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NC SUSTAINABLE
ENERGY ASSOCIATION

February 7, 2013

FILED
FEB 07 2013
Clerk's Office
N.C. Utilities Commission

Honorable Gail Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: North Carolina Sustainable Energy Association ("NCSEA") Avoided Cost Comments
(Commission Docket No. E-100, Sub 136)

Dear Ms. Mount:

Enclosed for filing are:

- An original and thirty (30) copies of the **confidential** versions of NCSEA's Comments and exhibits.
- An original and two (2) copies of the **public, redacted** versions of NCSEA's Comments and exhibits.

The information redacted from the public version of the Comments and exhibits has been removed by NCSEA at the direction of Duke Energy Carolinas and Progress Energy Carolinas. Any requests for the confidential versions of the Comments and exhibits should be directed to Duke Energy Carolinas and Progress Energy Carolinas.

Sincerely,

Michael D. Youth
Counsel & Policy Director

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 136

In the Matter of:	)	
Biennial Determination of Avoided Cost Rates	)	**NCSEA'S COMMENTS**
for Electric Utility Purchases from Qualifying	)	**[PUBLIC VERSION]**
Facilities - 2012	)	

NCSEA'S COMMENTS

Pursuant to the North Carolina Utilities Commission's ("Commission") 18 June 2012 *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing*, the North Carolina Sustainable Energy Association ("NCSEA") sought to intervene in this proceeding and was permitted to intervene by Commission order dated 29 June 2012. Pursuant to the Commission's 28 December 2012 *Order Establishing Discovery Schedule and Extending Times*, NCSEA now submits comments and exhibits. NCSEA's comments, which are based predominantly on information provided by Progress Energy Carolinas, Inc. ("PEC") and Duke Energy Carolinas, LLC ("DEC") in response to NCSEA's data requests, address a number of questions related to PEC's and DEC's calculation of their proposed avoided cost rates – questions that merit Commission scrutiny, including:

- Did PEC's and DEC's collaborative approach in proposing new rates violate the "independent operation" provision within the PEC/DEC Code of Conduct?
- Was the PEC/DEC joint assumption of a higher combustion turbine ("CT") rating appropriate?
- Was the PEC/DEC joint assumption of a 35 year useful life for a CT appropriate?
- Was a reduction of owner's contingency costs appropriate?

- Was the exclusion of costs associated with transmission system upgrades appropriate?
- Was DEC's assumed discount rate appropriate?
- Was it appropriate for PEC and DEC to exclude hedging costs from their development of proposed avoided *energy* costs?

NCSEA believes that Commission scrutiny of these issues will lead it to conclude that PEC's and DEC's sharply lower proposed avoided cost rates must be revised upward so as to more accurately reflect PEC's and DEC's actual avoided capacity and energy costs. NCSEA's comments also urge the Commission to adopt the outcomes advocated for by the Renewable Energy Group with respect to (1) adjusting the performance adjustment factor for solar and wind, (2) addressing the "cut-off" dates embedded in the IOUs' proposed rate schedules, and (3) amending the IOUs' standard contract terms and conditions.

THE CLEAN ENERGY INDUSTRY'S INTEREST IN THIS PROCEEDING

North Carolina's clean energy sector has grown substantially since enactment of the Renewable Energy and Energy Efficiency Portfolio Standard ("REPS law") in 2007. This sector has become a significant contributor to the State's economy. NCSEA's 2012 *North Carolina Clean Energy Industries Census*[1]("2012 Census") found that "North Carolina's clean energy sector accounts for over 15,200 full-time equivalent (FTE) employees as of September, 2012[,]" Exhibit ("Ex.") A at P2, and "conservatively generated over $3.7 billion in North Carolina annual gross revenue" in 2012. *Id.* Within this sector, small power producers constitute a growing subsector which accounted for at

[1] The full Census can be viewed at http://energync.org/assets/files/podcast_episodes/north-carolina-renewable-energy-energy-efficiency-industries-census/2012-nc-clean-energy-industries-census.pdf (accessed on 27 January 2013).

least $100 million in private investment in the State during tax year 2011 alone. *See NCSEA's Reply Brief in Opposition to Progress Energy Carolina's Motion,* p. 4, Commission Docket No. E-100, Sub 136 (5 December 2012) (bar graph based on North Carolina Department of Revenue data showing annual investment).

The 2012 Census also found that, as in so many industry sectors,

> [a] common theme among respondents was the importance of stability and predictability to the clean energy industry. Clean energy companies want laws and regulations that allow[] them to focus resources on developing their business, rather than reformulating their business plans in reaction to policy changes.

