costs (such as increased operating reserves and

125 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 39.

> load imbalance charges) and operational challenges, in turn reducing costs for customers.[126]

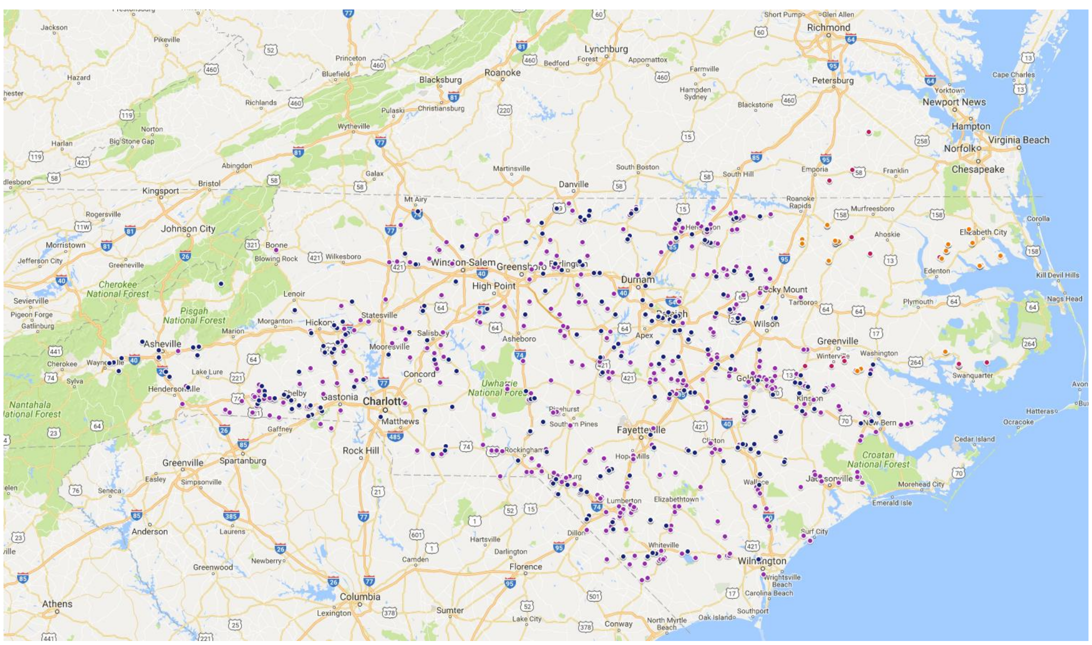
To the extent optimal diversity is not yet being achieved with respect to cloud cover, this is not a reason to abandon the existing market-driven approach to solar QF investment. Markets can be as effective, or more effective, than a purely administrative process in directing investment to locations where it will be most beneficial to society – assuming adequate information and price signals are provided to market participants.

The inherent ability of market-driven processes to advance the public good has long understood by economists. In fact, this is the essence of Adam Smith's famous "invisible hand" which refers to the way market forces can achieve highly beneficial outcomes for society, despite the fact that each individual market participant is not concerned with helping society, but is merely responding to price signals, incentives and other information in an effort to earn a return on their investment. As an economist, I am convinced that markets can be more effective than purely administrative processes in maximizing societal benefits – provided there is sufficient transparency and widespread distribution of information to market participants.

126 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, pp 10-11.

Q. HAS QF DEVELOPMENT IN NORTH CAROLINA BEEN CLUSTERED IN JUST A FEW LOCATIONS?

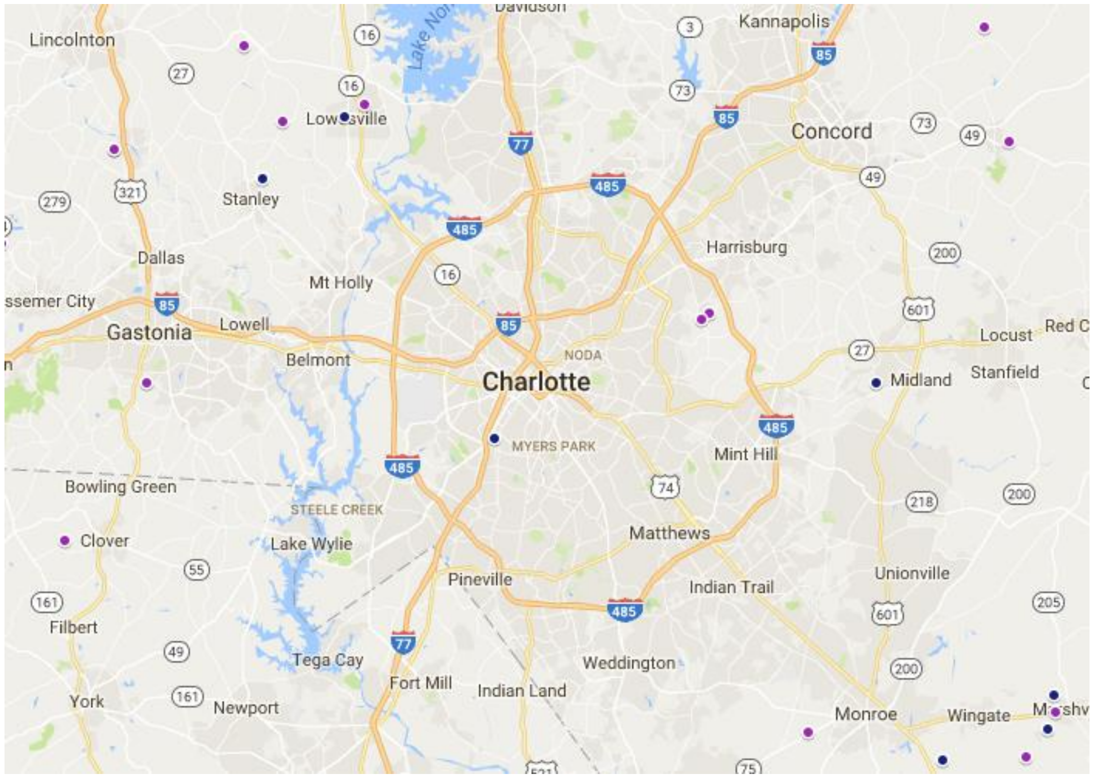
A. No. To the contrary, solar project are widely scattered throughout the state. In fact, as discussed earlier in my testimony, the state has experienced widespread distribution of small solar projects, which contrasts favorably with the relatively small number of relatively large projects that are being developed in some other states, like Florida and Georgia. This was shown on the US map I discussed earlier in my testimony, and is confirmed on this map, which shows the location of solar facilities connected to both Duke's system (dark blue dots) and DNCP's system (red dots).



The map also shows all 4,600 MW of potential projects that are currently in Duke's queue (purple dots) and projects with a PPA or LEO within DNCP's service area (orange dots).

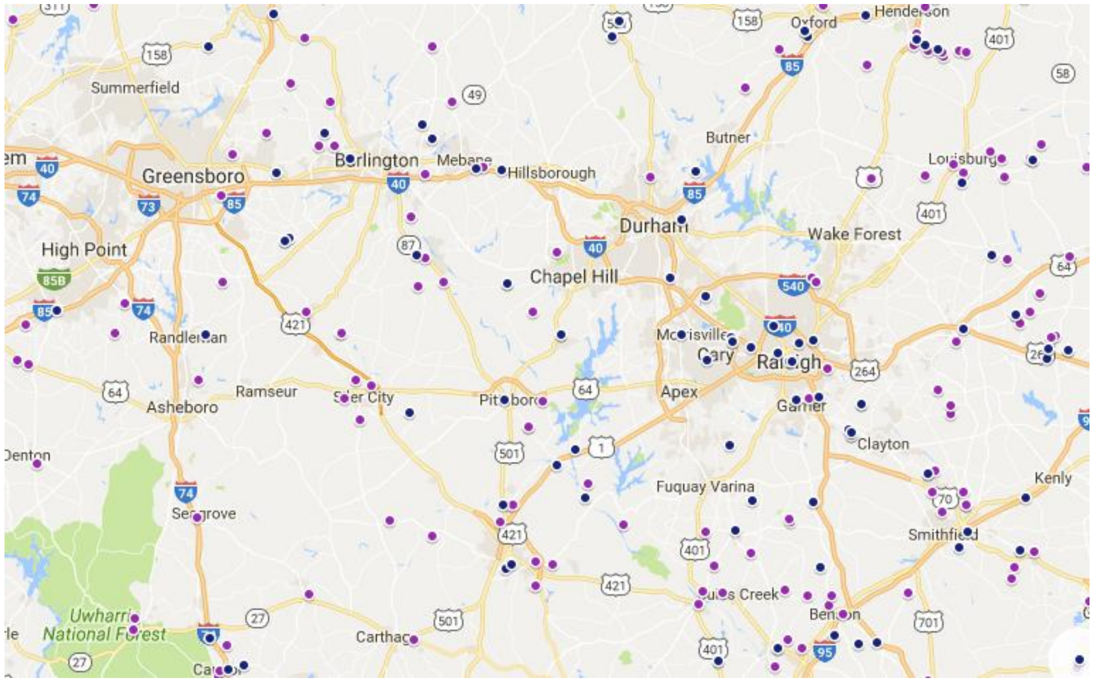
Q. IS DEVELOPMENT UNIFORMLY DISTRIBUTED EVERYWHERE IN THE STATE?

