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August 7, 2015

Gail Mount
Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street
Raleigh, NC 27603 – 5918

Re: Affidavit of Ben Johnson – Public
NCUC Docket No. E-100, Sub 140

Dear Ms. Mount:

Enclosed for filing in the above-referenced docket is the Affidavit of Ben Johnson – Public.

Should you have any questions or comments, please do not hesitate to call me. Thank you in advance for your assistance and cooperation.

Regards,

/s Charlotte Mitchell

4847-9065-5268, v. 1

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Biennial Determination of Avoided Cost	)	**AFFIDAVIT OF**
Rates for Electric Utility Purchases from	)	**BEN JOHNSON,**
Qualifying Facilities - 2014	)	**PH.D.**

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

Purpose

1. My name is Ben Johnson. This affidavit was prepared at the request of the North Carolina Sustainable Energy Association ("NCSEA"), for use in Docket No. E-100, SUB 140.

2. I have been asked to provide factual evidence concerning the calculation of avoided costs of Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") and Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP") (collectively, the "Utilities"), to analyze the Utilities' March 2, 2015 filings (the "March 2015 Filings") in this docket, to analyze the comments filed in this

docket on June 22, 2015 by the North Carolina Public Staff ("Staff") and the Southern Alliance for Clean Energy ("SACE"), and to provide recommendations to the Commission for its consideration in resolving the disputed issues in this proceeding.

Qualifications

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, water, wastewater, and telecommunications industries.

6. My firm has participated in more than a dozen 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 it's proposed acquisition of Westcoast Energy, Inc.; Docket Number E-2, Sub 760, the 2000 proceeding in which CP&L Holdings, Inc. requested permission to acquire Florida Progress Corporation; Docket Nos. E-7, Sub 828 & 829 E-100, Sub 112, a 2007 Duke Energy Carolinas case; Docket Nos. E-7, Sub 909, a 2009 Duke Energy Carolinas 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; and Docket No. E-100, Sub 136 a 2012 proceeding concerning avoided costs. The majority of our consulting work in North Carolina has been on behalf of the Public Staff, but on some occasions, as in this case, we have provided assistance to other parties.

Preparation

7. I have reviewed the Commission's December 31, 2014 Order Setting Avoided Cost Input Parameters ("Order Setting Parameters"), the Utilities' March 2015 Filings, the Utilities' responses to discovery propounded by NCSEA, the Public Staff and SACE (including confidential responses, where applicable), the Comments submitted by the Public Staff and SACE on June 22, 2015 in this proceeding, and various other documents from Phase I and Phase II of this proceeding, the 2012 Avoided Cost proceeding (Docket No. E-100, Sub 136), and the 2014 Integrated Resource Planning proceeding (Docket No. E-100, Sub 141).

Generation Expansion Plans

8. In the 2014 Integrated Resource Planning proceeding the Utilities studied multiple generation expansion plans, considering a variety of different assumptions and scenarios, as reflected in Dominion North Carolina Power's and Dominion Virginia Power's Report of Its Integrated Resource Plan Filed August 29, 2014 (DNCP 2014 IRP) at page 4, in Duke Energy Carolinas Integrated Resource Plan, September 1, 2014 (DEC 2014 IRP) at Page 29 and in Duke Energy Progress Integrated Resource Plan, September 1, 2014 (DEP 2014 IRP) at Page 29.

9. All of the Utilities' "base" generation expansion plans were influenced to varying degrees by their expectations and assumptions concerning the cost of carbon in the future. For instance, DEC and DEP analyzed different potential generation portfolios "under scenarios that represent both a carbon-constrained future (With CO 2) and a future without carbon constraints (No CO 2), as explained in the DEC and DEP 2014 IRPs at Page 29. The "base" expansion plan selected by DEC and DEP included more nuclear capacity than was optimal under the "No CO2 cost" scenario, as explained in the DEC and DEP 2014 IRPs at Page 30. In the case of DNCP, it increased its capacity reserve margin in the "base" expansion plan, due to uncertainties related to carbon, as explained in the DNCP 2014 IRP at page 44 and as further explained in the DNCP 2014 IRP at pages 48-51.

10. The Utilities used their "base" generation expansion plans in developing their March 2, 2015 filings. This is indicated in DEC's Response to Public Staff Data Request 6-3, DEC's Response to Public Staff Data Request 6-4 and DNCP's Response to NCSEA Data Request 2-10 (l). Because DEC and DEP included additional nuclear generating capacity in their "base" plan, as explained in the DEC and DEP 2014 IRPs at Page 30, they relied more on nuclear units with high capital costs and low operating costs, and less on older generating units with poor heat rates and high variable costs when modeling their production costs in this proceeding. In turn, this had the effect of reducing the variable operating costs of the "marginal" units, which translated into lower avoided energy cost estimates. Similarly, because DNCP included a larger reserve margin in their "base" plan, as explained in the DNCP 2014 IRP at page 44, they relied

more on newly constructed, highly efficient combined cycle units and less on older generating units with poor heat rates and high variable costs when modeling their production costs in this proceeding. In turn, this had the effect of reducing the variable operating costs of the "marginal" units, which translated into lower avoided energy cost estimates.