Ex. A at P2.

It should come as no surprise that the clean energy industry preference for stability and predictability extends to avoided cost rates – rates that shape the entire clean energy landscape. These rates are intended to approximate "the incremental cost to the electric utility of the electric energy which, but for the purchase from a small power producer, the utility would generate or purchase from another source." N.C. Gen. Stat. § 62-156. Perhaps obviously, avoided cost rates set the prices small power producers are paid for the electricity they generate. Less obviously, avoided cost rates play a significant role in determining whether the utilities' proposed demand-side management and energy efficiency ("DSM/EE") measures and programs are deemed cost effective,[2]

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[2] For example, the cost recovery and incentive mechanism employed by the Commission for PEC states:

> PEC Mech 36. The per kW avoided capacity costs and the per kWh avoided energy costs used to calculate net savings for a vintage year shall be determined annually by PEC using comparable methodologies to those in the most recently approved biennial avoided cost proceeding. PEC's assumptions used in these methodologies, as well as the methodologies, are subject to the Public Staff's review and acceptance at the time PEC

which in turn impacts the utilities' DSM/EE projections in their integrated resource plans ("IRPs"). Avoided cost rates also affect the standby charges utilities charge their net-metering customers.[3]

When one considers in tandem (a) how extensively avoided cost rates shape the clean energy landscape *and* (b) the clean energy industry's need for stability and predictability, it is unsurprising that NCSEA's members are alarmed by PEC's and DEC's unpredictably sharp drops in their proposed avoided cost rates. Given the sharp drops, the clean energy industry has an understandable interest in seeing that the Commission scrutinizes the utilities' proposed rates to ensure that only fair and non-discriminatory rates are ultimately approved.

THE SHARP DROP IN PEC'S AND DEC'S PROPOSED AVOIDED COST RATES

Commission Rule R8-67(b)(1)(v) requires electric power suppliers to include "the current and projected avoided cost rates for each year" in their REPS compliance plans. On 4 September 2012, PEC and DEC filed their 2012 REPS compliance plans in

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> files its petition for annual cost recovery pursuant to Rule R8-69 and this Mechanism.

As avoided cost rates drop, the benefit per dollar of cost of DSM/EE programs drops as well. This makes it more difficult for new measures and new programs to pass the various cost effectiveness tests employed by the Commission. Without approval of enticing new measures and programs, PEC's and DEC's respective opt-out "problems" will persist and attainment of their DSM/EE goals may be thwarted.

[3] Thus, for example, PEC's "New Rider SS includes a monthly Generation Reserve Charge of $0.98 per kW of standby service for both customers above and below 60% planning capacity factor. . . . This equivalent reservation charge is calculated by applying PEC's 15% generation planning reserve margin to PEC's marginal generation cost that was calculated pursuant to the methodology approved in the Commission's order for Progress Energy in the most recent avoided cost proceeding, Docket E-100, Sub 127." *Pre-filed Direct Testimony of Michael T. O'Sheasy*, p. 51, Commission Docket No. E-2, Sub 1023 (12 October 2012).

Commission Docket No. E-100, Sub 137. Neither PEC nor DEC projected a drop in avoided costs rates in its filing. Instead, as evidenced by the two excerpts *infra*, both companies' September filings projected avoided cost rates to remain at their current Commission-approved levels through the 2013-2014 biennium.

VII. CURRENT AND PROJECTED AVOIDED COST RATES

The current and projected avoided cost rates represent the annualized avoided cost rates for Cogeneration and Small Power Producer (CSP) Schedule CSP-27, approved in the Commission Order issued in Docket No. E-100, Sub 127 in August 2011.

Table 7: Annualized Capacity and Energy Rates (cents per KWh)

	2012 (Current)	2013 (Projected)	2014 (Projected)
Variable Rate	5.786¢	5.786¢	5.786¢
5 Year	6.184¢	6.184¢	6.184¢
10 Year	6.816¢	6.816¢	6.816¢
15 Year	7.286¢	7.286¢	7.286¢

A. CURRENT AND PROJECTED AVOIDED COST RATES

The current and projected avoided cost rates represent the annualized avoided cost rates in Schedule PP-N (NC), Distribution Interconnection, approved in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued in Docket No. E-100, Sub 127 (July 27, 2011).