A. No. This follows logically from the fact that it is easier and less costly to develop solar projects away from urban congestion. The same QF rate applies throughout each utility's service area, so there is no revenue-based incentive to incur the extra cost and effort required to permit and build solar facilities in the state's urban areas. Hence it is not surprising that relatively little QF investment is flowing into the state's largest metropolitan area.



Q. ARE THERE SOLAR GENERATORS IN SOME OTHER URBAN AREAS?

A. Yes. Raleigh, Durham and Greensboro have all attracted some solar investment, as shown below.



Q. DO THE UTILITIES RECOGNIZE THAT QF INVESTMENT IS NOT NECESSARILY BEING OPTIMALLY DEPLOYED?

A. Yes. DNCP witness Gaskill in particular seems to realize the current QF rates do not provide any price signals to encourage more urban investment, or to discourage excessive concentration of QF projects in areas where power is starting to backflow onto the transmission system.

> One of the key limitations with the current manner in which PURPA is implemented in North Carolina is the Company's inability to incentivize QFs to locate in one location over another. This is because all QFs under 5

> MW, regardless of location, are eligible for the same standard contract and rates.[127]

Duke witness Yates made a somewhat similar observation.

> As a general rule, DEC and DEP have historically had little influence on the volume or location of these projects on the utility system. This has created a distorted marketplace...[128]

However, the Utilities did not explore the issue in detail, or provide any suggestions for how their QF tariffs might be improved to "incentivize" QFs to locate in areas where distributed generation is most beneficial.

Q. CAN THE TARIFFS BE IMPROVED TO ENCOURAGE GENERATORS TO BUILD IN SPECIFIC NEIGHBORHOODS?

A. Yes. QF investment is occurring in many locations in the state, but with further refinement, the QF tariffs could provide much more useful and important information about different locations – and the tariffs could even provide corresponding price signals to market participants.

The current system of state wide tariffs combined with ad hoc, site-specific grid integration studies is not ideal from the perspective of either the utility or the QF. For instance, a small power producer is currently forced to invest

127 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 17.

128 Yates Direct, p. 7.

significant time and effort in identifying and acquiring a site without knowing in advance whether it is likely to be good location from the utility's perspective. Only after making this investment does the QF obtain the results of a site study prepared by the utility's engineers, which enables the QF to find out whether interconnection costs will be large or small at that particular site. This is an expensive, cumbersome, and unnecessarily inefficient approach.

Instead, the utility could publish, in their tariff, information identifying all of the substations and feeder circuits where interconnection costs are likely to be above average. The converse could also be communicated. The tariff could list all feeder circuits and substations where distributed generation is anticipated to be particularly beneficial, by enabling the utility to avoid future system upgrades, and the like.

In fact, the tariffs could not only provide better information to QFs, the rate design could be improved to provide more precise price signals that is consistent with that information. Higher avoided cost rates could be paid for in locations where a local power source would be most valuable, and lower avoided cost rates could be paid in locations where local power is not needed, and the power would likely backflow onto the transmission system and be sent to another part of the state. These sorts of improved price signals would be in the best interest of the utility, the QFs and the using and consuming public.

In sum, the Utilities' current and proposed QF tariffs provide minimal information of use to small power producers in deciding where to build more generating facilities, and they set forth highly simplified, statewide average rates. With millions of dollars at stake, there is no reason not to increase the complexity and sophistication of the QF tariffs in order to provide better information to market participants. With a little more effort, the QF tariffs can provide better, more precise price signals, which would help encourage optimal deployment of distributed generation. The end result will be significant benefits for society that more than outweigh the cost of a more complex tariff development process.

Q. WHAT INFORMATION WOULD BE NEEDED TO PROVIDE BETTER PRICE SIGNALS?

A. The tariff development process needs to move past the general discussion of benefits and costs of integrating solar facilities into the grid, as occurred in the last biennial proceeding. Building on the important investigative work the Utilities have recently accomplished in understanding and evaluating solar integration costs in general, the Utilities will have to collect and analyze the detailed factual information they will need in order to list specific locations and provide better price signals in their tariffs.

While the data collection and analysis effort will be significant, the QF tariffs themselves need not change very much. They could simply list two or more rates (analogous to on-peak and off-peak rates), and list the specific feeder circuits, or substations, where those rates are paid. This tariff development process could initially be a collaborative effort involving input from the Public Staff and other interested parties. However, the Utilities are in the best position to collect the needed information, and will need to be at the forefront of this effort.

Once the Utilities are ready to move away from statewide average prices, it will be necessary to estimate how much higher the avoided costs are in locations where a local power source would be most beneficial. Similarly, it will be necessary to estimate how much lower than average the avoided costs are where distributed generation is less valuable. The examples offered in DNCP's testimony concerning locations where power is already backflowing onto the transmission system is an excellent place to start – but more analysis is needed.

In general, the goal is straightforward: to identify locations where distributed generation helps the Utilities avoid distribution and transmission costs, and distinguish those locations from places where distributed generation doesn't avoid these types of costs. The distribution engineers already work with the underlying information that is needed when developing capital budgets and planning for upgrades and replacements of specific portions of the grid. With some reorientation and a longer-term outlook, these engineers can help compile and analyze the information needed to prioritize different locations within the state – helping to identify the feeders and substations where local generation would be most beneficial over the 30+ year economic life of the facility.

Ideally, detailed location-specific information would be developed that considers each of the factors mentions by DNCP witness Gaskill: (1) proximity to load centers and other factors which influence line losses, (2) opportunities to reduce congestion on distribution lines, substations, and transmission lines which could postpone or avoid upgrades to these facilities within the relevant planning horizon, and (3) opportunities to improve local reliability.

In sum, solar generation is being placed all over the state, but there is room for further improvement. Statewide average tariffs are not optimal, and there is no reason not to move toward more a more sophisticated rate design. The QF tariffs can and should be improved, to send better, more precise price signals to the QFs that enable them to weigh the pros and cons of investing in specific locations.

Q. PLEASE SUMMARIZE DNCP'S PROPOSAL TO LOWER THE QF ENERGY RATES BASED UPON PJM LOCATIONAL PRICE DIFFERENCES.

A. According to DNCP witness Gaskill, this proposal is based upon observed differences in Locational Marginal Prices ("LMPs") for energy at different geographic locations within its system.

> PJM calculates the locational marginal price or LMP that reflects the value of energy at each specific node on the grid. Areas in which generation is needed to meet load will realize higher LMPs in order to incentivize generation to locate in that place. Conversely, locations where generation is not as valuable due to congestion and/or losses will realize lower LMPs. ...LMPs in the Company's North Carolina service territory have been consistently lower than the prices for the DOM Zone as a whole.
>
> Lower LMPs mean that additional generation in this area is less valuable than generation in other areas of the DOM Zone.[129]

DNCP witness Petrie describes their proposal to reduce the QF energy rates in response to these observed LMP differentials.

> The adjustment to the avoided cost energy rates is based on the historical energy price differences between the DOM Zone and the North Carolina service area. The Company based its calculated value of energy in the North Carolina area on the average day-ahead LMPs at six locations, which were selected because they are

129 Gaskill Direct, p. 23.

> geographically dispersed, and because they are known to have QF development at or near those locations.[130]

Q. WHAT IS YOUR RESPONSE TO THIS LOCATION-BASED PRICING PROPOSAL?

A. On a purely conceptual level, I have no objection to using LMP data to help refine the QF rates. LMPs may potential relevance to the problem of how best to improve QF price signals, in order to encourage QF power to be generated where it is most valuable.