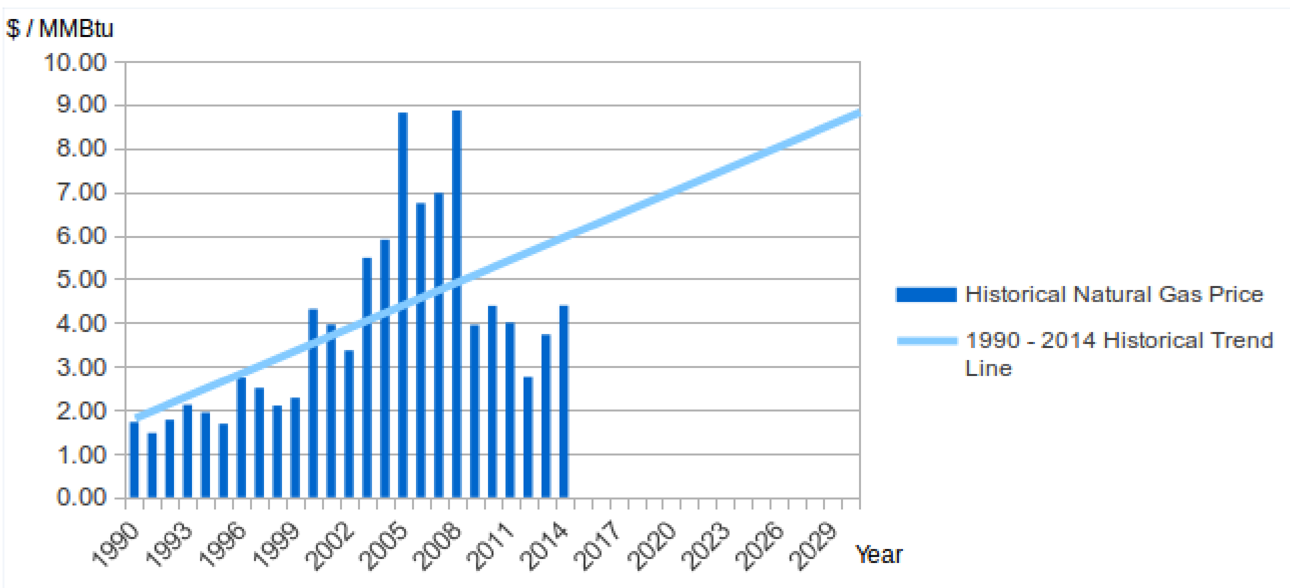
11. It is inconsistent and inappropriate to model avoided energy costs based on generation expansion plans that were influenced, directly or indirectly, by assumptions concerning increases in the cost of carbon, if the increased cost of carbon is excluded from consideration for other purposes (e.g. fuel costs). Accordingly, I recommend the Commission require DEC and DEP to recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include additional nuclear units. Similarly, I recommend the Commission require DEC and DEP to recalculate their avoided energy rates utilizing a generation expansion plan that does not include additional base load generating capacity added for the purpose of supporting a larger than normal reserve margin, due to DNCP's concerns about restrictions on the use of carbon, or the high cost of carbon, in the future.

Natural Gas and Coal Price Forecasts

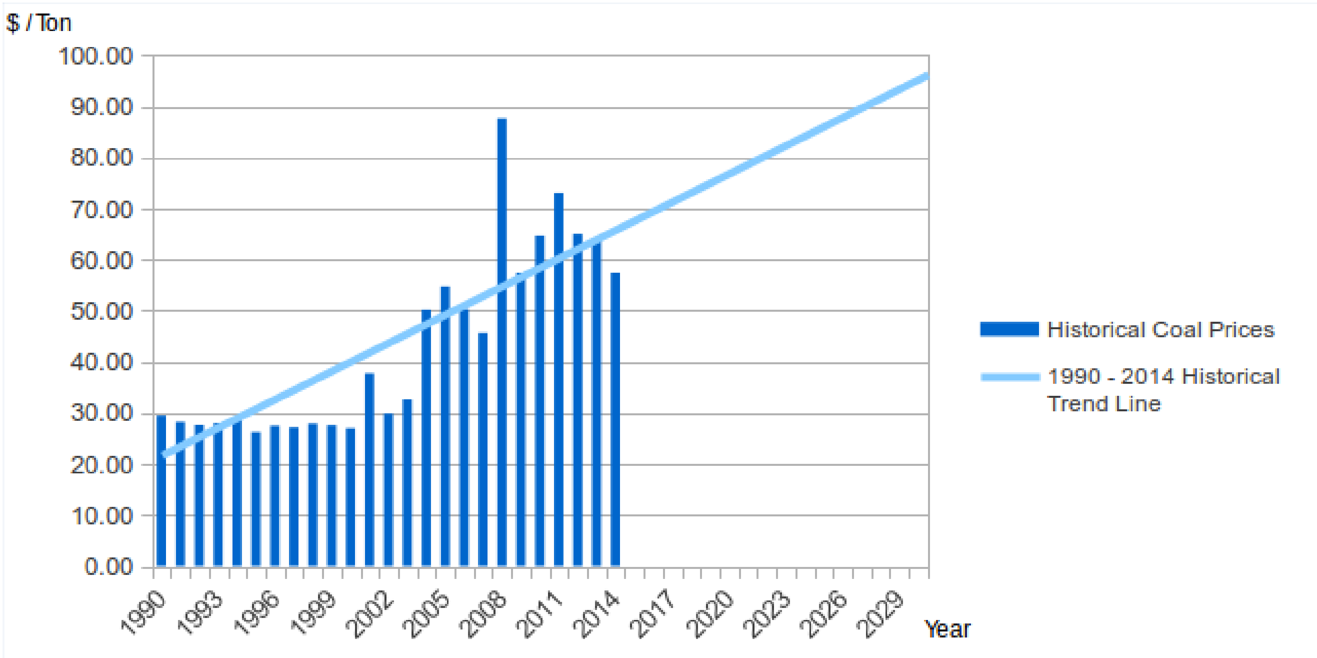
12. The assumed fuel (commodity) prices are critically important to the avoided energy cost calculations, since fuel prices represent the vast majority of the

avoided energy costs. Any discrepancy between assumed fuel prices and actual prices that are ultimately paid by the utilities will translate into a corresponding discrepancy between the estimated level of avoided energy costs and the actual level of energy costs that is avoided when electricity is obtained from a QF instead.

13. I developed the following graph, which shows the trend in natural gas prices over the 25 year period from 1990 through 2014, using data I obtained from Reuters (1990-96) and from the Energy Information Administration (1997-2014):



14. Similarly, I developed the following graph, which shows the trend in the average of coal prices reported for each of the 25 years from 1990 through 2014, using publicly available data I obtained from British Petroleum (1990-2013) and the Energy Information Administration (1990-2014):



15. I also developed the following graph, which compares the trend in historical natural gas prices with the forward-looking gas prices DNCP assumed for purposes of developing its avoided energy cost estimates:

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[redacted]

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16. In this proceeding, DNCP is assuming that natural gas prices will remain at very low levels during the first seven years of the 15-year horizon and that gas prices will never again approach, much less reach, the long term historical trend line.