Table 2: Annualized Capacity and Energy Rates (cents per KWh)

	2012 (Current)	2013 (Projected)	2014 (Projected)
Variable Rate	5.48¢	5.48¢	5.48¢
5 Year	5.63¢	5.63¢	5.63¢
10 Year	6.28¢	6.28¢	6.28¢
15 Year	6.63¢	6.63¢	6.63¢
20 Year (extrapolated)	7.02¢	7.02¢	7.02¢
25 Year (extrapolated)	7.42¢	7.42¢	7.42¢

See Ex. B (containing more complete excerpts of the utilities' public 2012 REPS compliance plan filings). PEC's and DEC's September filings stand in stark contrast to Dominion North Carolina Power's ("DNCP") 2012 REPS compliance plan filing, where a decline in rates was actually projected (compare, for example, the approved 2013 on-peak rate of $54.84 set out in DNCP's Figure 1.6.1 below with the projected 2013 on-peak rate of $47.22 set out in DNCP's Figure 1.6.2 below):

1.6 AVOIDED COST RATES

In accordance with Rule R8-67 (b) (v), the Company provides the following statement regarding the current and projected avoided cost rates for each year.

Figure 1:6.1 identifies the projected avoided energy and capacity cost from the Biennial Determination of Avoided Costs Rates for Electric Utility Purchases from Qualifying Facilities – 2010 proceeding E-100, SUB 127 before the North Carolina Utilities Commission. Avoided energy and capacity cost as used in the 2012 IRP are given below in Figure 1.6.2.

Figure 1.6.1 PROJECTED AVOIDED ENERGY AND CAPACITY COST (from E-100 sub 127)

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2012	52.31	40.09	20.23
2013	54.84	41.19	8.41
2014	60.13	45.22	18.27

Figure 1.6.2 PROJECTED AVOIDED ENERGY AND CAPACITY COST (from NC 2012 IRP)

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2012	44.39	29.51	20.05
2013	47.22	33.80	8.30
2014	50.38	37.97	30.58

Id.

Despite their September REPS compliance filings, PEC and DEC were already working as early as 29 August 2012 to develop common inputs that would drastically lower their proposed avoided cost rates. Ex. C at P45-P48. By 2 October 2012, PEC was internally quantifying the sharp energy drop it would propose in its 1 November 2012 avoided cost filing:

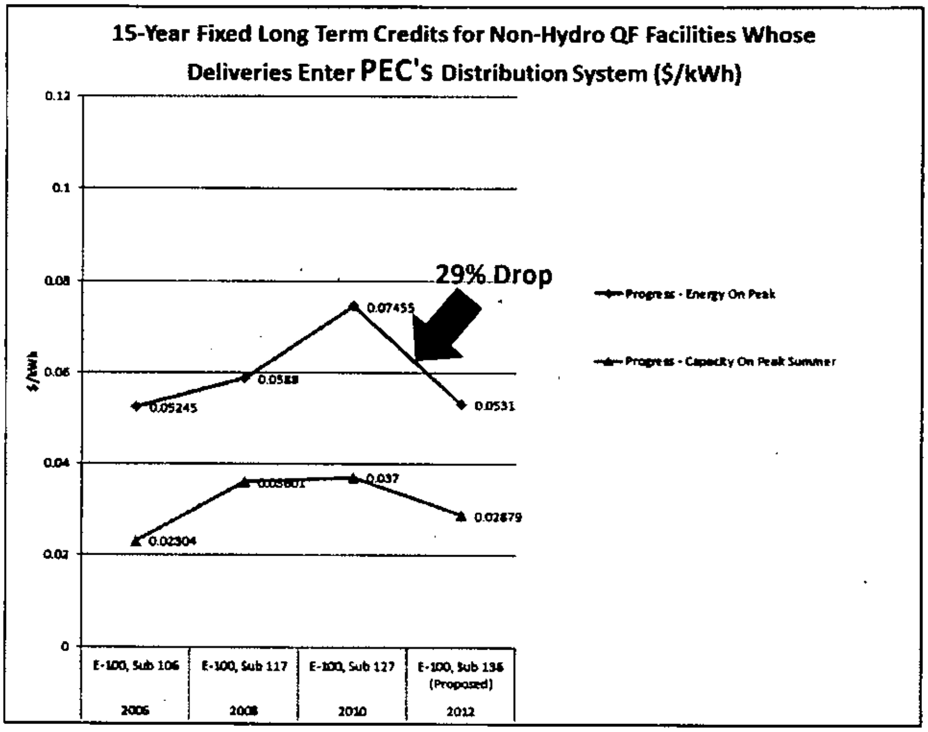
> On a ¢/ kwhr basis, compared to the 2010 CSP filing, incremental energy seems to be [redacted]¢ lower on peak, and roughly [redacted]¢ lower off- peak. This translates to a roughly [redacted]% - [redacted]% decline in avoided incremental energy costs.