> PJM uses locational marginal pricing to set prices for energy purchases and sales in the PJM market and to price transmission congestion costs. Congestion is when the lowest-priced energy is prevented from flowing freely to a specific area on the grid because heavy electricity use is causing parts of the grid to operate near their limits. True to its name, locational marginal pricing is based on the location in which the power is received or delivered.
>
> Locational marginal pricing is analogous to a taxi ride for megawatts of electricity. When traffic is light, you can expect a consistent and predictable taxi fare, which would represent a period with little to no congestion on the grid. Similarly, heavy traffic results in a higher fare, which is similar to a time of congestion on the transmission system.[131]

However, significantly more information and analysis needs to be provided so that the Commission and interested parties may evaluate the merits of DNCP's

130 Petrie Direct, p. 9.

131 PJM Learning Center, Locational Marginal Pricing, available at https://learn.pjm.com/three-priorities/buying-and-selling-energy/lmp.aspx (last accessed March 27, 2017).

idea of using location-specific LMP data. More thought is also needed concerning the policy implications of this proposal, as well as the merits of the specific calculations DNCP has proposed. Additional granularity and further refinement of the calculations is likely appropriate.

At a minimum, there are nine issues that ought to be investigated before the Commission decides whether to accept some variation of this proposal: 1) if, on average, North Carolina LMPs have been consistently running about 5% below the DOM Zone average, what are the underlying factors that are causing this differential; 2) how large is the variation in LMPs observed at specific locations within DNCP's system in North Carolina; 3) does the differential at individual locations remain fairly stable, or does it fluctuate significantly over time; 4) is it appropriate to average the differential across DNCP's entire North Carolina service area, or or should more granularity be retained; 5) what are the underlying factors that explain the pattern of LMP differentials; 6) to what extent do the differentials vary in response to changes in these explanatory factors; 7) does generating more QF power near a specific bus impact the observed LMP at that bus, and if so how large an impact is there on the LMP; 8) does generating QF power in North Carolina and sending it to the rest of the DOM Zone have a consistent, predictable impact on the LMP differentials; and 9) if the Commission is going to recognize this differential in developing the QF energy rates, whether it would be appropriate for the sake of consistency to also use the same differential to make a downward adjustment factor to the retail energy rates.

Section 6: QF Capacity Rates

Q. ARE THERE ALSO SPECIFIC ASPECTS OF THE PROPOSED QF CAPACITY RATES YOU WOULD LIKE TO DISCUSS?

A. Yes. I would like to discuss two aspects of the Utilities' proposals that are essentially the same as ones that have been proposed and rejected in the past – the use of zeros in calculating the avoided capacity rates, and reducing the Performance Adjustment Factor ("PAF") from 1.20 to 1.05.

Q. PLEASE EXPLAIN THE PROPOSED USE OF ZEROS.

A. The Utilities are proposing to calculate the avoided cost of capacity as zero during the initial years of their long term fixed rate QF rate calculations. This is the main justification for reducing the proposed capacity rates so drastically.

Difference in QF Rates: Duke Progress Current versus Proposed

	DEC Capacity	DEP Capacity	Average
2014 QF Rate	1.386 cents	1.303 cents	1.345 cents
Proposed QF Rate	0.478 cents	0.573 cents	0.526 cents

Difference	-0.908 cents	-0.730 cents	-0.820 cents
Percent Difference	-65.5 %	-56.0 %	-60.9%

The reason this table does not show any zeros is because the rates have been levelized (15 years for the 2014 rate and 10 years for the proposed rate). DNCP witness Gaskill explains the rationale for using zeros.

> Simply stated, the Company does not have a near-term need for additional generation capacity and, even if it did, additional Solar DG in North Carolina beyond what is already under contract would not defer future capacity needs.[132]

Duke witness Snider explained

> the capacity rates decreased primarily because the Companies do not have an actual capacity need during the initial years of the 10-year contract term period.[133]

Bowman offered a similar explanation for making essentially the same proposal.

> ...the capacity component of the Companies' avoided cost rates recognizes the capacity value of the QF starting in the first year that the Companies' IRPs demonstrate an actual capacity need. The Companies moderate their near term lack of capacity need by levelizing the capacity

132 Gaskill Direct, p. 28.

133 Snider Direct, p. 11.

> component over the 10-year term of the proposed standard contract.[134] Bowman Testimony Page 44

Duke witness Snider further explained this reasoning.

> Avoided capacity costs are represented on an annual basis in a similar fashion to the fixed cost of a car or home being represented as an annual car payment or mortgage payment. To appropriately incorporate the need for capacity consistent with PURPA, the annual fixed capacity costs that go into the avoided cost rate should include only the annual fixed capacity costs for years in which an actual capacity need exists as determined by the utilities' most recently filed IRPs.[135]

Q. HAS THE COMMISSION PREVIOUSLY DEALT WITH THIS LINE OF REASONING?

A. Yes. The Commission rejected the proposed inclusion of zeros in calculating the avoided capacity rate in the 2014 biennial proceeding. While some of the specifics might differ slightly, the arguments offered in that case are similar to those offered here:

> In support of DEC, DEP and DNCP's proposal to include zeroes in their avoided capacity cost calculations during the early years of the planning horizon, DEC/DEP witness Bowman testified that PURPA was not intended to force utilities to pay for capacity that they do not otherwise need ...DEC/DEP suggest that ...the avoided cost rate should include only the annual fixed capacity costs for years in

134 Bowman Direct, p. 44.

135 Snider Direct, p. 34.

> which an actual capacity need exists as determined by the utilities' most recently filed IRP.
>
> ...witness Petrie asserted that DNCP has all the capacity it needs and that it will not avoid any capacity costs if new QFs commence operation during this time period.[136]

After reviewing the Utilities' arguments in the 2014 avoided cost proceeding, the Commission rejected them:

> It is inappropriate in this docket, when employing the peaker method, to require the inclusion of zeroes for the early years when calculating avoided capacity rates.[137]
>
> The Commission determines ...that the avoided cost rate should [not] be reduced as advocated when the utility shows no need to acquire QF capacity when QF contracts are entered into.
>
> ...the FERC rejected claims bearing some similarities to the claims made by the utilities in this case, that a short-term lack of need because of a recently built plant justifies not making capacity payments. In Hydrodynamics (146 FERC ¶ 61,193), the FERC explained that avoided cost rates need not include the cost for capacity in the event that the utility's demand or need for capacity is zero. However, the FERC made clear that the time period over which the need for capacity needs to be considered is the planning horizon.
>
> ...Based on the facts of Hydrodynamics, the FERC determined that if a utility needs capacity over its planning horizon, i.e., it can avoid building or buying future capacity by virtue of purchasing from a QF, the avoided cost rates must include the full cost of the future capacity

136 <u>Order Setting Avoided Cost Input Parameters</u>, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 32.

137 <u>Order Setting Avoided Cost Input Parameters</u>, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 8.

> that would be avoided. The Commission is concerned that including zeroes ...may not equal the full cost of a CT and system marginal energy costs as a proxy for a baseload plant, as intended by the peaker method. ...It also is significant that the utilities typically are not penalized for having capacity that results in a reserve margin at or above the upper range of what is optimal ...each of the three shows the need for more than 3,000 MW of generation over the next 15 years, and it is that future generation that QFs can defer or avoid.[138]

I agree with the decision reached by the Commission in the 2014 proceeding, and I believe it is appropriate to again reject the use of zeros based upon the circumstances of this proceeding.

Among other reasons, I believe the use of zeros is inconsistent with the fundamental goals of PURPA, as well as the most appropriate interpretation of the concepts of "incremental cost" and "avoided cost." Furthermore, the use of zeros is inconsistent with the concept of "ratepayer indifference," and it leads to undue discrimination against small power producers.

138 Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014, p. 35.

Q. WHY ARE ZEROS INCONSISTENT WITH THE GOALS OF PURPA AND THE CONCEPTS OF INCREMENTAL COST AND AVOIDED COST?

A. If zeros are used, small power producers will not be fully compensated for their capacity. This is inconsistent with the goal of encouraging expanded use of biomass, solar and other targeted technologies which have long been neglected by the electric utility industry. Needless to say, refusing to pay for QF capacity is also inconsistent with the goal of encouraging investment in small power producers, making it harder small power producers to expand and exert competitive discipline on the incumbent firms.

