BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	**NCSEA'S INITIAL**
Rates for Electric Utility Purchases from	)	**COMMENTS**
Qualifying Facilities – 2018	)	
	)	

Attachment 1
[PUBLIC]

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

I, BENJAMIN FRANKLIN JOHNSON, being first duly sworn, do depose and say:

<u>PURPOSE</u>

1. My name is Benjamin Franklin Johnson. This affidavit was prepared at the request of the North Carolina Sustainable Energy Association ("NCSEA"), for use in Docket No. E-100, Sub 158.

2. I have been asked to provide factual evidence concerning the calculation of avoided costs of Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") and Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("DENC") (collectively, the "utilities"), to review the utilities' November 1, 2018 initial filings in this docket, to assist with the preparation of discovery requests, to review responses to discovery requests, to analyze the comments and other information filed in this docket by the North Carolina Public Staff ("Staff") and other parties, and to provide recommendations to the Commission for its consideration in resolving the disputed issues in this proceeding.

<u>QUALIFICATIONS</u>

3. I am a consulting economist and President of Ben Johnson Associates, Inc. (BJA), a firm of economic and analytic consultants specializing in the area of public utility regulation. My business address is 5600 Pimlico Drive, Tallahassee, Florida 32309.

4. 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.

5. I have prepared and presented 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. I have been actively involved in more than 400 regulatory dockets. My work has spanned a wide range of different subject areas, involving the application of economic theory and principles to public policy issues involving the electric, gas, telecommunications, water and wastewater industries.

6. My firm has participated in more than 30 proceedings before the North Carolina Utilities Commission, beginning in 1983 with Docket No. P-55 Sub 834, a Southern Bell rate case. Some of the firm's other North Carolina consulting engagements include: Docket Number 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 Number E-100, Sub 66, a 1993 proceeding concerning avoided costs; Docket Number E-100, Sub 74, a 1995 proceeding concerning avoided costs; Docket Number E-100, Sub 75, a 1995 proceeding concerning Least Cost Integrated Resource Planning; Docket Number 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, and E-100, Sub 112, a 2007 Duke Energy Carolinas case; Docket Nos. E-7, Sub 909, a

2009 Duke Energy Carolinas 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, a 2012 proceeding concerning avoided costs, Docket No. E-100, Sub 140, a 2014 proceeding concerning avoided costs, Docket No. E-100, Sub 148, a 2016 proceeding concerning avoided costs.

7. The great majority of our consulting work in North Carolina has been on behalf of the Public Staff, although in recent years we have been working for NCSEA.

PREPARATION

8. I have reviewed the Commission's October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (the "Sub 148 Order"); the utilities' Initial Filings in this proceeding; the utilities' responses to discovery in this proceeding; the utilities' 2018 Integrated Resource Plans submitted in Docket No. E-100, Sub 157; and House Bill 589 ("HB 589").

MORE ACCURATE QF PRICE SIGNALS ARE NEEDED

9. Stronger, more accurate price signals help market participants make better, more efficient decisions concerning where to invest capital, which technologies to use, how to best to configure facilities, and how to operate those facilities.

10. In adopting PURPA, Congress was not just encouraging a shift toward more diverse energy supply sources, it was also pursuing a strategy of diversification away from the monopoly supply of electrical energy generation.

11. 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 effectively suppressed by government policy. PURPA largely reflects the same pro-competitive philosophy that underpinned airline deregulation, which was implemented around the same time. However, unlike the changes that were implemented in the airline industry, Congress sought to gain some of the benefits of increased competition without foregoing the benefits of traditional monopoly rate base regulation.

12. In North Carolina, PURPA has been successful in encouraging investment by small firms using solar and other non-traditional technologies, through carefully thought-out constraints on monopsony power by the traditional rate base- regulated utilities. To continue to fully achieve the benefits provided by QF competition, it is becoming increasingly important to provide QFs with better, more accurate price signals. This is particularly important as the number of market participants increases, the overall scale of their investments has become larger, and QFs become more experienced and sophisticated in their investment decisions. Appropriately implemented, PURPA functions somewhat like a competitive agricultural market. All farmers receive a similar price for their production, and all are free to produce as much as they want. Hence, success or failure largely depends on their own decisions – which crops they plant, the timing of when they plant, how frequently they fertilize, what fertilizers they use, the extent to which they irrigate, how and when they harvest their crops, and so forth. Every firm makes slightly different decisions, and some decisions prove to be better than others.

13. In competitive markets, winners and losers emerge over time, with inefficient firms earning less than their cost of capital, and eventually going out of business. The most efficient firms expand and thrive, and other firms attempt to emulate their success – adopting their innovations and trying to match their decision-making prowess. This is fundamentally different from what happens in a monopoly market, where the monopolist is shielded from competition by legal or other barriers to entry, regardless of how badly mistaken some of its decisions turn out to be, and regardless of how much those mistakes harm consumers and society as a whole.

14. PURPA envisions a hybrid market structure, where electrical distribution (and to a lesser extent transmission) continues to function as a monopoly, but competition is encouraged in power generation. Independent power producers are allowed to enter the market and produce as much electricity as they want – provided they use small generators and specific technologies, like hydro, solar, biomass, geothermal, and wind. This creates a more competitive environment, it helps diversify our energy supply, and it reduces exposure to the risks associated with fossil fuels.

15. While PURPA relies on competition, it recognizes the continued presence of entrenched monopolists that retain enormous levels of market power. Accordingly, it provides a crucially important role for monopoly regulation – helping to resolve conflicts between the monopolist and its competitors concerning the prices the competitors will receive for their production. The Commission's role in the price-setting process is of pivotal importance, because of the crucially important functions that prices serve in all functioning markets – including, in particular, the way prices provide vitally important information to market participants.

16. In the familiar retail context, prices signals help consumers decide how much they can afford to consume, and they help them optimize their consumption decisions – how much to purchase of one item rather than another, and whether to purchase a product with one set of features, or an alternative product item with a different mix of features. Prices play a similar role for producers – helping guide their decisions concerning how much to produce of one item or another, how and where to invest their capital, and what specific set of inputs to use in the production process.

17. I believe – and I think most economists would agree with me – that the information embedded in prices is crucially important in explaining why well-functioning markets are so successful at achieving societal goals. In fact, history has repeatedly demonstrated that a well-functioning market can be more successful at accomplishing many societal goals than a system with greater centralized control, even when that system is attempting to directly advance those same public policy goals.

18. Experience has repeatedly shown that freely functioning markets with strong, accurate price signals advance the public interest, in part because of the vital role that price signals play in helping to achieve the "wisdom of crowds." With effective competition, buyers and sellers interacting in the marketplace function like an "invisible hand," increasing efficiency, encouraging innovation, and improving economic wellbeing throughout society far beyond what can possibly be achieved by a single decision maker, or group of bureaucrats.

19. The crucial role of prices has repeatedly been demonstrated whenever governments have arbitrarily controlled prices in an attempt to override the underlying economics of supply and demand. This is most vividly seen when prices are held at an

arbitrarily low level, but it has also been seen in the reverse context – when prices are kept higher than warranted.

20. Whether studying the results of "rent control" in various cities in the United States, or price controls that are imposed by national governments in other countries in an effort to keep food and other basic commodities "affordable," the result has always been the same: too little is produced, rationing becomes increasingly necessary, and ever more severe government intervention becomes necessary over time. Often, the final result is worse than if the market had been allowed to function normally; in fact, many of of the people who were supposed to be helped end up being worse-off, because of the shortages that result from arbitrarily preventing prices from performing their normal informational and market-clearing function.

21. The reverse pattern has also been observed when attempts are made to prop-up prices to benefit a powerful industry group or cartel: it eventually becomes necessary to punish individual producers for producing too much, or massive surpluses build up that the government must buy up or destroy.

22. One of the problems with attempts to prevent prices from reflecting the true underlying economics of the situation is that prices are prevented from achieving one of their vitally important functions: providing information to market participants. For instance, price controls intended to make certain items more affordable tend to discourage production of those items, which discourages innovation and investment and leads to more and more severe shortages, or the need for more and more costly government intervention and subsidies, in an effort to keep the shelves stocked.

23. These problems have been observed occur throughout economic history – arbitrary and inaccurate pricing decisions by the authorities (however well-intentioned) inevitably leads to poor technology decisions, undesirable surpluses and shortages, "white elephant" investments, and many other problems. The misery and humanitarian crisis that we've been observing in Venezuela during the past few years is merely one of the most recent and most prominent examples of a long history of failed experiments in arbitrarily preventing prices from fully performing their normal market function.

24. One might argue that it isn't necessary to adopt better, more accurate price signals in this proceeding, since the standard offer tariffs are of relatively limited importance, particularly since HB 589 requires larger QFs to negotiate prices with the utilities, or to sell their production pursuant to a competitive procurement process (rather than through standard offer tariffs). However, it would be short-sighted to dismiss the opportunity to develop better, more accurate standard offer rates, since the decisions made by the Commission in these biennial avoided cost proceedings have historically had a far wider impact than just the standard offer tariffs.

25. The decisions made in this proceeding are also important to QFs that have existing PPAs that will expire in the future. These decisions also have significant implications for the "Green Source Advantage" procurement program that was authorized by HB 589. Furthermore, decisions adopted in biennial proceedings are a primary source of guidance to the utilities and QFs who negotiate contracts for larger projects, even if those negotiations are not explicitly tied to the standard offer rates.

26. Moreover, the CPRE process established by HB 589 is explicitly tied to avoided cost information. Information that is gleaned and decisions that are made in this

proceeding will very likely help determine how avoided costs will be developed and applied in future HB 589 procurements. Specifically, the price paid to procure energy, capacity and RECs under CPRE may not exceed the utility's avoided costs calculated pursuant to the Commission's most recently approved methodology. Similarly, the bill credit provided to participating customers under the statutorily created Green Source Advantage program for large commercial and industrial customers may not exceed avoided costs. Accordingly, the Commission should require better, more accurate avoided cost calculations and price signals in this proceeding, regardless of how few (or how many) QFs sell their output based upon the specific rates established in this proceeding.

27. Better, more accurate QF prices will directly benefit the state of North Carolina, by encouraging QFs to make better, more efficient long term investment decisions, and by helping these firms avoid investing in undesirable or inefficient technologies that will remain in the state for 30 years, based upon oversimplified, misleading price signals that will only be applicable to the initial contract term, if these prices do not provide a meaningful indication of the underlying economics and long term prospects for investing in the state.

28. Better, more accurate prices also will help to avoid undue discrimination against particular QFs or technologies. Under PURPA, there is no need for the Commission or the utilities to pick and choose between different technologies, or to decide which QFs should be encouraged to invest in the state, and which ones should be encouraged to invest their capital in some other state. By sending strong, accurate price signals, the Commission can ensure that QF prices play their crucial role in determining

competitive outcomes, allowing the competitive process itself to effectively direct investment decisions and determine which firms flourish and which ones do poorly.

29. It might be argued it isn't necessary to adopt better, more accurate price signals, since QF power has been flourishing in North Carolina. However, the very fact that QF power has grown in magnitude and importance is one of the key reasons why better, more accurate QF prices are needed going forward.

30. As QF energy becomes a larger share of the state's overall energy mix, and as market participants become more knowledgeable and sophisticated, oversimplified and inaccurate prices will lead to increasingly serious problems. Accordingly, rather than continuing to accept the inaccurate, over-simplified rate structures developed by the utilities, the Commission should require them to adopt rates that more accurately reflect the level of costs that are actually avoided when electrical energy is provided by QFs in specific locations, and at specific times.

31. At a minimum, QF rates should better reflect the impact of (a) geographic diversity, (b) variations in "net" system load and avoided costs based upon relatively stable and predictable seasonal and hourly patterns, and (c) less stable and predictable changes in the weather. The third factor can result in changes to "net" system load and avoided costs that can only be anticipated on a near-term basis, not years in advance of when they occur.

32. Improving pricing precision along all three of these dimensions will help ensure that QF prices advance the public interest by improving economic efficiency, encouraging entrepreneurial experimentation and innovation, and encouraging better investment decisions. Among other benefits, this will avoid requiring retail customers to

bear the risks associated with rate base investments, when those investment risks can readily (and more appropriately) be borne by QF investors instead. In sum, better, more accurate QF price signals will strengthen North Carolina's economy and avoid burdening retail customers with excessive or unnecessary costs and risks.

<u>MORE ACCURATE SOLAR MODELING IS NEEDED</u>

33. In preparing their 2018 Integrated Resource Plans and their avoided cost studies in this proceeding, the utilities failed to thoroughly analyze, explain, or forecast changes to solar output that are expected to occur within their respective service areas over the next 10 years. Their "net" system load forecasts for the next 10 years could have, and should have, been based upon a more robust, detailed modeling effort – analogous to the econometric modeling approach they used to forecast their "gross" system load (before estimating the impact of solar output).

34. To be clear, the utilities appear to be relying on software systems, provided by third-party vendors, to help them anticipate fluctuations in solar output on a real-time basis for operational purposes. However, they did not include any information about this real-time forecasting effort in their filings in this proceeding, nor did they rely upon it to develop or refine their 10 year avoided cost estimates. No information was provided in their filings concerning the underlying causal relationships that are reflected in that software, or which help determine the level of solar output at particular locations and particular times. Nor did the utilities make any effort to explain to the Commission why and when solar output will vary from the "normal" or average level of output that is typical for any given time, month, or season.

35. The Biennial Avoided Cost and Integrated Resource Planning filings were based upon a highly simplified approach to solar modeling, which overlooks, ignores, or oversimplifies many of the key issues. Unlike the sophisticated econometric modeling they used to forecast system load, the utilities have not disentangled or examined the underlying factors which explain why solar output is high or low at any given time, nor have they analyzed how output is likely to change over the next 10 years, in response to changes to the competitive procurement process, technological changes, or changing market conditions.

36. In fact, the utilities did not even discuss the need to improve their solar modeling capabilities, nor did they include any disclaimers in their initial filings to acknowledge the weaknesses and flaws in their solar modeling efforts, or the potential impact of these modeling problems on their avoided cost estimates. Whatever the reason for the simplified approach they've taken, it stands in stark contrast to their detailed, sophisticated econometric modeling of "gross" system load. The end result is that their estimates of solar integration costs have been overstated, their estimates of avoided energy costs have been understated, and the impression may be given that solar energy is unusually risky and difficult to combine with other energy sources.

37. In addition to providing more accurate avoided cost estimates, improved solar modeling capabilities would provide the ability to examine multiple "what if" scenarios, which would enable the Commission to better understand and anticipate the potential impact of alternative regulatory policies, as they relate to potential future changes in market conditions and technology.

38. While improved modeling would be beneficial for all of the utilities, the need is less acute for DENC, because it is an integral part of PJM – and solar energy continues to hold a relatively small share of the overall market for electrical energy and capacity within that very large region. In DEP's case, the need to more accurately model solar output is especially acute, because solar is already providing a significant share of total energy during some hours, and solar will continue to grow in significance over the next 10 years. Similarly, solar energy is expected to grow even more rapidly in DEC's service area, so the need for accurate solar modeling in that service area is also clear.

39. To provide an indication of the level of sophistication and detail which is feasible, consider PJM's current efforts to produce its real time and near-future Solar Power Forecast. All solar generators connecting to the PJM system with 3 or more MW of capacity are required to install a Real Time Meteorological Station. This provides PJM with detailed temperature and irradiance data along with detailed electrical output data, on a continuous, real-time basis from many different locations. In the case of solar + storage, PJM requires separate metering of each component of the system, to ensure that solar forecast accuracy is protected.

40. PJM develops three different types of forecasts for each individual solar park, which it combines into an aggregate forecast. The Short-Term Forecast provides forecasted output data at five minutes intervals, for the next six hours; it is updated every ten minutes. The Medium-Term Forecast predicts solar output with an hourly interval for the subsequent forty-two hours; it is updated hourly. The Long-Term Forecast is also updated hourly. It forecasts solar output on an hourly basis for the following one hundred twenty hours.

41. This entire process is clearly data-centric, since PJM is collecting and analyzing data from numerous individual solar generators, allowing it to consider how micro-climate differences affect output at different locations, and enabling it to gain a deeper understanding of how solar output varies with irradiance, temperature and other weather conditions during specific times and seasons.

42. Although the weather data collected from individual solar generators is mostly focused on fluctuations in temperature and irradiance, this type of data can also be analyzed in conjunction with broader meteorological data (obtained from the National Weather Service or another data source) – providing insight into how solar output at each location varies in the context of the larger scale weather systems that lie at the heart of a typical weather forecast – including high- and low-pressure systems, warm fronts, cold fronts, and the like.

43. Given the importance of solar energy to the state's energy mix, there is a clear need for the utilities to evaluate and model how solar output responds to specific weather conditions and other underlying explanatory factors. The need for better modeling of "net" system load is directly analogous to the improvements that were needed and implemented decades ago, when it became increasingly clear that "gross" system load could not reliably be forecast by simply assuming that historical trends would continue.

44. Adopting a more detailed and accurate approach to the modeling of solar output and "net" system load will yield multiple benefits, including an improved ability to understand and anticipate variations in solar output on both a long-term and short-term basis. This will pay dividends by – improving the utilities' long-term planning (e.g. the

timing and selection of new generating units as well as the retirement of older, less efficient units).

45. Improved modeling will also enhance day-to-day operations, including the selection of generating units to include in the resource stack, and development of better strategies for engaging in off-system purchases and sales. For instance, a robust modeling effort will help the utilities distinguish between factors that explain normal or typical solar output, and factors which explain why solar output sometimes varies from the norm. In turn, this will reduce the need for larger operating reserves, and increase opportunities for profitable off-system sales, since it will reduce uncertainties with regard to the pattern of solar output that can be expected during specific hours on specific days.

46. Absent a better understanding of how solar output relates to specific weather conditions and other underlying explanatory factors, the only viable option may seem to be keeping plenty of flexible generation connected to the system, standing ready to instantaneously respond if a thunderstorm is moves through the area, or rapidly changing cloud cover causes solar output to fluctuate. With better, more accurate solar modeling, however, these issues become much more manageable, and the response can be more narrowly targeted and cost-effective. To cite two simple examples: if the day will be clear and sunny, there may be little or no need for additional operating reserves to respond to solar fluctuations; if the forecast suggests a chance of afternoon thunderstorms, additional operating reserves may only be needed in the afternoon, not in the morning.

47. The need for accurate solar modeling not only impacts the day-to-day operations of the utilities, it also impacts the way those operations were simulated in developing the avoided cost estimates filed in this proceeding. Inaccurate, oversimplified

analysis of solar variability and the impact of that variability on the operation of other conventional generating units results in distorted, inaccurate avoided cost estimates.

48. Accurately modeling solar output and the related impacts can be challenging, because solar output, system load, system design, and system operations are closely related, the underlying causal relationships are complex, and there are important subtleties that can easily be overlooked, misunderstood, oversimplified or ignored. To provide a more detailed explanation of these modeling problems as they relate to DEC and DEP's avoided cost proposals and Integrated Resource Plans, I prepared a report titled "Modeling the Impact of Solar Energy on the System Load and Operations of Duke Energy Carolinas and Duke Energy Progress." This report, attached to this affidavit as **Exhibit A**, was prepared by me at the request of NCSEA; it is true and correct to the best of my knowledge and belief.

49. These modeling problems fundamentally undermine the validity of the utilities' avoided cost estimates, because unreliable and inaccurate assumptions concerning solar energy were input into the production cost modeling software (e.g. Prosym) that was used to develop the avoided energy cost estimates. By starting with inaccurate assumptions concerning solar output, the production cost modeling software develops inaccurate, sub-optimal decisions concerning the selection and operation of specific generating units during specific days and time periods. The simulation of this selection process is fundamental to the production cost modeling process that lies at the heart of the Peaker method. Hence, the failure to accurately model solar output fundamentally undermines all of the results produced by Prosym.

50. Similar pervasive problems exist with the Astrape Solar Capacity Value study, which underlies DEC and DEP's capacity cost and QF rate design proposals, and the Astrape Solar Ancillary Services study, which underlies their proposed Solar Integration charges. Moreover, the failure to accurately model "net" system load on a daily and seasonal basis makes it impossible to accurately evaluate the optimal changes to off-system power purchases and sales which will occur in response to increased solar, and it precludes an accurate evaluation of other steps that can and should be taken to maximize the benefits and minimize the costs associated with solar energy.

SOLAR INTEGRATION COSTS AND ANCILLARY SERVICES

51. All three utilities are proposing changes to their QF tariffs related to the costs of solar integration and ancillary services. The concept of refining the QF rates to consider the costs and benefits associated with solar integration and ancillary services is not objectionable, per se. However, the proposals in this proceeding should be rejected, because the utilities failed to analyze these issues from an unbiased, balanced perspective, and they developed integration cost estimates that are substantially overstated.

52. The utilities only considered negative impacts (costs) imposed by the solar QFs, without considering positive impacts (benefits). Most notably, they ignored the fact that QFs are widely scattered at diverse geographic locations – including many locations that are relatively close to where electricity is consumed. This geographic attribute results in significantly lower transmission and distribution costs over the long run – a benefit that was ignored by the utilities. If this positive attribute of increased geographic diversity were balanced against the negative attribute of intermittency, the net impact would be the

reverse of the pattern suggested by the utilities: the geographic benefits would significantly outweigh the costs of intermittency.

53. DENC is proposing to charge QFs $1.78 per MWh based upon an estimate of re-dispatch costs, which it describes as the additional fuel and purchased energy costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. It is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, because solar generation varies with cloud cover which cannot be forecast with perfect accuracy. Nevertheless, these costs can be reduced by more accurately modeling solar output, as discussed earlier – so any estimate of the associated costs is highly dependent upon the assumptions that are made concerning how accurately solar output can be forecast, and the extent to which the benefits of increased geographic diversity can be achieved.

54. With accurate solar modeling, more flexible generators can be deployed on days when solar output is expected to be relatively volatile, while this costly precaution won't be needed on days when the skies are expected to be clear, and solar output will be relatively stable and predictable – rising in the morning as the sun rises in the morning, peaking at mid-day, and falling as the sun sets in the evening, with minimal uncertainty related to cloud cover. Similarly, on days when the skies will be heavily overcast throughout the day, the impact of shifting cloud cover is less of a concern, and the impacts are more easily predicted than on a day that will be partly sunny and partly overcast.

55. As more data is collected, and solar modeling becomes more sophisticated, any additional re-dispatch costs resulting from solar generation should diminish. Furthermore,

while these costs will never completely disappear, they will be heavily concentrated in specific time periods – like a Summer afternoon when the forecast calls for a chance of thunderstorms, since the exact timing and impact of thunderstorms can't be accurately predicted in advance.

56. Geographic diversity also reduces re-dispatch costs. As a cloud moves over a solar QF, its output will dip, then increase, as the cloud moves away – suggesting a need for flexible generation sources elsewhere on the grid, in order to accommodate this volatility. However, the need for flexible generation (and the potential for re-dispatch costs to occur) is ameliorated by the effects of geographic diversity. The same cloud that moves past one facility might soon move over another facility.

57. When solar output is viewed on an aggregate basis, the net impact of output volatility will tend to be much less significant than when output is measured at any one location. DENC only partly considered the benefits of geographic diversity – its analysis was based upon an analysis of solar output data at 26 individual sites where solar output data was collected. DENC has more than 100 solar facilities in its interconnection queue, including more than 60 facilities that have already been energized. The benefits of geographic diversity are understated in DENC's analysis, and those benefits will further increase as more solar QF's are energized.

58. Re-dispatch costs can also be reduced by engaging in power purchases and sales with other utilities. Rather than relying entirely on its own when generating units if solar output falls short of the expected level, the most efficient response may be to make a short-term purchase of energy from another utility. Similarly, if solar output is greater than anticipated, the economically rational response may be to sell energy to a

neighboring utility, rather than reducing output from a low-cost fossil fueled unit that is already connected and running. Correctly calculated, avoided costs should be developed on a "net" basis, as if the utility is operating as efficiently as feasible with or without the QF's output. In DENC's case, re-dispatch costs should clearly be estimated on a "net" basis, taking into account PJM purchases and sales.

59. DENC's analysis of re-dispatch costs is based upon a weighted average of multiple different scenarios and assumptions. It is not obvious why DENC averaged so many different scenarios together, rather than focusing on the ones that appeared to be more appropriate and relevant. Excluding just one of these scenarios – the one that excludes consideration of PJM purchases and sales – results in a decrease in their estimate of re-dispatch costs from $1.78 to $1.48. If the scenario which focuses exclusively on generation costs is also excluded, giving equal weight to the scenarios that consider "All Costs" and the one that assumes "No Pumped Storage," DENC's estimate of re-dispatch costs drops further – from $1.48 down to $1.10.

60. An even lower cost estimate results if the scenario with the lowest assumed level of solar nameplate capacity (80 MW) is excluded or given minimal weight. With this change, DENC's re-dispatching cost estimate drops from $1.10 to $0.69.

61. Similar, but more severe, problems exist with the Astrape Solar Ancillary Services study, which DEC and DEP used to support their proposed "Integration Services Charge." The rate of $1.10 per MWh proposed by DEC is shown on Table 20 on page 47 of that study. The analogous charge of $2.39 per MWh proposed by DEP is shown on Table 21 on page 50 of that study. Neither of these cost estimates should be accepted by the Commission, since they are based upon inaccurate solar modeling.

62. The severity of these modeling problems is demonstrated by the fact that Astrape's cost estimates are extremely sensitive to the assumed level of volatility in solar output – something that was not modeled in detail and was simply input into the SERVM cost model that Astrape used to develop their cost estimates. When Astrape tested the effect of reducing their "raw volatility" assumptions by 25%, this reduced their cost estimate for DEC by 75%. Similar testing of the DEP results indicated that reducing the "raw volatility" assumptions by 25% resulted in a 39% reduction in the calculated costs.

63. The severity of these modeling problems is further confirmed by the fact that Astrape's cost estimates per-MWh increase sharply as they move from early scenarios (corresponding to existing levels of solar plus "transition" solar) to later scenarios (corresponding to later tranches of the CPRE procurement process). While solar integration costs should increase in total as more solar is added, when calculated on a per-MWh basis, these costs should logically decline over time.

64. Consider, for example, the increased cost of re-dispatching: these costs arise when the utility has difficulty forecasting precisely how much solar energy will be available and ends up deploying a less-than-optimal mix of generating units for the day. Logically, these costs should decline (on a per-MWh basis) as more tranches of solar are added to DEC and DEP's systems. As aggregate solar nameplate capacity increases geographic diversity will often increase, and this increased diversity will typically ameliorate the output volatility that occurs at any given location. In addition, as more tranches of solar are added, the utilities will be moving farther down the learning curve, and they will be able to collect and analyze more data. As a result of having access to better data, and learning more about how to analyze this data, they will be able to forecast

solar output more and more precisely – thereby reducing the forecast errors which lead to the re-dispatching costs.