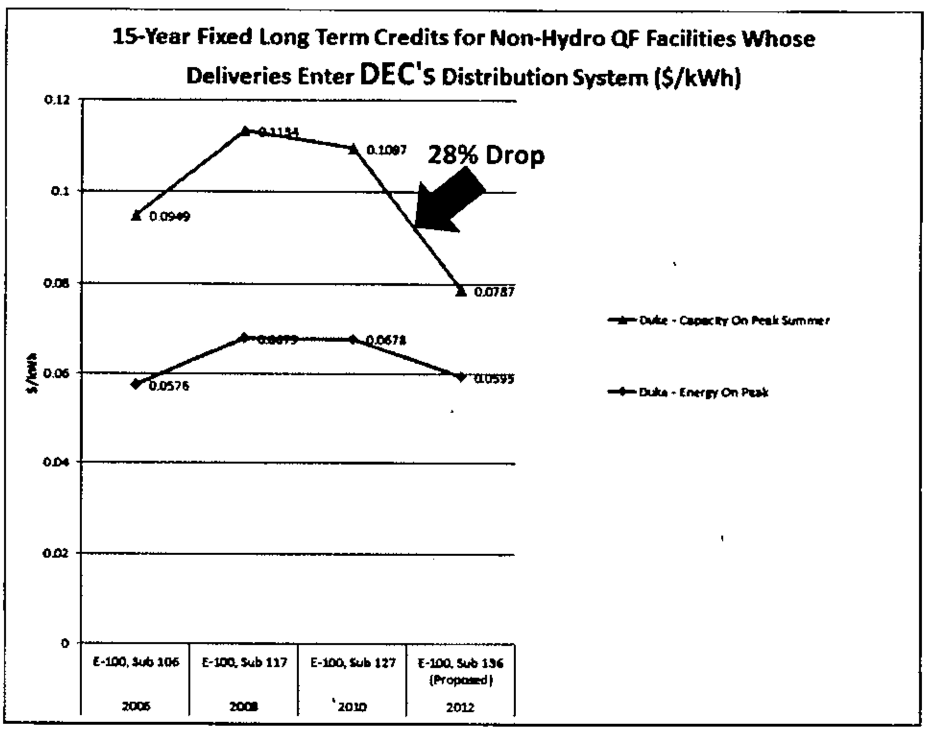
Ex. C at P42 (email from PEC's Lead Regulatory Specialist for Utility Regulatory Planning, [redacted]). On the eve of filing their proposed rates, PEC and DEC were aware that their proposed rates would be poorly received by small power producers/qualified facilities ("QFs"), as evidenced by the following email:

> Both DEC and PEC will file updates to their avoided cost rates with the NCUC tomorrow. These rates set the price at which DEC and PEC purchase power from qualifying facilities. The utilities have coordinated to ensure consistent inputs into the avoided cost calculations and, as a result, the proposed rates will be fairly consistent, with DEC's rates being just slightly higher than PEC's. However, PEC's filing will propose a ~20% decrease compared to the current rates and DEC's filing will propose a ~10%-15% decrease. *This will not be popular among the qualifying facilities.*

Ex. C at P139 (email from Duke's Manager of Rates and Regulatory Strategy, [redacted]) (emphasis added).

The graphs, *infra*, help to illustrate the *magnitude* of the drops in key components of PEC's and DEC's proposed overall rates. The graphs depict the rates approved in the 2006, 2008, and 2010 avoided cost proceedings *and* the 2012 proposed rates that apply to small power producers/QFs who deliver electricity into PEC's and DEC's distribution systems during summer on-peak periods under 15-year fixed term agreements.





Additional comparisons of PEC's and DEC's 2012 proposed rates to the 2010 approved rates can be found in Ex. C at P86, P99-P100, P108-P109, P118-P120, P128, P130, P146

(PEC's internal comparisons) and at P56-P57, P86, P118-P119, P130, P137 (DEC's internal comparisons).

PEC and DEC might offer the following overly simple explanation for their lower proposed rates: Lower costs associated with building and operating a CT plus lower natural gas fuel prices equals lower avoided cost rates. However, such a simple explanation is inadequate to explain the *magnitude* of the drops in their proposed rates. In any attempt to explain the *magnitude* of the drops, the role of PEC's and DEC's questionable assumptions becomes evident. Thus, for example, in a 31 October 2012 email, Duke's Manager of Rates and Regulatory Strategy, [redacted], explained the chief causes of PEC's proposed lower rates as follows:

> The primary drivers for the decrease for PEC are – lower gas prices, higher ratings for the new avoided CT units without a significant increase in the total cost of the units (leading to lower per kw costs), and an increase in the *assumed* life of the avoided CT units from 25 years to 35 years.