17. For comparison, I developed the following graph, which shows the gas prices used by DNCP in preparing its 2014 Integrated Resource Plan, and demonstrates that the forecast prices DNCP used in the IRP proceeding are much more consistent with the historical trend line:

BEGIN CONFIDENTIAL

[redacted]

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18. I developed the following graph, which compared the historical natural gas price trend with the gas prices DEC assumed for purposes of developing its avoided energy cost estimates:

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[redacted]

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19. DEC and DEP are assuming that natural gas prices will remain at very low levels during the first 11 years of the 15-year horizon that begins in 2015, and that gas prices will only begin to approach the long term historical trend line near the end of this planning horizon.

20. For comparison, I developed the following graph, which shows the gas prices used by DEC and DEP in preparing their 2014 Integrated Resource Plan, and demonstrates that the forecast prices DEC and DEP used in the IRP proceeding are much more consistent with the historical trend line:

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[redacted]

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21. The difference in fuel prices used in developing their avoided cost estimates and the fuel prices used for Integrated Resource Planning purposes can be traced to the Utilities' decision to replace or reduce reliance on fundamental forecasts during the early years of the planning horizon, replacing this data with, or putting greater reliance on, lower “forward prices” derived from futures markets. This is a significant change in methodology relative to the approach the Utilities used in the 2014 IRP, in the

2012 Avoided Cost proceeding, and in the application for a certificate of public convenience and necessity ("CPCN") to construct the 84 MW Sutton blackstart CT ("Sutton Blackstart CT Project"), which was filed on April 25, 2015. In each of these cases the Utilities consistently placed greater emphasis on fundamentals-based forecasts, and put relatively little reliance on "forward prices".

22. This change in methodology is not an improvement, since "forward prices" are not a more accurate or reliable basis for predicting prices in the future. Fundamentals-based forecasts, like the ones the Utilities have traditionally relied upon, continue to be the most reliable and consistent basis for estimating prices that will actually be paid for fuel that will be purchased and burned in future years. They are based upon a detailed analysis of historical price trends, contributing factors that influence prices, and the interaction between different fuel markets, among other "fundamental" factors. As a result, fundamentals-based forecasts are an exact match to what is needed in this proceeding (a prediction of prices that will actually be paid by the Utilities in the future).

23. In contrast, "forward prices" are conceptually different and are not a direct match to the data that is needed for input into the production cost models that are used in estimating avoided costs. What is needed is an estimate of the price that will actually be paid by the Utilities for fuel purchased at specific dates in the future. Forward prices are not predictions or estimates of prices that will be paid in the future. Rather, they are prices that can be paid currently for a contract to receive fuel in the future. While these

sound almost the same, they are conceptually different, and the difference is important. Due to this difference, "forward prices" tend to systematically understate the true cost of acquiring fuel that will be burned in the future. The extent of the understatement tends to increase over time, so the problem becomes increasingly severe when "forward prices" are used as a substitute for a true forecast for a long time period, as the Utilities are doing in this proceeding.

24. Futures markets provides a standardized mechanism that enables a buyer to purchase the right to receive delivery of a given quantity of a particular type of fuel at a specific date in the future. The prices observed in the futures markets are generally not for the fuel itself, but for contracts that represent a carefully structured, highly standardized bundle of legal rights and obligations.

25. Utilities do not typically purchase fuel in futures markets in order to receive physical delivery of the fuel at future dates. If they were to do so, they would incur substantial carrying costs for fuel purchased in this manner, over and above the "forward price" paid for the futures contract itself. These carrying costs include interest on their investment and the cost of equity capital during the entire time from the date when they purchase the futures contract until they date when they receive physical delivery of the fuel, months or years later. Because futures prices do not include these carrying costs, they tend to systematically understate the actual cost of acquiring fuel for future delivery. This understatement becomes more serious the longer the time period over which future prices are being used as a data source. The understatement is not

particularly serious if “forward prices” are blended with fundamentals-based forecast prices during the first few years of a long planning horizon, as DNCP did in the IRP proceeding, when it blending the “forward price” data with a fundamentals-based forecast during just three years (2015 – 2017) and relied entirely on the fundamentals-based forecast during all remaining years. However, the problem becomes much more serious when the “forward prices” are used by themselves (not blended with forecast data), or they are used for a much longer number of years, as the Utilities are proposing to do in this proceeding.

26. I recommend the Commission reject the Utilities' excessive reliance on “forward prices” in this proceeding for four reasons: (1) Forward prices are not accurate predictions of, or a reliable indicator of what actual commodity prices will be in the future. (2) Additional costs would need to be added to the “forward prices” if the Utilities were to purchase futures contracts in an effort to “lock-in” current prices for fuel to be delivered and burned in the future. (3) The futures-based “forward” prices used by the Utilities are substantially lower than, and inconsistent with, the long term historical trend in prices, as demonstrated in the above graphs. (4) Under current circumstances it would be particularly unreasonable to place heavy reliance on the current low level of “forward prices” because the upside price risks are greater than the downside risks (prices are more likely to go up than go down in the current situation), and in fact, prices might be near the bottom of a cyclical downturn, in which case prices could move sharply higher, or move back toward or above the long term trend line, within the next few years.

27. If the Commission approves avoided energy costs based upon these low "forward" prices, QF development will tend to be discouraged, and ratepayers will likely end up paying more for power generated by the Utilities than they would have paid for QF power. The standard of "financial indifference" will not be achieved unless the Utilities are required by the commission to use higher, more realistic assumptions concerning future fuel prices like those used in the 2014 IRP proceeding.

28. I recommend the Commission require each of the Utilities use the same fuel prices in this proceeding they relied upon in developing their 2014 Integrated Resource Plans. This would provide more reasonable cost estimates, would provide greater consistency between the two proceedings, and would provide greater consistency with the long term historical price data, as shown in the above graphs.