65. A similar pattern will occur with other impacts as more solar tranches are added. For example, as more tranches are added and the total volume of solar energy increases, there will be an increased opportunity (and incentive) to optimize off-system power purchases and sales. With larger volumes of solar, the cost differentials between DEC and DEP neighboring systems will become larger at times when solar output is high. With larger cost differentials, there will be more opportunities to engage in profitable off-system sales and purchases – including "swaps" of energy produced at low cost by one system at one time and low-cost energy produced by a neighboring system at a different time. While these sorts of arbitrage opportunities have always existed, opportunities will increase as cost differentials become larger and more frequent.

66. When neighboring systems are all operating a similar mix of nuclear, gas and coal fired plants, the cost differentials at any given hour will tend to be less than if one of those systems is fundamentally different – e.g. it enjoys the benefit of large amounts of low-cost solar energy, which pushes that system's marginal production costs to very low levels during certain hours and days. One way of thinking about this is that increased amounts of solar energy leads to economies of scale in off-system arbitrage opportunities. If this benefit is correctly evaluated, it will lead to a reduction in the cost of solar integration (on a per-MWh basis) as more solar capacity is added to the system.

67. While DEC's proposed charge of $1.10 per MWh (based upon the "DEC Existing Plus Transition" scenario) is lower than the other proposals, it should also be rejected, since it not based upon a solid cost foundation. In fact, in the scenario where

Astrape assumed 1,500 MW of additional solar tranches, its estimate of DEC's integration costs increased from $1.10 to $17.78 per MWh – a completely implausible 1,516% cost increase.

68. Similarly, the $2.39 per MWh charge proposed by DEP (based on the scenario "DEP Existing Plus Transition") is also highly dependent on inaccurate solar modeling, as indicated by the fact that with 1,500 MW of additional solar tranches, Astrape's cost estimate for DEP skyrockets to $38.34 per MWh – a 1,504% increase.

69. The magnitude and direction of these cost results is clearly unreasonable. For comparison, consider that testing the sensitivity of DENC's Integration Cost analysis indicates that an assumed 2,000 MW increase in Dominion's solar capacity (from 2,000 MW to 4,000 MW) translates into a 35% decrease (<u>not</u> an increase) in their estimate of re-dispatching costs.

70. The extreme sensitivity of Astrape's cost estimates in response to changes in their solar nameplate capacity assumptions clearly demonstrates the need for more accurate solar modeling – a topic which is that discussed in more depth in the report "Modeling the Impact of Solar Energy on the System Load and Operations of Duke Energy Carolinas and Duke Energy Progress."

71. Another reason why the Astrape study results are so unrealistic is that DEC and DEP systems were modeled as "islands" rather than viewing them as part of the much larger Eastern Interconnection. This unrealistic assumption is fundamentally inconsistent with the way the DEC and DEP systems actually function, and it greatly distorts their results. By adopting this arbitrary and unrealistic assumption, the Astrape cost model calculates costs that will never actually materialize under real world conditions.

72. For perspective, consider that on a typical Spring day, the combined load on DEC and DEP's systems is likely to total somewhere in the vicinity of 20,000 MW. Both utilities are connected to the TVA system, which will likely be serving another 20,000 MW of load at that same time – effectively doubling their combined ability to respond to fluctuations in customer usage and solar output. In addition, DEC and DEP maintain transmission ties with PJM West, which is likely to be serving another 50,000 MW of load at that same time. DEC and TVA both maintain transmission ties with the Southern Company, and it is likely to be serving another 25,000 MW or more at the same time. In addition, DEP maintains ties to PJM South, which is likely to be serving around 10,000 MW of additional load at the same time.

73. Succinctly stated, a 500 MW fluctuation in solar output – or even a 1,500 MW fluctuation – is not as difficult, or as costly to accommodate when the fluctuation occurs within the broader context of the Eastern Interconnection.

74. Another reason why the proposed Solar Integration Charges are excessive and inequitable is because they would force solar QFs to pay for costs that – to the extent they exist – could more cost-effectively be avoided by simply providing the QFs with better, more accurate price signals.

75. Consider one example: Astrape assumed that massive costs would be incurred to keep additional conventional generators connected to the grid (operating below their optimal output level) in order to provide added flexibility and to help overcome the inherent ramping limitations of these generators. In effect, the Astrape study assumes the problem is too much solar generation given the technical limitations of the existing conventional generating fleet – the limited ability to rapidly flex these units up or down.

However, another way of looking at the issue is to recognize that the flexing problem results from the decisions made by DEC and DEP: they are not providing QFs with strong enough, or accurate enough price signals.

76. Rather than running older, less flexible conventional generators more, the most cost-effective solution may be (at least in part) to provide an incentive for solar generators to send less power to the grid during particular times. With better price signals, QFs would see when their power is most valuable, and when it is not as valuable. They would then be able to respond in the normal way that supply and demand functions in most markets: by providing less energy at times when a surplus of exists, and more energy at other times, when it is needed more.

77. Assume that a surplus of solar energy exists during certain mid-day hours, forcing conventional generators to rapidly reduce their output only to reverse course a few hours later, rapidly increasing their output once the mid-day surplus diminishes. The best solution to this problem may be to provide the solar generators with appropriate price signals, so they adjust their investment and operating strategies to avoid sending too much power to the market at times of surplus. One obvious potential industry response would be to use higher inverter loading ratios. This would result in clipping off some of the extremely high mid-day production levels, but that would make economic sense if, with a lower inverter loading ratio, the energy is going to be sent off-system and yield relatively little value – or (in the worst case) thrown away through curtailment.

78. Another potential market response would be to add storage to solar facilities. This would enable QFs to send energy into storage at times when a surplus exists, or the price of power is low, while sending that energy to the grid at a later time, when a

shortage exists, or the price of power is much higher. Solar + storage can reduce the need for ramping of conventional generating resources, and it can provide ancillary services, like spinning reserves. Solar + storage is discussed in more detail in the report "Modeling the Impact of Solar Energy on the System Load and Operations of Duke Energy Carolinas and Duke Energy Progress."

79. The proposed Solar Integration Charges should also be rejected because they are unduly discriminatory and anti-competitive, since QFs would be forced to pay the increased cost of regulating reserves and other ancillary services, without being given any meaningful opportunity to avoid or ameliorate these charges, or any opportunity to provide the needed ancillary services themselves – even if they could provide them at lower cost than has been assumed in the Astrape study.

80. Consider the example of a solar QF equipped with advanced inverters. This QF would be required to pay the proposed Solar Integration Charge, which includes a pro-rata share of Astrape's estimate of the additional cost of maintaining a continuous balance between generation and load as a result of increased solar energy volumes. Yet, modern solar facilities are capable of competing with the traditional spinning reserves that help carry out this process. Many QFs have, or could readily acquire, the necessary technical capability to provide the equivalent of spinning reserves (at least during daytime hours). Given the right opportunity and economic incentives, QFs could potentially provide these ancillary services at lower cost than the Astrape study calculated.

81. If Solar QFs were given the opportunity to compete in the market for ancillary services, solar QFs might prove to be very innovative and effective competitors. Solar plants equipped with advanced inverters can potentially respond to fluctuations in grid

conditions, or central dispatch instructions, more quickly, and at lower cost, than what can be achieved by exclusively relying on conventional generators.

82. Combining the technical benefits of extreme flexibility offered by advanced solar inverters with the geographic benefits of their widespread diversity across the grid, QFs would be strongly positioned to compete, if the Commission were to create a market for ancillary services. Solar QFs would have the ability to provide ancillary services more quickly and precisely, and more cost-effectively, than is possible with many conventional generators – particularly if those generators were operated in the costly manner that is assumed in the Astrape study.

83. The discriminatory and anti-competitive nature of the utilities' proposed Solar Integration Charges is especially apparent in the case of solar + storage QFs. These QFs are fully capable of providing ancillary services during both daytime hours and night time hours. They would just need to maintain an adequate amount of energy in storage, to be used in providing grid support.

84. Hydro generators with ponding capabilities are also in an ideal position to provide ancillary services. These hydro facilities can be equipped to rapidly adjust their output up or down in response to dispatch instructions, or in response to instantaneous fluctuations in voltage and other attributes of the power flowing over the grid which indicate a momentary need for a little more or a little less power. With a limited amount of seasonal rainfall, and the constrained ability to store water, hydro generators have no incentive to continuously run at 100% of their rated capacity. In fact, if they were to do so they would soon run out of water. Accordingly, it makes sense for these generators to optimize the timing of when they deliver energy to the grid, based on market incentives.

However, these incentives are highly dependent on price signals. With a poorly structured set of prices, hydro QFs cannot, and will not, operate as efficiently as if they were provided with better, more accurate prices signals.

85. Currently, the opportunities for hydro QFs to optimize the delivery of their output is very limited. Their primary opportunity is to refine the timing of their output to deliver more of their power during on-peak hours and less of their power during off-peak hours, when the price is lower.

86. If the market for ancillary services were opened to competition, hydro generators with ponding, solar QFs, and solar + storage QFs all would have an incentive to keep some of their capacity in reserve, and to use this to provide voltage regulation and other ancillary services. This could be accomplished by responding to instantaneous fluctuations in grid conditions, or to dispatch requests. The most important element that is missing is an appropriate price mechanism and economic incentive to encourage QFs to do this. Other necessary pieces of the puzzle will include data collection and billing methods to ensure each QF is appropriately compensated for the ancillary services it provides, and to ensure that payment is withheld (or a penalty applied) if a QF experiences an equipment failure or otherwise fails to provide the expected level of service at a particular time. These issues have been readily resolved in the significant fraction of the country where system operators run markets for ancillary services.

PERFORMANCE ADJUSTMENT FACTOR

87. In the Sub 148 Order, the Commission reaffirmed its conclusion that the availability of a CT is not determinative for purposes of calculating a performance adjustment factor ("PAF"). It concluded, that a more reasonable approach is to develop

the PAF based on a "system availability metric that represents the reliability of the system during peak demand periods." The Commission discussed several alternatives to how such a measure might be developed in future proceedings, while indicating a preference for consistency between the avoided cost filings and other routine filings. It noted that "equivalent availability may be the more appropriate metric" and it required the utilities to address the PAF and to "support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for the utility fleets in total" in their initial filings.[1]

88. In their initial filing, DEC and DEP proposed a PAF of 1.05[2] while Dominion proposed a PAF of 1.07[3]. The numerical difference results, at least in part, from differences in the months DEC and DEP used to analyze their fleet availability, compared to the months used by Dominion. DEC and DEP used data from the months of January, February, July and August, while Dominion used data from those months plus June.

89. While DEC and DEP claim that calculating a higher PAF using data from other months would cause "customers to overpay for the capacity value that QFs provide" they do not provide any evidence to support a claim that the higher QF rates resulting from a higher PAF would actually represent an overpayment. DEC and DEP merely assert that a higher PAF would result in an overpayment, without providing any data (or even offering any logic) to support this characterization.

90. The fundamental purpose of the PAF is to ensure non-discriminatory treatment of QFs. Ratepayers pay the full cost of generating capacity that is included in the rate

1 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, pp. 55-56, Docket No. E-100, Sub 148 (October 11, 2017).

2 DEC and DEP Joint Initial Statement and Exhibits, p. 16.

3 Initial Statement and Exhibits of Dominion Energy North Carolina, p. 5.

base, even if that capacity is not available during some of the hours when it is most needed. QF capacity payments are strictly tied to the amount of energy the QF actually provides during a specified set of hours when the QF capacity rate is applicable. This capacity pricing approach ensures that QFs are never paid for capacity that isn't actually available during the specified hours – but since the utilities are paid for their capacity regardless of whether it is available when needed, this tariff design can result in a systematic underpayment of QFs, unless an appropriate PAF is included in the underlying rate calculations. To ensure non-discriminatory treatment, and to fairly compensate QFs for the actual capacity costs they enable the utilities to avoid, the PAF should consider the actual availability of the utilities' generating units during all critical peak hours whenever they occur.

91. In its Sub 148 Order, the Commission indicated that the PAF should provide a "fair comparison between on-peak reliability of all generation resources and a reasonable expectation of QF availability." The closely related goals of fairness and non-discriminatory treatment cannot be achieved under DEC and DEP's proposal to exclude months like December, which is unquestionably a critically important time to maintain adequate generator availability.

92. In their initial filing, DEC and DEP acknowledged that the Commission "directed the utilities to support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for the utility fleets in total in this proceeding."[4] Thus, even DEC and DEP acknowledge the appropriate focus is on the entire "peak season" – not just some of the times when extremely high peaks can occur.

4 DEC and DEP Joint Initial Statement and Exhibits, p. 16.

93. Tellingly, DEC and DEP did not claim in their initial filing (or in their responses to discovery) that the months of January, February, July, and August are the only months when extremely high peaks can occur. Nor have they claimed these are the only months that can properly be included in an appropriately defined "peak season." Nor have they offered any data to support their selection of these particular months to the exclusion of all others.

94. DEC and DEP state that they are focusing on the "critical peak season months" (emphasis added). DEC and DEP offer no explanation of what they mean by "critical" months, but this wording seems to suggest these particular months are the only "critical" ones from a system planning and load forecasting perspective. However, that is not actually true, and DEC and DEP do not explain why these particular months should be considered "critical" while others are not.

95. To my knowledge, DEC and DEP have never previously defined their "peak season" as being limited to the four months of January, February, July and August.

96. While different approaches have been used in different contexts, DEC and DEP have generally defined the peak season to include all of the Summer months when high peaks occur – not just July and August. For instance, DEP's tariff for Large General Service Time of Use rates (Schedule LGS-TOU-51) applies the highest per-kW demand rate to the Summer months of June through September; significantly lower per-kW rates are applied during other months.[5] Similarly, DEP's Demand Response Automation program (which requires participants to reduce their demand below their "seasonal

5 Available at https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/g10ncschedulelgstoudep.pdf?la=en (last accessed December 26, 2018).

contracted curtailable demand") defines the Summer peak period as June-September, while the Winter peak period is defined as December-February.[6]

97. The seasonal definition used by DEC and DEP for developing their proposed PAF is also not consistent with the seasonal definitions they used in developing their new QF rate design proposals. DEC is proposing to pay capacity credits during Summer months that are defined as July and August, and during Winter months that are defined as December through March."[7] DEP is proposing to pay capacity credits that will be "applicable in Winter months only, defined as the calendar months of December through March."[8]

98. As explained in the report "Providing Better Price Signals" (attached to this affidavit), the DEC and DEP system peaks have historically occurred most frequently during the months of June through September. However, less frequent peaks also occur on during extremely cold winter days. The winter peaks are particularly hard to anticipate or predict long in advance, since they occur in response to unusual weather events. While the coldest weather usually occurs during January of most years, extreme cold weather peaks can also occur during the months of December, February and March.

99. To achieve a high degree of system reliability, as much generating capacity as possible needs to be available during cold days in January. However, this is not the only concern. Nearly as much capacity needs to be available to serve the peak loads that occur during unusually cold days in December, February and March.

6 Available at https://www.duke-energy.com/_/media/pdfs/for-your-business/drabrochure.pdf?la=en (last accessed December 26, 2018).

7 Joint Initial Filing, DEC Exhibit 1, page 3 of 11.

8 Joint Initial Filing, DEP Exhibit 1, page 3 of 11.

100. While the highest winter peaks most often occur during January, very high peaks also occur from time to time during December, February, and (to a lesser extent) in March.

101. The historical data does not justify treating February as a peak month to the exclusion of December or March. Consider, for example, the winter of 2016-2017. DEC experienced a peak load of 17,410 MW on December 16, 2016 and a peak load of 17,690 on March 16, 2017. The December and March peaks were both higher than the highest peak that occurred during February, which was 15,918. During the winter of 2013-2014, the DEC peak in March was 16,898 – which nearly equaled the February peak of 16,982. The December peak (16,436) was nearly as high. During the winter of 2010-2011 the December peak was 18,985, which far exceeded the February peak of 16,470. During the winter of 2007-2008, the December peak of 16,428 almost exactly matched the February peak of 16,432.[9]

102. The historical winter peak data for DEP confirms that a narrow focus on January and February is not appropriate. During the winter of 2016-2017, the December and March peaks both exceeded the February peak. During the winter of 2013-2014 the December peak fell just short of the February peak, and the March peak exceeded the February peak. During the winter of 2010-2011 the December peak exceeded both the January peak and the February peak. During the winter of 2008-2009 the March peak (12,919) nearly matched the January and February peaks. During the winter of 2007-2008 the December peak exceeded the February peak.[10]

---

9 FERC 2006 – 2017 Form 714 Database, available at https://www.ferc.gov/docs-filing/forms/form-714/data.asp (last accessed December 27, 2018).

10 Ibid.

103. On balance, it is fair to say that cold weather can trigger unusually high peaks during any of the months from December through March. Given the uncertainties surrounding the timing of cold weather, it is important to maintain an adequate level of generator availability during all of the months from December through March. Both DEC and DEP defined the winter season as December through March in their proposed QF rate design. Consistent with this peak season definition, they should have included these months when analyzing their generator fleet availability.

104. A careful examination of the historical data supports a somewhat similar conclusion with respect to the Summer: the historical data does not support an exclusive focus on the months of July and August. In many years, the highest peak during June has nearly matched the highest peak during July or August. In fact, during 2015 the DEC peak in June (20,003) slightly exceeded the peaks in July and August, and the peak in September (18,681) was not far behind. DEP experienced a somewhat similar pattern of monthly peaks, with the June peak (12,849) exceeding the July and August peaks. The DEP peak in September 2014 exceeded the July and August peaks of that year, while the June peak exceeded the July and August peaks in 2008. Similarly, the DEC peak in June 2008 exceeded the July and August peaks that Summer.

105. Because of growth in solar energy, which helps meet peak loads during hot, sunny days, DEC and DEP are forecasting that loss of load risks will diminish on hot summer days. As a result, they are forecasting that loss of load risks will become relatively more serious on cold winter days. While this forecasted change in seasonal patterns may justify focusing more on winter peaks, it does not justify focusing exclusively on January, February, July and August. Even by their own forecast, DEC and

DEP will continue to face significant loss of load risk during December and March – and those risks will become more important relative to the Summer risks, which will diminish as solar output grows. In fact, in the scenario they developed which assumed all four tranches of solar energy, DEC and DEP's consultants estimated there will be more loss of load risk during December and March than during **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[11]

106. The calculated PAF is sensitive to the selection of months used in developing the calculations.

107. If historical data for December and March 2013-2017 are included in the calculations (together with 4 months used by DEC and DEP) the PAF increases to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The overall fleet average increases to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[12]

108. If the Summer peak season is defined as June through September, and the winter peak season is defined as December through March, the 2013-2017 historical PAF for DEC is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[13]

109. Defining the peak season more narrowly to only include the winter months of December through March, the 2013-2017 historical PAF for DEC is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[14]

---

11 DEC and DEP Response to NCSEA DR 1-47, attachment NCSEA_DR_1-47_D-SAF_2018_CONFIDENTIAL.xlsx.

12 DEC and DEP Response to Public Staff Joint DR2-13.

13 Ibid.

14 Ibid.

110. A similar pattern can be observed in the forecasted data DEC and DEP developed for the years 2019-2023. If the months of March and December are included along with the four months selected by DEC and DEP, the System Equivalent Availability for their combined fleet is forecasted to be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which translates to a PAF of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[15] Defining the peak season more broadly, to include December through March and June through September, the forecasted System Equivalent Availability equates to a PAF of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[16] Defining the peak season more narrowly to focus exclusively on the winter season from December through March, the forecasted PAF is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[17]

111. In response to discovery, DEC and DEP argue it is appropriate to focus exclusively on data from the four months of January, February, July and August because these "are months that are typically between planned maintenance intervals. Including additional months would lower the equivalent availability due to planned maintenance, and thus raise the PAF…"[18]

112. Concentrating the analysis on two months in the winter and two months in the Summer has the effect of minimizing the calculated PAF, but this procedure does treat QFs fairly. Regardless of how carefully DEC and DEP schedule their maintenance activities away from the winter and Summer, extreme system peaks occur in response to extreme weather conditions – and this can overlap the time period when maintenance

---

15 DEC and DEP Response to Public Staff Joint DR4-5.

16 Ibid.

17 Ibid.

18 DEC and DEP Response to Public Staff Joint DR4-2.

occurs. Whether as a result of unusual weather conditions, or the inability to complete all of the scheduled maintenance within the scheduled target window, the fact is that some generating units will not be available during the months of December, March and June, despite the significant risk of extreme system peak conditions during those months.

113. To fairly compensate QFs for the capacity costs they enable the utilities to avoid, the PAF should consider the actual availability of the utilities' generating units during all critical peak hours whenever they occur – including times when unusual weather conditions overlap with scheduled maintenance. By systematically excluding this portion of the availability data, DEC and DEP are biasing their calculations, resulting in a lower PAF for QFs. If this approach is accepted, it will discriminate against QFs, and understate the extent to which QF power helps avoid capacity-related costs.

114. I recommend the Commission reject DEC and DEP's proposal to exclusively focus on January, February, July and August generator availability data. Based upon a review of the historical and forecast availability data for both DEC and DEP, as well as their loss of load forecasts, I recommend adopting a PAF of 1.10.

Seasonal Allocation of Capacity Costs

115. DEC and DEP have overstated the extent to which they have become winter peaking utilities, and their proposal to allocate virtually all avoided capacity costs to the winter season should be rejected.

116. The studies that were developed to support the DEC and DEP proposals in this proceeding generally assume their Demand-Side Management (DSM) or Demand Response programs will continue to emphasize peak load reductions in the Summer, rather than in the winter.

117. For Summer peaking utilities, an emphasis on peak demand reductions in the Summer is (and was) appropriate. For DEC and DEP, however, the growth in solar energy will lower the Summer peak on a "net" basis (and the Summer peak will shift to later in the evening). Solar will have less of an impact in reducing the winter peak, so the net impact of more solar energy will be to reduce the magnitude and importance of the Summer peak while leaving the winter peak relatively unchanged. Although DEC and DEP's have not done an adequate job modeling these changes, the direction of change is clear, and the magnitudes are substantial. As a result of the increased importance of extreme winter peaks relative to the Summer peaks, DEC and DEP should immediately begin reorienting their DSM programs to primarily focus on reducing extreme winter peaks, rather than Summer peaks.

118. Extreme winter peaks are typically both less frequent and of shorter duration than the analogous extreme Summer peaks. Because of this difference in frequency and duration, winter-focused DSM offerings can be designed to be more attractive to customers and more cost effective for the utility than an analogous Summer-focused DSM offering. By reorienting the DSM offerings to primarily focus on winter peaks, DEC and DEP should be able to achieve a larger number of MW of demand reduction than they are currently achieving, or reduce the cost of these programs, or both. This improvement in overall magnitude and cost effectiveness follows directly from the fact that winter peak reductions tend to be less frequent and of shorter duration. This makes a winter-oriented DSM program more attractive to more customers, yet it will be just as effective (or more effective) in meeting the shorter, less frequent peaks that occur during the winter season.

119. The DSM assumptions used by DEC in the Astrape studies and the avoided costs estimates submitted in this proceeding are similar to the DSM magnitudes used in its 2018 Integrated Resource Plans. For example, Table 12-E on page 61 of the DEC Integrated Resource Plan shows 447 MW of winter DSM in 2019, increasing to 458 MW in most of the years 2022 to 2033. The analogous Table 12-F shows 1,035 MW of Summer DSM in 2019, increasing to 1,109 MW in the years 2024 to 2033.

120. The DSM assumptions used by DEP in the Astrape studies and the avoided costs estimates developed for this proceeding are also similar to the DSM magnitudes used in its 2018 Integrated Resource Plans. For example, Table 13-E on page 64 of the DEP Integrated Resource Plan shows 490 MW of winter DSM in 2019, increasing to 578 MW in 2033. The analogous Table 12-F shows 923 MW of Summer DSM in 2019, increasing to 1,058 MW in 2033.

121. The DSM assumptions used by DEC and DEP in this proceeding should be rejected, because these assumptions fail to minimize the cost or maximize the effectiveness of the DSM programs.

122. It will take time and effort to redesign the DSM programs, educate customers concerning the benefits of the revised programs, and market them to customers. However, the time and effort will be more than offset by the long-term cost reductions, reliability increases and other benefits that will be achieved by realigning and expanding the DSM programs to focus on the shorter duration, less frequent winter peaks.

123. The assumptions used in Prosym and other parts of the avoided cost analysis should be changed (or the cost results should be adjusted) to assume a phased reduction

to the number of MW of DSM that is available in the Summer and a corresponding increase in the MW of DSM that is available in the winter.

124. More specifically, it would be reasonable (although conservative) to require both DEC and DEP to modify its avoided cost estimates to reflect the following cumulative changes to the assumed level of DSM available in each year (relative to the assumptions DEC and DEP used in their respective avoided cost filings): No change in 2019. Increase winter 100 MW, decrease Summer 100 MW in 2020. Increase winter 200 MW, decrease Summer 200 MW in 2021. Increase winter 400 MW, decrease Summer 400 MW in 2022. Increase winter 600 MW, decrease Summer 600 MW in 2023. Increase winter 700 MW, decrease Summer 700 MW in 2024. Increase winter 800 MW, decrease Summer 800 MW in 2025 and all subsequent years.

125. DEC and DEP are both proposing to change the allocation ratios they use to assign capacity costs to different seasons. In Docket No. E-100, SUB 158 they proposed, and the Commission accepted, allocation ratios of 80% winter and 20% Summer. In this proceeding DEC is proposing to set QFs rates based upon an allocation of 90% of capacity costs to the winter with the remaining 10% allocated to the Summer. DEP is proposing to set QF rates based upon an allocation of 100% of capacity costs to the winter.

126. The proposed allocation ratios place too much emphasis on the winter because they are derived from an analysis of loss of load risks that placed excessive emphasis on the potential for extremely severe winter peak events that have rarely been observed. This flaw in the underlying analysis results in an overstatement of the winter loss of load risks relative to Summer risks.

127. The proposed allocation ratios also place too much emphasis on the winter because they are based upon inappropriate assumptions with respect to the DSM programs. Reorienting the DSM programs to focus on winter peaks will reduce the calculated loss of load risks in the winter.

128. The proposed allocation ratios also place too much emphasis on the winter because they fail to adequately take into account additional geographic diversity benefits that are available in the winter by obtaining power from generators in the PJM system, which is not winter peaking. While off-system transactions are important to consider at all times, they are particularly important when neighboring systems tend to peak at different times.