In general, the goals of PURPA and the interests of society as a whole, including the using and consuming public in North Carolina specifically, are best promoted when PURPA is implemented in a way that focuses on long run incremental cost, rather than a short run measure of cost that excludes capacity costs. More specifically, QF avoided cost rates should reflect the full long run cost of building and operating the utilities' generating facilities, including years when new generating units are not being added.

Because of economies of scale, large utilities find it cost effective to construct very large plants. These plants are so large, they only need to be added at multi-year intervals. For example, assume the utility decides the optimum size plant is 600 MW or larger. If the utility needs to add capacity at the rate of 100 MW per year, it will not add a 100 MW plant every year. Instead, it will add a 600+ MW plant in a single year, then wait 5 or 6 years before adding another 600+ MW plant, then wait another 5 or 6 years before adding another 600+ MW plant. Under these circumstances, economic theory tells us there are long run capacity costs present in every year; they are not zero in some years and present in others.

This stair step pattern (which economists call "lumpiness") shows zero physical need for new capacity in most years. But, the utility is constantly growing and its older plants are slowly becoming costlier to maintain and operate as they gradually near retirement. Given these circumstances, even during years when "zero" capacity is planned, the long run cost of capacity is the same, or nearly the same as it is during other years, when a new block of capacity is scheduled for commercial operation.

This stair-step pattern with zeros is typical of the electric utility industry and it is descriptive of the actual generation expansion plans of DEC, DEP and DNCP. Accordingly, we know from economic theory that absence of a need for new capacity during some years (zero MW added) does not mean capacity has an economic value of zero or a long run incremental or avoided cost of zero during those years.

Q. HOW DOES THE PROPOSED USE OF ZEROS DISCRIMINATE AGAINST SMALL POWER PRODUCERS?

A. PURPA specifically states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers."[139] Under rate base regulation, the incumbent utilities are allowed to recover the cost of large new generating plants as they are completed and put into commercial operation (allowance for funds used during construction is accrued prior to that time), even though some of the capacity is being added prior to the time it is required (due to lumpiness). The QF rates should give QFs similar treatment – small power producers should be paid for the energy and capacity they provide to the utility as as each new generating plant is added to the grid. Capacity payments should not be held to zero until the first year when the incumbent utility plans to add a new generating plant.

Stated a little differently, since the incumbent utility is allowed to recover its capacity costs during the "zero" years just after a lumpy new plant has been added and its reserve margin is higher than the required minimum, to avoid discrimination, the QF should be treated the same – it should also be paid for capacity costs during the "zero" years, even though the QF capacity has the effect of pushing the reserve margin a little higher above the required minimum.

139 16 U.S.C. § 824a-3(a).

The simplest way to avoid discriminating against QFs is to ensure they are paid full capacity costs during every year, consistent with the long run incremental cost of building and operating new generating plants over their entire economic life cycle. Properly implemented, this long-run measure of avoided costs ensures that retail ratepayers pay the same amount for QF power that they are paying for power produced by the Utilities– no more and no less.

Q. Q. WHAT IS DUKE PROPOSING WITH RESPECT TO THE PERFORMANCE ADJUSTMENT FACTOR?

A. Consistent with its position in the 2014 biennial proceeding, Duke once again proposes to

> Reduce the performance adjustment factor ("PAF") from 1.20 to 1.05 to more appropriately align capacity payments to QFs under the peaker methodology with the availability of the avoided capacity resource, which is a combustion turbine ("CT").[140]

The same issue was debated in the last biennial proceeding.

> DEC/DEP witnesses Bowman and Snider testified that DEC and DEP are proposing to reduce the PAF to 1.05 to align its application better with the reliability of a natural

140 Snider Direct, p. 5.

> gas CT, the unit which the QF is presumed to avoid under the peaker method.[141]

To be clear, the issue in dispute is not what PAF represents the number of hours a CT is available each year. Rather, the issue is whether the PAF should be based upon CT availability or should it be based upon a broader interpretation of the purpose that is served by this factor.

Under the Peaker Method as historically interpreted and implemented by this Commission, it is more appropriate to focus on availability data for a<u>ll types of units</u>, including coal units and combined cycle units. Consideration needs to be given to the performance of all baseload generating plants because these are the units that produce the energy reflected in the avoided energy cost calculations. Similarly, consideration needs to be given to the entire life cycle of these units, including data showing the performance of older, less reliable units which are nearing retirement.

Q. PLEASE EXPAND UPON YOUR REASONING.

A. In the Peaker Method, the fixed costs of a peaking unit are used as a proxy for the capacity-related portion of the fixed costs of all units, including baseload units. Hence, I believe the availability of other types of generating units (e.g.

141 <u>Order Setting Avoided Cost Input Parameters</u> N.C.U.C., Docket No. E-100, Sub 140, December 31, 2014, p. 54.

coal and combined cycle units) must be considered, contrary to the narrower viewpoint expressed by the Utilities.

In this regard, I find persuasive the points made by Public Staff witness Ellis in the last biennial proceeding:

> Public Staff witness Ellis described the PAF and its history and noted that the Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive the capacity payments that the Commission had determined constitute the utility's avoided capacity costs.
>
> ...He stated that a 1.2 PAF allows a QF to receive the utility's full avoided capacity costs if it operates 83 percent of the on-peak hours. He noted that the Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.
>
> ...Witness Ellis testified that the Public Staff believes that the reduction of the PAF to 1.05 as proposed by the utilities is unjustified. The Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. He stated that performance at that level is commensurate with a baseload plant under any definition. He further stated that none of the data provided or arguments made is persuasive to justify a departure from that conclusion. In this regard, it should be considered that when the capacity factors reported by the utilities in their monthly baseload power plant performance filings are averaged over the last three calendar years, none of them operated their baseload fleet at an 83 percent capacity factor, which is the relevant statistic for comparison because QFs are paid for capacity

> on a kWh basis. For the calendar years of 2011, 2012, and 2013, the baseload plants in the rate bases of DEC, DEP and DNCP averaged capacity factors of 75.67 percent, 74.52 percent, and 74.83 percent, respectively, while recovering all of their capacity costs through rates.[142]

While the precise calculation of the PAF can be disputed, the key point is that QFs are supposed to be treated in a non-discriminatory manner, consistent with the treatment afforded the Utilities. Achieving a reasonable degree of consistency is also important because QF rates are supposed to leave customers financially indifferent between purchases of QF power and the construction and rate basing of utility-built resources.[143]

Retail customers are paying for all of the Utilities generating units, including ones that only operate a few hours of the year, and ones that are not available when needed during the peak hours, due to scheduled maintenance and other factors. This consistency should be viewed from the perspective the entire life cycle of the unit, not just the first few years after it is built when reliability is at its peak, and maintenance requirements are low. As units age, more maintenance may be required, more outages may occur, reliability may

142 Order Setting Avoided Cost Input Parameters, N.C.U.C., Docket No. E-100, Sub 140, December 31, 2014, p. 55.

143 See, e.g., Southern Cal. Edison, San Diego Gas & Elec., 71 FERC ¶ 61,269 at p. 62,080 (1995) (noting that "the intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives").

decline, and it may no longer be cost-effective to operate the unit 24 hours a day all year long.

The key point is that retail customers pay the full cost of owning and operating the Utilities' older units as long as they remain in the rate base, regardless of how often they are down for maintenance, or how infrequently they are operated. Hence, to meet the standards of ratepayer indifference and non-discrimination, it is necessary to remember that customers are pay the full ownership-related costs of Duke's generating units, regardless of how few hours they produce electricity during any given year. In contrast, the QF only receives capacity payments when it is producing electricity.

Reducing the performance adjustment factor to 1.05 would have the effect of requiring a QF to produce at full capacity during 95% of the on peak hours in order to receive full payment of the avoided capacity costs. For instance, a solar generator would not receive full payment of the avoided capacity costs, because it is incapable of generating electricity during 95% of the on peak hours due to the fact that many on peak hours occur when the before the sun rises or after the sun sets.