Fuel Hedging

29. In their March 2015 Filings DEC and DEP did not include an accurate estimate of the value of hedging against fuel price volatility. They claim to have provided an allowance for the value of hedging based upon by using "ask" prices, rather than lower prices closer to the midpoint between "bid" and "ask" prices when using "forward" prices in developing their fuel cost inputs. However, this does not quantify the

benefit of avoiding future price volatility, nor does it indicate what it would cost to hedge against this volatility.

30. The bid-ask spread is not a reliable measure of volatility, nor does it provide an accurate basis for estimating what it would cost to hedge against volatility. To the contrary, the bid-ask spread is primarily related to market liquidity. If numerous transactions are constantly taking place in the market, with many different buyers and sellers, and there are many different market makers actively participating in the market, the spread tends to be small. Since the bid-ask spread primarily reflects liquidity, not volatility, it does not provide an adequate basis for estimating the cost or value of hedging.

31. DEC and DEP support their approach by contending that "if the Company actually wanted to hedge the natural gas" it could purchase the fuel in advance for future delivery, but this does not provide a valid basis for relying on "ask" prices in lieu of an accurate estimate of the cost or value of hedging.

32. It is theoretically true that DEC and DEP could purchase the right to obtain fuel for delivery many months or years later, but if they were to do so they would incur substantial additional carrying costs in addition to the "ask" price. For instance, if they were to purchase the right to receive delivery of fuel in 18 months, paying the full "ask" price in cash, DEC and DEP would incur an approximately 15% in carrying costs

over and above the “ask” price, if their cost of capital (including taxes) were 10% (10% per annum times 1.5 years).

33. Even if they were to purchase futures contracts on margin, carrying costs would not be avoided entirely, because they would still incur “opportunity costs” related to the margin they would need to deposit in order to purchase the contract, as well as the additional capital they would need to tie up, in order to stand ready to immediately meet margin calls whenever necessary. These carrying costs and opportunity costs would need to be added to the “ask” prices in order to gain any meaningful insight into the cost of hedging against fuel price volatility by purchasing futures contracts.

34. In its March 2015 Filing DNCP provided “$3.2 million (based on 2012/13 cost data) for gas broker transaction costs and financing costs” which it divided by “the aggregate Mwh amount of non-nuclear energy supply that could potentially be displaced by renewable generation” as explained in DNCP's response to Public Staff Data Request 3-14.

35. This does not accurately calculate the cost of fuel hedging on a per-Mwh basis, nor does it accurately measure the fuel hedging benefit that is provided when electricity is obtained from a QF.

36. The DNCP calculations do not provide an appropriate matching of the numerator and denominator. The numerator is limited to the portion of DNCP's fuel

costs which was hedged during 2012/13, whereas the denominator includes electricity generated using fuel that was not hedged. To develop a meaningful ratio the numerator and denominator should be more consistent with each other. For instance, if just 20% of DNCP's fuel purchases were hedged in 2012/13, then just 20% of its 2012/13 Mwh should logically be used in the denominator.

37. The burden of volatility remains on customers even if it is not being hedged. Fuel price volatility imposes a burden on customers, which is avoided when electricity is obtained from a QF at a fixed (non-volatile) price. A valid hedging analysis would consider the full extent of price volatility over the 1 to 2 year time horizon specified by the Commission – not just the portion of that volatility the utility is hedging against.

38. The Utilities' avoided energy costs should be revised to include a reasonable allowance for the value of hedging against price volatility over the 12 to 24 month period immediately preceding the time when fuel is burned.

39. I have reviewed the April 25, 2014 testimony of Dr. Richard E. Brown in phase I of this proceeding, filed on behalf of the Public Staff, and agree with his conclusion that a reasonable hedging allowance can be developed by subtracting the cost of put options from the cost of call options, as explained at Page 30 of his testimony.

40. I agree that the approach described at page 36 of the Initial Statement of

the Public Staff, filed on June 22, 2015 in this proceeding, is a reasonable application of the methodology recommended by Dr. Brown. I also agree with the Public Staff that it is reasonable to use the Black-Scholes options calculator located at: http://app.fintools.com/calcs/OptionsCalc.aspx, in this proceeding, but I disagree with the Public Staff 's decision to use a short-term interest rate of 1.00% in developing its calculations.

41. The documentation provided with this Black-Scholes options calculator, which becomes visible when hovering over the question mark adjacent to the interest rate field, clearly and unambiguously states the appropriate number to input into the interest rate field is “The risk-free interest rate expressed as a percentage.” The “risk-free rate” is a well-understood term of art that is used for many purposes, including development of equity cost estimates using the Capital Asset Pricing Model.

42. In Docket No. E-7, Sub 1026 Robert Hevert testified on behalf of Duke Energy Carolinas, LLC that in developing his equity cost estimates for DEC, he “used three different estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasurey bonds (i.e., 2.85 percent); (2) the projected 30-year Treasure yield (i.e., 3.14 percent), and (3) the long term projected 30-year Treasury yield (i.e., 5.10 percent)” as set forth on pages 27 and 28 of his prefiled direct testimony.

43. In Docket No. E-22, Sub 479, Robert Hevert testified on behalf of Dominion North Carolina Power that in developing his equity cost estimates for DNCP

he “used two different estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (i.e., 3.09 percent); and (2) the projected 30-year Treasury yield (i.e., 3.50 percent)” as set forth on pages 26 of his prefiled direct testimony.

44. In Docket No. E-2, Sub 1023 Robert Hevert testified on behalf of Duke Energy Progress, Incthat in developing his equity cost estimates for DEP, he “used three different estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (i.e., 2.65 percent); (2) the near-term projected 30-year Treasury yield (i.e., 3.00 percent); and (3) the long-term projected 30-year Treasury yield (i.e., 5.30 percent)” as set forth on pages 28 of his prefiled direct testimony.

45. In my opinion, the risk-free rate has not changed substantially over the past several years, and currently remains in the vicinity of 3.10%.