129. The proposed seasonal allocation ratios also should not be accepted because are they are based upon solar modeling that is inaccurate and unreliable, as discussed above. This is an important point to recognize, since the balance between winter and Summer "net" system load (and corresponding loss of load risks) is highly sensitive to the volume of solar capacity included in the analysis, and the assumptions or modeling that is used with respect to solar technology. While growing amounts of solar output will tend to reduce loss of load risks in the summer relative to the winter, Duke's inaccurate and unrealistic modeling assumptions overstate this impact. As explained in the report "Modeling the Impact of Solar Energy on the System Load and Operations of Duke Energy Carolinas and Duke Energy Progress," solar + storage investments and other "feedback effects" will change the magnitude, timing and shape of the "net peak" demand on Duke's system.

130. The importance of this issue is particularly evident in the case of Astrape's loss of load analysis for DEC. In the "0 solar" scenario, DEC calculates allocation ratios of 41% winter and 59% Summer.[19] In the "Existing Plus Transition" scenario, DEC calculates allocation ratios of 69% winter and 31% Summer. It is only in scenarios that include Astrape's inaccurate forecast of the impact of additional solar from the CPRE procurements that DEC calculates a winter allocation ratio that matches or exceeds the 80% factor that was used in the Sub 148 proceeding. While I don't disagree that a lot more solar is going to be added to DEC and DEP's systems, I believe an increasing fraction of this capacity will be paired with storage. Since solar + storage is likely to be a significant part of the total capacity added through the CPRE process, it is more logical to put similar weight on both the winter and summer peaks.

131. Since all of these problems tend to bias the allocation ratios by putting too much emphasis on winter load risks, the Commission should reject DEC and DEP's proposals to further shift the seasonal allocation ratios by placing more emphasis on winter peaks. A 50/50 allocation factor would be far more reasonable than the approach proposed by DEC and DEP, and more consistent with the totality of the available evidence, including the historical peak data, recent trends in peak loads, the growing impact of solar energy on "net" peak loads, and the various "feedback effects" which will ameliorate those impacts, as discussed in the report "Modeling the Impact of Solar Energy on the System Load and Operations of Duke Energy Carolinas and Duke Energy Progress."

19 DEC and DEP Response to NCSEA Data Request 3-13, attachment Monthly_LOLE_NCSEA.xls.

PURCHASED POWER CONTRACTS

132. Many existing QFs in North Carolina have contracts that will expire during the next 10 years. While most of these older contracts involve relatively small amounts of capacity, they are helping to meet the utilities' capacity needs, and there is no principled basis for refusing to pay them for the capacity costs they are helping to avoid when their contracts come up for renewal. Yet, if their proposals are accepted in this proceeding, the utilities will pay existing QFs (as well as new QFs) nothing for their capacity during several years – if not the entirety – of the contract renewal term.

133. These proposals are deeply discriminatory, and they rest on an unreasonable form of circular reasoning. In effect, the standard offer capacity rates during some of the next 10 years would be set to zero based on the assumption that all existing QF contracts will be renewed, and their capacity will continue to be relied upon by the utilities. Yet, those same QFs will be paid the standard offer rate, which will pay them nothing for their capacity during some years.

134. Not only does this involve circular reasoning, it would seem to violate, or at least significantly undermine, the fundamental purpose of PURPA, which is to treat QFs fairly, and to prevent them from being treated as "captive" suppliers at the mercy of a monopoly buyer.

135. Under PURPA, QFs are generally entitled to be paid the full amount of avoided costs, including both energy and capacity costs. Historically, the Commission has relied on the Difference in Revenue Requirements and Peaker Methods to develop these cost estimates. In recent years, the Commission has largely relied on the Peaker method to evaluate avoided capacity costs. This methodology combines the capital costs of a

hypothetical newly constructed peaking unit (typically, a combustion turbine) with marginal production costs (fuel and other variable operating and maintenance costs) for the system as a whole that would hypothetically be incurred if a QF were to displace a portion of the existing resources. By adding these two disparate cost calculations together, the intent is for the QF to be fully compensated for all avoided costs.

136. The Joint Initial Statement filed by DEC and DEP claims that DEC's next avoidable capacity need is a planned 460 MW (winter rating) of combustion turbine unit ("CT") capacity in 2028, while DEP's next avoidable capacity need is a planned 30 MW short-term market capacity purchase in 2020. I disagree with these claims, since they are not consistent with a full understanding of the relevant factual circumstances, including the fact that DEC plans to increase the capacity of some of its existing generating units, it plans on renewing existing purchased power contracts (which provided needed capacity) and it plans on maintaining (not mothballing or retiring) existing generating units that are very costly to operate, in order to maintain its reserve margins.

137. My conclusion is based, in part, on my understanding of how some key concepts are (or should be) interpreted, particularly with respect to the federal requirements set forth in PURPA, the associated FERC regulations, and the requirements set forth in HB 589. I am not an attorney, so my understanding of these provisions is based upon my perspective as an economist who is very familiar with PURPA and the electric utility industry.

138. It is my understanding that HB 589 does not supersede or change any of the federal requirements set forth in PURPA or in any of the associated FERC regulations; instead, it imposes limitations on the Commission's discretion in deciding how to

implement these federal requirements. Under the Peaker Method, compensation for capacity costs is not tied to the function of the QF – whether it will have operating characteristics like a peaker, like a base load plant, or have unique characteristics of its own. Similarly, under the Peaker Method, the key question is whether a QF can avoid some of the utility's capacity costs. To qualify for payment, there is no requirement that the QF offer the same number of MW as a peaker, or that the timing of when the unit will come on line be identical to when a peaker will, or could, be brought on line.

139. Because of my deep familiarity with the Peaker Method as it historically has been implemented in North Carolina, NCSEA asked me to review the requirements set forth in HB 589 and evaluate whether, and how, these provisions can be reconciled with the Commission's historical reliance on the Peaker Method.

140. The conclusion I reached is that HB 589 introduces some new requirements that must be followed by the Commission, and it might be easier to ensure compliance with these requirements while simultaneously complying with all applicable federal requirement if the Commission were to switch to the Differential Revenue Requirements (DRR) method (which the Commission has also accepted on occasion). However, I see no fundamental incompatibility between the Peaker method and HB 589. However, I do think it will be important to more carefully investigate the utilities' purchased power arrangements, in order to ensure that both state and federal requirements are appropriately fulfilled.

141. Looking closely at the provisions in HB 589, and comparing these to statements made in DEC and DEP's joint initial filing, it is not clear to me whether DEC and DEP have adequately complied with HB 589's requirements. In particular, it seems

questionable whether they have correctly stated whether they have "capacity needs" that can be "displaced" by QFs – or the timing and extent of that potential for displacement. In particular, I question whether it is reasonable for DEC to conclude that it has no avoidable "capacity need" prior to 2028. To the contrary, I think it would be acceptable under HB 589, and more consistent with the intent of PURPA, to provide some opportunity for QFs to be compensated for avoided capacity costs prior to 2028.

142. My understanding of HB 589 is that the Commission is required to consider "the expected costs of the additional or existing generating capacity" which could be "displaced" by power provided by a QF. I am unsure precisely how the Commission will interpret this provision, or what findings it will make in the integrated resource planning proceeding that is currently ongoing. I am also unsure what specific facts the Commission intends to analyze in deciding whether capacity can or cannot be "displaced" by a QF, as this concept is set forth in HB 589. One thing is clear to me, however: the Commission should consider more facts than simply the timing of when the next generating unit is scheduled for construction.

143. For example, DEC is planning improvements to some of its existing generating units which will occur in 2021, 2022, 2023, 2024 and 2025. These investments, and the resulting capacity increases are clearly relevant to an analysis of DEC's "capacity need." Similarly, the capacity to be provided by these improvements can potentially be "displaced" by QF capacity in much the same way QF capacity can potentially "displace" capacity that is expected to be available from a newly constructed generating unit. Uprating or other improvements to existing generating units, construction of new

generating units, and the renewal or replacement of purchased power agreements are all equally relevant factors that need to be considered.

144. I believe an analysis of existing purchased power agreements, and any planned or potential new purchase agreements, should be included in the Commission's evaluation of the capacity "need," along with all planned capacity additions and improvements, like the ones planned by DEC. All of these planned and existing capacity resources can potentially be "displaced" by the QF – as these concepts are set forth in HB 589. By including a careful evaluation of purchased power agreements, along with the timing of new generating units and improvements to existing units, the Commission can ensure the requirements of HB 589 are appropriately fulfilled without inadvertently violating or ignoring the federal requirements under PURPA.

145. Absent an appropriation of all existing and planned capacity resources, QFs may be treated unfairly, contrary to the federal requirements, because QFs could be denied an opportunity to be fairly compensated for the capacity they are providing, and the capacity costs they are helping the utility to avoid. Based upon my reading of the federal requirements, I don't believe the timing of planned new construction will suffice, standing on its own, as an adequate basis for denying a QF any opportunity to be compensated for avoided capacity costs.

146. HB 589 states that: "A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to G.S. 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer." This language does not focus exclusively on new plant construction, and as I

do not see anything in the statute that suggests the timing of new plant construction is the only thing the Commission is supposed to consider. From my perspective as an economist, a "need to serve system load" can be evidenced by many things other than just new plant construction. For example, plans by the utility to renew or replace existing purchased power contracts, plans to upgrade or improve some of its existing generating units, or plans to maintain (rather than mothball or retire) older generating units that are costly to maintain and operate could all provide evidence indicating a "need to serve system load" exists.

147. It is not clear to me how the Commission will interpret this provision of HB 589, or how this interpretation will be influenced by, or depend upon, the unique factual circumstances that arise in any given case. However, I strongly recommend that the Commission undertake a careful evaluation of how existing and planned purchased power agreements (including QF contracts) should be evaluated before deciding whether a "projected capacity need" exists during any given year.

148. It does not seem reasonable to skip past such an evaluation to simply assume that all existing purchased power agreements are a "given" that are irrelevant in evaluating whether a "projected capacity need" exists. Nor does it seem reasonable to assume an avoidable capacity need does not exist simply because most existing contracts are likely to be renewed, and no new generating units are scheduled for construction before a particular year.

149. In my opinion, the Commission should review the status of all existing and proposed purchased power contracts when evaluating whether, and to what extent, a "projected capacity need" exists. At a minimum, this review should include consideration

of the capacity provided by power purchase agreements that are subject to renewal, in recognition that some of this purchased capacity could be "displaced" by a QF.

150. From my perspective as an economist, I believe an evaluation of whether capacity obtained pursuant to a power purchase agreement could be "displaced" by a QF should consider at least three elements: (a) when the agreement is scheduled to expire, (b) whether there is 100% certainty it will be renewed or whether there is any chance the seller could cease operation or sell their power elsewhere, (c) whether the agreement includes any provisions that effectively provide an option to cancel or shorten the duration of the agreement under some circumstances, (d) whether the utility is effectively prevented from selling or transferring its rights under the agreement – analogous to a lease provision that prohibits subleasing.

151. The significance of existing and planned purchased power agreements, is apparent from the information included in the integrated resource plans.

152. The DEC Integrated Resource Plan shows it is relying on capacity obtained through purchase power agreements.[20] DEC expects to have the benefit of 259 MW of capacity in 2019 and 2020, and varied amounts of capacity ranging between 173 MW and 123 MW during the years 2021 through 2033 as a result of purchased power arrangements.[21] DEC is planning to rely even more heavily on capacity purchases during the Summer – 353 MW in 2019, 397 MW in 2020, 313 MW in 2021 and amounts ranging between 344 MW and 294 MW during each of the years 2022 through 2033.[22]

153. The DEP Integrated Resource Plan shows it expects to rely even more heavily on wholesale capacity purchases. DEP's plan for meeting its winter capacity needs

20 DEC 2018 Integrated Resource Plan, Table 12-E, page 61.
21 Ibid.
22 Ibid, Table 12-F, page 62.

includes 2,013 MW of purchased capacity in 2019, 1,703 MW in 2020, 1,646 MW in 2021, 1,140 MW in 2022, and varied amounts of capacity ranging between 738 MW to 463 MW during the years 2023 through 2032.[23] DEP is also planning to heavily rely on purchased power during the Summer. It anticipates purchasing 2,207 MW of capacity in 2019, 2,170 MW in 2020, 1,705 MW in 2021, 1,445 MW in 2022, and amounts ranging between 1,461 MW and 1,208 MW during each of the years 2022 through 2032.[24]

154. Both PURPA and HB 589 mention "incremental cost." By its very nature, incremental costs are somewhat hypothetical in nature. In the context of PURPA it has long been understood that QFs are to be compensated based upon cost calculations that are somewhat hypothetical – "as if" the QF provided power rather than some other, existing or planned resource.

155. To fulfill the fundamental purpose of PURPA, it is appropriate to treat QFs "as if" they were not captive to the utility. This well-understood concept is equally applicable to the appropriate interpretation of HB 589. It would not be reasonable to assume existing QFs are captive to the utility, or to ignore the fact that some QF purchased power contracts are going to expire during the next 10 years. Nor would it be reasonable to treat the energy provided by existing QFs as a "given" which cannot be displaced by any other QF, simply because the QFs are captive. Rather, an evaluation should be made of when the QF contracts expire, and the Commission should acknowledge that QFs can potentially shut down, or sell their power elsewhere, if they are not fairly compensated. The fact that existing PPAs are subject to renewal suggests a "need for capacity" exists,

---

23 DEP 2018 Integrated Resource Plan, Table 13-E, page 64.

24 Ibid, Table 13-F, page 65.

and QFs are capable of helping to fill that need (indeed, they are currently doing so, and will continue to do so if their contracts are renewed).

156. In general, I believe it is appropriate to analyze "incremental" or avoided costs in this proceeding "as if" existing QF contracts could potentially be displaced by new QF contracts. For example, at least in theory, a QF can refuse to renew its fixed price contract, and sell – at least during peak hours – into the PJM market, or to another buyer. Unless an approach like this is taken, which acknowledges that existing contracts are helping to meet the utility's "capacity need" there is a severe risk the Commission would effectively be treating QFs as if they were "captive" and on that basis force them to provide capacity to the utility without providing fair compensation for the value of that capacity.

157. From my perspective as an economist, I do not see any fundamental incompatibility between this approach and the requirements of HB 589. Not only is purchased power relevant from an economic perspective, but it is explicitly included in HB 589's list of factors the Commission must consider. The "expected cost of fuel and other operating expenses of electric energy production which a utility would otherwise incur in generating or purchasing power from another source" is specifically mentioned as part of the information the Commission must consider in determining avoided costs. Since payments to QFs and other independent power producers are classified as operating expenses, this provision clearly encompasses purchased power costs in the list of factors to consider in evaluating incremental costs or deciding what costs can be avoided. Accordingly, from my perspective as an economist, there is no reason to assume that HB 589 requires the Commission to exclusively focus on the timing of when new generating

capacity will be constructed, or to ignore the potential for the capacity provided by one existing QF to be "displaced" by another QF – or new QF of comparable size and operating characteristics.

158. In deciding whether a "projected capacity need" exists, it is reasonable to evaluate whether some of the capacity that is expected to be purchased wholesale (including purchases from existing QFs) could potentially be displaced by a QF that will be paid pursuant to the standard offer rates set in this proceeding. In so doing, the Commission should carefully evaluate the factual circumstances applicable to these existing or anticipated purchase contracts. My review of the available data indicates that many of DEC's older QF purchase contracts are up for renewal, or could be subject to cancellation or replacement, over the next 10 years. If these existing and planned purchases are appropriately analyzed, along with the planned upgrades to existing generating units, I believe the Commission can, and should, conclude that DEC has a "capacity need" that is being served by QFs and that can potentially be served by new QFs, and this need exists (and the corresponding need to include avoided capacity costs in the QF rates exists long before 2028, when DEC plans to construct its next new generating plant.

159. Since the focus is supposed to be on the cost of supplying capacity, and the extent to which any given QF can potentially displace other sources of power, I do not believe it would be reasonable to make a blanket assumption (on a class-wide basis) that none of the smaller, older QFs are helping to fulfill DEC's capacity needs, or to treat these QFs as if they were "captive" to the utility. Neither would it be reasonable to adopt an approach that effectively forces existing QFs to renew their contracts, and continue

providing their capacity to the utility, without being adequately compensated for this capacity.

160. Even the smallest generators have the ability to help fulfill the utility's capacity needs if they are supplying energy when capacity is needed. One of the benefits – indeed, one of the motivations – for most wholesale power purchase agreements is to help meet the purchaser's capacity needs. This remains true even if the contract is small, or the contract does not include an explicitly stated payment for capacity (e.g. if it were structured as a firm energy sale). Similarly, QF sales contracts can provide valuable capacity benefits to the purchasing utility, regardless of how small the QF is, or whether only a fraction of its nameplate capacity is available to the purchaser at times when capacity is needed. Rather than refusing to make any capacity payments, the appropriate solution is to scale back the size of the capacity payments, to reflect the actual benefits provided by the QF.

161. There is no reasonable basis for ignoring the benefits provided by small QFs, or to pay them nothing for their capacity merely because they are small, or because they may feel captive to the utility. At least in theory, they could wheel their power to a market like PJM, or sell it to a municipality or electric co-op, in an attempt to be fairly compensated for their power. If they were to do so, the utility would need to replace that energy and capacity – potentially even from another QF. Accordingly, it is clear that one QF is capable of effectively "displacing" the capacity provided by another QF.

162. Even if a QF is too small to realistically pursue any other options for marketing its power, that does not provide a reasonable or valid basis for paying it nothing for the capacity it provides to the system, or for treating its capacity as a "given" that is taken for

granted, without making sure the QF is treated fairly. Existing QFs were built and financed on the assumption that regulation would ensure that they will be compensated for the energy and capacity they provide even after their initial contract term expires – that their capacity and energy cannot simply be taken by the utility without ensuring they are fully and fairly compensated, consistent with all applicable state and federal requirements.

163. Given this context, assuming capacity provided by existing purchase contracts is a "given" – that it cannot possibly be lost or "displaced" by other QFs – is not appropriate. Nor would this treatment be consistent with the concepts of "incremental cost" and "avoided costs" as these concepts are appropriately used in implementing PURPA. Regardless of how plausible it might seem on the surface, it is not reasonable to assume all QF contracts will be renewed even if nothing is paid for their capacity.

164. The relevance and importance of the capacity benefits provided by existing purchased power contracts is confirmed by the fact that generating reserves shown in the integrated resource plans include the capacity provided by small QFs along with other wholesale providers of energy. If any of these purchases were to be terminated or expire, or if the rights to power provided by any of these existing contracts were to be transferred to a different buyer, the reserve margins calculated in the integrated resource plans would be correspondingly reduced.

MODIFICATIONS TO A QF GENERATING FACILITY

165. DEC and DEP are proposing changes to their standard contract Terms and Conditions which would effectively give them the unbridled power to prevent QFs from making material improvements to their facilities. Under their proposal any "material

modification to the Facility, including without limitation … the addition of energy storage capability shall require the prior written consent of Company, which may be withheld in Company's sole discretion."[25]

166. The intent of this provision is apparently to prevent QFs from being over-compensated for new investments, based upon the payment of "stale" contract rates pursuant to earlier biennial avoided cost proceedings. While their concern is understandable, their proposed "solution" is anti-competitive and discriminatory, since it would give DEC and DEP the sole right to decide which QFs will be allowed to upgrade or improve their facilities. They would also have the sole right to decide what improvements are "material" and it would effectively allow them to block QFs from investing in their facilities even when those investments are not motivated by an attempt to gain the benefit of "stale" rates. Moreover, the proposal would effectively stifle competition, by discouraging or preventing QFs from experimenting with new technologies, fixing mistakes in the design of their facilities, or responding to changed market conditions. This provision might even be used to prevent a QF from investing in equipment upgrades and replacements that are needed to maintain the facilities in good operating condition, replacing equipment that is damaged by storms, or compensating for the decline in output which occurs over time due to wear and tear and physical degradation.

167. Among other problems, this provision would vest far too much discretion in the utility. There is no requirement for DEC and DEP to engage in good faith negotiations with the QF, and it provides blanket authorization for the utility to impose excessive, draconian penalties in response to routine investment decisions that under any other

25 Joint Initial Filing, DEC Exhibit 4, page 5 of 24 and DEP Exhibit 4, page 4 of 20.

circumstances would be considered to be normal – indeed, desirable – behavior by a competitor responding to changing market conditions and technological improvements.

168. As worded, this provision is clearly not consistent with the public interest, since it provides DEC and DEP too much freedom to abuse their monopsony power and it will have the effect of discouraging QFs from investing in new and improved technologies, investing in storage technologies at their current locations, or making other needed and desirable changes to their existing facilities.

169. To the extent the Commission is concerned about "stale" rates, and it wants to avoid problems in future purchased power agreements, this could reasonably be accomplished in a more narrowly targeted manner. With appropriate changes to the standard contract language going forward, QFs would continue to have a stable revenue stream, that would not be subject to arbitrary reduction by the utility, and they can be provided with an incentive to improve their facility, and try new technologies, without placing an undue burden on retail customers.

170. If a QF wants to add more solar panels or make other investments to improve its facility, there is no logical reason to prevent it from doing so – or to force it to abandon the revenues it is receiving from its existing contract, assuming it does not increase the AC rating of the facility.

171. Any changes to the standard tariff language or standard contract terms and conditions related to facility modifications should be very carefully evaluated, to ensure the changes do not have the effect of discouraging efficient investments by QFs, or giving the utility unbridled discretion to block new investments in the state.

172. If the Commission concludes that some adjustments are appropriate to the standard terms and conditions with respect to material modifications to an existing facility, those changes should be implemented on a going-forward basis – they should not be retroactively applied to any existing QF contracts – and the new language should be carefully tailored to ensure the QF will continue to be compensated for its initial investment over the entire initial contract term based upon the rates set forth in the purchased power agreement, even if facility modifications are implemented.

173. Stability of the initial revenue stream is both appropriate and necessary to ensure that financing can be obtained on reasonable terms. To the extent different rates might be applied under some circumstances (for instance, if the AC rating were increased), the utility should not have broad discretion to use this as an opportunity to demand a reduction in the existing flow of revenues, or to punish the QF for making improvements to its facility.

174. Instead, the standard terms and conditions could include a provision indicating that major modifications of a facility may require negotiation of a new rates that consider "current" avoided cost data, while ensuring the QF retains the full benefit of its existing revenue flow – which it relied upon in making its initial investment. Stated another way, any such rate negotiations should focus on incremental changes to the QF's revenues, as compared to incremental changes to then-current (not "stale") avoided costs.

175. Needless to say, this approach would only be appropriate if applied prospectively to new PPAs. It should not be made retroactive to existing PPAs, since that would conflict with the reasonable expectations of QFs when they entered into those PPAs – including the expectation that the provisions of the PPA would remain in effect

during the initial term of the contract, and the expectation that they would be able to maintain and improve their facilities over time.

176. If the Commission concludes that the standard contract terms and conditions should be changed for new PPAs that are signed in the future, there are several considerations that should be considered in deciding how to word the new provisions. (a) the provisions should be carefully worded and should not be vague, (b) the utilities should not be given broad discretion to interpret how the new provisions will be applied to specific circumstances (or to specific QFs), (c) there should be a specific output threshold below which the contract rates would continue to be applied to all output, and there would be no need to negotiate a new PPA rate applicable to increased output, (d) modifications that merely enhance the QF's ability to shift the timing of energy delivery from off-peak to on-peak should be allowed without any restrictions, or any requirement to renegotiate the rates. Delivering more energy during on peak times, when rates are higher, is exactly what QFs should be encouraged to do. In fact, the higher rate that is paid for on peak energy and capacity is specifically intended to provide the appropriate price signal to encourage QFs to deliver energy at times when it is most valuable, and avoided costs are highest.

CORRECTING THE TIME FRAME USED IN DEVELOPING THE AVOIDED COSTS

177. DENC **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** treats January 1, 2019 as the starting point for its avoided cost and QF rate calculations. That is an arbitrary, and obviously unrealistic, assumption about when QFs qualifying for the avoided cost rates established in this proceeding will be placed in service, or the time period which will apply to the rates set in this proceeding.

178. Since the standard offer tariff establishes a single set of rates that apply to all QFs eligible for the tariff, regardless of when they are placed in service, it is appropriate to use a less arbitrary, more reasonable, estimate of when that will first occur. Given the fact that few QFs are likely to seek to establish LEOs under the new rates until after the rates have been finalized, and considering the lengthy amount of time that typically elapses from the time the LEO date until revenues are received under the PPA (due to delays attributed to interconnection studies and the time required for permitting, equipment procurement and construction), it is reasonable to assume a QF eligible for these rates will be place in service and start receiving revenues on or about December 31, 2021 – or three years later than the arbitrary, unrealistic date proposed by DENC **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

179. In the case of negotiated PURPA PPAs (and the avoided cost calculations used for CPRE and GSA) it should be feasible to be even more precise, by specifying a "cost curve" (or matrix of rates) which varies based upon the actual in-service date. For example, in the case of a large QF with negotiated rates, there is no logical reason to lock the rates to a single best estimate in-service date; it would be equally feasible to calculate how the avoided costs change depending on the in-service date, and to use this information during the rate negotiations, to specify what rates will apply if the project is delayed.

180. An unrealistic assumed time line distorts all of the avoided cost calculations, including the avoided energy rates, but the most obvious impact is on the avoided capacity rates. Consider, for example, DENC's calculations. DENC assumes the QF will start delivering power in January 2019, and it does not pay for capacity during the years

2019, 2020 and 2021. This effectively reduces its capacity rate by about 30% for a 10-year fixed rate contract. However, this 30% rate reduction is not merited, since the QF will probably begin delivering capacity to DENC just about the same time when DENC has a recognized its need for more capacity. In reality, if the QF energizes near the end of December 2021, it will provide capacity benefits, and should be paid for avoided capacity costs during the entire 120 months of the 10-year contract term.

181. A similar problem exists with DEP's capacity rate, due to its decision to assume the QF will begin delivering power on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** even though this is entirely implausible. In reality, the QF will probably not be energized until years later – at a time when DEP has acknowledged it has a need for capacity. Accordingly, the proposed reduction to DEP's capacity payments is entirely an artifact of this unrealistic timing assumption.

182. Similar problems exist with DEC's capacity rate. It reduces its capacity rate based on the assumption it doesn't need capacity until **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. However, this is entirely unrealistic. In reality, a QF that signs a 10-year fixed rate contract pursuant to the standard offer rates set in this proceeding will begin delivering energy around December 2021 or even later. Hence, it will actually provide capacity benefits to DEC for at least **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the 10-year fixed rate contract. The Commission may conclude that capacity costs can be avoided during additional years as well (depending on how the purchased power issue is resolved) but at this point I am only focusing on the timing problem. Accordingly, DEC's proposed capacity rate is

understated by more than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as a result of this unrealistic timing assumption.