Ex. C at P131 (emphasis added).

Neither NCSEA nor its membership questions the fact that lower natural gas prices mean the avoided cost rates ultimately approved in this proceeding will be lower than the 2010 approved rates. NCSEA and its membership do, however, believe that scrutiny of PEC's and DEC's proposed rates will show them to be unreasonably low – particularly in light of the general upward trend in CT prices. Commission scrutiny should lead, in any final order, to a significant reduction in the *magnitude* of the PEC and DEC rate drops.

<u>PORTIONS OF PEC'S AND DEC'S FILINGS THAT MERIT SCRUTINY</u>

A. The Commission Should Examine Whether PEC's and DEC's Collaborative Approach in Proposing New Rates Violated the PEC/DEC Code of Conduct. If the Coordination was Violative, the Commission Should Unwind PEC's and DEC's Proposed Rates to Eliminate the Impact of the Coordination.

The PEC/DEC Code of Conduct contains a provision entitled "Separation" which provides in pertinent part:

> DEC, PEC, Duke Energy, and the other Affiliates shall operate independently of each other . . . to the maximum extent practicable.

Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, § III.A.1. of Appendix A to Appendix A, Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986 (29 June 2012). In connection with their proposed avoided cost rates, there is no question that PEC and DEC "coordinated to ensure consistent inputs into the avoided cost calculations" and to produce "fairly consistent" proposed rates. Ex. C at P139 (31 October 2012 email from Duke's Manager of Rates and Regulatory Strategy, [redacted]). As has already been mentioned, this coordination resulted in sharply lower PEC and DEC proposed rates – rates which NCSEA believes are lower than either utility would have proposed had they operated independently to the maximum extent practicable. While it is unclear to NCSEA whether PEC's and DEC's coordination runs afoul of their Code of Conduct, it is clear that Commission scrutiny is merited.

The Code of Conduct's "independent operation" provision quoted above is somewhat ambiguous. The PEC/DEC Regulatory Conditions, however, offer guidance as to how the "independent operation" provision should be construed. The Regulatory Conditions are "intended to protect the jurisdiction of the Commission against the risk of federal preemption as a result of the Merger, including risks related to agreements and transactions between and among DEC, PEC, and any of their Affiliates[.]" *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, § III of Appendix A (Preamble), Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986. While no Regulatory Condition directly addresses the avoided cost docket, several conditions indicate that PEC/DEC collaborative work that gives the impression that PEC and DEC are in substance operating "a single integrated electric system[,]" or are "joint[ly] planning[,]" or working toward "any equalization of PEC's and DEC's production costs or rates" is problematic. *Id.* at § III of Appendix A, Conditions 3.5[4]; 3.6(a) & (b)[5]; 3.10(b)[6]; and § IV of Appendix A, Conditions 4.1[7]; 4.9.[8] NCSEA believes these conditions help to flesh out the meaning of the "independent operation" provision in the Code of Conduct.

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[4] "DEC and PEC shall each retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law."

[5] DEC and PEC "shall continue to serve [their respective] Retail Native Load Customers with the lowest-cost power it can reasonably . . . obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers."

[6] "No agreement shall be entered into, . . . by or on behalf of DEC or PEC, that . . . commits DEC or PEC to, or involves either of them in, joint planning, coordination, dispatch or operation of generation, transmission, or distribution facilities with each other[.]"

[7] "DEC and PEC acknowledge that the Commission's approval of the merger and the transfer of dispatch control from PEC to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA, control area or transmission system, (c) joint planning or joint development of generation or transmission, . . . or (f) any equalization of DEC's and PEC's production costs or rates."

[8] "Neither DEC, [nor] PEC . . . shall assert in any forum . . . that any aspect of the JDA or successor document is intended to diminish or alter the jurisdiction or authority of the Commission over DEC and PEC, including, among other things, the jurisdiction and authority of the Commission to . . . require DEC and PEC to engage separately in least cost integrated resource planning."

PEC's and DEC's collaboration on their proposed avoided cost rate calculations appears to contradict the mandate that they operate independently of each other to the maximum extent practicable. Their coordination lends itself to an impression that they are jointly planning the operation of a single integrated PEC/DEC electric system and that, as part of this joint planning, they are working to equalize production costs and rates. PEC's and DEC's collaboration on calculating the cost to build and operate a CT and on deriving a natural gas price forecast exemplify the types of coordination that, in the aggregate, give rise to this impression. Evidence of each of these collaborative efforts is provided below.