46. Changing the interest rate input from 1.00% to 3.10% results in a higher, more accurate, estimate of the cost of the both the call option and the put option, as can be seen by comparing these two screen shots of the Black-Scholes options calculator used by the Public Staff:

OptionsCalc

Model	Black-Scholes
Stock Price	3.11
Exercise Price	3.10
Value Date	06/10/2015
Early-Exercise Date	05/31/2016
Expiration Date	05/31/2016 (356 days)
Volatility (%)	20.00
Interest Rate (%)	1.00
Dividend Method	Continuous
Yield Rate (%)	0.00

	Call	Put
Theoretical Value	0.2637	0.2236
Delta	0.5653	-0.4347
Delta 100's	56.5309	-43.4691
Lambda (%)	6.6682	-6.0469
Gamma	0.6407	0.6407
Gamma (1%)	0.0199	0.0199
Theta	-0.0004	-0.0003
Theta (7 days)	-0.0027	-0.0021
Vega	0.0121	0.0121
Rho	0.0146	-0.0154
Psi	-0.0171	0.0132
Strike Sensitivity	-0.4821	0.5082
Intrinsic Value	0.0100	0.0000
Time Value	0.2537	0.2236
Zero Volatility	0.0401	0.0000
Market Option Price	20.04	8.51
Implied Volatility (%)	No Solution	No Solution

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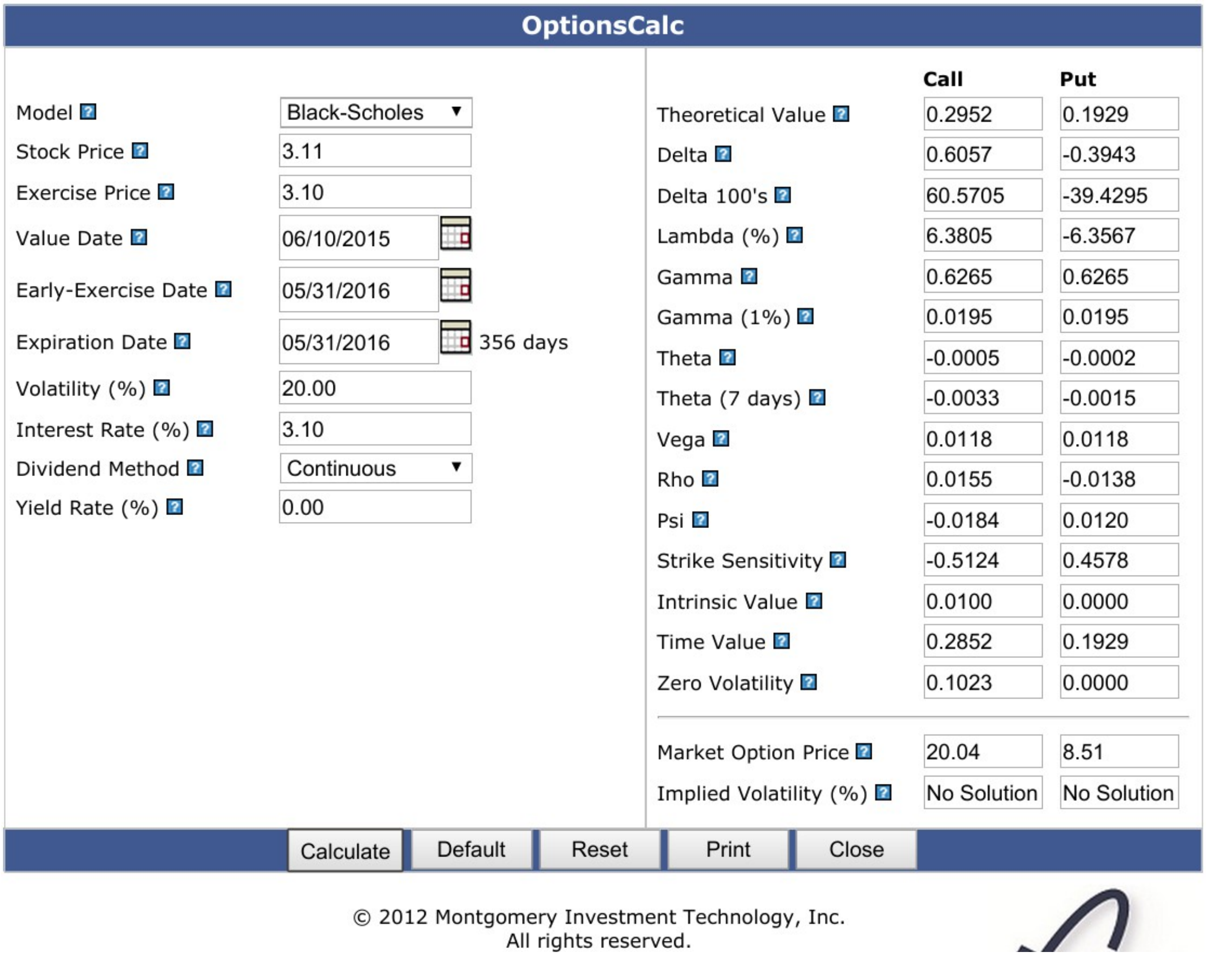
OptionsCalc

Model	Black-Scholes
Stock Price	3.11
Exercise Price	3.10
Value Date	06/10/2015
Early-Exercise Date	05/31/2016
Expiration Date	05/31/2016 356 days
Volatility (%)	20.00
Interest Rate (%)	3.10
Dividend Method	Continuous
Yield Rate (%)	0.00

	Call	Put
Theoretical Value	0.2952	0.1929
Delta	0.6057	-0.3943
Delta 100's	60.5705	-39.4295
Lambda (%)	6.3805	-6.3567
Gamma	0.6265	0.6265
Gamma (1%)	0.0195	0.0195
Theta	-0.0005	-0.0002
Theta (7 days)	-0.0033	-0.0015
Vega	0.0118	0.0118
Rho	0.0155	-0.0138
Psi	-0.0184	0.0120
Strike Sensitivity	-0.5124	0.4578
Intrinsic Value	0.0100	0.0000
Time Value	0.2852	0.1929
Zero Volatility	0.1023	0.0000
Market Option Price	20.04	8.51
Implied Volatility (%)	No Solution	No Solution