THE QF RATES SHOULD BE REVISED TO PROVIDE BETTER PRICE SIGNALS

183. The QF rates should be revised to include avoided transmission and distribution costs, and this portion of the rate should be geographically granular.

184. Because the proposed QF rates are not geographically granular within each service area, they do not provide an incentive for QFs to invest in locations where the utilities can avoid transmission and distribution costs to the greatest extent. Except for DENC's Schedule 19 – LMP, the utilities are proposing to pay the same rates throughout their entire service area. None of the proposed rates adequately reflect the extent to which avoided costs vary between different locations.

185. With uniform geographic rates throughout the utility's service area, QFs are given a strong incentive to build their facilities wherever permitting is easiest, land costs are lowest, and electrical interconnections can most easily be achieved. While these locational factors are important, retail customers (and the state as a whole) would benefit if QFs were provided with geographically granular price signals, so avoided cost differences could be weighed against the benefits associated with providing electrical energy closer to customer load centers, in locations where distribution or transmission upgrades could be avoided or delayed by generating power closer to customers.

186. With geographically granular price signals that indicate where transmission and distribution costs can be avoided to the greatest extent, QFs would be given the opportunity to make better, more prudent investment decisions, which would reduce risks

and strengthen the underlying economics of their investments. This would benefit retail ratepayers by avoiding or delaying increases in the rate base, and the state's economy as a whole (by increasing economic efficiency, improving the investment climate, and strengthening the competitive market for independent power production).

187. With geographically granular rates, QFs can weigh the higher costs of land acquisition and permitting in relatively congested urban and suburban locations against the benefits of providing power in these locations, which are closer to many customers. Over the long term, the total costs to society will be reduced, efficiency will be improved, and long-term investment risks will be minimized, if QFs receive better, more accurate price signals. This will provide QFs with an economic incentive to locate where the utility avoids the most transmission and distribution costs, rather than exclusively considering where land can be acquired cheaply and where permits and electrical connections can be most easily obtained.

188. The proposed QF rates designs should also be revised to better recognize how costs vary across different seasons and different times of the day.

189. DEC and DEP are proposing two seasons, while DENC is proposing three seasons, although some of DENC's proposed rates have been averaged across multiple seasons. All three utilities are proposing to define a Summer season that stretches from May through September. DENC is proposing to define a winter season that includes December, January and February and a shoulder season that includes the remaining, spring and fall months. DEC and DEP are proposing to combine all of the non-Summer months together, thereby obliterating important differences in the avoided cost patterns in the various non-Summer months.

190. I agree that it is reasonable to define the Summer season to include May through September – although it would also be feasible, and might be a little more precise, to define a slightly shorter Summer season, starting May 16 and ending September 15.

191. I strongly disagree with DEC and DEP's proposal to not define a separate winter season, and DENC's proposal to use some of the same rates, and some of the same rate periods in more than one season. Electrical usage, "net" system load, marginal production costs and avoided costs all follow distinctly different patterns during different times of the year.

192. All of the utilities made some attempt to reflect these variations in their proposed QF rates, but none of them go far enough – they all employ excessive and unnecessary cost averaging, which obscures the underlying cost patterns and weakens the price signals.

193. DENC is proposing an oversimplified daily on-peak and a daily off-peak rate. Although the timing of each rate period varies by season, the rate is averaged across all three seasons. For example, the on-peak rate applies from 11 am until 9 pm Monday through Sunday during the Summer, the same rate applies to the hours of 6 am to noon and 5 pm to 9 pm during the Winter, Spring and Fall. A uniform off-peak rate applies to all other hours, including certain holidays.

194. DEC's QF rate proposals are also oversimplified. During the Summer DEC is proposing an on-peak energy rate from noon until 11 pm Monday through Friday. The off-peak energy rate applies to all other hours, including weekends and holidays. During the Non-Summer season, DEP is proposing an on-peak energy rate from 6 am until 10 am

and from 5 pm until 11 pm. The Non-Summer off-peak energy rate applies during all other hours, including weekends and holidays. The proposed capacity rates involve a similar amount of excessive cost averaging, although the seasons and rate periods are defined differently, which has the potential for being somewhat confusing.

195. DEP is also proposing an excessive amount of cost averaging. During the Summer DEP is proposing an on-peak energy rate from 1 pm until midnight Monday through Friday. The off-peak energy rate applies during all other hours, including weekends and holidays. During the Non-Summer season, DEP is proposing an on-peak energy rate from 5 am until 9 am and from 5 pm until midnight. The Non-Summer off-peak energy rate applies during all other hours, including weekends and holidays. The proposed capacity rates also use a significant amount of cost averaging , although the seasons and rate periods are defined differently.

196. All of these rate design proposals should be rejected, because rates are being oversimplified, and averaged across time periods with distinctly different cost characteristics. To appreciate the extreme degree of cost averaging the utilities are proposing, it should be realized that detailed avoided cost data (as well as forecasted system load and solar output data) is available for all 8,760 hours during each of the next 10 years. In fact, this level of granular detail is not only readily available, it was actually used in developing the proposed QF rates. However, nearly all of this detail was lost in the final rates that were proposed. Averaging away so much important detail is highly inappropriate and unduly discriminatory in the context of QF rates.

197. For use in this proceeding, a reasonable alternative would be to calculate separate rates for each hour of each month. This may seem radical, but it would actually

be quite practical and simple to implement. All of the rates could easily be displayed in a tariff, as evidenced by discovery responses provided by the utilities. These discovery responses show their avoided cost data in a simple matrix of 12 rows and 24 columns. Even the smallest QFs are sophisticated enough to read this sort of matrix in a tariff, and to respond accordingly.

198. One reason why the 12x24 pricing approach is so simple is that it eliminates the complexity of separately keeping track of holidays or distinguishing between week days and weekends. In the context of some retail rates, this added complexity might offer some minor benefits, since consumption patterns for commercial customers often vary widely between business hours and other hours – which is influenced by the timing of holidays and weekends. Depending on the purpose of the tariff, there might also be some small benefit from encouraging retail customers to wait until the weekend before engaging in highly energy-intensive activities.

199. However, the added complexity associated with keeping track of weekends and holidays is not really necessary, or particularly useful, in the context of QF rates. While cost differences can exist between week days and holidays and weekends, the distinction is not particularly important or significant for QFs. For instance, hydro and solar energy production varies over time, but none of this variation is related in any way to whether it is a weekend or holiday. Furthermore, most QF investment and operational decisions will not be affected one way or the other with respect to whether a specific hour occurs during a holiday or weekend. This is especially true since any cost differences that result from reduced system loads on holidays and weekends are not extreme – while the

distinction is measurable, it is not significant enough to make it imperative to include this nuance when setting QF rates.

200. Although a 12x24 rate design offers a high degree of granularity, this is not the only approach that is worth considering. Another reasonable approach to use in this proceeding would define the Summer season to include May through September; Winter would include December through February; the remaining months (October, November, March and April) would be grouped together as the "Other" season, and within each of these seasons there would be three rate periods. The main difference between this approach and the one used by the utilities is that the hours in each rate period and the rate paid in each rate period will vary for each season, to ensure the QF rates provides strong, accurate price signals that closely track the utility's underlying load characteristics and cost patterns.

201. To illustrate this approach, I developed some examples for DEC and DEP which are nearly as simple as their rate proposals, yet they provide much strong, more accurate price signals. For simplicity in explaining this example, the rate periods are stated in terms of Daylight Savings Time during the Summer, and Eastern Standard Time during the rest of the year.

202. For DEC, the Summer Rate Period 1 (with the highest rate) would apply from 3 pm until 9 pm. Rate Period 3 (with the lowest rate) would apply from 3 am until noon. In the Winter, Rate Period 1 (with the highest rate) would apply from 5 am until 9 am and also from 5 pm until 10 pm. DEC Rate Period 3 (with the lowest rate) would apply from Noon until 4 pm. In the Other season, DEC Rate Period 1 (with the highest rate) would

apply from 6 am until 7 am and from 5 pm until 10 pm. Rate Period 2 would include all other hours.

203. The rate periods for DEP East would be the same in the Summer: Rate Period 1 (with the highest rate) would apply from 3 pm until 9 pm. Rate Period 3 (with the lowest rate) would apply from 3 am until noon. In the Winter, DEP East Rate Period 1 (with the highest rate) would apply from 5 am until 10 am and from 5 pm until 10 pm. Rate Period 3 (with the lowest rate) would apply from midnight until 3 am and from Noon until 4 pm. In the Other season, DEP East Rate Period 1 (with the highest rate) would apply from 6 am until 8 am and from 5 pm until 10 pm. Rate Period 2 would include all other hours.

204. Avoided costs for DEP West could be blended with the data for DEP East, in which case the same time periods should apply to DEP West, since it is much smaller. However, if the Commission would like to establish separate rates for DEP West, the time of day pattern for that area could be different.

205. A separate DEP West Rate Period 1 could apply from 4 pm until 10 pm in the summer, and Rate Period 3 would apply from 1 am until 1 pm. During the Winter, a separate DEP West Rate Period 1 could apply from 6 am until 10 am and from 6 pm until 8 pm, in which case Rate Period 3 would apply from midnight until 5 am and from 10 am until 3 pm. Similarly, a separate DEP West Rate Period 1 could be applied in the Other season from 6 am until 9 am and from 4 pm until 11 pm. Rate Period 3 would apply from 11 am until 3 pm. Rate Period 2 would apply to all other hours.

206. Regardless of whether DEP East and DEP West are separated, this approach to designing QF rates would be simple to implement, easy for QFs to understand, and far

more effective in providing strong, accurate price signals that closely track the underlying cost patterns.

207. To further improve the alignment of QF rates with the underlying pattern of avoided costs, and to provide even stronger, more precise price signals, one further refinement should be implemented: Real Time Pricing should be applied to QFs under extreme conditions – the relatively small number of hours when system costs are extremely high or extremely low. Fixed prices would continue to be applied during the vast majority of the hours each year, thereby providing QFs and their investors with adequate revenue stability and predictability.

208. The timing of when Real Time Pricing should be applied cannot be predicted in advance and published in a tariff, since it will depend upon actual system conditions as they occur and are reflected in System Lambda.

209. LMP prices could be used for DENC during the Real Time Pricing periods, and System Lambda could also be the basis for the rate paid by DEC and DEP during the Real Time Pricing periods. However, this would require a similar level of pricing transparency as exists in PJM. There would need to be adequate disclosure of how DEC and DEP are calculating System Lambda, and they would need to publish this data on the Internet immediately after each hour occurs, so that QFs and other interested parties can monitor this data, on a nearly Real Time basis.

210. A simpler, more familiar alternative would be for the Commission's traditional Peaker approach to be used in setting the Real Time prices. All that would need to be done is to remove the extremely low and extremely high cost hours from the avoided cost averages that are used in setting rates during Rate Periods 1, 2 and 3. The costs from

these “outlier” hours would instead be used in calculating the rate that will apply during Real Time pricing events. Either way this concept is implemented, it will effectively pass through to the QF the strongest possible incentive to provide as much power as possible during extreme system peaks (consistent with economic efficiency). Similarly, this structure will provide the strongest possible incentive to deliver as little power as possible during the specific hours when extremely mild weather and high volumes of solar output will combine to result in a system unbalance, or extremely low or negative cost conditions.

211. To make this approach fully effective and acceptable, it will be necessary to impose some reasonable limitations on the way the utilities apply Real Time Pricing. These limitations are also necessary to ensure that QFs are able to forecast their expected annual revenues with a reasonable degree of predictability and uncertainty. Specifically, I recommend imposing three limitations.

212. First, the utility would be required to provide the QF with 36 hours advance notice prior to any hour when it anticipates extremely high or low-cost conditions are likely to be encountered (times when Real Time Pricing might be applied). This advance notice can be provided using the same short-term forecasting process the utility uses internally, to plan which generating units it will most likely want to deploy during the next day or two.

213. Second, the utility would be required to provide the QF with at least 4 hours advance notice prior to any hour in which Real Time Pricing will actually be applied. Advance notice is needed to ensure the QF has an adequate opportunity to decide how it will respond to the real time prices. For instance, with some advance notice, a QF with

storage capacity can decide whether it wants to hold some of its power in reserve in anticipation that even higher real time prices may occur later in the day (e.g. on a hot summer night), or whether to deliver as much stored energy as quickly as possible during the hour that is likely to have the highest peak and the highest price (e.g. from 7 to 8 am on an cold winter morning). Similarly, advance notice of an anticipated energy surplus resulting in low or negative Real Time Pricing will enable the QF to make sure it has storage capacity available, so it can store as much energy as possible during that time period.

214. Third, the tariff would specify a minimum number of hours when High Real Time Pricing will be applied during any rolling 12-month period, and it would specify a maximum number of hours when Low Real Time Pricing will be applied during any rolling 12-month period. Bracketing the uncertainty in this manner will provide the QF with a reasonable degree of assurance of the minimum level of revenues it can anticipate during any 12-month period.

215. The upper and lower constraints do not necessarily need to be symmetrical, but the avoided cost data used to set the fixed rates applicable to other hours will need to be appropriately adjusted, to maintain consistency with whatever Real Time Pricing limitations are provided in the tariff. If the maximum number of Low Real Time Pricing hours were set at 500 hours, for example, 500 of the lowest cost hours in the avoided cost data would be removed before calculating the fixed rate that is applicable when Real Time Pricing does not apply.

216. Upper and lower constraints serve similar, but slightly different, purposes. The cap on Low Real Time Pricing hours is needed to provide reassurance to bankers and

investors concerning the minimum revenues the QF can reasonably anticipate during any given year. This limitation will be important since Low Real Time Pricing is likely to generate zero, or even negative, revenues for the QF during some hours.

217. The floor under the number of hours with High Real Time Pricing serves a very similar purpose. It will provide bankers and investors with the clarity and predictability they will need to estimate the range of revenues that can potentially be achieved by the QF. Historical System Lambda data is publicly available, and they can use this information to estimate the additional revenues they are likely to achieve as a result of High Real Time pricing – providing there is some indication of the minimum number of hours each year when prices will be tied to System Lambda. This floor on hours is also needed to provide a reasonable degree of predictability for analyzing the potential returns on investment in storage capacity. This same information will also be useful in estimating the net impact of various other investment decisions, like the inverter loading ratio, as well.

218. A key component of a QF's investment analysis will be the expected level of revenues that will be achieved by delivering as much energy as possible during times when High Real Time Pricing is available and as little energy as possible during times of Low Real Time Pricing. These are times when higher or lower than normal revenues will be generated because prices will be tied to System Lambda. With appropriate brackets on the number of hours when this form of pricing applies, a reasonable degree of predictability will emerge, so that prudent and efficient investment decisions can be made by QFs.

219. Because the available avoided cost data in this proceeding suffers from the effects of the solar modeling problems discussed above, it isn't feasible to precisely estimate the impact of Real Time Pricing. In general, however, I believe the solar modeling problems have caused the utilities to overestimate the degree to which costs will fluctuate in any given hour, and these same modeling problems have caused them to over estimate of how many hours each year costs will drop to extremely low or negative levels. The solar modeling problems might also be affecting the frequency and timing of when extremely high costs are expected to be incurred. To be clear, I am mentioning the solar modeling problems in this context because it reduces the ability to precisely simulate the impact of different rate designs.

220. With Real Time Pricing these modeling problems area of less concern, since prices during extreme conditions will be tied to actual costs (as measured by System Lambda), not the inaccurate cost estimates that were derived from the inaccurate solar modeling.

221. With that caveat, I developed some illustrate rates that are based on the assumption that High Real Time pricing will be applied to not less than 125 hours in any rolling 12-month period, and Low Real Time pricing will be applied during not more than 500 hours in any rolling 12-month period.

222. Using these limitations in conjunction with DEC's detailed cost data, I developed the following illustrative estimates of the impact of Real Time Pricing on the fixed energy-only prices that would be applicable during all non-Real Time Pricing hours under a 10-year contract. DEC Summer: Rate Period 1 - \$40.72, Rate Period 2 - \$36.61, \$34.13. DEC Winter: Rate Period 1 - \$41.38, Rate Period 2 - \$33.36, Rate Period 3

$29.31. DEC Other: Rate Period 1 - $38.25, Rate Period 2 - $34.69, Rate Period 3 $35.14.

223. Using the same minimum and maximum hour limitations in conjunction with DEP's detailed cost data, I developed the following illustrative estimates of the impact of Real Time Pricing on the energy-only fixed prices that would be applicable during all other hours under a 10-year contract. DEP Summer: Rate Period 1 - $46.18, Rate Period 2 - $34.33, $30.77. DEP Winter: Rate Period 1 - $34.83, Rate Period 2 - $28.29, Rate Period 3 $25.01. DEC Other: Rate Period 1 - $39.53, Rate Period 2 - $31.56, Rate Period 3 - $31.76.

224. These illustrative rates only recover avoided energy costs. The QF should also be paid for avoided capacity costs including avoided Transmission and Distribution costs – preferably on a geographically granular basis.

225. The QF should also be compensated for avoided capacity costs using essentially the same rate structure. None of the avoided generating capacity costs would be paid during Low Real Time Pricing hours, or Rate Period 2 or 3. The recovery of transmission and distribution capacity costs should be concentrated in Rate Periods 1 and 2, while taking into account the relevant, geographically granular load patterns on the transmission and distribution system.

226. It is appropriate to allocate a portion of the avoided capacity costs to during Winter Rate Period 1 (say, 25%) and a similar portion during the Summer Rate Period 1 (say, 25%). This approach is appropriate since it aligns capacity cost payments with hourly loss of load risks and other considerations which are important in defining appropriate capacity cost price signals, while also providing a reasonable degree of

revenue predictability for QFs. The remaining portion (say 50%) of the avoided capacity costs should be recovered during High Real Time pricing hours, whenever they occur. This will ensure that QFs have a very strong incentive to deliver energy to the grid at the specific times when capacity is most needed.

227. This pricing structure will provide QFs with much stronger, more accurate price signals to help them make efficient investment and operating decisions than the proposed QF rates. Under this rate design, the highest fixed rates will tend to be paid during early morning and evening hours in the winter, and during late afternoon and evening hours in the summer. These are also the times when High Real Time Pricing is most likely to be in effect – but the specific days, and precise hours, when those payments will be received will be determined in real time based upon the actual weather conditions that are encountered each year.

228. With this rate structure, the QF will have a strong economic incentive to deliver as much energy as possible during the precise hours when a Polar Vortex or extreme heat wave is creating a severe need for capacity as indicated by the fact that marginal fuel costs are at extremely high levels. This is also the precise time when the capacity provided by QFs will be extremely beneficial to the system, improving reliability and reducing the risk of an outage. Accordingly, it makes sense to require a significant fraction of the QF's capacity cost payments to be tied to its actual, demonstrated ability to deliver power during these critical peak times as indicated by extremely high System Lambda levels.

229. This relatively simple, flexible, and far more accurate rate design will enable QFs to make better, more efficient investment decisions.

230. Consider, for example, the tradeoffs between installing solar panels in fixed arrays and installing panels that track movement of the sun. With much higher payments on early Winter mornings and Summer evenings (including higher fixed rates as well as the chance to benefit from Real Time Pricing), some QFs will very likely conclude that it will now be profitable to invest more of their capital in tracking the sun – which extends the timing of when energy can be produced to begin earlier in the day and to extend later into the evening (but with less peak output in the middle of the day).

231. For essentially the same reason, this more accurate rate design will enable QFs to make better, more efficient decisions concerning the number of solar panels they install relative to the electrical capacity of the inverters and grid connection. With a higher inverter ratio (oversizing the panels relative to the inverters) the QF can generate and deliver much more energy to the grid during the early morning and late evening hours. This is true because the nameplate capacity of the inverters and grid connection don't limit the ability to deliver energy produced by the early morning or late evening sun. In contrast, during the middle of the day, solar output is naturally much higher, so some of the solar energy will be lost or "clipped" because it can't reach the grid.

232. Without accurate price signals, the QF is unlikely to choose an optimal inverter loading ratio, because extra solar panels are costly to install, and some of the extra output from the additional panels will be "clipped" or lost during times when solar output is very high. However, the engineering analysis that is performed on the basis of an oversimplified rate structure based upon broad rate averages can be very misleading, because it fails to consider the fact that power delivered during the middle of the day (when clipping is most likely to occur) is less valuable than power delivered during other

times. With the large amounts of solar coming on line in North Carolina, the failure to accurately model and evaluate these cost differences will lead to more and more serious deviations from the economically optimal outcome. With stronger, more accurate price signals, as described above, all QFs will have stronger incentives, and better information, to correctly evaluate the true underlying tradeoffs underpinning these investment decisions.

233. With stronger, more accurate price signals, QFs are likely to reach the conclusion that a higher inverter ratio is optimal, because of the added revenues that will be generated during early Winter mornings and late Summer evenings (because of the higher fixed rates that are paid in these hours, as well as the opportunity to benefit from High Real Time Pricing).

234. With stronger, more accurate price signals, QFs will also have a stronger incentive to investigate and consider investing in storage capacity. The importance of better price signals is particularly obvious in the case of solar + storage, because muted price signals destroy the economics of storage investments. The closer rates converge toward a single uniform year-round rate the less opportunity there is for QFs to recognize and respond to cost differences – defeating one of the fundamental purposes of wholesale prices.

235. With appropriately designed, granular rates QFs will be rewarded for delivering energy at times when it is most needed – which are also the times with the greatest fuel cost savings and capacity benefits. This will benefit retail customers far more than a system of over-simplified rates which fails to distinguish between times when energy is most needed and times when it is in surplus. With any form of storage, a

commodity can be stored when prices are low, and delivered when prices are high. This is the fundamental principle that underpins the economics of firms that store grain, crude oil, soybeans, natural gas, and many other commodities. If different price signals do not exist, or prices do not accurately indicate times when costs are low and when they are high, the full economic potential of storage cannot be realized.

236. With the oversimplified rates proposed by the utilities, the same average rate will be paid to QFs for energy delivered throughout broad time periods, obliterating important cost differences that exist within these broad time periods. This excessive, unnecessary cost averaging destroys the economics of storage, since it provides very little, or no, incentive for the QF to benefit from storing electricity when it is cheap, or a surplus exists. It also hurts the economics of storage because it prevents the QF from gaining the benefit of delivering energy to the grid at times when a shortage exists, or fuel costs are extremely high. These problems can be solved by implementing a better, more accurate rate structure like the one I have illustrated.

237. The rate design I am recommending is superior to the one proposed by the utilities because QFs will be rewarded when they deliver energy when it is most needed – during the specific hours when the grid is most stressed, and the highest loss of load risks exist. It is well understood these times primarily occur during cold winter mornings and hot Summer evenings, so the fixed portion of the rate follows this pattern. However, the most extreme cost variations occur in response to weather, and the exact timing of when the most extreme weather conditions arise will vary from year to year. By rewarding QFs for delivering energy during extreme weather conditions, when it is most needed, (by including a Real Time Pricing element in the rate design), the incentives facing the QF

will be closely aligned with the interests of retail customers and society as a whole.

238. With this approach there will also be much less reason to worry that a QF might end be compensated for capacity it is unable to deliver during extreme conditions, when it is most needed. For that reason, as well as the other reasons stated above, I recommend the Commission reject the rates proposed by the utilities, including Dominion's proposal to impose an Annual Capacity Payment Cap. With correctly designed rates, any possible justification for imposing such a cap is eliminated.

FURTHER THE AFFIANT SAYETH NOT.

This the 12th day of February, ~~2018.~~ 2019

Benjamin Franklin Johnson, Ph.D.

Sworn to and subscribed before me
this the 12h day of February, ~~2018.~~ 2019

Notary Public

My commission expires:

(Seal)

JOSEPH MEROLA
MY COMMISSION # FF 946824
EXPIRES: January 3, 2020
Bonded Thru Notary Public Underwriters

Exhibit A

PRINCIPAL OFFICES
5600 PIMLICO DRIVE
TALLAHASSEE, FLORIDA 32309
850-893-8600
FAX 850-893-3000

ECONOMIC RESEARCH
AND ANALYSIS

Modeling the Impact of Solar Energy

on the System Load and Operations of

Duke Energy Carolinas and Duke Energy Progress

6070 HILL ROAD
BOISE, IDAHO 83703
208-342-1700
FAX 208-384-1511

VISIT OUR WEBSITES:
benjohnsonassociates.com
utilityregulation.com

ELECTRONIC MAIL:
bj@benjohnsonassociates.com

Report Prepared for the

North Carolina Sustainable Energy Association

February 11, 2019

Introduction

The North Carolina Sustainable Energy Association ("NCSEA) asked Ben Johnson Associates, Inc. ("BJA") to prepare this report in conjunction with NCSEA's participation in two proceedings before the North Carolina Utilities Commission ("NCUC"): E-100 Sub 157 ("2018 IRP proceeding") and E-100 Sub 158 ("2018 Biennial Avoided Cost proceeding").

This report focuses some issues involved with modeling the electrical output from solar energy facilities ("solar modeling) as it relates to the system load and operations of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke" or "the utilities").

The first section discusses system load characteristics, with a focus on predictable variations in customer energy usage related to seasonality and time of day, as well as weather fluctuations. This section also briefly introduces the concept of "net" system load (the portion served using conventional energy resources).

The second section discusses solar modeling, with a focus on geographic diversity, predictable patterns related to the day of the year and time of day, and variations in solar output that depend upon cloud cover and other weather conditions.

The third section discusses modeling of "net" system load, taking into account variations in system load and solar output.

The fourth section discusses modeling of future changes to "net" system load, with a focus on economic incentives and other factors which will influence solar output volumes and timing of when solar energy is sent to the grid.