It is important to remember that Duke is not being held to this high a standard—i.e., 95%—for its fossil-fueled plants. For example, Duke has coal fired units that were designed and intended to be operated at full load during all of the peak hours. Yet, these units are not producing this much energy under current conditions – some coal units are now being dispatched like intermediate units, instead. The end result is that ratepayers are paying a very high amount per kWh for these units, since their fixed costs are being spread over a unexpectedly small amount of energy output. If Duke were held to the same standard as QFs, it would only receive payment for the portion of its fixed costs that could be recouped from the limited amount of energy the units are actually producing during the on peak hours. The PAF is an important element of the Commission's implementation of the Peaker Method, since it helps ensure a reasonable level of compensation to QFs, notwithstanding the fact that their capacity related revenue is tied to the amount of kWh that is produced over a broadly defined on peak period.

Section 7: Operational Concerns and QF Rate Design

Q. ARE THERE ANY OTHER ASPECTS OF THE UTILITIES' RATE PROPOSALS THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. I would like to discuss their proposals concerning seasonality and hourly cost variations, particularly as these relate to the operational challenges and concerns that have been identified by the utilities.

Q. WHAT ARE THE UTILITIES PROPOSING WITH REGARD TO HOURLY COST VARIATIONS?

A. DEC, DEP and DNCP are all proposing to retain their existing on peak and off peak hours. As a result, the Utilities are proposing to continue to use very broadly defined time periods. This is anomalous, since Duke and DNCP also go to great effort to identify and describe various concerns they have related to the growing volume of solar energy that is being generated during certain hours of the day – during specific parts of the year.

Q. WHY IS THIS ANOMALOUS?

A. Because many of the problems they are describing are so clearly time-related, it is surprising they are not looking for solutions that are specific to these time periods. As an economist, it strikes me as completely anomalous to hear about a time-specific problem, yet no effort is being made to solve the problem in a time-specific manner. In fact, the first thing that comes to mind when I hear about a time related problem is to see whether improved price signals can solve the problem, or at least ameliorate it.

For example, the classical economic solution to highway congestion is to charge a time-variant price for use of the highway during peak hours. I recall hearing this example in one of my first undergraduate courses in economics in the 1970s. The professor explained that society was wasting the time of drivers who were stuck in traffic, and wasting millions of dollars of their taxes constantly building more and more highways, with more and more lanes, just because we were not send the correct price signals.

The solution is to improve prices signals as necessary in order to avoid wasting everyone time sitting in traffic. Ideally, the highest price is charged during the busiest hours, lower prices are charged during moderately busy hours, and a very low (or zero) price is charged late at night and during weekends when the highways are empty.

By charging a higher price during rush hours, some of the people will start to drive at an earlier or later time (or wait until the weekend to run their errands). Improved price signals, or creating price signals where they are entirely lacking, has the predictable result of encouraging people to voluntarily car pool, or modify their work hours to avoid the peak hour. Simply by sending better price signals, much of the congestion may go away. But, to the extent the peak hour continues to be congested, the money collected from the rush hour price can be used to pay for more lanes and more highways – neatly solving the remainder of the problem without having to raise taxes on people who don't drive during the rush hour.

Years ago, many non-economists were not familiar with the benefits of improving price signals. But, now everyone is at least somewhat familiar with the concept. For instance, some cities and states are using computers to adjust highway tolls multiple times each day, in response to operational challenges and concerns that have been identified by the utilities' response to traffic patterns. Now that human toll collectors are not required to collect the fee from frequent drivers, it is effortless for everyone involved to calculate and collect at different prices at different times – sometimes even adjusting and posting notice of the price on a fluid basis in response to real time conditions.

It is increasingly common to see variations on this approach in many different industries – from movie theaters to airlines. Most people are at least vaguely aware of the fact that the airline industry is constantly improving and refining their pricing methods in an effort to maximize the yield every time a plane takes off – and too keep the planes filled nearly to capacity, 24-hours a day.

Hence, it is somewhat anomalous that Duke is proposing multiple, broad brush changes to their QF tariffs which will greatly increase the risks faced by small power producers and discourage investment in solar energy, yet they have not proposed any changes to more precisely tailor their QF rates or improve the price signals being sent to small power producers.

Q. WHAT ARE THE UTILITIES PROPOSING WITH REGARD TO SEASONS?

A. As with the hourly rates, they are not proposing any improvements to the seasonal aspect of their rates. Duke, however, is proposing to change the allocation of capacity costs between the summer and non-summer seasons. Duke witness Snider explains the rationale for this proposed change.

> In the past, the Companies' annual peak demands were projected to occur in the summer. Additionally, the Companies' generating fleets have greater output during winter periods compared to summer periods, particularly for gas-fired CT and combined-cycle units. ...Thus, summer load and resources have driven the timing need for new resource additions, and a summer reserve margin target provided adequate reserves in both the summer and winter periods and was sufficient for ensuring overall resource adequacy.
>
> The load and resource balance has changed drastically in the past two-three years, driven primarily by the high penetration of solar resources and the significant load response to cold weather experienced during the 2014 and 2015 winter periods. As discussed in more detail later in my testimony, solar resources contribute significantly more to the summer afternoon peak than they contribute to the winter morning peak. As such, the 2016 resource adequacy studies demonstrated that the loss of load risk is now heavily concentrated during the winter period. Thus, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, and winter load

> and resources now drive the timing need for new capacity additions.[144]

Based on this reasoning, Duke is proposing to allocate 20% of the avoided capacity costs to the summer (June through September) QF months. The other 80% will be allocated to the remaining non-summer months (October through May). This is a drastic change from the last biennial proceeding, where Duke gave 60% weight to the summer and 40% weight to the non-summer months.

Q. WHAT IS YOUR RESPONSE TO THESE PROPOSALS?

A. I recommend the Commission reject the proposal to give 80% weight to the non-summer months. As well, I recommend the Commission initiate steps to provide stronger, more precise peak and off peak price signals in the QF tariffs. These steps do not necessarily need to be completed in this proceeding, but there is no question in my mind that this is the direction the Commission should be heading.

Stronger, more precise price signals are needed, which are narrowly tailored to carefully identified hours during the summer and deep winter months. The price signals that are optimal during a hot summer day and a cold summer morning are conceptually similar, but the hours are different. The price signals that are optimal during other months of the year, when the weather is

[144] Snider Direct, pp 22-23.

much milder, are very different. The one constant across these different seasons is that the hourly rates need to be more precisely defined, and better, more meaningful price signals sent to small power producers, to encourage them to provide more of their power when it is most valuable, and less when it is least valuable. Among other benefits, improved price signals will help to ameliorate or prevent problems that might otherwise arise as a larger and larger percentage of the energy supplied to the system comes from solar facilities of all types (including those owned by the Utilities, individual retail customers, and QFs).

More precise price signals are a superior solution to many of the concerns the Utilities have identified which are related to, or directly attributable to, growth in solar energy. Among other benefits, if the utilities continue to resist adopting technology-specific rates, there is a mechanism in place that can ensure that small power producers that use wind, methane derived from landfills, hog or poultry waste and non-animal biomass are not penalized for problems (or perceived problems) that are specific to solar energy. Unless the rate design is improved, changes that are made to the standard offer rates in response to solar-specific concerns (whether implicitly or explicitly) have the potential to impose massive "collateral damage" on all other types of QFs.

If the Commission is concerned about the potential impact of "operationally excess energy," then its response should be tailored in a way that targets that specific concern and avoids adopting changes that broadly and unfairly impact all types of QFs. This is particularly obvious with respect to the operational concerns that have been identified by the Utilities, including the growth of what they call “operationally excess energy” which only occurs during specific hours of specific months, but the same principal applies generally. Before the Commission takes drastic steps to slash rates paid to QFs or make those rates less predictable, thereby making it much harder to finance QF investments, it should focus on improving the rate design in ways that are responsive to the specific concerns that have been identified.

Q. CAN YOU PROVIDE THE COMMISSON WITH DATA THAT EXPLAINS WHY YOU DISAGREE WITH ALLOCATING 80% OF CAPACITY COSTS TO THE WINTER?

A. Yes. The following chart is derived from a detailed analysis of hourly load data for DEC and DEP for the years 2006-2015, as filed by the utilities at the FERC on FERC Form 714.

The hourly load data indicates that approximately 86.5% of the most extreme system peaks (at or above 99% of the annual coincident system peak) occurred during the months of June through September, while the remaining 13.5% occurred during the months of December, January and February. None of these extreme peaks have occurred during any other months. A very similar pattern is reflected in the data for peaks of less extreme magnitude, as shown in the following table.