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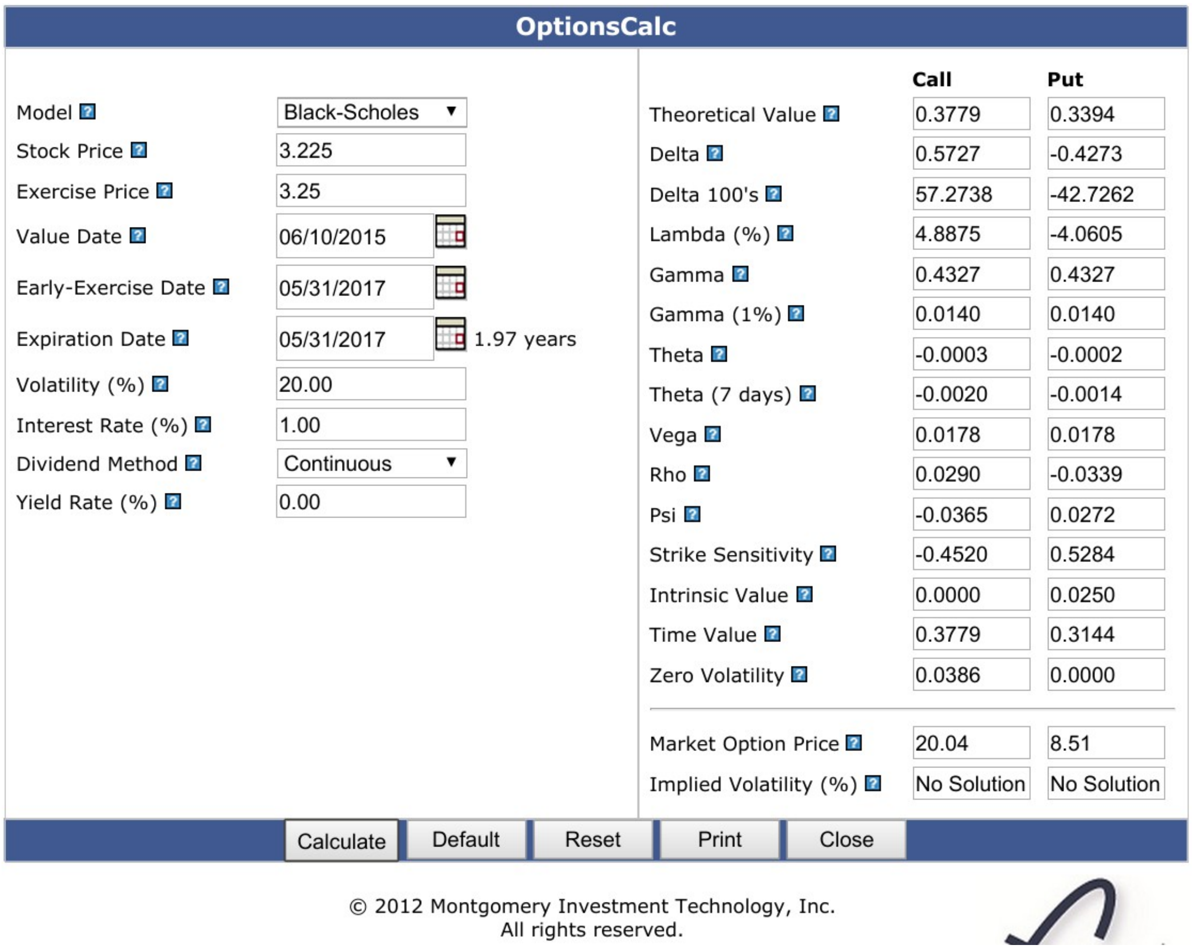
47. Using a risk-free rate of 3.10%, and subtracting the cost of the put option (.1929) from the cost of the call option (.2952) indicates the value of hedging over a 12 month horizon is .102 per dekatherm, rather than .0401 as computed by the Public Staff.

48. Using a risk-free rate of 3.10%, and subtracting the cost of the put option (.2734) from the cost of the call option (.4414) indicates the value of hedging over a 24 month horizon is .168 per dekatherm, rather than .0385 as computed by the Public Staff:



OptionsCalc

Model	Black-Scholes
Stock Price	3.225
Exercise Price	3.25
Value Date	06/10/2015
Early-Exercise Date	05/31/2017
Expiration Date	05/31/2017 (1.97 years)
Volatility (%)	20.00
Interest Rate (%)	3.10
Dividend Method	Continuous
Yield Rate (%)	0.00

	Call	Put
Theoretical Value	0.4414	0.2734
Delta	0.6296	-0.3704
Delta 100's	62.9649	-37.0351
Lambda (%)	4.6005	-4.3694
Gamma	0.4166	0.4166
Gamma (1%)	0.0134	0.0134
Theta	-0.0004	-0.0001
Theta (7 days)	-0.0026	-0.0008
Vega	0.0171	0.0171
Rho	0.0314	-0.0290
Psi	-0.0401	0.0236
Strike Sensitivity	-0.4890	0.4516
Intrinsic Value	0.0000	0.0250
Time Value	0.4414	0.2484
Zero Volatility	0.1680	0.0000
Market Option Price	20.04	8.51
Implied Volatility (%)	No Solution	No Solution

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49. Converting .102 to .168 per dekatherm to an equivalent cost per kwh results in a hedging allowance of .071 to .118 cents per kwh, using the same assumptions and calculations as the Public Staff. The Staff converted the per mmbtu (dekatherm) hedging value to cents per kwh based on an assumed heat rate of 7,000 btu/kwh. For example, $.102/million btu x 7,000 btu/kwh = $.00071/kwh x 100 cents per dollar = .071 cents per kwh. Similarly, $.168/million btu x 7,000 btu/kwh = $.00118/kwh x 100 cents per dollar = .118 cents per kwh.