1. PEC's and DEC's Joint Use of An Average CT Cost

PEC and DEC collaborated to calculate one "average" cost to build and operate a CT that both companies used as a basis for proposing avoided capacity cost rates. In a 4 September 2012 email, DEC's Engineering Manager of CTCC Projects, [redacted], wrote: "My understanding is that [DEC's Director of Carolinas Resource Planning and Analytics,] [redacted] would like to use an average normalized costs PEC and DEC with sufficient backup." Ex. C at P2. Mr. [redacted] understanding was confirmed by 29 October 2012 comments written by Duke employee [redacted] and attached to an email:

> Capital Cost per kW shows a decrease. Capital costs for the "peaker" unit, which is a [redacted] MW Simple Cycle CT were provided by [redacted] and [redacted] in the IRP and Analytical department. The CT fixed O&M expenses that are used in this study were also provided by [redacted] and [redacted]. *PEC and DEC are utilizing the same base construction costs.*

Ex. C at P133 (emphasis added). Mr [redacted] understanding was also confirmed by PEC's and DEC's respective responses to an NCSEA data request:

> In terms of input data, prior to the merger, DEC and PEC each individually commissioned third party engineering firms to provide cost estimates for new generation options including estimates for the installed cost of a gas fired simple cycle peaker. After the merger, in the development of common inputs, *the companies settled on an averaging of the two studies which resulted in slightly higher CT capital costs for PEC and slightly lower costs for DEC as compared to the individual studies.*

Ex. D at P3-P4 (emphasis added).[9]

PEC's and DEC's joint use of an "average" CT cost required coordination on a number of issues, including for example joint determination of the useful life of the "average" CT, joint determination of whether to include system upgrade costs, and joint determination of an approach to calculating a discount rate. Evidence of PEC's and DEC's collaboration on each of these issues follows:

a. PEC's and DEC's Use of a Common CT Useful Life

On 18 October 2012, PEC's Lead Regulatory Specialist for Utility Regulatory Planning, [redacted], wrote in an email:

> This relates to a PEC avoided cost tariff to purchase power from small qualified facilities to be filed with the NCUC on November 1st. The useful life of a CT drives the annual capacity cost in this tariff (based on the cost of an avoided peaker). For the last several years, the useful life of a CT has been assumed to be 25 years, applied as a modeling assumption for this tariff as well as economic analysis and resource planning analysis. . . . Currently, DEC is going through this same process on their tariff, and they have been using 30 years. *This round though, PEC and DEC will both use the same CT technology and cost assumptions, and the same useful life.*

[9] While NCSEA is hesitant to raise any argument that might result in even lower avoided cost rates in PEC's territory, it is critically important that this and future proceedings be governed by rules. Consequently, it seems appropriate to ask if it was proper under Regulatory Conditions 3.5 and 3.6 for PEC to average its study results with DEC's study results where the average resulted in "slightly higher" proposed avoided cost rates to be borne by PEC's customers.

Ex. C at P75-P76 (emphasis added). Ultimately, just days before their filings, PEC and DEC jointly determined that a book life of 35 years was appropriate for a CT. Ex. D at P3-P4 (PEC and DEC responses to NCSEA Data Request 1-3).

b. DEC's Adoption of PEC Practice of Excluding System Upgrade Costs

In response to an NCSEA data request, DEC wrote: "*DEC adopted the assumption that PEC has used in prior filings* of including only transmission and natural gas infrastructure costs related to the avoided simple cycle peaker and *not to include an estimate of system related costs on the gas and transmission systems*." Ex. D at P4 (emphasis added). In a 4 September 2012 email, DEC's Engineering Manager of CTCC Projects, [redacted], wrote in an email: "Per [DEC Director of Carolinas Resource Planning and Analytics [redacted]'s] direction, I have included the cost of the on-site switchyard and the tie-in. . . . [DEC employee [redacted]] is uncomfortable with the assumption that the system upgrade costs should not be included in the Avoided Cost and is following up further." Ex. C at P1.

c. PEC's Adoption of DEC Approach to Calculating Discount Rate

In response to an NCSEA data request, PEC wrote that, as to the calculation of its discount rate, PEC "*adopted DEC's approach* of using capital structure and costs of debt and preferred capital from its most recent surveillance reports filed with the NCUC[.]" Ex. D at P9 (emphasis added).