Magnitude of Peak	June - September	December - February	Other
Hourly Load +> 99% of Annual Peak	86.5%	13.5%	0.0%
Hourly Load +> 97% of Annual Peak	90.3%	9.2%	0.6%
Hourly Load +> 95% of Annual Peak	90.4%	9.0%	0.6%
Hourly Load +> 90% of Annual Peak	90.4%	9.0%	0.6%

This data is entirely inconsistent with Duke's proposal to allocate 80% of the capacity costs to a broadly defined non-summer period that starts in October and ends in May. If the Commission is going to move away from the 60% Summer 40% Non-Summer allocation percentages that were used in the last biennial proceeding, then any movement should place more emphasis on the hot summer afternoons and less emphasis on months like October, November, April and May – when extreme peaks almost never occur.

Q. WHAT DO YOU RECOMMEND WITH REGARD TO SEASONS?

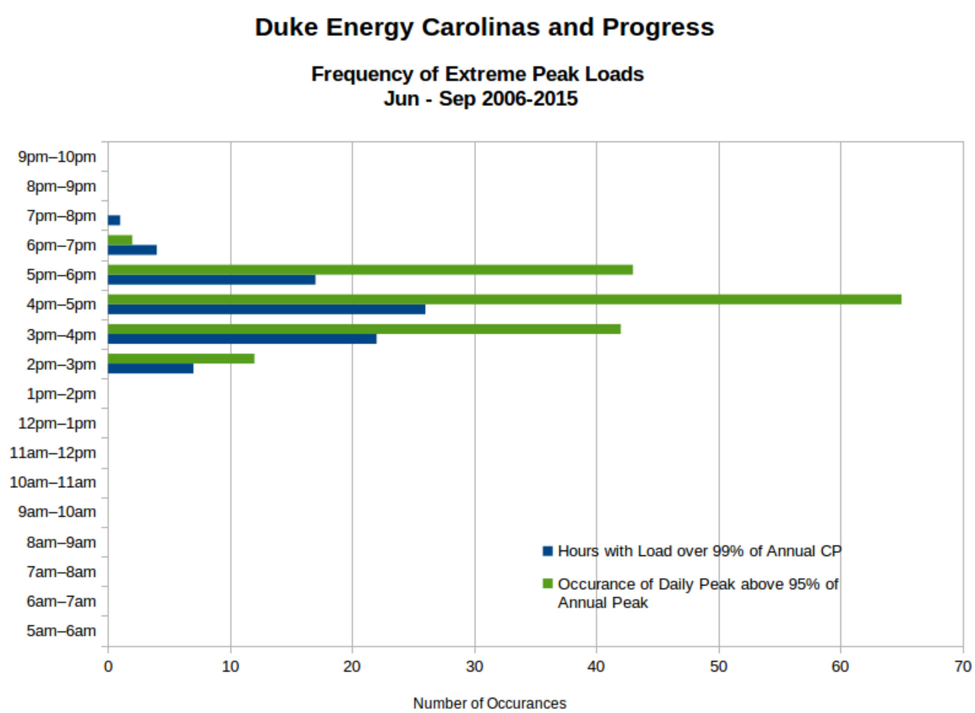
A. Ideally, the QF rates would distinguish between three distinct seasons. 80% of the capacity costs would be allocated to the months of June through September, and recovered during the hot afternoon peak hours. The remaining 20% would be allocated to the months of December through February and recovered through the cold morning hours. The remaining months (October through November and March through May) tend to have the mildest weather, and hourly peak variations are not as extreme. Hence the QF rates in those months would ideally be designed differently, taking this into account.

I prefaced those comments with the word "ideally" because I do not think it is of critical importance to resolve this issue at this time. I recognize the Commission has many issues to work through and want to make clear that simply retaining the 60% summer/40% non-winter allocation that was used in the 2014 proceeding would also be an acceptable approach. That would avoid moving in the wrong direction and provides a reasonable basis for evaluating other, higher priority issues, like specific hours that are defined in the QF tariffs.

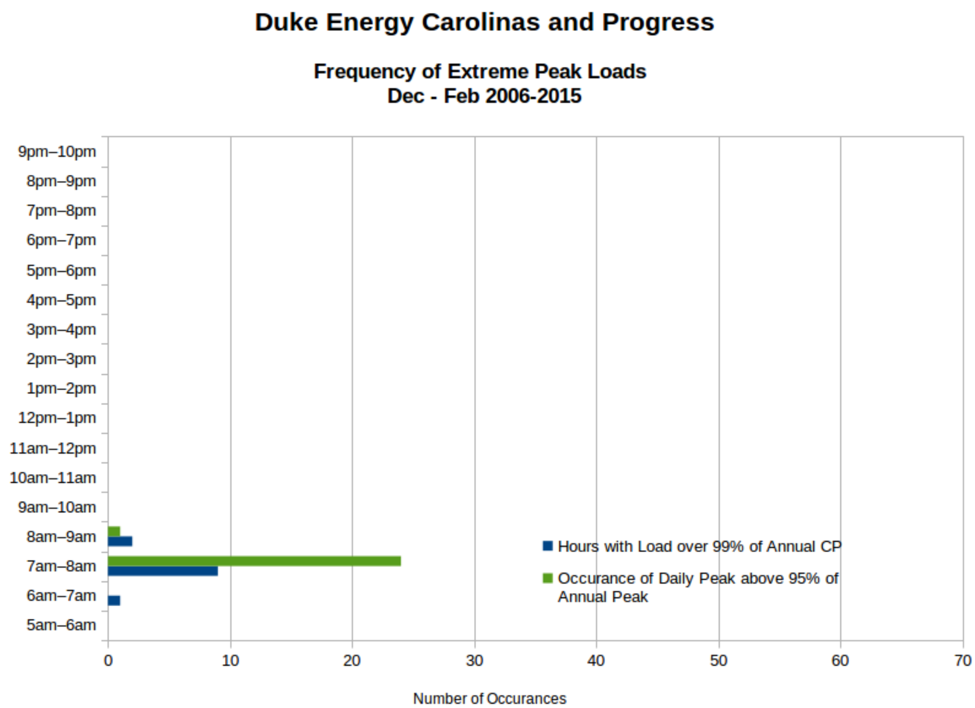
Q. CAN YOU ALSO PROVIDE THE COMMISSION WITH SOME DATA THAT SHOWS WHY YOU THINK THE PEAK AND OFF PEAK PERIODS SHOULD BE DEFINED MORE NARROWLY?

A. Yes. I also studied in considerable detail the same load data taken from DEC and DEP's Form 714 submitted to FERC for the years 2006-2015 to see if clear, more precise hourly patterns in the data can be identified. This detailed analysis of more than 175,000 hourly data points confirms the obvious: peak loads on Duke's system are highly weather sensitive, following some straightforward, predictable patterns.

In this first graph, the dark blue bars indicate the frequency when loads above 99% of the annual system coincident peak occurred. The green bars indicate how often the maximum daily peak occurred during a given hour during days when the daily peak was above 90% of the annual peak.



This data demonstrates the most highest, most important extreme peak conditions occur on hot afternoons in the summer, from approximately 2:00 p.m. until 6:00 p.m. The next graph shows the analogous data for the months of December, January and February.



Since all of this data is from the same source, and the scales are the same, it is readily apparent that the only remaining peak hours of any major importance are those that occur in the early morning hours of December through February. In most years, these peaks occur less frequently, and are less severe than those that occur during hot afternoons in the summer.

Two important exceptions occurred during 2014 and 2015 when some extreme needle peaks were briefly experienced under severe cold "Polar Vortex" weather conditions. These peaks actually exceeded the annual summer peaks in those years. However, it would be a mistake to overreact to these brief peaks. While they are important, and help justify allocating a reasonable share of total capacity costs to the months of December through

February, the basic pattern remains unchanged: the most important non-summer peaks all occur on cold early mornings in just three months of the year. All other hours, and all other months are of drastically less importance when deciding how to shape the QF price signals.

Even under those years, however, the extreme peaks that occurred on winter mornings were different than those that occurred on summer afternoons – they were both of shorter duration, and less frequent. All of these observations can easily be confirmed by studying the following graphs which summarize the hourly load data.

Q. WHAT CONCLUSIONS HAVE YOU REACHED BASED ON THE HOURLY LOAD DATA?

A. The most extreme system peaks (at or above 99% of the annual coincident system peak) tend to occur during June through September in the late afternoon, around 4 p.m. The late afternoon is also when the maximum daily peak almost invariably occurs on days when the daily peak is at least 90% of the annual system peak. The existing QF rate design is not adequately tailored to this pattern, since it establishes an overly broad on-peak period which dilutes the price signals and fails to inform small power producers when their capacity is most valuable.