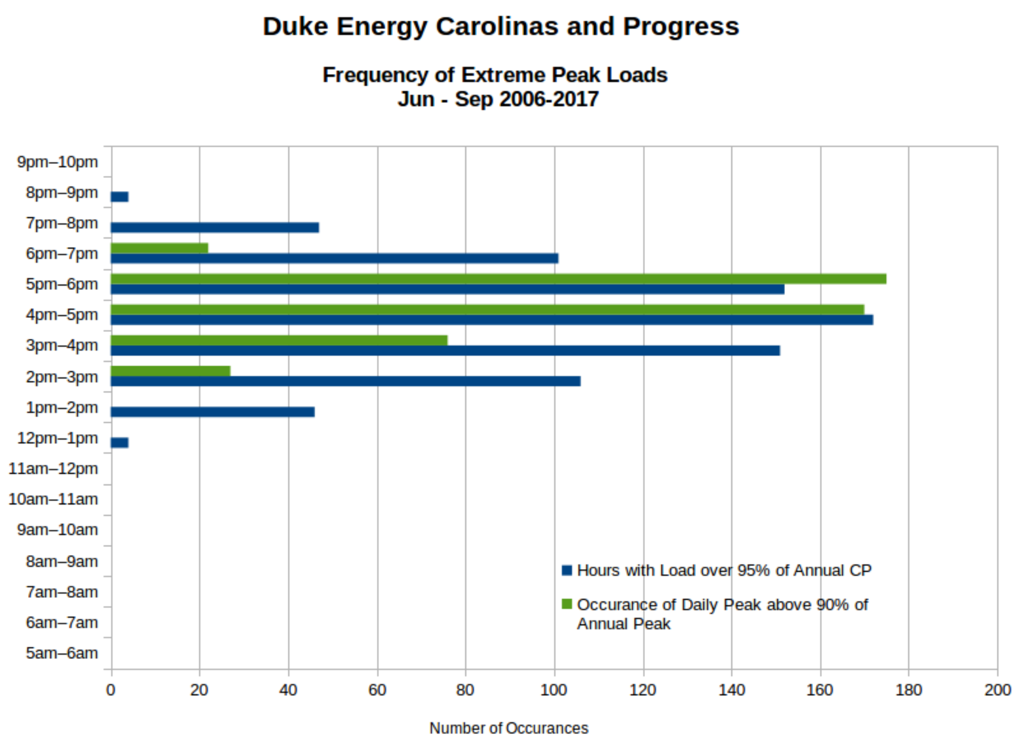
System Load

Seasonal and daily customer energy usage patterns are the underlying foundation for Duke's investment in its generating fleet. These patterns influence the mix of technologies used in the fleet, how Duke operates the fleet, and Duke's purchases of power from other utilities and Independent Power Producers. Accordingly, system load characteristics provide a logical point of entry into the discussion of solar modeling and related issues which follows later in this report.

To analyze system load characteristics, BJA started with hourly load data provided by Duke to the Federal Energy Regulatory Commission ("FERC") on Form 714 for the years 2006-2017.

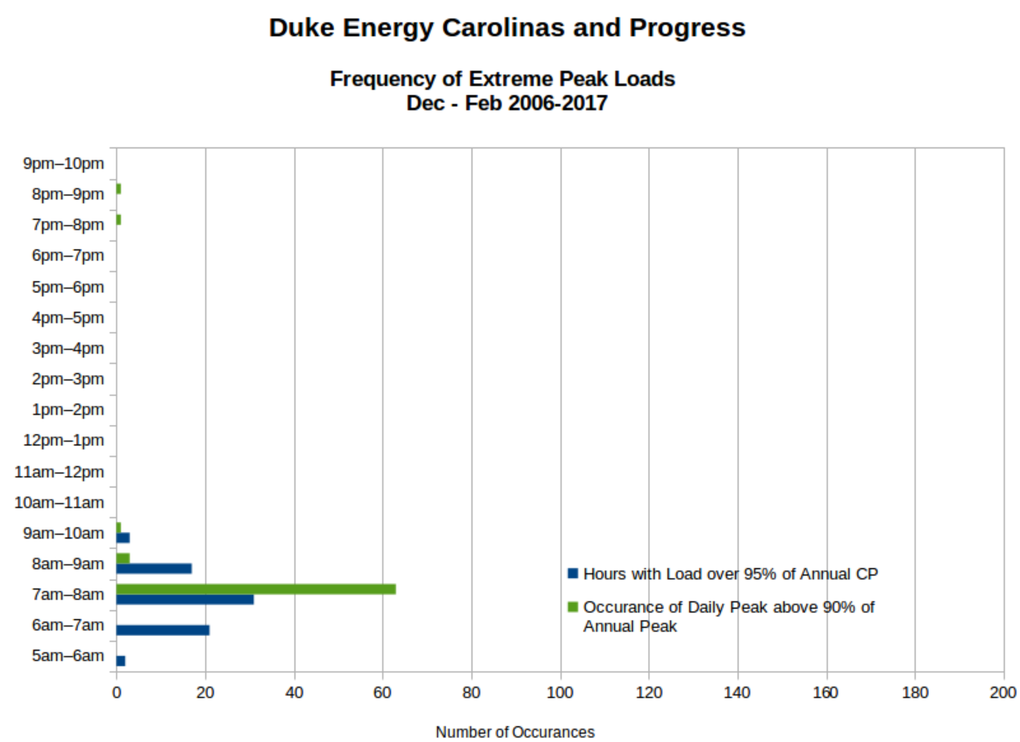
From an electric utility's perspective, the most challenging problem is meeting customer load during peak periods – hours when customers are using an unusually large amount of electricity. As shown in the following series of graphs, Duke has historically been classified as a "summer peaking" utility, because the hours when its generating capacity has been most severely taxed have most frequently occurred during the late afternoon and evening hours on hot summer days.

In this first graph, the dark blue bars indicate the number of hours when the total DEC and DEP system load exceeded 95% of the annual system peak during the summer months of August through September 2001-2017. Note the blue bars include more than one hour on the same day if extreme peak levels of demand last for several hours during that day.



The green bars look at the same underlying data in a slightly different way. They show the hours when the daily peak occurred (but only if the daily peak exceeded 90% of the annual system peak).

The following graph is directly comparable to the one above, except the data is for the months of December through February during the same years. Note the horizontal scale is the same in both graphs, so a bar of equivalent length represents the same number of hours in both seasons.

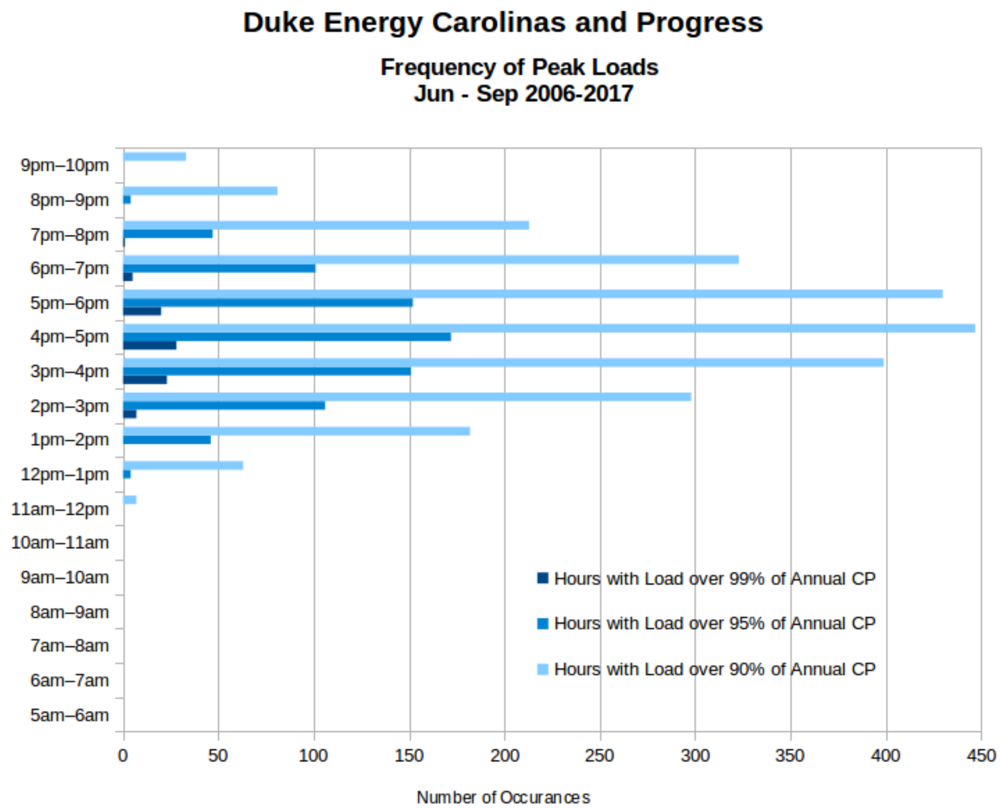


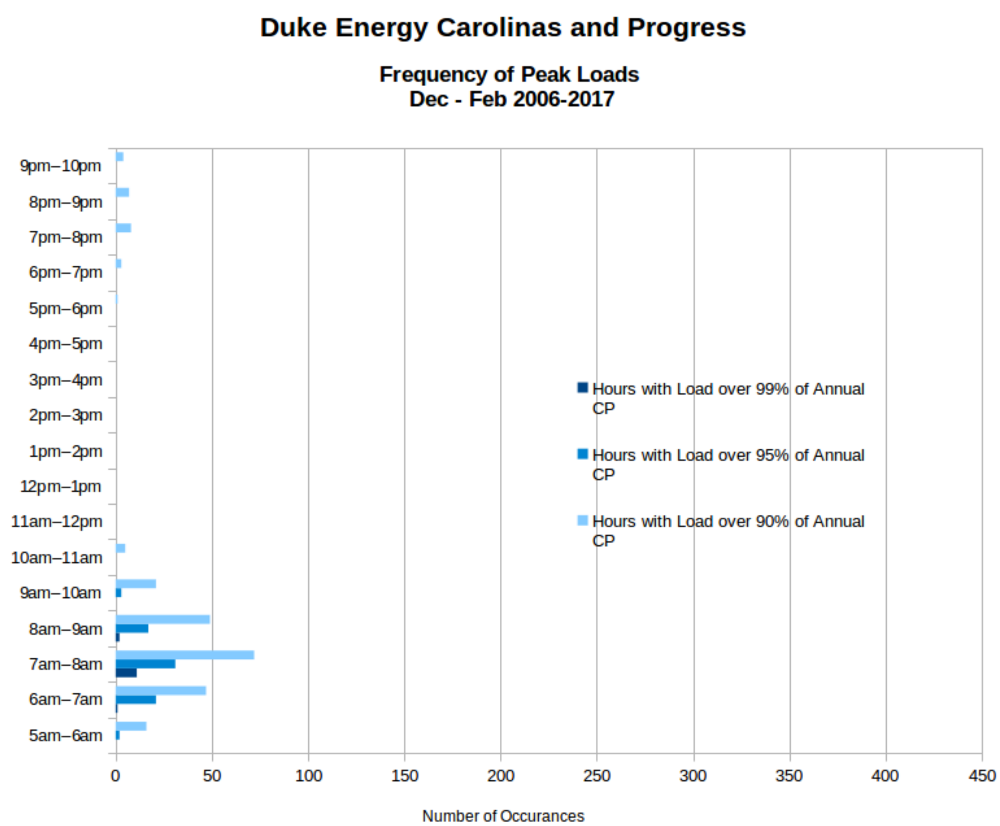
Because North and South Carolina generally experience mild winters, and many customers rely on natural gas or another energy source for heating, the winter peaks tend to be less severe and less frequent. As well, the highest peaks tend to be of shorter duration, since the coldest weather often occurs overnight; by the time commercial and industrial demand starts to peak, the day will have warmed up and heating needs will subside.

Winter peaks are still important, however. In fact, there are some years – like 2017 – when the highest peaks in the winter exceed the highest peaks in the summer. These relatively rare, peaks tend to occur during a Polar Vortex or other extremely cold winter weather, when the need for electric heat elevates system demand overnight. This type of weather results in very brief, very extreme peaks, which primarily occur about the time when residential customers begin to wake up, adjust their thermostat, take showers and cook breakfast. These extreme peaks begin to subside once the sun comes over the horizon, causing the need for heat to diminish.

These predictable summer and winter weather-related system load characteristics are further confirmed on the following two graphs, which are derived from the same data source but include a wider range of data.

The bars show the number of hours when peak usage exceeded 99%, 95% and 90% of the annual peak. The most extreme peaks are shown in dark blue and less extreme peaks are shown in light blue.





The first graph confirms that peaks during the summer tend to begin in the afternoon and extend into the evening. Milder peaks tend to occur early in th afternoon, the maximum peaks often occur sometime around 4 pm and milder peaks can extend well into the evening.

The second graph shows similar information for the winter, using the same scale so a bar of equivalent length represents the same number of hours in each season.

Not only do peak loads occur less frequently during the winter than in the summer, the peaks tend to be of shorter duration, and they occur mostly in the morning rather than the afternoon. Lower peaks do sometimes occur on winter evenings, before people go to sleep, as indicated by the handful of short light blue bars at the top of the graph.

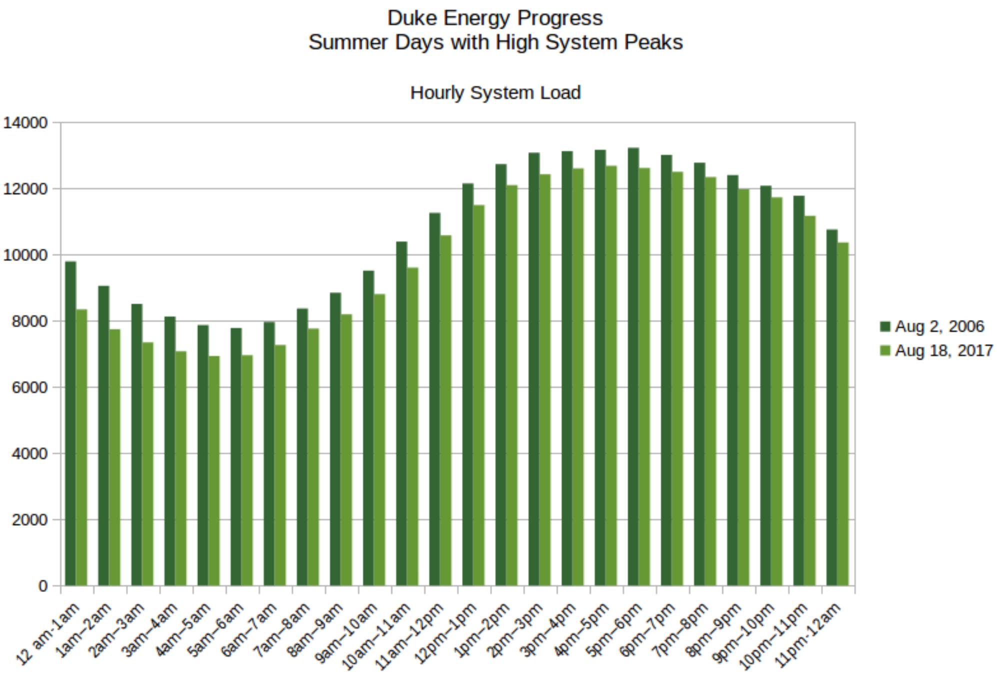
We analyzed the system load data by greater detail by focusing on example of specific days during the Summer, Spring/Fall and Winter seasons.

<u>Summer Days with High Daily Peak</u>

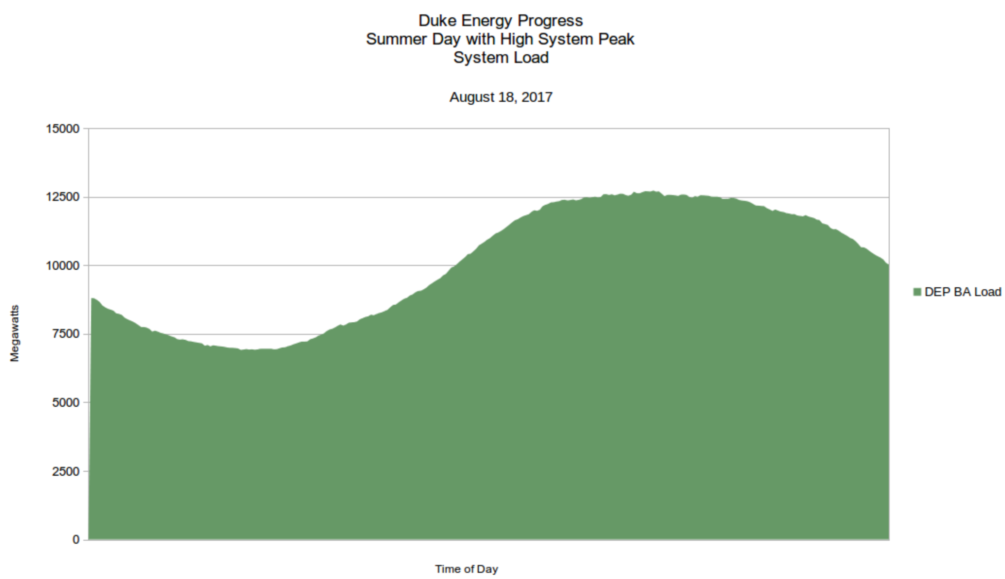
The following graph shows the pattern of electrical usage over the course of two summer days with high levels of system load, as a result of intensive air conditioner usage. The system usage tends to peak in a fairly wide, broad manner, with peak usage on both days approaching or exceeding 12,000 MW from about 1 pm until about 8 pm.

System load on August 2, 2006 (shown in dark green) reached 13,226 MW. This was also the highest peak reached that year. The daily peak on August 18, 2017 (shown in light green) was 12,684 MW. It was the highest peak of the month, but fell well below the annual peak for the year, so this data was not included in the earlier graphs.

On both cases, system load declined during the evening as the outside temperature falls, reached an overnight low during the wee hours of the morning, and began to increase around 6 am. Load continued to increases throughout the day until reaching the daily peak (around 5 pm in both cases), and repeating the process of declining in the evening..

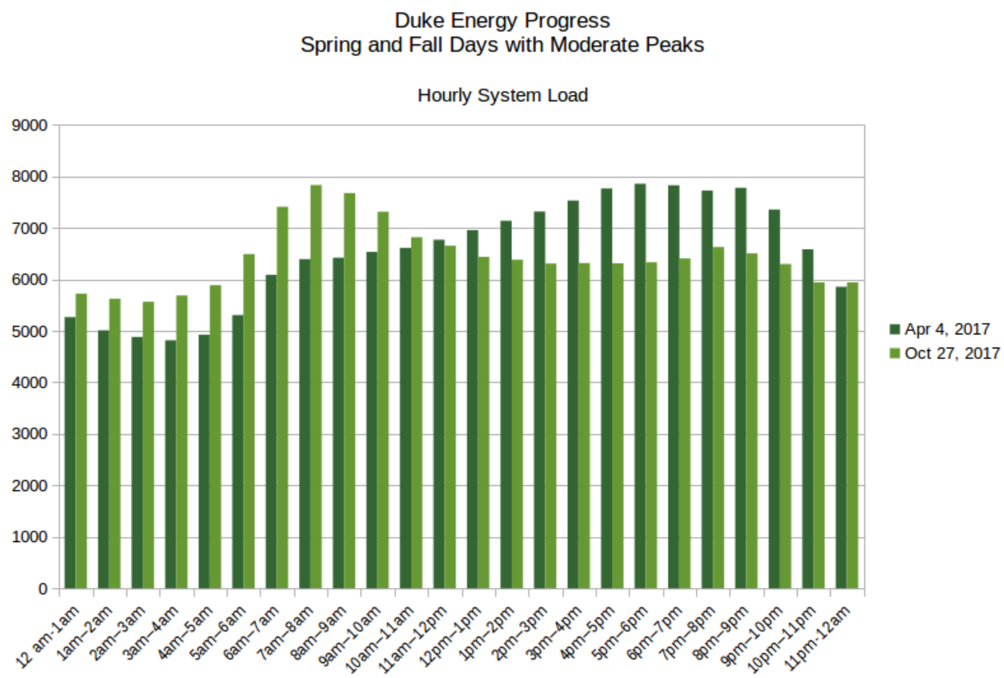


The following graph shows system load data for the second of these two days – August 18, 2017 – in 5 minute intervals. A close examination of the graph shows the fluctuations that occur within each hour, with 5 minute granularity.



Spring/Fall Days with Average Daily Peak

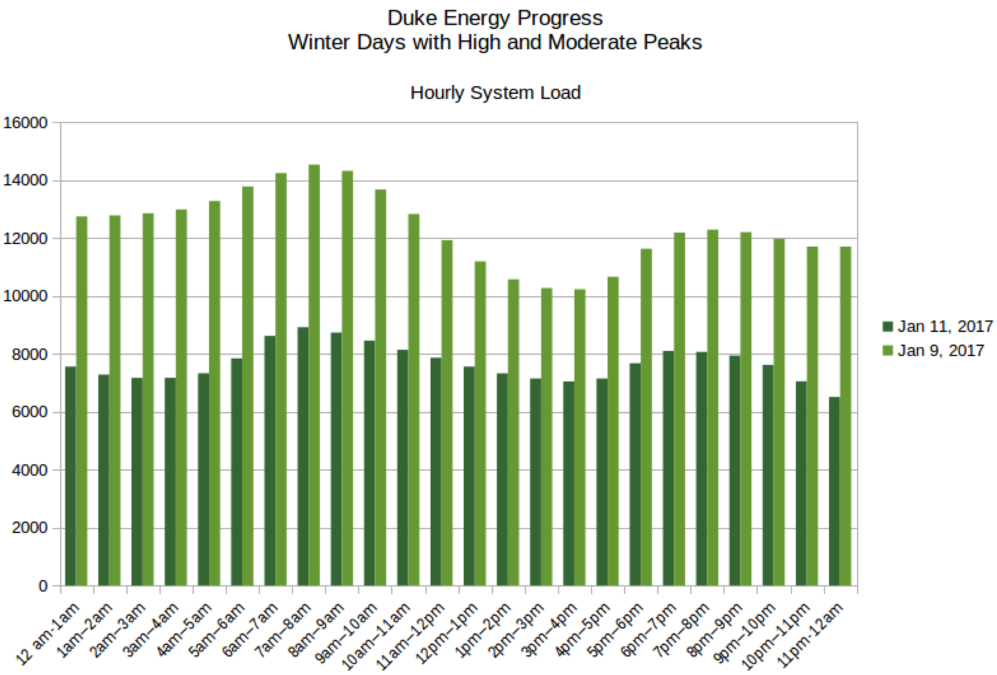
The following graph shows the pattern of electrical usage during the period between summer and winter. While the daily peaks are of similar magnitude, April 4, 2017 (shown in dark green) was more like a summer day, with a broad afternoon peak, while October 27, 2017 was more like a winter day, with a brief morning peak.



In both cases, the peaks are just under 8,000 MW, which is much lower than what is experienced on a hot summer day, and more than 5,000 MW lower than the highest peaks, experienced during days with particularly extreme temperatures.

Winter Peaks

The following graph electrical usage on two winter days in 2017– one with the highest peak of the year and one with a more normal winter peak.



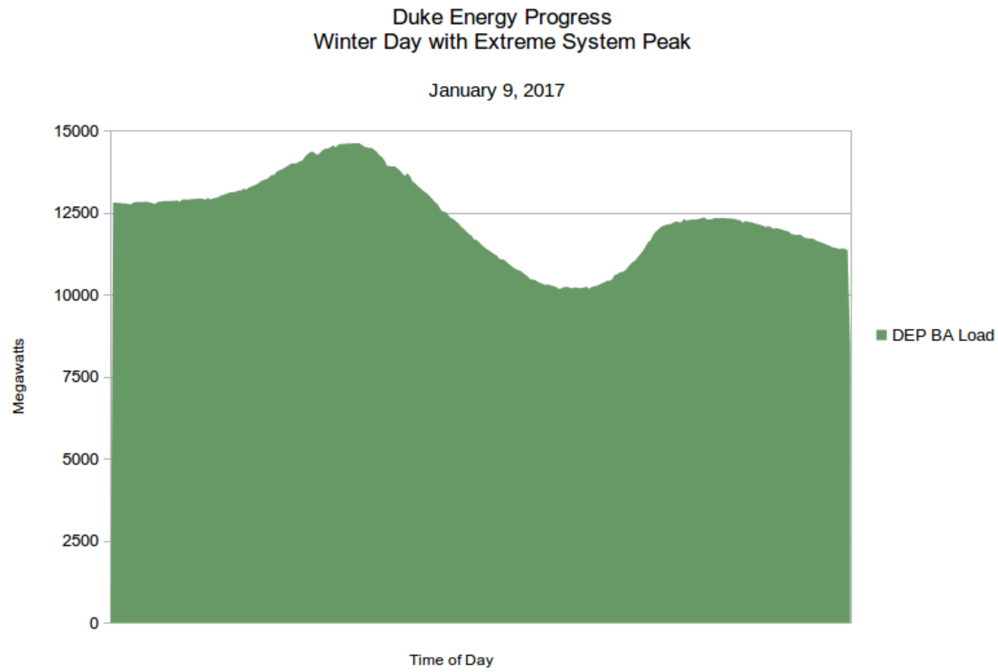
Both days follow similar patterns, but load is much higher, and the variation in load is much more pronounced on the coldest day.

In one sense, cold winter days can be similar to hot summer days: the maximum peak can easily be several thousand MW higher than normal.

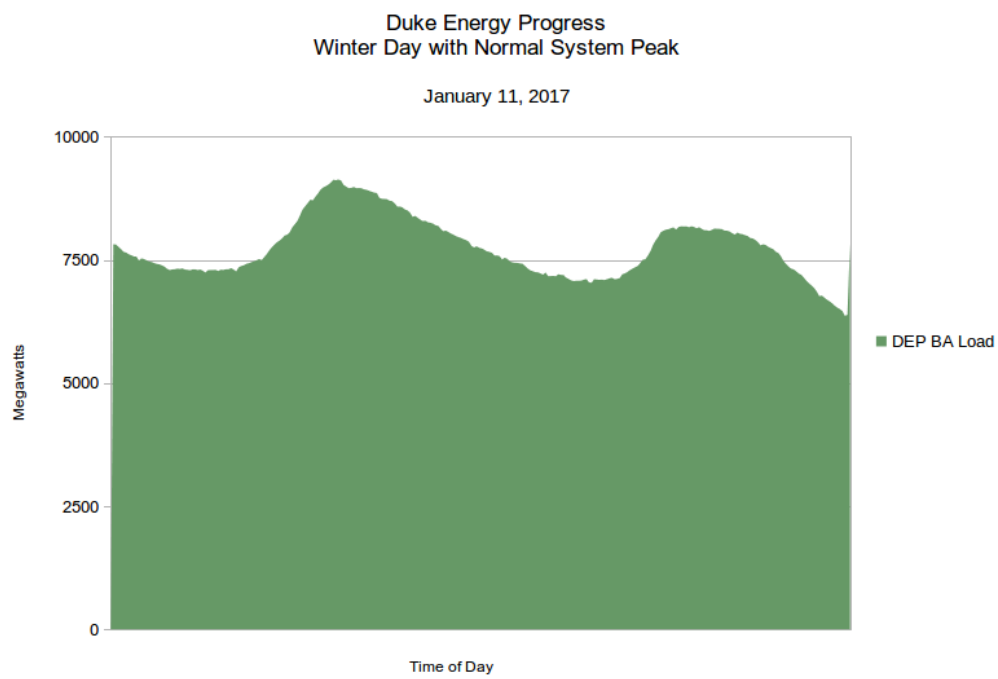
However, there are also some notable differences. As shown in the above graph, because of the heating demand during the night, system load often will remain elevated through the entire night (over 10,000 MW on January 9, 2017 (dark green) and over 6,000 MW on January 11, 2017 (light green). Another difference is that Winter days frequently experience two peaks – one in the morning and another in the evening – with the early morning peak typically exceeding the evening peak.