50. I recommend the Commission use a hedging value of at least .09 cents per kwh in this proceeding, based on the methodology and calculations developed by the Public Staff, with one correction: use a more accurate estimate of the risk-free interest rate of 3.10%. This hedging value of .09 cents should be added to all of the avoided energy rates established in this proceeding. This .09 cent factor provides a reasonable estimate of the value of hedging against fuel price fluctuations during the 12 to 24 months immediately before electricity is purchased – a value that is relevant to, and should be applied to, each year of a QF contract.

CT Cost Adjustments

51. DNCP did not use the "installed cost" of a CT "per kW" from a publicly available source, although such an estimate was available in one of the primary source

documents it relied upon: the report prepared by the Brattle Group and Sargent & Lundy, dated May 15, 2014 (the “Brattle Study”).

52. The Brattle Study, which was provided by DNCP in response to NCSEA Set 1 Data Request 2(f), estimates the installed cost of a CT in Dominion's service area is $977 per kW, as shown on page 26. This estimate, which includes AFDC, is stated in 2018 dollars. It is equivalent to approximately $900/kW in 2014 dollars.

53. DNCP made more than a dozen different adjustments to the Brattle Study, all serving to reduce the cost per kW, as summarized in the “Adjustments” column of Figure 1 on page 5 of Section III of DNCP's March 2 filing. None of these adjustments were necessary to adapt the Brattle cost per kW estimate to the Carolinas and Virginia, since the Brattle Study explicitly sets forth a cost estimate that is already tailored to the geographic area served by Dominion, as shown in column 5 on page 26 of the Brattle Study (labeled “Dominion”).

54. DNCP's largest adjustment replaced the GE turbines used in the Brattle Study with Siemens turbines. I recommend the Commission reject this adjustment even if it accepts some of the other adjustments. All of the Utilities use GE turbines to generate electricity for their customers in North Carolina. There is no need to substitute Siemens turbines for GE turbines, and this adjustment is certainly not “clearly needed” to adapt the Brattle study to the Carolinas and Virginia.

55. DEP and DEC developed their capacity cost calculations using confidential data obtained from two non-public sources: the Electric Power Research Institute (EPRI) TAGWeb Version 3.1 Database and "generic unit cost estimates" provided by the engineering firm Burns & McDonnell (B&M), as explained in DEC's response to Public Staff Data Request 7-3.

56. The EPRI data was based upon a plant capacity of **BEGIN CONFIDENTIAL** [redacted] **MW END CONFIDENTIAL**. This is shown in Attachment to DEC response to Public Staff Data Request 7-3 Rev1 CT Capital Cost_PDSD_CONFIDENTIAL.xlsx at Tab "EPRI Tag" at Cell C8.

57. The <u>Order Setting Parameters</u> requires the Utilities use cost estimates from publicly available sources on a "per kW" basis. DEC and DEP did not use EPRI's per-kW cost estimate. Instead, they took EPRI's total cost estimate for this **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** plant and divided it by **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**. This is shown in Attachment to DEC response to Public Staff Data Request 7-3 Rev1 CT Capital Cost_PDSD_CONFIDENTIAL.xlsx at Tab "Summary of Adjustments" at Cell B9. The effect of this modification was to reduce the cost per kW below the level estimated by EPRI.

58. The rationale offered by DEC and DEP for this modification was that the higher capacity rating was available in some recent 2015 data obtained from B&M, as

explained in DEC's response to Public Staff Data Request 7-3. However, this rationale is inconsistent with the requirement that modifications should be made "only to the extent clearly needed to adapt any such information to the Carolinas and Virginia" as set forth in the Order Setting Parameters at Page 48. I recommend the Commission reject this modification and instead use the same MW capacity EPRI used in developing its per kW cost estimate.

59. The modification proposed by DEC and DEP has the potential to introduce errors. Any potential improvement in accuracy that might potentially be achieved by relying on more recent MW capacity data is outweighed by the potential for distortions being introduced by mixing data from different sources, developed at different times, using different assumptions. For example, a larger capacity generator might require the installation of larger, more costly gas or electrical interconnection facilities than the ones that were assumed in the 2014 B&M data relied upon by DEC and DEP. Similarly, EPRI might have published larger cost estimates for certain facilities if it had assumed these facilities would be used with larger turbines, consistent with the MW capacity assumptions made by DEC and DEP.

CT Economies of Scale and Scope

60. All three Utilities included Economies of Scope in their capacity cost estimates, thereby reducing those estimates on a per-kw basis.

61. DNCP primarily relied upon the Brattle Study. As explained on Page 8, the authors of this study assumed “two turbines at one site (a “2x0”) to capture savings from economies of scale.” Since both turbines were assumed to be constructed at the same time, the cost estimates in the Brattle Study include cost savings from economies of scope as well as economies of scale.

62. Although DNCP did not propose any upward adjustments to remove economies of scope from the Brattle cost data, it did propose downward adjustments to reflect additional economies of scale, corresponding to a 4-unit site rather than a 2-unit site, in two cost categories: electrical interconnection and gas interconnection. As shown in DNCP's response to NCSEA Data Request 1-2, Attachment NCSEA Set 1-2(e).xlsx at Cells E28, E29, H28 and H29, DNCP essentially cut the Brattle cost estimates in half. This adjustment substantially overstates the actual impact of economies of scale, and is particularly excessive in this context, where additional units are being constructed sequentially, rather than simultaneously.

63. DEC and DEP based their calculations on the assumption they would simultaneously build 4 units at 2 different sites, thereby including both economies of scale and scope.

64. I agree with DEC's rationale for not using the EPRI data for a 4-unit site, as DEC explained in its response to Public Staff Data Request 7-3: “Use of the 1 x 4-unit

site data would recognize total economies of scale and scope for building four units at the same site at the same time. Thus, use of this data would violate the Commission's order."

65. I don't agree with DEC's decision to use the EPRI data for 2-unit sites, rather than its data for 1-unit sites. DEC's decision to not use the EPRI data for 1-unit sites seems to be premised on the rationale that it needed to include economies of scale in developing its cost estimates. However, I find no such requirement in the Order Setting Parameters, which allows consideration of "economies of scale for the construction of up to four CTs at one site." This provision appears to me to place an upper limit on economies of scale, but it does not mandate including any particular minimum allowance for economies of scale.