2. PEC's and DEC's Joint Use of a Common Natural Gas Price Forecast

In addition to collaborating to calculate one "average" cost to build and operate a CT, PEC and DEC coordinated to derive a common natural gas price forecast that both companies used as a basis for proposing avoided energy cost rates. In a 17 September

2012 email, DEC's Director of Carolinas Resource Planning and Analytics, [redacted], wrote, "As you know we are filing an avoided cost rate on November 1 for both DEC and PEC. *As part of that filing we are seeking to use a common gas price forecast for both DEC and PEC*." Ex. C at P9 (emphasis added). On 19 September 2012, this same director wrote another email: "Remember to use consistent [Henry Hub] gas prices between DEC and PEC throughout the analysis based on these prices and then based on the DEC fundamental curves 2019 and beyond." Ex. C at P10.

As the foregoing examples illustrate, PEC's and DEC's "development of common inputs," Ex. D at P3-P4, the two companies did not operate independently to the maximum extent practicable. Rather, PEC's and DEC's coordination appears – in large part – to have been aimed at equalizing PEC's and DEC's avoided cost rates. Evidence of this aim can be found in several emails and merits Commission scrutiny. In a 19 October 2012 email, PEC's Lead Regulatory Specialist for Utility Regulatory Planning, [redacted], wrote: "Here is recent comparison of PEC & DEC all in proposed rates (combined capacity & energy), using draft files from [redacted][.]" Ex. C at P84. A tabular comparison attached to the email reflects an equalization of PEC's and DEC's then-proposed non-hydro 15-year fixed rates – evidenced by the fact that in the "DEC vs. PEC Higher (Lower)" column, there is a 0% difference between the two companies' rates. *Id.* at P86. Next, two days before PEC's and DEC's 1 November 2012 filings, in a 30 October 2012 email, Ms. [redacted] wrote: "Both tariffs now reflect the 35 year useful life assumption, and *the all-in rates are 1% to 6% apart between the 2 utilities*." *Id.* at P126, P130 (emphasis added). Mention of the rate differential points to an intent to minimize it. Finally, as already recited *supra*, on 31 October 2012, Duke's Manager of Rates and Regulatory Strategy, [redacted], wrote:

> The utilities have coordinated to ensure consistent inputs into the avoided cost calculations and, as a result, *the proposed rates will be fairly consistent*, with DEC's rates being just slightly higher than PEC's.

Ex. C at P139 (emphasis added); *see* Ex. C at P131 ("rates for the two utilities are fairly comparable").

Substantial evidence shows that, with regard to their proposed avoided cost rates, PEC and DEC operated in near lockstep rather than independently to the maximum extent practicable. Given this evidence, NCSEA believes the Commission should construe the "independent operation" provision in the PEC/DEC Code of Conduct and determine whether PEC's and DEC's extensive collaboration and coordination violated the provision. In the event that their development of common inputs was violative, the Commission should unwind PEC's and DEC's proposed rates to eliminate the impact of the coordination.

B. The Commission Should Examine A Number of PEC's and DEC's Inputs and Assumptions to Determine Whether They Are Reasonable. Where the Inputs and Assumptions Are Not Reasonable, the Commission Should Require PEC and DEC to Use a Reasonable Input or Assumption.

Regardless of whether the Commission determines that PEC's and DEC's coordination was violative of their Code of Conduct or not, the Commission should scrutinize the jointly developed inputs and assumptions on which PEC and DEC based their proposed avoided cost rates to determine whether these inputs and assumptions are appropriate. Specifically, at a minimum, the Commission should examine the following aspects of PEC's and DEC's proposed avoided *capacity* costs:

- Was the joint assumption of a higher CT rating appropriate?

- Was the joint assumption of a 35 year useful life for a CT appropriate?

- Was a reduction of owner's contingency costs appropriate?

- Was the exclusion of costs associated with transmission system upgrades appropriate?

- Was DEC's assumed discount rate appropriate?

The Commission should also examine whether it was appropriate for PEC and DEC to exclude consideration of hedging costs from their development of proposed avoided *energy* costs.

Substantial evidence, attached hereto as exhibits, suggests PEC's and DEC's jointly developed inputs and assumptions were not appropriate and that their avoided cost rates should instead be based on the following alternative inputs and assumptions:

- PEC and DEC should use lower CT ratings that are consistent with their 2012 IRP assumptions.

- The assumed useful life of a CT should continue to be 25 years for PEC and 30 years for DEC.

- DEC should have used the full estimated owner's contingency costs that were included in the Sargent & Lundy engineering study it commissioned.[10]

- DEC should have included transmission system upgrade costs so as to be consistent with its 2012 IRP assumptions.[11]

- DEC should have used a discount rate that is more comparable to PEC's and DNCP's discount rates.