Many of these load variations are clearly weather related – as indicated by the fact that the maximum daily load tends to vary with the ambient temperature, and the fact that winter load drops as it warms up outside, and it increases when the temperature drops in the evening.

The following graph shows the system load during January 9, 2017 in 5 minute intervals, to reveal some of the intra-hour variation.



While winter peaks can potentially be as extreme as summer peaks, these extremes events happen less often, and the peaks tend to be of shorter duration than what typically occurs in the summer. An example of a brief winter morning peak is shown in this 5 minute interval graph for January 11, 2017.



Modeling System Load

Capacity and energy costs are closely related to daily variations in system load. Additional costs are incurred because energy isn't consumed at a uniform rate throughout the day and year. Higher costs are associated with (a) system peaks, (b) rapid changes in load (load balancing and ramping requirements) and (c) forecast uncertainty. Accordingly, system load is typically modeled on both a short-term and long-term basis, to help optimize the system and minimize costs.

Like most other major utilities, Duke uses statistical modeling in an effort to forecast system load. The models used in developing its 2018 Integrated Resource Plan ("IRP") separately forecast system peak load and energy demand, and energy demand is analyzed separately for residential, commercial and industrial customers. All of these long-term forecasts are based upon statistical equations applied to multiple explanatory variables.

Like most econometric modeling efforts, a load forecasting model is typically built up from a conceptual understanding of the factors that explain or cause the phenomena being studied (in this case, variations in energy consumption and peak usage). Data is sought that reflects these explanatory factors, although substitutes and short-cuts are sometimes used – particularly when data isn't readily available for some of the factors that help explain the phenomena in question.

Both long-term and short-term load forecasts are affected by weather. Of course, weather variations cannot easily be predicted years in advance, so they are often treated on a "scenario" basis – to simulate the uncertainties concerning how cold or hot the weather will be during a particular day, month or year.

In the case of short-term load forecasts developed for operating purposes (planning which generating units to use in the next few days, a day ahead, or in the next few hours) a "what if" probability simulation is not sufficient – it's important to investigate what the weather conditions are likely to be during the forecast time period. If a cold front is moving into the area, that will result in significantly different energy usage and hourly daily load patterns than if a weather system is moving through the area that will result in unusually mild weather.

For a short-term load forecast, the most important explanatory factor to understand and anticipate is what the temperature will be during each hour. While an abundance of weather data is readily available, by far the most important explanatory factor that explains why load increases or decreases is simply how hot or cold it is. For that reason, it is common for utilities to focus on “cooling degrees” or “heating degrees” (how far the temperature deviates above or below or a nominal benchmark like 65 degrees), without mentioning other available data like relative humidity, cloud cover, barometric pressure and wind speed.

Modeling “Net” System Load

Duke is increasingly relying on solar energy to help meet its system load, so the energy from conventional sources – primarily coal and natural gas – during any given hour will increasingly be determined in part by how much solar energy is available during that hour.

Succinctly stated, in North Carolina conventional generators are no longer serving total energy demand – what could be described as “gross” load. Instead, they are serving “net” load – the portion of total system load that is not supplied by solar energy. To minimize costs and operate the conventional generating fleet efficiently, it is imperative to understand and accurately forecast the amount of solar energy that will be available.

In preparing their filings in the Biennial Avoided Cost and IRP proceedings, Duke and its consultants have oversimplified their analysis of key issues related to the variability of solar output. The result is a significant overstatement of the costs associated with increased solar, and an understatement of the avoided costs and benefits associated with increased solar.

These modeling problems also affect how solar is valued when analyzing the summer and winter reserve margins in the IRP. The need for accurate solar modeling extends beyond regulatory proceedings, since the selection of conventional generators that will be connected to the grid each day, cannot be optimized without some effort to accurately forecast solar output during the upcoming day.

The remainder of this report explores some of the more obvious patterns that can be observed in solar output data, and how this relates to variations in system load.

Modeling Solar Output

Solar output depends on astronomical factors that are extremely stable and easily predicted, because they are determined by the movement of the planet relative to the position of the sun. Output stops overnight and it tends to reach the daily maximum at mid-day. Similarly, output is less in late December, during the shortest days of the year, and greater in late June, during the longest days of the year.

Solar production also varies in response to atmospheric factors that are not as stable nor as capable of being accurately predicted in advance. These weather-related explanatory factors are, however, capable of being understood and analyzed so they can be forecast with some degree of accuracy, assuming enough data is collected and sufficient effort is devoted to analyzing the data and understanding how it can be used to anticipate when clouds and atmospheric haze will reduce solar output.

Other explanatory factors are also relevant, and these can also be analyzed and used to anticipate solar availability. For convenience, these facts can be grouped into three categories: (a) public policy considerations, including taxes, statutory requirements and regulatory decisions, (b) incentives and choices applicable to Independent Power Producers, and (c) incentives and choices applicable to the utility that receives the solar energy.

Modeling Solar Output at Individual Locations

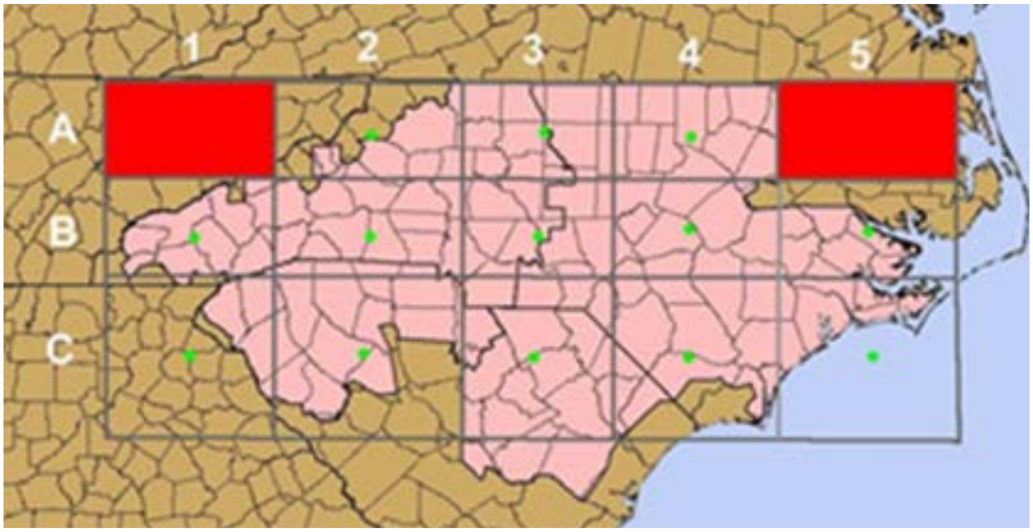
A wide variety of data and simulation tools are available for solar modeling at specific locations. For the purpose of this discussion, we have used solar output data for 2006 which is readily available from the National Renewable Energy Laboratory ("NREL"). Equally detailed data can be produced for other locations and other years using widely available solar modeling tools.

The NREL explains this data set is "synthetic" data (rather than data from an actual solar plant) that is generated using a "Sub-Hour Irradiance Algorithm" applied to each specific location. The data set is further described as follows:

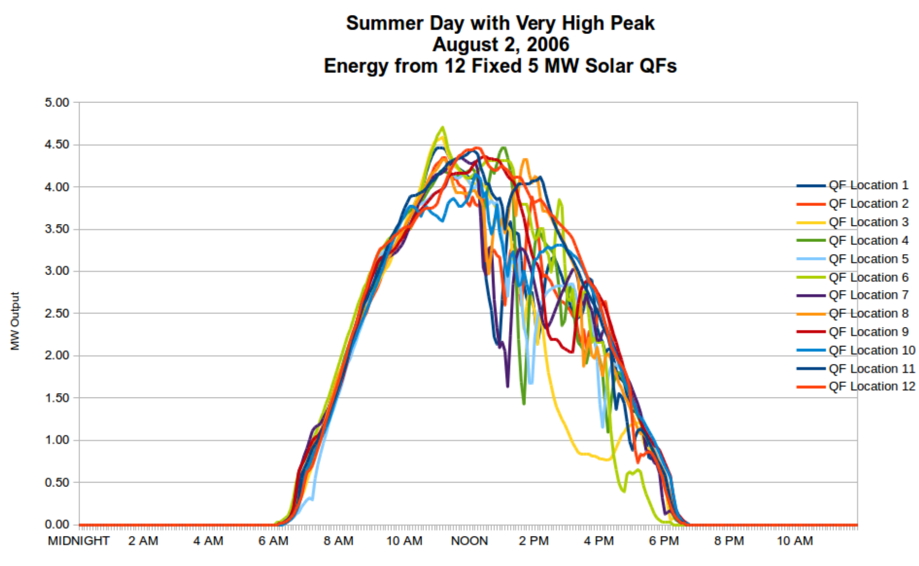
> NREL's Solar Power Data for Integration Studies are synthetic solar photovoltaic (PV) power plant data points for the United States representing the year 2006. … The data are intended for use by energy professionals — such as transmission planners, utility planners, project developers, and university researchers — who perform solar integration studies and need to estimate power production from hypothetical solar plants.[1]

This data is available from the NREL for both tracking and fixed arrays at multiple locations within each of the grid cells referenced in the Astrape Solar Capacity Value study and the Astrape Solar Ancillary Services study developed by Duke for the 2018 IRP proceeding and the 2018 Biennial Avoided Cost proceeding.

1 https://www.nrel.gov/grid/solar-power-data.html



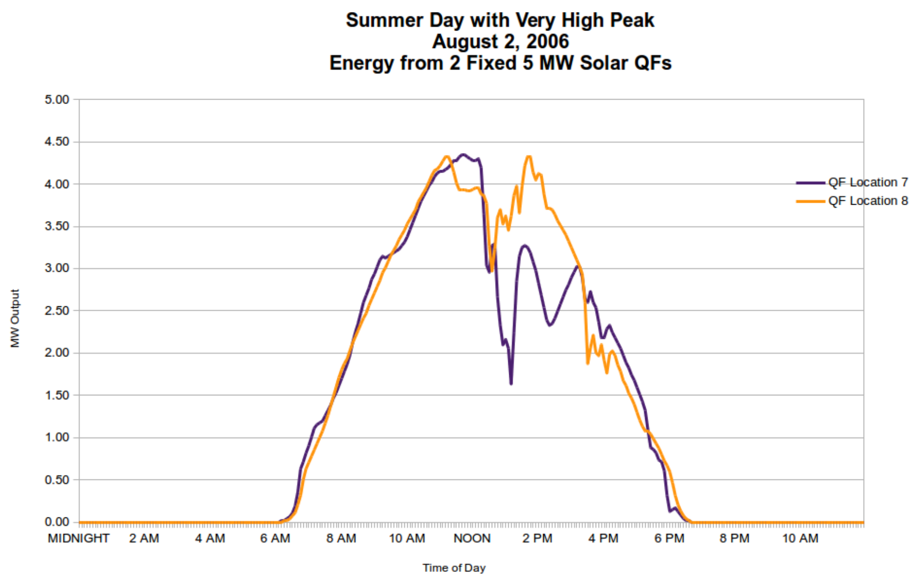
For illustrative purposes, we will focus on the NREL 5 minute interval data for 12 fixed array solar facilities within one of these grid cells – A3. In the graph below, the output from each solar facility is shown in a separate color.



For ease of understanding and discussion, we scaled the NREL data to be equivalent to the output from 12 solar plants that each have 5 MW of capacity – one plant at each location. In contrast, Astrape's simplified solar profiles were developed for just a single location within each grid cell.

The simplified approach used by Astrape is entirely inappropriate in this context, since Astrape was attempting to value solar output, and measure solar integration costs. For both of these applications greatly oversimplified, unrealistic solar profiles are not a viable or meaningful tool to use. Among other problems, this approach overstates the degree to which solar output is variable and inherently difficult to forecast. It also understates the extent to which solar production will reliably be available to help meet peak demands, and it exaggerates the extra costs of load balancing, re-dispatching and spinning reserves.

The error that occurs when using data from a single location to simulate the impact of a much larger volume of energy that would be produced at numerous separate locations can be demonstrated on a small scale by simply comparing the differences in output variability at any two of the locations in the NREL data set. One example is shown below:



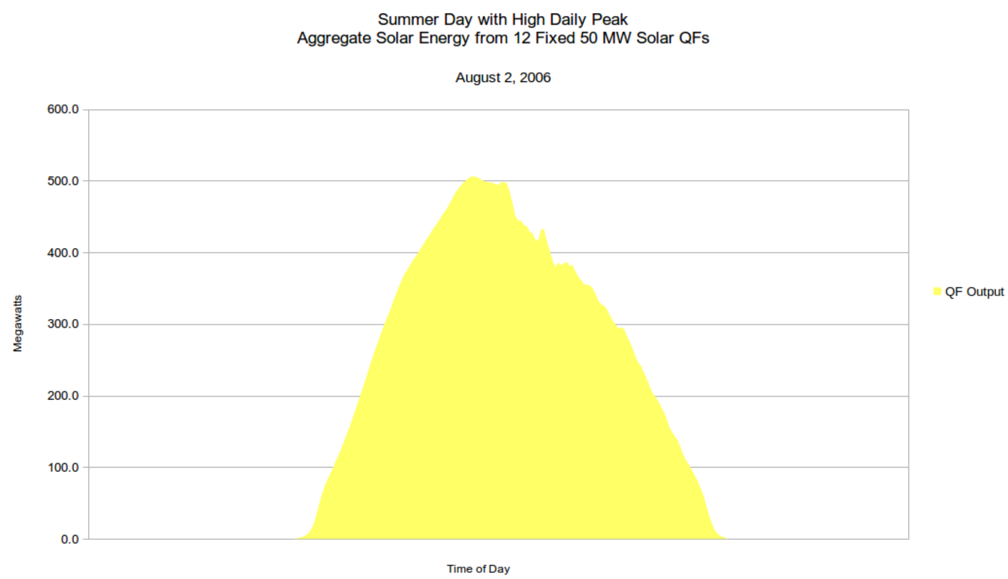
At times during the day, output from both locations moves in the same direction while there are other times a downward fluctuation in one location is offset by an upward fluctuation at the other location. This demonstrates that when solar data from numerous locations is aggregated, it becomes more stable and provides a stronger basis for understanding, forecasting, and responding to solar output variations.

Although this is not the only flaw in their approach, Astrape's decision to use simplified daily solar profiles from a very small number of locations prevents them from reaching meaningful conclusions from the remainder of their modeling efforts. The problem is exacerbated by their decision to place enormous weight on so few locations. For instance, Astrape gave 89% weight to 5 locations when modeling the output from DEP's standard PURPA contracts. Similarly, Astrape gave 94% weight to just 6 locations when modeling DEC's standard PURPA contracts. A similar process resulted in giving 70% weight to data from just 3 locations when modeling the impact of

CPRE Tranches 1 – 4 on DEP's operations, and 75% weight to the data from another 3 locations when modeling the CPRE impact on DEC. This excessive weight on a very small number of locations greatly exaggerates the degree to which solar output is variable and hard to forecast.

In reality, power production from existing PURPA locations already displays some significant benefits from geographic diversity; the benefits will increase as locations are added with the transition and CPRE tranches.

A partial indication of the benefits from even a small amount of added diversity can be seen in the following graph, which uses the NREL data to simulate the effect of aggregating output from 12 QFs (with 50 MW capacity apiece) at the 12 locations we studied in Grid Cell A3. This is the exact same data shown with the colored lines in the prior graphs, with the output aggregated and scaled up:



Needless to say, if this much smoothing occurs with such a small data set (just 12 locations in a single grid cell), the output from hundreds of small facilities that are widely dispersed across two states will be even smoother and more easily forecast.

Aggregate output will become smoother and more predictable in the future for another reason, as well: not every power producer is going to make the same engineering decisions, like those assumed in this NREL data set (or the analogous simplified assumptions used by Astrape in developing their solar profiles). As different engineers working for different QFs make different decisions concerning the optimal configuration at each location, aggregate solar output will become smoother and more predictable.

Because of these fundamental flaws in the solar output data used by Astrape, it understated the capacity benefits offered by solar and it overstated the extent to which solar output will be volatile and unpredictable – thereby leading them to reach inaccurate conclusions concerning the conventional generating resources that will be needed to compensate for intra-hour solar fluctuations, forecast uncertainty and increased ramping.

Astrape's approach greatly exaggerates the difficulties inherent in trying to forecast solar output on a day-ahead or shorter-term basis, for essentially the same reason why pollsters cannot question a dozen voters and expect to accurately forecast the outcome of an election.

A tiny sample size destroys any ability to accurately forecast the outcome of the election because a large sample size is needed to fully benefit from the law of large numbers.

With a large enough solar data set, including cloudiness and irradiance data for each location, it becomes possible to observe meaningful patterns in the data, determine the underlying factors which influence fluctuations in the data, and then to extrapolate from those patterns to understand and forecast what is likely to happen under analogous conditions in the future. This sort of forecasting is particularly viable when dealing with forecasts that extend over the next few hours or days, since the the range of possible atmospheric conditions tends to be much more limited over a shorter time frame.

Extrapolating from simplified solar profiles at a small number of locations, Astrape assumed solar growth will lead to an explosive increase in "net" system load volatility. This led to false conclusions about the degree to which increased solar will result in a need for larger operating reserves and spinning reserves, re-dispatch costs, and the like.

Modeling "Net" System Load

To further explore these modeling issues, it is useful to focus on the "net" amount of energy Duke will need from nuclear, fossil and hydro power sources. BJA estimated "net" load by subtracting recent historical QF energy production data from Duke's hourly system load during the same time periods, at 5 minute intervals. This results in a reasonable estimate of the load Duke will continue to serve using traditional generating sources.

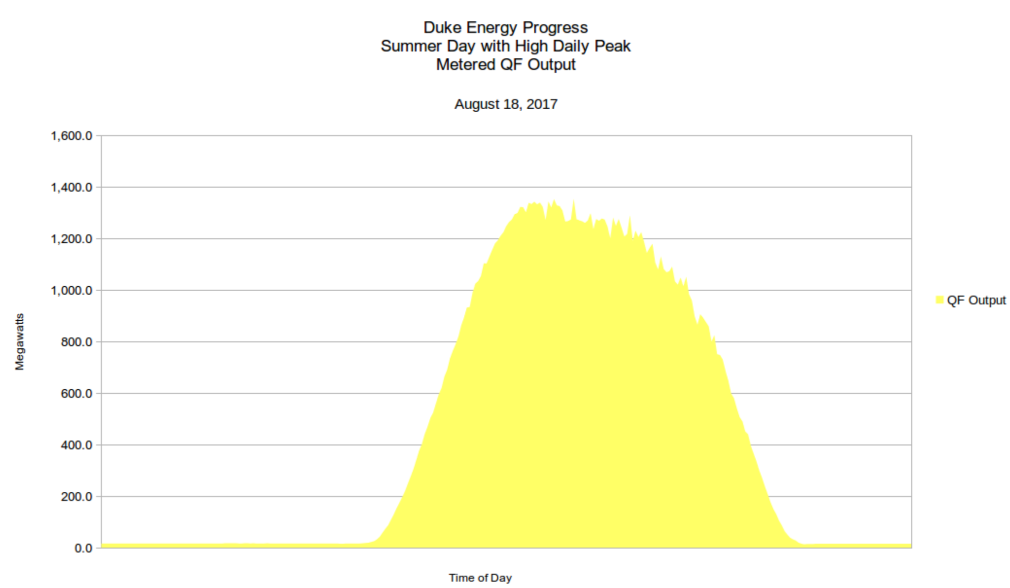
This "net" load varies from minute to minute, based on fluctuations in customer demand and based on fluctuations in the amount of solar energy obtained from QFs (as discussed above). Better modeling of solar output, and a more thorough analysis of "net" load patters is needed, because variations in customer demand and solar production are largely but not entirely independent of each other (since both are affected by weather, but not in the same exact way).

For example, Duke will use all of its most fuel-efficient generators (and some of the other, more costly generators) during hot summer days. On these particular days, system demand tends to remain high throughout the afternoon and well into the evening, due to air conditioning. On the hottest days, solar output will almost inevitably be fairly high, helping to reduce fuel consumption and helping to meet the peak capacity needs at these times.

In contrast, during a heavily overcast day, solar production is likely to be lower, but customer demand is also likely to be lower – since customers won't be using their air conditioning as intensively on a heavily overcast day.

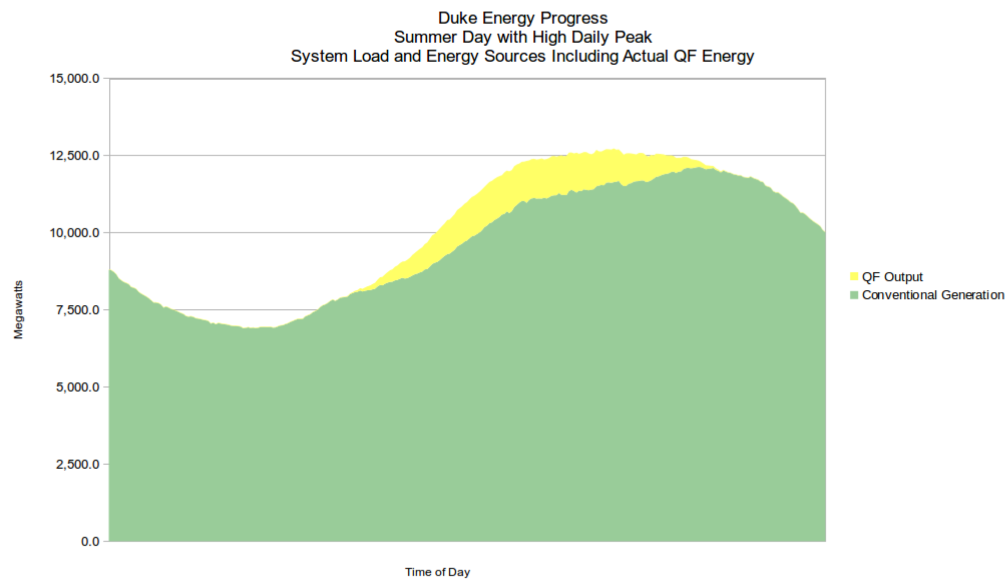
Summer Day with a High Peak

The following graph shows actual metered QF energy production on August 18, 2017 on DEP's system. Virtually all of the energy is being provided by solar, which can be verified by by comparing the thin yellow line across the graph, representing the small amount of QF energy that is sent to the grid during the night.



This next graph shows system load and the energy sources used to serve this load in 5 minute increments during August 18, 2017 – a summer day with a high peak.

Energy provided by conventional resources (fossil, nuclear and hydro) is shown in light green. Energy from QFs (predominantly solar) is shown in yellow. The QF output is the same data set shown in the previous graph. The overall height of the graph represents the total ("gross") system load.



As can be clearly seen in this graph, QF energy is helping to reduce the "net" peak load throughout the middle of the day. As a result, the highest "net" peak is experienced hours after the "gross" peak – at a time when customer demand remains high but solar production is ebbing.

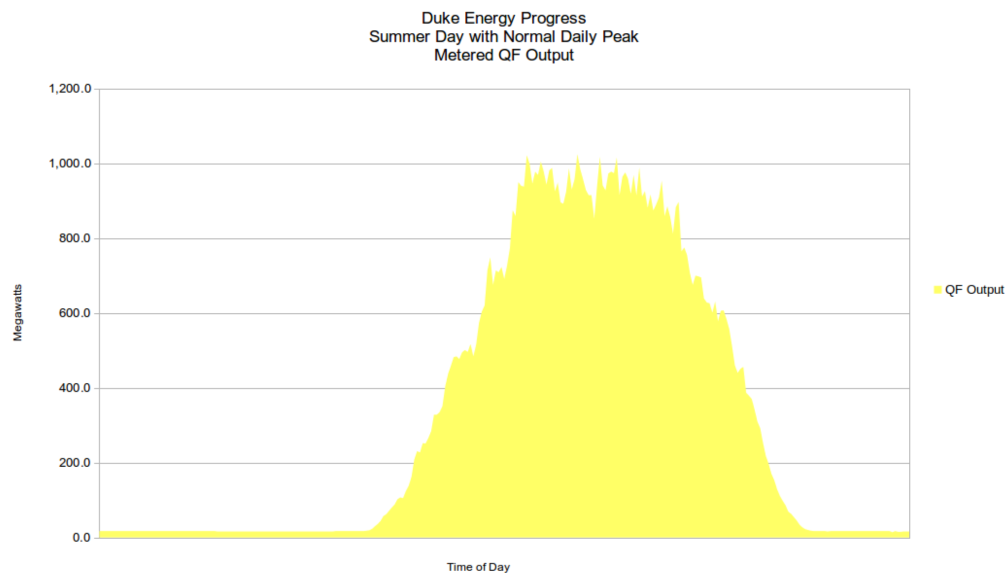
About 1,000 MW of solar is flowing when customer demand peaks, at about 4 pm (EDT), and throughout the broad, flat peak of approximately 12,500 MW which occurs throughout the afternoon.

On a "net" basis the daily peak is pushed back about four hours – close to 8 pm – at a time when solar production is waning, and customer demand is also dropping. The "net" peak (shown in green) of approximately 12,100 MW lasts less than 20 minutes. The "net" peak then gradually declines to about 10,000 MW near midnight (EDT).