To provide stronger, more precise summer price signals, I recommend narrowing the on peak period to the four hours from 2:00 pm until 6:00 pm during June through September. If a more complex rate design is acceptable, an adjacent “shoulder peak” period could be identified starting an hour earlier (at 1:00 p.m.) and extending two hours later (8:00 pm).

A similar, even more severe problem exists with the non-summer rate design. In reality, all of the highest, most important non-summer peaks tend to occur in the early morning around 8 a.m. during December, January and February. The current rate design completely fails to convey this important price signal to small power producers. Instead, it provides the impression that their capacity is equally valuable during many other hours and months.

To provide stronger, more precise non-summer price signals, I recommend limiting the on peak period to the two hours from 7:00 am until 9:00 am during December through February. If a slightly more complex rate design is acceptable, a “shoulder peak” period could be identified that starts an hour earlier and ends an hour later. The rate during these shoulder hours would be modestly higher than during the off peak hours, but substantially less than the rate that applies during the on peak hours.

Q. CAN YOU PROVIDE SOME FURTHER EXPLANATION OF YOUR REASONING BEHIND THESE RECOMMENDATIONS?

A. Yes. It is logical to recover most of the capacity-related costs around the time when the most extreme peaks have the greatest probability of occurring. However, it would be a mistake to recover the entirety of the capacity-related costs from a single hour of each year, or even during a single hour of each day, since capacity also has value during other hours, when there is moderate probability of extreme peaks occurring.

Needless to say, the precise hour when the system peak will occur during any given year (or during any given day) cannot be known in advance. The same thing can be said with respect to the summer and winter peaks. It would be a mistake to treat cold winter mornings as irrelevant, since the peaks during those times reach 90% of the annual system peak on a fairly frequent basis. As well, there are times when the weather is cold enough that an even more extreme peak occurs which approaches or even briefly exceeds the sort of extreme peaks that are much more frequently and routinely observed during hot summer afternoons.

Capacity is most valuable during the hours when the greatest probability of high system peak occurring, but capacity value is not limited to the one or two most extreme peaks that occur during any one year, or any single decade. Thus, for example, it would be a mistake to focus the price signals exclusively on the early morning hours merely because extreme needle peaks sometimes occur at that time – for instance during a Polar Vortex.

The approach I am recommending provides a reasonable balance by sending much stronger, narrower price signals, while avoiding the mistake of over-reacting to extremely unusual weather events, or treating the single annual peak as the only hour having any importance.

Accordingly, given the load characteristics of the DEC and DEP systems, it is reasonable to assign the bulk of the avoided capacity-related costs to summer afternoon hours when the extreme peaks have the greatest probability of occurring, to assign a lesser portion of the capacity-related costs to "shoulder" hours before and after that critical time period, and to assign the remaining costs during the months of December through February, especially in the early morning from 7 a.m. to 9 a.m., which is when "needle peaks" occasionally occur during extreme cold snaps.

Q. WHAT ARE THE OPERATIONAL CHALLENGES AND CONCERNS YOU MENTIONED EARLIER?

A. Both Duke and DNCP express some concerns about the rapid growth in solar energy, which is posing some new challenges for them. Duke witness Yates testifies that:

> [T]he continuing surge in utility-scale solar QF generation is increasingly challenging how the Companies plan and operate their generation fleets, manage their transmission systems, and assure reliable power is delivered to our customers over local distribution circuits on a minute-by-minute basis. Unless thoughtful solutions are implemented to address the current situation, the number, severity, and consequences of these challenges are expected to increase as the level of variable and non-dispatchable solar energy increases.[145]

Duke witness Holeman succinctly described Duke's main concerns, when he testifies that:

> Based on this continuing, rapid growth over the past 18 months and the associated operational experience in accordance with NERC's reliability requirements, the Companies have identified the following challenges associated with integrating these significant levels of PURPA solar: (i) managing "unscheduled" and "unconstrained" solar QF energy injections bounded by the Security Constrained Unit Commitment of reliable load following service; (ii) managing the variability and intermittency of solar energy injections; (iii) managing the growing amounts of operationally excess energy injected by solar facilities, particular during the spring, fall, and winter periods; and (iv) ensuring compliance with NERC

145 Yates Direct, p. 9.

> reliability standards, specifically including the BAL standards.[146]

Q. DO YOU AGREE THESE ARE LEGITIMATE CONCERNS THAT NEED TO BE RESOLVED?

A. Yes. Some operational challenges and concerns are unavoidable and inevitable during any major transition in an industry. Regardless of whether the changes are resulting from technological innovations, shifting cost curves, industry restructuring, competitive forces, or any other source of fundamental changes to the way an industry has historically operated, it is important for industry participants to be aware of the changes and develop appropriate, timely responses.

In this case, the challenges and concerns Duke has identified are a result of the success of decades-long efforts by state and federal policy makers to encourage a shift toward increased use of solar and other renewable energy sources, as part of an "All of the Above" strategy. Rather than thinking about these challenges as indications something is going wrong, it is more appropriate to view them as "growing pains" that are occurring as solar energy is finally becoming more cost effective, and it is starting to create fundamental

146 Direct Testimony of John Samuel Holeman III on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, N.C.U.C. Docket No. E-100, Sub 148, February 21, 2017 ("Holeman Direct"), p.10.

economic dislocations, as it begins to partially displace coal and other historically vital energy sources.

Of course, the fact that this shift toward a more diversified energy mix has long been sought by state and federal policy makers doesn't change the fact that the transition period can be difficult. Changes of this importance and magnitude will require appropriate managerial, operational and strategic responses by many parties, but most especially by the incumbent utilities. Since this is a regulated industry, it is also vitally important for the Commission to be aware of the changes that will increasingly be taking place as solar grows in importance.

Q. DO THESE CHALLENGES CREATE A CRISIS WHERE A QUICK RESPONSE IS ALMOST MORE IMPORTANT THAN THE CORRECT RESPONSE?

A. No. While solar is growing, it is starting from a small base. As I noted earlier, Duke Energy Corporation reported that Solar provided well under 1% of its total generation during 2016.[147] The challenges are being identified early, while the impacts are still quite manageable.

147 Duke Energy Corporation, 2016 Form 10-K, Page 12.

Q. DO YOU AGREE DUKE'S PROPOSED RESPONSES?

A. Duke does seem to be starting to think proactively about potential solutions to some of these challenges, or at least it is starting to think about the implications of growing amounts of solar on other aspects of its decision-making process. For example, Duke witness Snider testifies as follows:

> ...increasing levels of variable unscheduled and unconstrained solar QFs may create an incremental need for faster response load following generation to meet system loads when solar generation either increases or decreases rapidly. In fact, the Companies have already added or are proposing to add more flexible resources to the system, such as fast-start CTs at Sutton, runner upgrades at Bad Creek Pumped Hydro Station, dual fuel optionality at Cliffside, and the recently announced expansion at the Lincoln County CT site. While increasing levels of solar on the system may not have been the primary driver for these projects, the operational flexibility these projects provide has value given the increasing levels of solar on the system. As more non-dispatchable solar is added, additional flexible resources of all types may be required to reliably manage system operations.[148]

Some solutions – like adding more quick start, flexible generation – seem intuitive, logical, and very likely will prove to be beneficial. However, some of the other solutions that are being considered might seem appealing from Duke's perspective, but they are clearly not appealing from the perspective of a small power producer, and would not be in the public interest.

148 Snider Direct, p. 25.

I am particularly troubled by the suggestion that Duke might start declaring a system "emergency" when solar energy is displacing some of Duke's less flexible generating resources, because those facilities do not have enough ramping flexibility. As testified by witness Holeman:

> [U]nder FERC's PURPA regulations, absent contractual agreement otherwise, a QF injecting energy into a system under a contract may be curtailed and the energy injections discontinued only in a "system emergency.". . . . The Companies' recent and growing experience indicates that solar QF energy is injected into the BA whenever the sun shines, and therefore, the BA operator has limited tools to maintain reliability in the face of these unscheduled and unconstrained injections of QF energy.[149]

If I understand this testimony correctly, Witness Holeman seems to suggest that whenever the sun is shining and the system load happens to be low, Duke should have the option to simply declare an emergency and stop paying QFs for their energy. I am confident that if the shoe were on the other foot, Duke would strongly object to this sort of one-sided solution to problem has many intertwined causes.