66. I also disagree with DEC's decision to use the EPRI data for 2-unit sites because they could have instead started with the 1-unit data and then made reasonable adjustments for economies of scale in the appropriate categories of "land, site preparation work, roads, buildings and structures, as well as general plant facilities" as identified by DEC in response to Public Staff Data Request 7-3.

67. The adjustments to include economies of scale would need to be computed net of the additional carrying costs (capital costs and property taxes) that would be incurred by acquiring a larger parcel of land, clearing and preparing a larger site, building additional roads, and constructing larger buildings and structures prior to the time when these are needed for the additional units.

68. Carrying costs would need to be considered for the same reason why Allowance For Funds Used During Construction (AFUDC) is accrued from the time capital is invested until the time a project is completed and fully operational. Similar reasoning applies in determining how much benefit will be gained by purchasing in bulk extra materials that are not needed immediately. The bulk purchase may offer a lower price per unit, but this needs to be weighed against the additional carrying costs that would be incurred from the time the items are purchased until the time they are actually needed.

69. Similarly, by acquiring a larger parcel of land to accommodate additional generating units, the per-unit cost of land may be reduced, but additional property taxes, interest, and other carrying costs will be incurred prior to completion of the additional units. A similar situation exists with respect to the cost of clearing and preparing a larger site, building additional roads, and constructing larger buildings and structures prior to the time when these are needed for the additional units. In each of these categories, per-unit cost savings can be achieved, but additional carrying costs will also be incurred, which need to be considered in estimating the net benefit from economies of scale, excluding economies of scope.

70. I recommend the Commission require the Utilities to revise their capacity cost estimates to completely exclude economies of scope, and include an adjustment for economies of scale which is appropriately calculated on a net basis, taking into account

the additional carrying costs that are incurred when sequentially building multiple units at a single large site.

CT Contingency Factor

71. The Utilities did not include a "reasonable contingency adder for a hypothetical plant in relatively early stages of planning" as required in the Order Setting Parameters at Page 9.

72. The contingency adders used by the Utilities are not adequate to ensure that ratepayers are "financially indifferent" between obtaining power from a QF at predictable, contractually fixed prices, and the alternative of obtaining power from a to-be-constructed plant at the early stages of the planning process – particularly since the utility will build and operate the plant under conditions that are similar to a "cost plus" contract where all of the risks and uncertainties are borne by ratepayers, and the utility will normally profit from the project even if it falls behind schedule or goes over budget.

73. In evaluating how large a contingency factor would be reasonable in this context, it's important to remember that the price paid for electricity from a QF is known in advance, while the price that will be paid for electricity generated by the utility is not. Given this fundamental difference, for ratepayers to be "indifferent between purchases of QF power versus construction and rate basing of utility-built resources" as referenced in

in the Order Setting Parameters at Page 21, the contingency adder must be large enough to leave ratepayers indifferent with respect to the risks and uncertainties associated with power to be generated by a hypothetical plant in the relatively early stages of planning.

74. When power is obtained from utility-owned plants that have not yet been constructed, ratepayers bear nearly all of the risks associated with any factors that are not, or cannot be, known before the plant is finished and operational, including what the final design will be, how long it will take to construct the plant, what the total cost of construction will be, whether the plant design will be successful and whether the plant will function as planned.

75. Ratepayers bear the risk of delays in receiving equipment and completing construction in a timely manner (e.g. through the accrual of additional AFUDC for the duration of any delay). Ratepayers also bear the risk of construction cost over-runs, whether due to underestimation of costs, unanticipated construction problems, difficulties obtaining an appropriate site, difficulties obtaining regulatory approvals, difficulties or delays in connecting to the planned fuel supply, unanticipated shortages of qualified labor, work stoppages or labor strife, and a myriad of other potential problems.

76. Except in rare cases of management imprudence, all of these types of risks are borne by ratepayers, not stockholders. In contrast, none of these types of risks are borne by ratepayers in the case of power acquired at tariffed rates from small QF's. Accordingly, in order to leave ratepayers "financially indifferent," a reasonable

contingency factor of at least 15 to 20% should be added to the per-kw capacity cost estimates, in order to compensate ratepayers for these risks and uncertainties.

CT Useful Life

77. The Utilities developed their avoided capacity cost calculations using longer economic lives than were used in the sources they relied upon for other aspects of their computations. For example, EPRI's estimate of the useful life of a CT is **BEGIN CONFIDENTIAL** [redacted], **END CONFIDENTIAL** as shown in Attachment to DEC response to Public Staff Data Request 7-3 Rev1 CT Capital Cost_PDSD_CONFIDENTIAL.xlsx at Tab "EPRI Tag" at Cells C14, D14, E14 and F14. Similarly, the Brattle Study used a "20-year economic life" as shown in the Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, May 15, 2014, at Page 39. In contrast, DEC and DEP assumed a **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** year life and DNCP used a 36 year life. This had the effect of reducing their cost estimates on a per-kwh basis.

78. No justification was provided in the March 2 filings for using these longer lives. In the absence of detailed studies supporting longer economic lives, I recommend the Commission use the economic lives set forth in the primary sources relied upon by the Utilities (20 years for DNCP and **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** years for DEC and DEP).

FURTHER THE AFFIANT SAYETH NOT.

This the 24th day of July, 2015.

Ben Johnson, Ph.D.

Sworn to and subscribed before me
this the 24th day of July, 2015.

Notary Public

My commission expires: 8-27-16

(Seal)

J. BAGUCHINSKY
MY COMMISSION # EE 830803
EXPIRES: August 27, 2016
Bonded Thru Notary Public Underwriters

NOTARY PUBLIC STATE OF FLORIDA

CERTIFICATE OF SERVICE

The undersigned certifies that she has served a copy of the foregoing **AFFIDAVIT OF BEN JOHNSON** upon the parties of record in this proceeding, or their attorneys, by electronic mail.

This 7th day of August, 2015.

/s Charlotte A. Mitchell