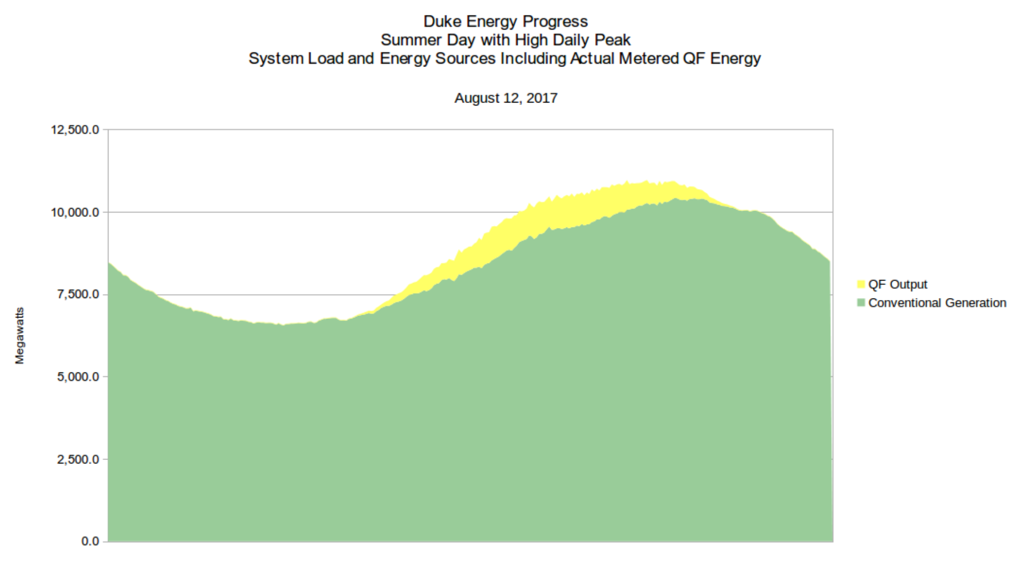
The overall pattern of solar production on this hot summer day is favorably aligned with customer demand, since it reduces the need for peak capacity and avoids the need to operate some of Duke's least fuel-efficient generators. There is also no indication of any significant need for more balancing or spinning reserves.

Summer Day with an Average Peak

The following graph shows actual metered solar production on August 12, 2017 – a day with a more typical summer daily peak.



This next graph shows the same solar data in conjunction with the conventional resources that were used to meet system load:



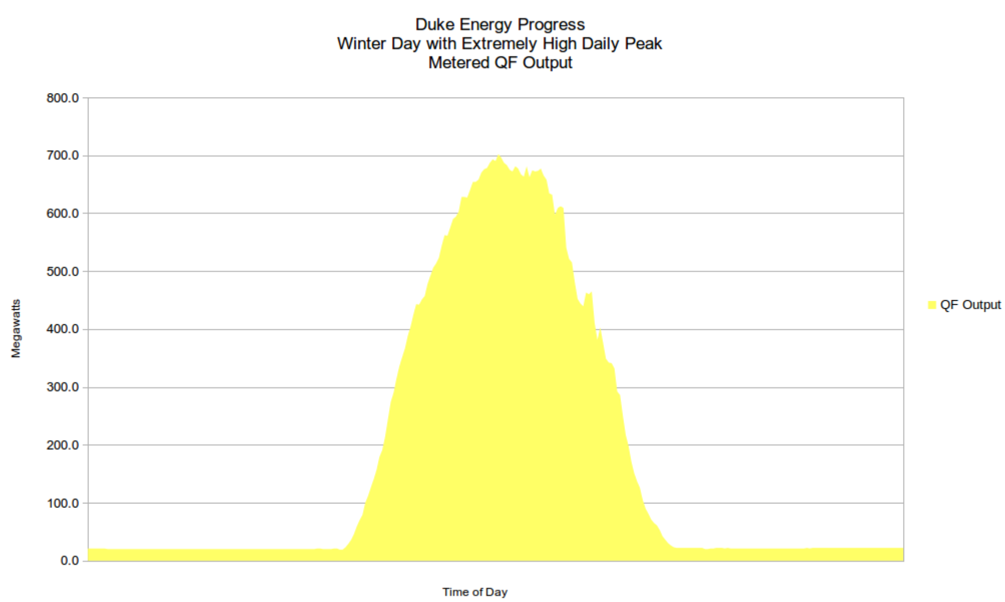
Here again, the overall pattern of solar production is generally favorable, with solar generation reducing the need for peak capacity throughout the afternoon.

Before considering solar energy, the highest peak (briefly more than 10,900 MW) occurs a little before 6 pm (EDT), when approximately 700 MW of solar is flowing to the grid. On a "net" basis the highest peak of the day is delayed about an hour. The "net" peak of about 10,400 MW lasts, which lasts for about 10 minutes, occurs shortly before 7 pm (EDT). Customer demand is already dropping at this hour, so the "net" peak declines to the vicinity of 8,500 MW by midnight (EDT) and beyond.

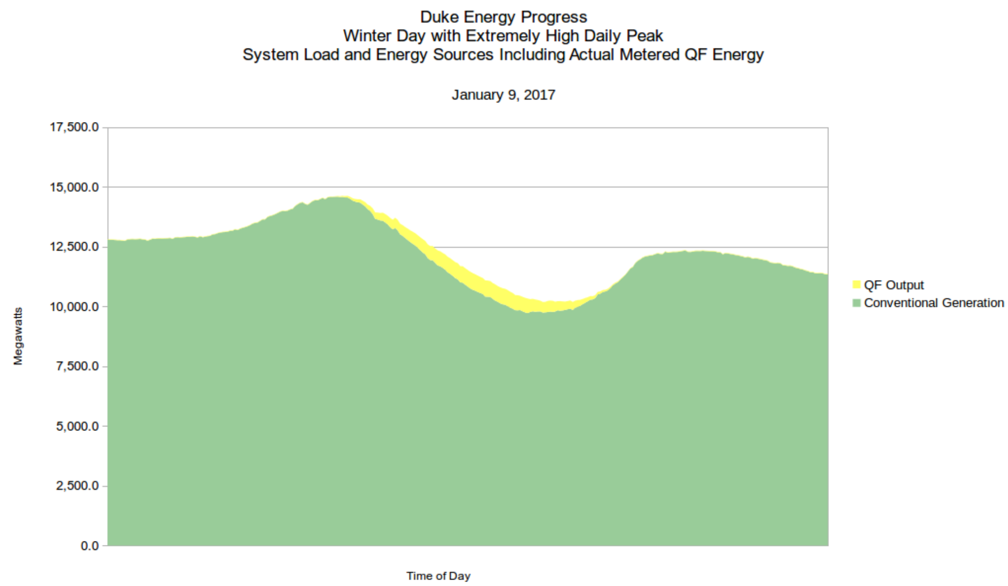
In both of these cases, solar production helps meet the need for peak capacity and it avoids running some of Duke's most fuel-inefficient generators. There is no indication of any significant increase in the need for load balancing or spinning reserves.

Winter Day with an Extremely High Peak

The following graph shows actual metered solar production on January 9, 2017 – a day with an extremely high winter morning peak.



The next graph show system load on that same day (January 9, 2017) in conjunction with actual metered solar production. This was an extremely cold day, with unusually strong demand for electric heat. customer demand for electric heating remains strong throughout the night. The system load subsequently rises in the early morning hours, as thermostats are adjusted, people take hot water for showers and they cook breakfast. As a result, the daily peak exceeds 14,500 MW for about an hour – starting shortly after 7 am – but it drops below this extremely elevated level shortly after 8 am.



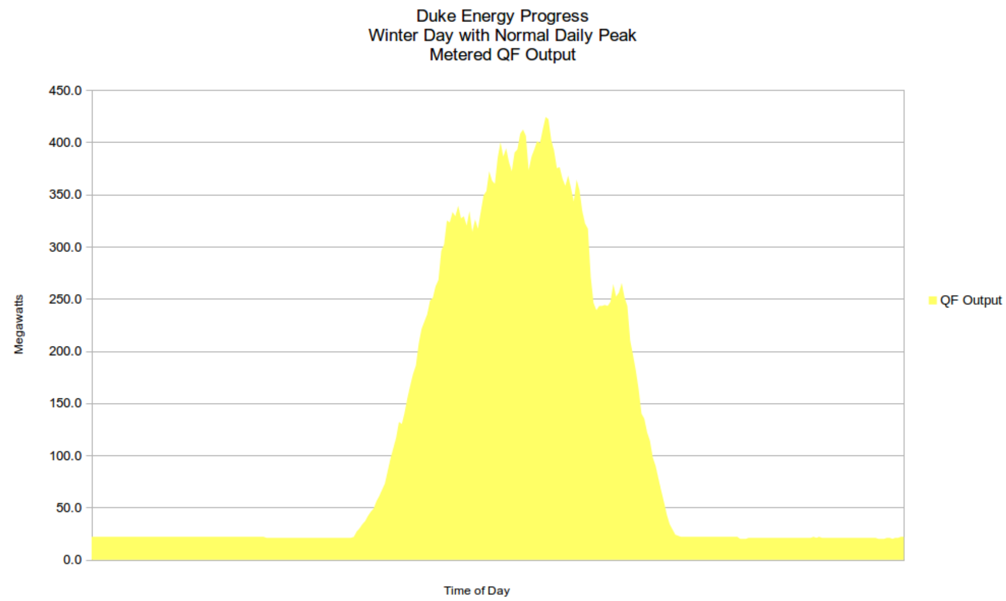
As the day warms up, the demand for electric heating falls, bringing the overall system load down as well. System load drops below 10,500 MW for a couple of hours (starting around 1:30 pm), before climbing to an moving back up to nearly 12,000 MW later in the evening.

As the above graphs demonstrate, solar output was moderate, providing a useful contribution to the latter part of the morning peak, and mildly accelerating the downward ramp in the morning. It also moderately increased the rate of upward ramping during the afternoon but in neither case was the impact particularly significant.

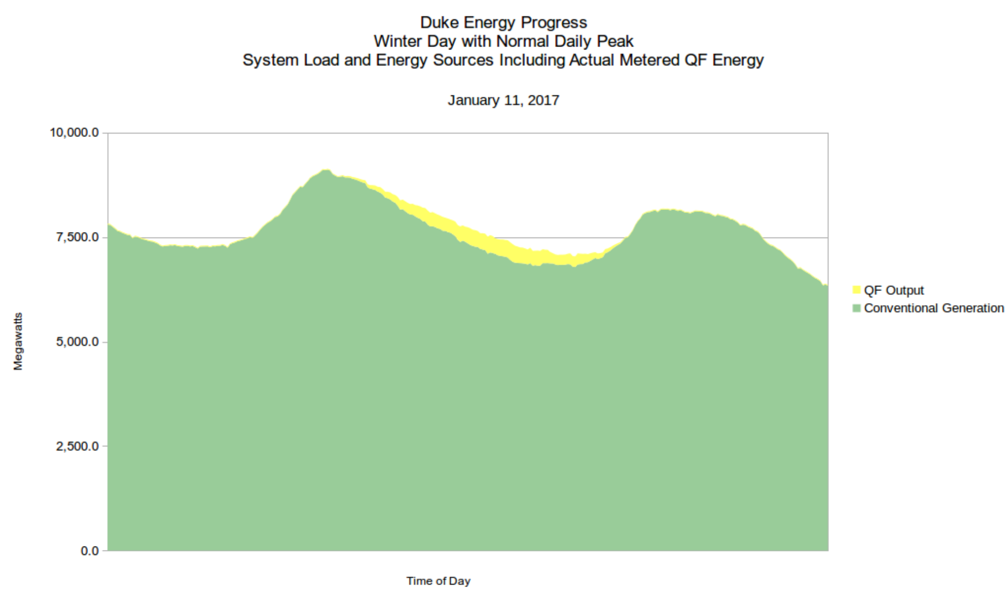
<u>Winter Day with a Normal Daily Peak</u>

The following set of graphs show system load on a more typical winter day – January 11, 2017. Solar output was lower than observed on January 9, 2017, but it again had a generally favorable impact, as shown in the second graph.

System “gross” load peaks above 9,000 MW shortly after 7 am. This peak is very brief, lasting about 30 minutes, and it occurs shortly before solar production begins, so the “net” and “gross” peaks are about the same.

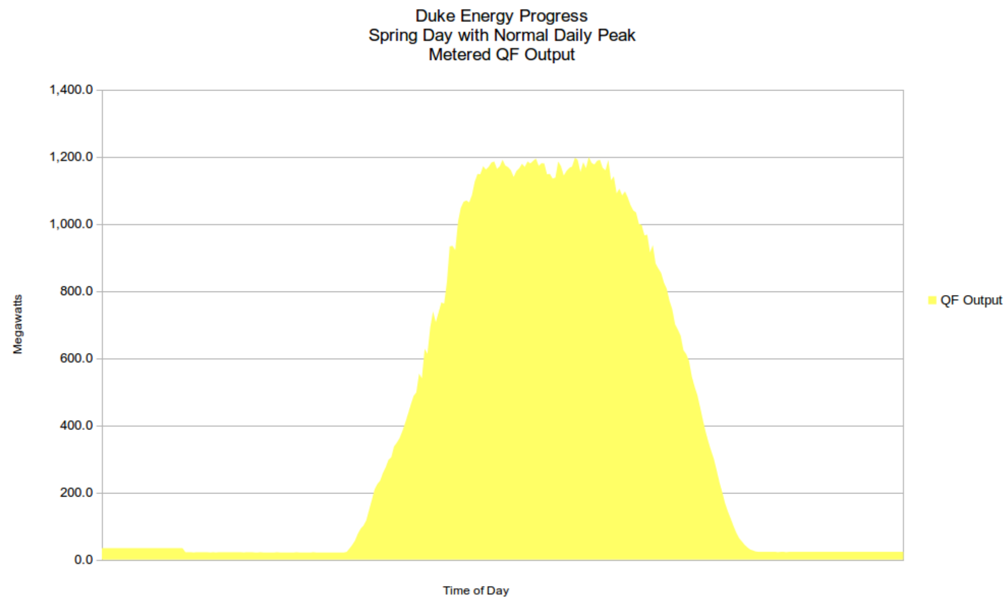


Gross system demand was above 8,000 MW from shortly before 6 am until shortly after 11 am; solar output was useful in meeting the need for energy and capacity during the latter half of this more broadly defined peak period, as well as the middle of the day.

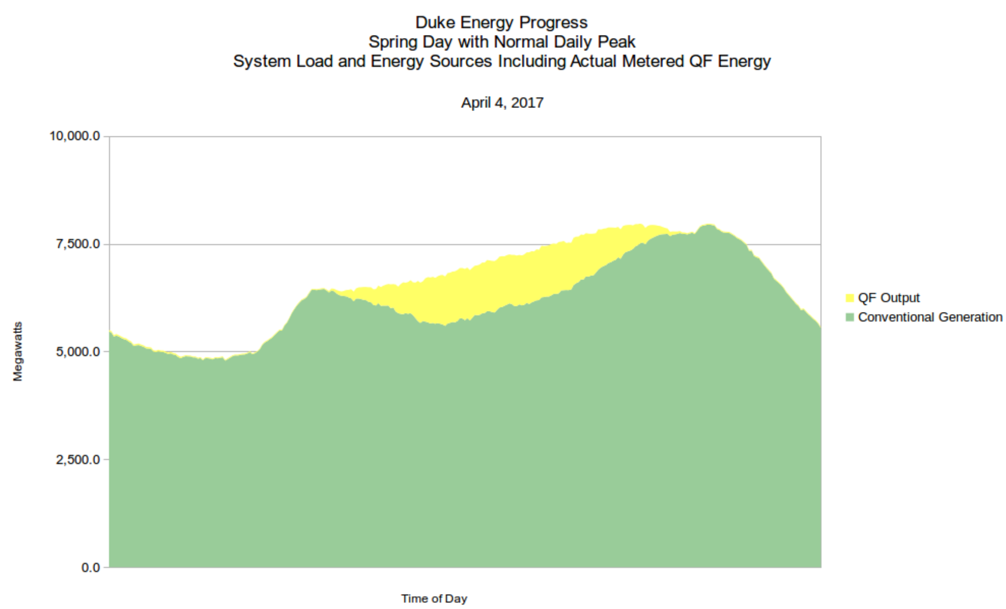


Spring Day with a Normal Daily Peak

The following graph shows actual QF output on April 4, 2017 – a fairly typical Spring day with a moderate system peak and very strong solar output throughout the entire day.



Not only is solar energy plentiful, it provides useful support for almost the entire duration of the broad afternoon peak. "Gross" system demand rises above 7,500 MW at about 3 pm, and continues above this level until about 9:30 pm. Solar energy is plentiful during most of this broad time period, so the "net" system load is about 1,000 MW lower during much of the day. The "net" system load only briefly exceeds 7,500 MW, from shortly before 6 pm until about 9:30 pm.



The overall impact of solar production is favorable – displacing conventional generation during much of the day. While the downward ramp in the morning and the upward ramp in the afternoon are both moderately accelerated, in both cases the resulting ramping is less severe than the downward ramping that occurs later in the night – which is not affected by the solar output.

Modeling Potential Changes to "Net" System Load

Succinctly stated, Duke failed to adequately consider the impact of technology trends, economic incentives, market forces, and industry growth in developing the assumptions it used to simulate an hour-by-hour forecast of 2019-2028 "net" system loads in its 2018 IRP and Biennial Avoided Cost filings.

Future changes to solar output and "net" system load cannot be adequately simulated by adopting simplified "solar profiles" or simply extrapolating (or scaling up) historical solar data or data that is produced by a solar modeling tool. While historical data and solar modeling tools provide a useful starting point, careful consideration must be given to economic "feedback effects" and other factors that are going to significantly impact the timing of when solar output is going to be delivered to the grid during the next 10 or 20 years.

For example, Astrape failed to even experiment with their solar modeling tool to investigate various "what if" scenarios with respect to different inverter loading ratios. If they had explored this issue, they would have discovered that the inverter loading ratio can affect the volatility of solar output, particularly during highly favorable solar conditions.

Similarly, Astrape didn't explore various scenarios with respect to the mix of tracking and fixed arrays, or the affect of mixing different assumptions in different combinations. Instead, Astrape selected some ratios based upon what has historically been observed, and applied these ratios without considering whether their assumptions were reliable, or how they might influence the issues they were investigating – like the slope of the early morning and late evening ramping periods. Nor did they consider how these relationships are likely to change over the next few years, in response to changing market conditions.

An even more glaring problem exists with respect to solar + storage, which was essentially ignored by Duke and Astrape. Yet, increased adoption of energy storage technologies will significantly impact several of the issues they studied. For example, the avoided cost results will be higher than Duke estimated during many hours (and perhaps lower during some hours) if successful bidders in the CPRE procurement process use storage to control the timing of when their energy is delivered to the grid.

The failure to evaluate the impact of solar + storage is particularly inappropriate at this time, since it is widely acknowledged that storage costs are rapidly declining, and the technology is expected to enjoy much more widespread adoption during the next 10 years.

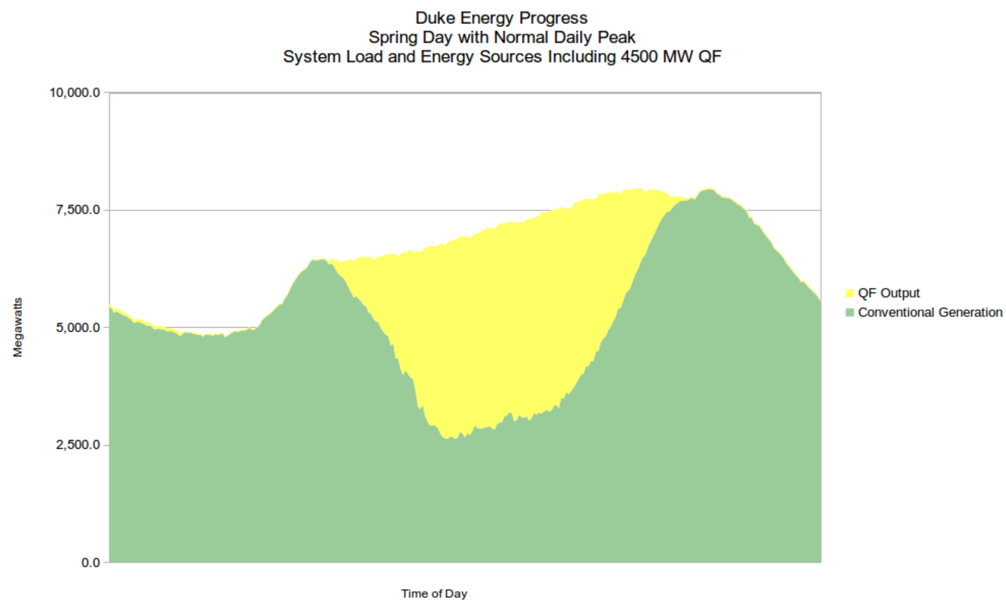
Given the benefits of economies of scale, rapid advances in storage technology, and other favorable trends, there is every reason to anticipate that Independent Power Producers in North Carolina will be at the forefront of this worldwide trend – just as these same firms have been at the forefront in the national trend toward increased production of solar energy.

The following series of graphs will clarify these issues, by starting with a simple "scaling up" of the historical metered QF output data. It should be noted his simple "scaling up" approach does not reflect diversity benefits that will increase as the industry grows – something to keep in mind when looking at these graphs.

We will use these graphs to illustrate the impact of economic incentives, competitive forces and other factors that cause "net" system load to differ from a simplified daily solar profile, or a simple extrapolation of historical data.

Economic Incentives and "Feedback Effects"

The following graph shows actual QF output on April 4, 2017 scaled up through simple extrapolation to simulate the impact of more than tripling solar output on that day, to the equivalent of 4,500 MW of QF capacity. This is roughly the level of capacity assumed in the Astrape Solar Capacity Value study for the Existing, Transition and Tranche categories.



In reviewing this graph, the most important point to notice is that "net" load drops deeply during the day, indicating a very low level of conventional generation (shown in green) during the middle of this typical Spring day.

The marginal cost of producing electrical energy will sharply decline during this time period, because the weather is mild and there is little need for heating or air conditioning – and favorable atmospheric conditions are simultaneously resulting in an abundance of solar energy, resulting in an imbalance between supply and demand.

Although Duke and Astrape did not analyze or model this issue accurately, it nevertheless had a serious impact on the results of their studies. For instance, the Astrape studies show thousands of MWh of energy being "curtailed." For this to occur, there must be other hours when the surplus conditions are not quite that extreme, but surplus energy is being dumped off-system as "economy" energy, at a very low price.

Duke and Astrape failed to go beyond a simple extrapolation to consider the economic significance of this surplus energy, when the marginal cost of generating electricity, or the market clearing price of electricity, is likely to be less than $5 per MWh.

A correct analysis of this type of imbalance must consider economic incentives and "feedback effects" – which Duke and Astrape failed to do. A simple example of an economic "feedback effect" is what happens in response to a bumper corn crop, which results in excess supply relative to demand. This imbalance initially translates into sharply lower corn prices. In severe cases, some farmers might even abandon or plow under their crop, because the price is too low to recoup the cost of harvesting and shipping their corn.

Meanwhile, commodities traders will also be active in the market, helping to bring demand into balance with supply, by purchasing surplus corn and physically storing it for sale at a later time when they hope corn prices will be higher. This is a reasonable gamble, since another predictable phenomena is that some corn farmers will respond to the sharp decline in prices by planting a different crop next season – perhaps soybeans or wheat. Similarly, some entrepreneurs will explore opportunities to export corn to other markets – perhaps selling it overseas, or finding new buyers who will figure out a way to use it as a fuel or feedstock.

The net impact of these economic "feedback effects" will be a less severe drop in corn prices, or one that doesn't last as long as would otherwise have occurred. As the market adjusts, less corn will be produced, and some of the surplus will be stored and sold at a later time, or it will be sold "off-system" (in other markets). All of these mechanisms help bring supply and demand back into a more reasonable balance, helping to absorb the surplus and ameliorating the drop in prices that would be estimated in the absence of these mechanisms.

These sorts of "feedback effects" have long been understood by economists, and they are crucial to an accurate understanding of how commodities markets function. While these phenomena may seem unfamiliar in the context of the electric utility industry, they are going to be increasingly important as the industry becomes more competitive. Regardless of how unfamiliar they may seem, these types of "feedback effects" and market mechanisms need to be considered to accurately estimate avoided costs over the next 10 years – or to develop a well-optimized IRP.

To further clarify and illustrate these points, we will illustrate some of the "feedback effects" that can be expected in the context of the competitive procurement mechanism mandated by Session Law 2017-192 (generally know as "HB 589").

Less sophisticated market participants in this competitive process may not realize the full extent of the potential for an imbalance between supply and demand during times of low customer demand and high solar output. Hence, they may not anticipate the extent to which this imbalance could reduce the price they will receive, or their chances of being a successful bidder in the CPRE procurement (just as farmers may fail to anticipate a corn surplus).

This is particularly likely for some QFs in North Carolina, because Duke treats the details of its avoided cost calculations, and many other details related to supply and demand conditions (like the ramp rates for its individual generating plants), as trade secret or "confidential" information.

Due to this lack of market transparency, and since some of the available data is not widely understood, some market participants will probably not realize the full extent to which Duke's marginal and avoided costs could drop over the next 10 years – or the specific hours when this is most likely to occur. While participants may initially have only a general sense of where the market is heading, the supply and demand imbalance will become increasingly obvious during the later tranches – just as excessive planting of a particular crop will eventually become obvious to everyone, once the surplus emerges and prices drop.

However, some market feedback effects could begin to show up almost immediately. For instance, some successful CPRE participants in Tranche 1 might submit bids based on educated "guesses" concerning the pattern of costs they think might be used by the bid administrator during the bid evaluation process. Other successful bidders might "throw darts at the wall" by submitting multiple bids based upon various different technology configurations. In both cases, their successful bids might turn out to be ones that were better suited to the pattern of excess production and low value that will exist on days with high solar production and low customer demand.

Whatever the timing, "feedback effects" will help bring supply and demand into a more efficient balance. For example, some QFs might find it better to invest in a "tracking" system, rather than a fixed array. A tracking system will produce more energy during the early morning and late evening hours, reducing the proportion of energy produced during times when revenue per MWh will be low.

Similarly, some QFs might experiment with a much higher inverter loading ratio. This will increase their investment in solar panels relative to other items, including the grid connection and inverters. Increasing the inverter loading ratio might seem inefficient from an engineering perspective, since a lot of energy will be "clipped" during favorable solar conditions. However, this might not be economically inefficient, if the clipped energy will mostly be produced at times when the price per MWh is very low or zero.

Finally, and most significantly, some QFs will invest in storage capacity, which will help them salvage value from energy that would otherwise be clipped, curtailed, or sold for a very low price.

As a result of all these market adjustments, less energy will be sent to the grid during the middle of the day, and more will be sent during the morning and evening, compared to a simple extrapolation that ignores these adjustments or "economic feedback" effects. These potential "feedback effects" can most easily be illustrated by focusing on single example: solar + storage.