This proposal would not be in the public interest, and should not be adopted. First, it forces the solar power producers to shoulder entirely too much risk, since there is no limitation specified on how often the "emergency" can be declared, or how much revenue a QF will lose. This "solution" would effectively give Duke too much power to decide how much revenue a solar

149 Holeman Direct, p. 11.

QF can receive during any particular day or month, simply by declaring an emergency. Needless to say, this uncertainty would make it much more difficult to finance solar projects.

Second, it would be fundamentally anti-competitive to give this sort of discretion to the incumbent utility, since it competes with QFs as a builder and operator of generating facilities.

Third, this proposed solution creates the impression that the problem is being caused by the solar firms, which is simply not true. In reality, the operational challenges he is discussing are the result of multiple factors interacting with each other. Growth in solar, and the variability of this generating source are two contributing factors, but an equally important factor is the mix of generating technologies that happen to exist on Duke's system. If Duke had built fewer plants with long ramping times, and instead built more quick start combustion turbines and combined cycle plants, with their more rapid ramping and greater operational flexibility, these challenges would not be as serious, or simple solutions would be more readily at hand.

Q. ARE THERE ANY OTHER OPTIONS FOR OVERCOMING THESE CHALLENGES?

A. Yes. Although I am confident many options are worth investigating, I will not attempt to provide an exhaustive list. Instead, two simple examples will suffice. One option would be to modify how Duke's pumped storage capacity is managed. Perhaps more pumping should occur from mid-morning until noon, when solar energy is plentiful the potential for operationally "excess" energy is a risk. The water can then be used to send electricity back onto the grid later in the day, after the sun sets but air conditioners are still running. A second example would be to negotiate "Take or Pay" contracts with some of the solar QFs connected to its system.

Q. HAS DUKE ALREADY THOROUGHLY STUDIED THE PUMPED STORAGE OPTION AND REJECTED IT?

A. No, not to my knowledge. In discovery, Duke was specifically asked about the first option, and it did not appear to have rejected it.

> <u>Request</u>:
>
> Has non-utility owned renewable generation caused the Company to modify its operations of its pumped storage hydroelectric facilities? If so, please provide a narrative on the changes in operation of the pumped storage facilities,

> including changes in scheduling of recharge or discharge of power.
>
> Response:
>
> The 2016 IRP did not evaluate this issue. This assessment would require running two production cost runs, one with non-utility owned solar and another without non-utility owned solar to then analyze the effect on pump storage operations. No such analysis was conducted in the IRP scenarios.[150]

Q. WHAT ARE TAKE OR PAY CONTRACTS?

A. The accounting firm Ernst and Young offers an excellent brief definition:

> A take-or-pay contract is a supply agreement between a customer and a supplier in which the price is set for a specified minimum quantity of a particular good or service and the price is payable irrespective of whether the good or service is taken by the customer. Take-or-pay contracts are commonly used in the [Power and Utility] industry and may involve the supply of gas, transmission capacity or electricity. These contracts can be long-term in nature and contain terms and conditions with varying degrees of complexity (e.g., fixed or stepped volumes; simple fixed, stepped or variable pricing)[151]

“Take or Pay" is a pricing concept that has a long history in the natural gas industry (e.g. interstate pipelines and LNG suppliers), but it has also occasionally been used by electric utilities.

150 DEC response to NCSEADR 11-4, Docket No. E-100, Sub 147; see also DEC response to PSDR3-6, Docket No. E-100, Sub 148.

151 Ernst and Young, “The revised revenue recognition proposal – power and utilities,” March 2012, p. 16, available at: http://www.ey.com/Publication/vwLUAssets/Power-Utilities:_revised_revenue_recognition_proposal/$FILE/Applying%20IFRS%20Power-Utilities%20-%20Revised%20proposals%20for%20revenue.pdf (last accessed March 27, 2017).

A take-or-pay contract is typically used to resolve a dilemma which would otherwise arise, because there is a mismatch between the seller's need for revenue predictability and the buyer's need for operational flexibility. On the one hand, the seller might need a high level of assured revenue to justify making a large specialized investment that has high fixed costs (e.g., a Liquified Natural Gas terminal). On the other hand, the buyer might need maximum flexibility to decide whether, and to what extent it actually uses the service provided by the seller.

Consider, for example, a buyer that wants complete flexibility to decide whether, and when, to use an LNG terminal. The buyer is given the flexibility to use the terminal whenever they have a ship available for importing or exporting gas, but the owner and operator of the terminal is promised the assured revenue stream it needs to finance the project and cover its fixed costs, even if the terminal is sitting idle most of the time.

Q. WHY MIGHT TAKE OR PAY CONTRACTS BE HELPFUL TO DUKE?

A. In the solar context, a take or pay structure can provide a "win-win" solution which gives both the utility and the solar producer what they want. The contract can reassure the solar producer it will be paid for its output even if it is not taken, while Duke can be given complete operational control over the output, to keep or throw away, as it sees fit.

A Take or Pay contract can be structured many different ways, but in a typical case, if the buyer decides not to "take" all of the service that is offered by the seller, the buyer is committed to nevertheless "pay" for the offered service. The idea is to guarantee a minimum revenue stream to the seller, making it easier to finance a project, or to shift specified risks from the seller to the buyer. In general, the idea is to ensure that adequate financial compensation is provided to the seller, regardless of whether or not the buyer actually uses the full volume of service that is provided by the seller.

Q. COULD DUKE BENEFIT FROM PAYING FOR SOLAR ENERGY IT DOES NOT TAKE?

A. Yes, although this possibility is not intuitively obvious, since solar has virtually no variable expenses. Thus, from the perspective of a simple fixed and variable cost analysis, one would expect the solar plant would always be placed at the very bottom of the dispatch stack, even before nuclear plants, which use uranium and incur other variable costs. In practice, of course, the picture isn't quite that simple, since there are operational challenges involved with nuclear plants which may make them less flexible than solar.

There is the potential to extract some valuable operational benefits from solar facilities, if some of the solar energy is effectively discarded rather than used. In essence, some of the capacity is held back in reserve, to be instantly ramped up and sent to the grid on a second by second basis, as and when desired. If energy injections from some solar facilities were finely controlled in this manner, they could be used to help maintain stable voltage or function like spinning reserve (but only during times when the sun is shining, of course).

Q. FINALLY, CAN YOU PLEASE COMMENT ON THE PROPOSAL TO REDUCE THE 5 MW CEILING FOR THE STANDARD OFFER TARIFF TO 1 MW?

A. I do not think it would be wise to accept this proposal – it is simply too extreme a change, with too little thought having been given to the potential for unintended consequences. Admittedly, this particular proposal is not as troubling to me as some of the other proposals, like forcing fixed cost solar facilities to rely on an unpredictable revenue stream. And, there are obviously some tradeoffs involved with this issue. I can see some potential benefit from encouraging the industry to build smaller plants, which can be more easily located in urban areas, and more of the potential benefits from distributed generation can be achieved.

Cutting the other way, however, is the risk of unintended adverse consequence from such a drastic change. The main concern I have is that many firms may be very reluctant to engage in costly, time consuming negotiations, which may force them to stay within the familiar terrain of the standard offer tariff. If this happens, we may suddenly see a five-fold increase in the number of projects moving through the queues. This will impose very significant and unnecessary costs on the Utilities and the QFs, because of all the added paper work, engineering studies, legal documentation and other unnecessary expense in response to this proposal.

For that reason, I think, on balance, it would be unwise to change the threshold so drastically. If the Commission is inclined to modify the threshold, I would recommend making a much smaller step in that direction – perhaps to 3.75 or 4 MW. This would allow the Commission to observe how the market reacts to a change in the threshold. Perhaps firms will want to continue to build and operate 5 MW plants, because this is a familiar size. Or perhaps some will decide that as long as they are going to be forced to expend the time and effort required for negotiations, they will get a better return on that investment by building fewer, larger projects. In that case, we may see a surge in 10 or 15 MW projects. Either way, taking a much smaller step toward lowering the threshold would be prudent, rather than drastically changing it from 5 MW to 1 MW. Needless to say, whatever decision the Commission makes, this is something that could be reconsidered in the next biennial proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

4822-3197-1653, v. 6