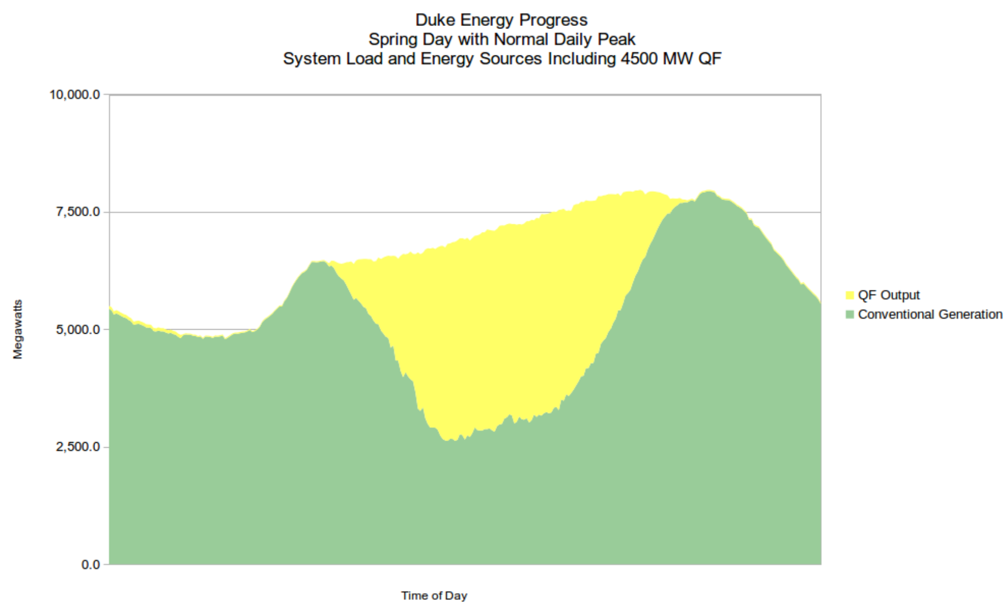
While the cost of storing electrical energy remains fairly high, it has been rapidly declining, and this trend is expected to continue. This downward cost trend is especially important in the CPRE context, which involves 20 year contracts. Even though storage costs are currently high, successful participants realize these costs are declining, so they may seek to include a major storage component in their project, anticipating the impact of lower costs over the majority of the 20 year contract or the full 30+ year economic life cycle of the solar panels.

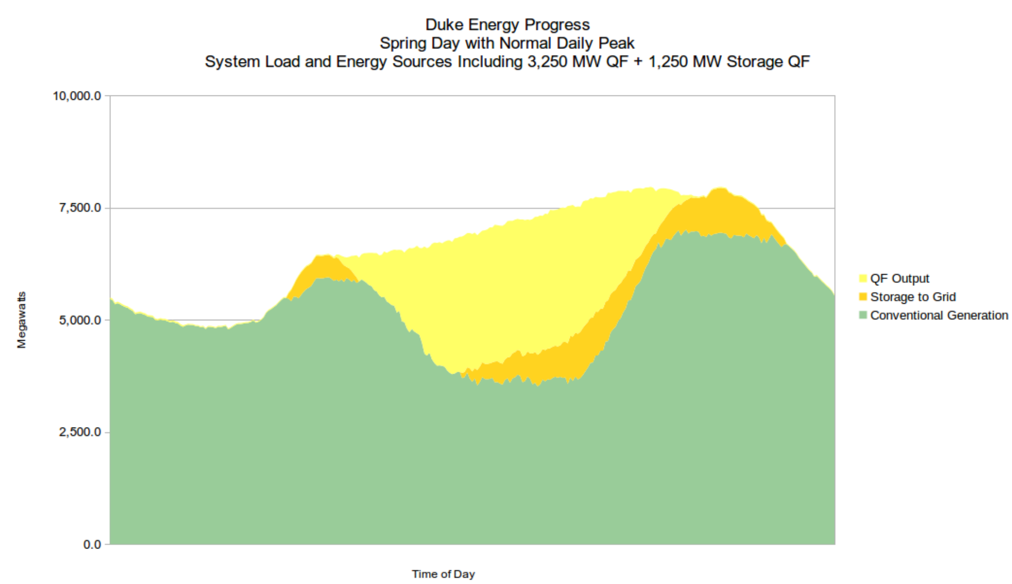
Modeling "Net" Load with Solar + Storage

We will illustrate the impact of solar + storage starting with the example of a typical Spring day. We will then extend the analysis to other seasons and daily "net" load patterns. In each example we will show that solar + storage can help bring supply and demand back into balance, resulting in greater economic efficiency, and very different levels of marginal and avoided costs.

The graph below shows the same typical Spring day shown earlier, using the same extrapolation assumption with just one change: we assumed the 4,500 MW of QF capacity will includes numerous solar + storage QFs, with an aggregate capacity of 1,250 MW, capable of storing 5,000 MWh that can be discharged over four hours.

For convenience in making visual comparisons, the earlier scenario and the analogous one with solar + storage are shown adjacent to each other.





Energy from solar + storage QFs is shown in the dark yellow color when it is sent to the grid. Production at the solar + storage QFs is assumed to follow the same pattern as the other QFs, based on a simple extrapolation of historic metered data. Their production is not displayed on the graph – only the volume of energy that is actually being sent to the grid.

In the second graph, energy is stored overnight and sent to the grid during the morning peak. Then, as the sun rises, the solar + storage QFs stop sending energy to the grid, and use their production to recharge their batteries. Charging continues throughout the morning then gradually tapers off, as the various batteries near a full charge.

By mid-day the amount of energy being sent from the solar + storage QF panels directly to the grid gradually increases, and is eventually supplemented with energy from storage. As a result, energy from the various solar + storage QFs continues to flow to the grid throughout the evening.

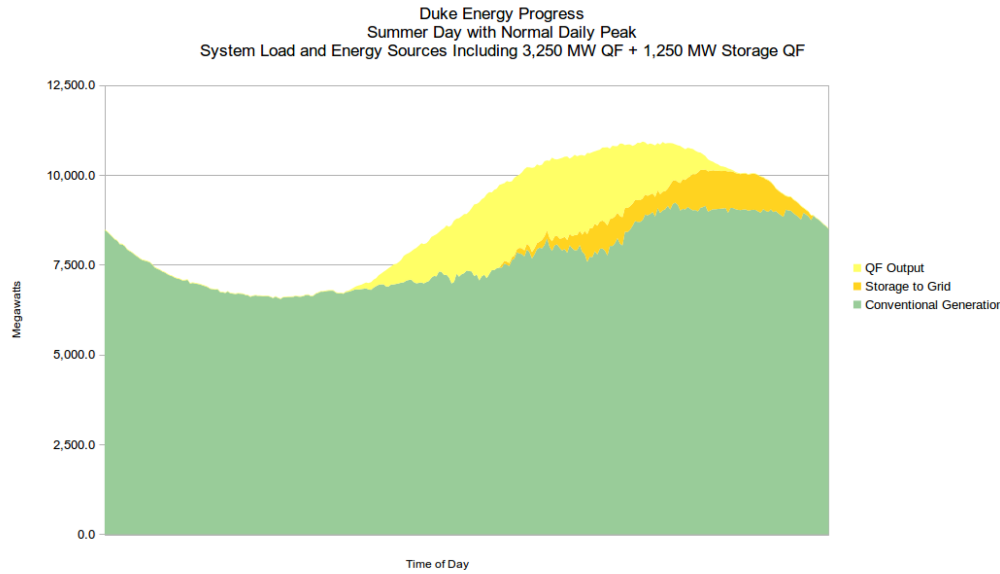
The end result is that various solar + storage QFs deliver substantial quantities of energy throughout the evening peak, when marginal costs are higher and the energy is more valuable than when it was produced. This flow tapers off toward the end of the evening, with some energy remaining in the batteries overnight, available to help serve the "net" morning peak the next day.

In this particular example, approximately 2,250 MWh of energy remains in the batteries at the end of the day, which is about 1,000 MWh more than we assumed happened to be present at the beginning of the 24 hour period.

One other point worth noting: the peak level of conventional generation is significantly lower in the morning and in the evening, and higher in the middle of the day, compared with the first scenario, in which all of the QFs were sending energy to the grid at the time of production, and none of them were using storage to improve the economics of their project.

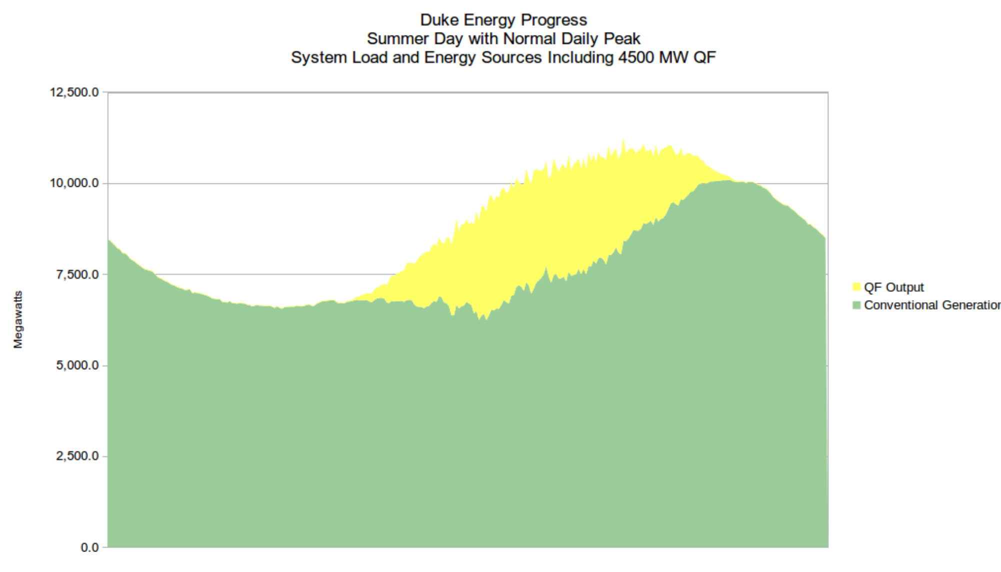
The next graph shows an example of energy storage and delivery during a normal summer day. We've assumed the same mix of regular QFs and solar + storage QFs exist, and we've again assumed they begin the day with 1,250 MWh in storage. However, there is no morning "net" peak, so none of the solar + storage QFs send energy to the grid in the morning.

A few differences are apparent, when comparing this example to the typical Spring day. Charging continues later into the day, because solar conditions aren't as favorable, so it takes longer to recharge the batteries, and most of the energy from the solar + storage QFs is delivered later in the day.

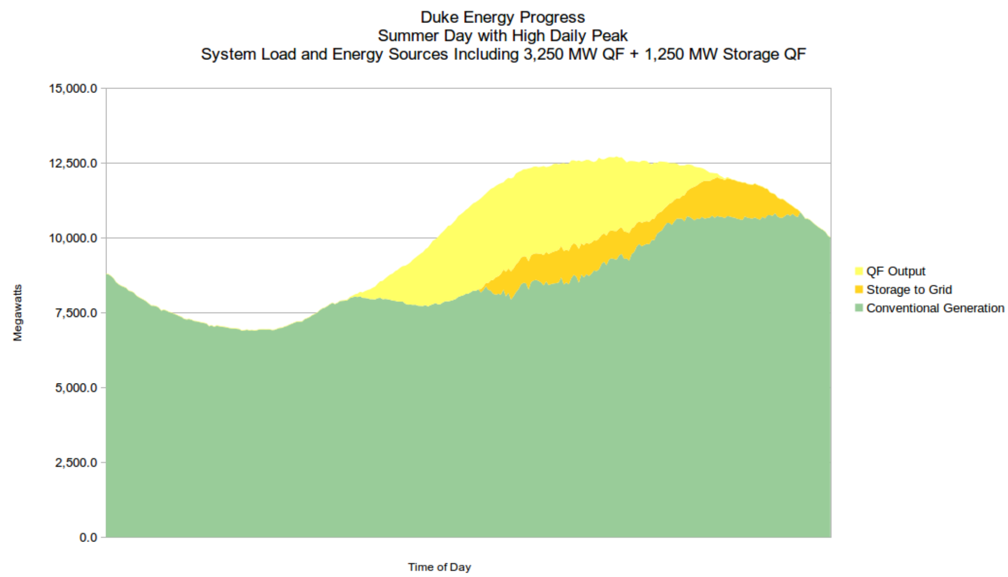


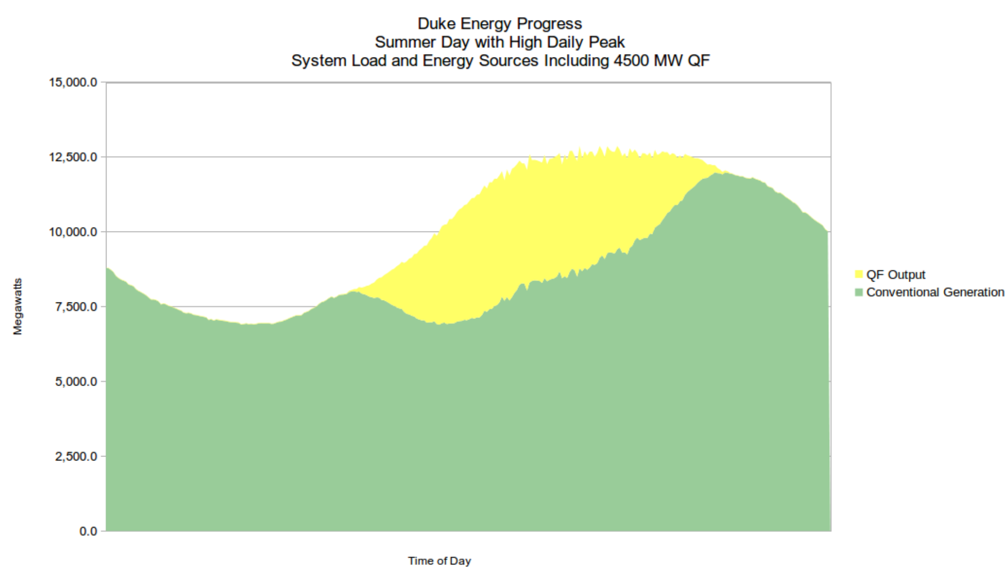
Another important point this example demonstrates: solar + storage can significantly reduce ramping requirements.

In the above example, conventional generation is remarkably flat throughout the day – especially when compared to the scenario in which none of the QFs use storage (repeated below, for ease of comparison).

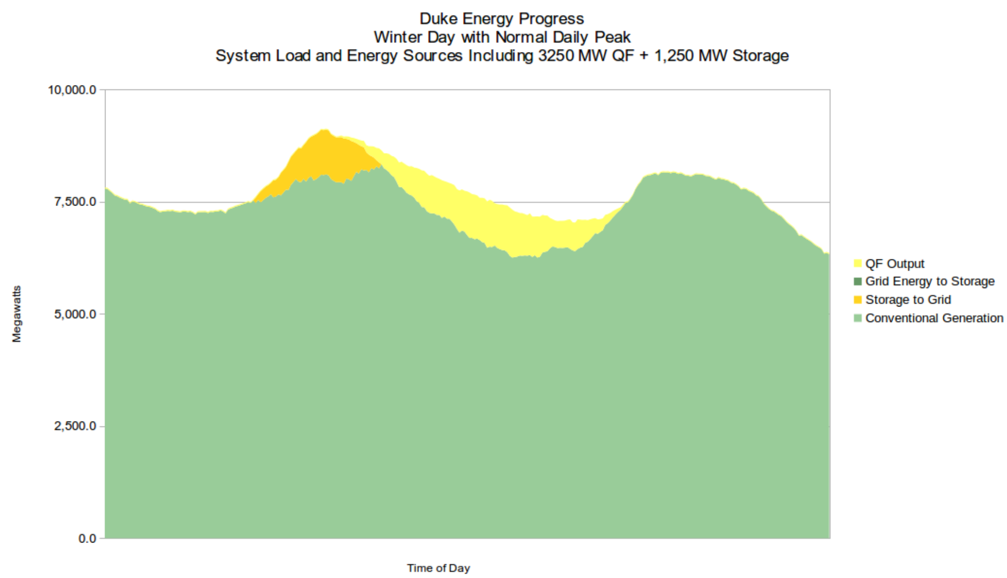


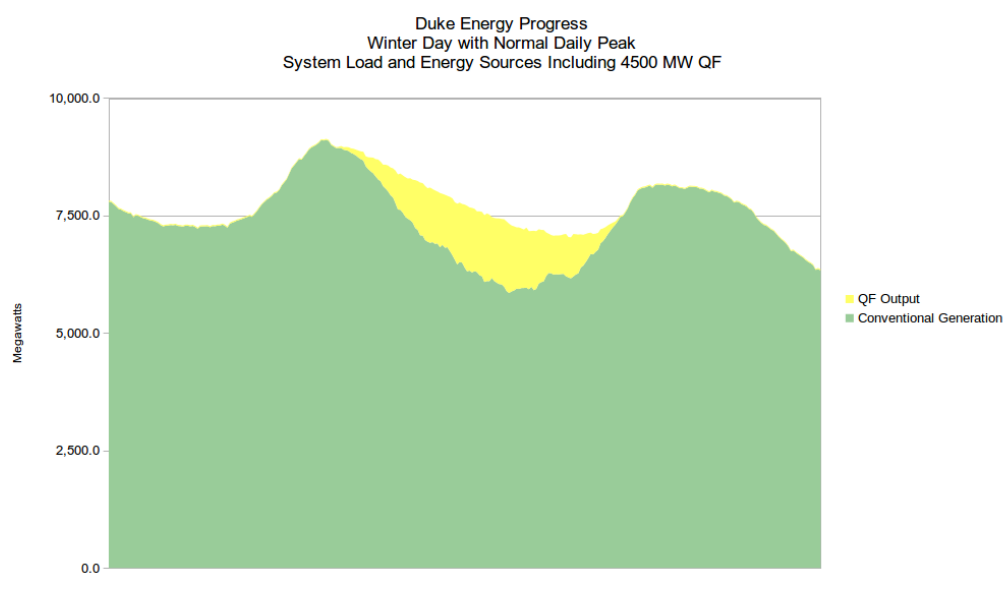
The following two graphs show a similar scenario on August 18, 2017, a Summer day with a much higher daily peak. Here again, the solar + storage QFs are very effective in reducing "net" peak load, and flattening out conventional generation, which reduces ramping requirements.





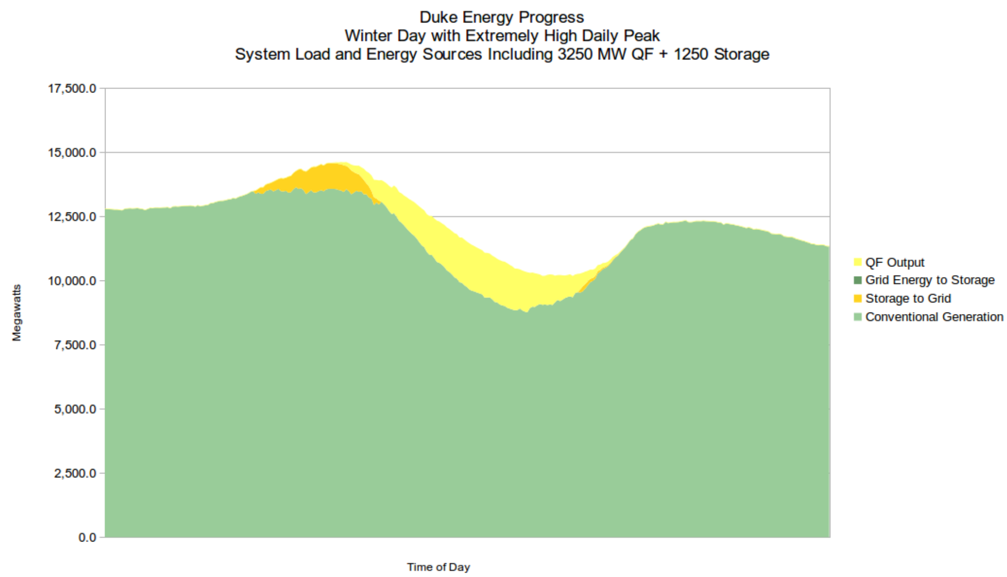
The following graph shows a similar scenario on January 11, 2017. The 1,250 MW of solar + storage QFs are assumed to start the day with 4,500 MWh of energy in storage, and they use some of this energy during the morning peak. After that, they use all of their solar production to recharge their batteries, ending the day with 4,000 MWh in storage.





Finally, the next pair of graphs show a similar scenario on January 9, 2017, a Winter day with an extremely high daily peak.

The solar + storage QFs are assumed to start the day with 4,000 MWh is storage and and they end the day with 5,000 MWh in storage. Most of their production is sent to their batteries, but a small amount is sent to the grid in the afternoon, as charging ends.



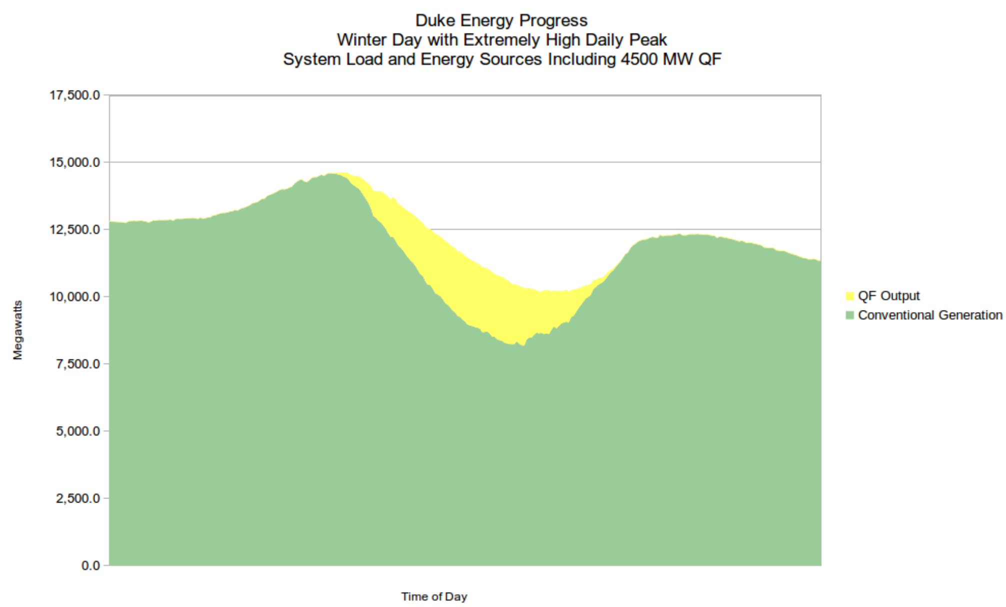


Exhibit B

Ben Johnson

Present position

Consulting Economist
Ben Johnson Associates, Inc.

Education

B.A. with honors, Economics - University of South Florida
M.S., Economics - Florida State University
Ph.D., Economics - Florida State University

Firm experience

As its founder and president, Dr. Johnson has developed the firm's approach to economic analyses. Dr. Johnson's doctoral areas of specialization were public finance (including taxation) and industrial organization (including utility regulation). His areas of professional specialization include antitrust, competition, cost analysis, and deregulation.

Dr. Johnson has been actively involved in more than 400 regulatory dockets, concerning electric, gas and other utilities. His work has spanned a wide range of different subject areas, involving the application of economic theory and principles to public policy, revenue requirements, rate of return and rate design issues. He has presented expert testimony on more than 300 occasions before the Federal Communications Commission, the Interstate Commerce Commission, and utility regulatory commissions in 35 states, two Canadian provinces, and the District of Columbia.

Dr. Johnson's experience in the electric utility field includes the full array of traditional rate base/rate of return issues, plus many issues involving performance regulation, decoupling, resource planning, grid modernization, non-wire alternatives, cogeneration and small and independent power production, avoided costs, cost/benefit analysis, resource life-cycle cost comparisons, feasibility studies, financial planning and modeling, and transmission constraints.

Dr. Johnson's clients have included a wide variety of public agencies and private corporations. Among the former are regulatory commissions in 14 states and the District of Columbia; public counsels in 15 states and the District of Columbia; attorneys general in 9 states; the Okeechobee County Property Appraiser; the Manattee County Property Appraiser; the Sarasota County Property Appraiser; the Utah Attorney General=s Office; the United States Department of Justice--Antitrust Division; the Canadian Department of Communications; the National Association of State Utility Consumer Advocates; dozens of municipal governments; the Florida Department of General Services; the Florida Municipal Electric Association; and the Provincial Government of Ontario.

Dr. Johnson's corporate and institutional clients have included: AMERICALL, Arkansas Telephone Company, Inc., BC Rail, Blountsville Telephone Company, Casco Bank and Trust, Consumers' Voice, Cube Hydro, Cypress Creek Renewables, East Maine Medical Center, the Harris Corporation, Interstate Securities Corporation, J.R. Simplot Company, LDDS, Liberty Telephone and Communications, Louisiana/Mississippi Association of Resellers, Merrill Trust Company, Midvale Telephone Exchange, Network Inc., Nevada Power Company, North American

Telephone Company, NC Sustainable Energy Association, Pan-Alberta Gas, Ltd., PenBay Memorial Hospital, PW Ventures, the South Carolina Solar Business Alliance, Southern Current, Stanton Telephone Company, Tel America, and Teltec Savings Communications.

Professional and business history

Ben Johnson Associates, Inc.:
1977-
Consulting Economist
State of Florida:
1975-77
Senior Utility Analyst, Office of Public Counsel
1974-75
Economic Analyst, Office of Public Counsel

Publications

Dr. Johnson has authored or co-authored 13 published articles appearing in such periodicals as The Southern Economic Journal, Proceedings of the Michigan State University Institute of Public Utilities, Public Utilities Fortnightly, West Virginia Law Review, Electric Ratemaking, and The New York Times.

Lectures, conferences and seminars

Dr. Johnson has lectured to undergraduate classes in economics at Florida State University on public utility regulation and economic theory and has addressed conferences and seminars sponsored by the National Association of Regulatory Utility Commissioners' Subcommittee on Law, the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), NTSA – the Rural Broadband Association, the Rural Electrification Administration, the North Carolina Public Staff Utilities Commission, the North Carolina State University Department of Economics and Business Center for Economic and Business Studies, and the University of Florida College of Business Administration.

Professional memberships

American Economic Association

Personal References

Erin Hogan, Director
Utility Intervention Unit
Division of Consumer Protection
NYS Department of State
1 Commerce Plaza
99 Washington Ave, Suite 1020
Albany, NY 12231
(518) 408-3746

Thomas W. Peters
Peters | Scofield
7430 Creek Road, Suite 303
Sandy, Utah 84093-6160
(801) 322-2002