[10] To the extent the contingency costs PEC used are different from those it was provided by its engineering firm, the Commission should scrutinize PEC's reduction as well.
[11] The Commission should also examine whether PEC's practice of excluding transmission system upgrade costs is appropriate.

- PEC and DEC should have incorporated hedging costs into their variable fuel/operating and maintenance costs.

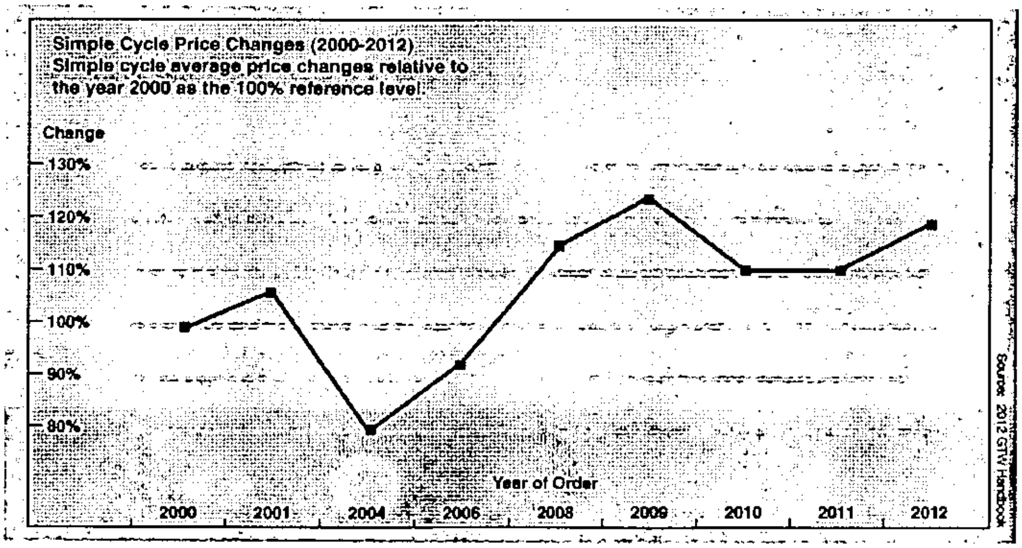
Each of these aspects of PEC's and DEC's proposed avoided cost rate calculations is addressed in more detail below.

1. PEC and DEC Should Use Lower CT Ratings That Are Consistent with Their 2012 IRP Assumptions.

PEC's and DEC's sharp drops in proposed rates are based on sharply lower per kW CT construction costs – despite the fact that CTs are generally more expensive to build now than they were at the time of the 2010 avoided cost proceeding. PEC and DEC were able to, in essence, manufacture the lower per kW construction costs by increasing the summer capacity of the "average" CT they used to model their avoided costs. Because the higher-rated CT used to derive PEC's and DEC's sharply lower proposed avoided cost rates is significantly different from the CTs each separately used to derive their 2010 avoided cost rates and from the "generic" CTs each separately used as an input for its 2012 IRP, the Commission should scrutinize the ratings change and consider directing both PEC and DEC to use CT ratings consistent with those used in their 2012 IRP filings.

Gas Turbine World's *2012 GTW Handbook*[12] includes the following graph illustrating the fact that CT prices trended upward in 2012:

[12] The *GTW Handbook* is recognized as a relevant resource by the Public Staff and the utilities. *See, e.g.*, Ex. C at P79-P80 (showing that both DEC and the Public Staff referenced the *2010 GTW Handbook* during the 2010 avoided cost proceeding).



2012 GTW Handbook, Vol. 29, p. 36, Pequot Publishing Inc. (December 2011) (relevant excerpt attached as Ex. E). Despite this general upward trend, "DEC's cost per KW in the current filing is $[redacted] vs $[redacted] in the 2010 filing[.]" Ex. C at P77 (19 October 2012 email from Duke employee [redacted]). As Duke employee [redacted] noted: "[T]he Public Staff is going to want the differences explained." *Id.*

A 18 October 2012 email from PEC's Lead Regulatory Specialist for Utility Regulatory Planning, [redacted], explains how a significant ratings increase can effectively negate upward trending construction costs: "While the construction costs of the average generic CT / site (GE 7FA machines) of $[redacted] per unit reflects a [redacted]% annual escalation rate from the $[redacted] / unit in the 2010 CSP 27, the [redacted]% to [redacted]% increase in CT ratings drove an overall [redacted]% decline in capacity costs / kw vs. the 2010 cost." Ex. C at P62.

In a 30 October 2012 email, Ms. Deshmukh translated the [redacted]% decline into dollars and cents:

> Of the roughly [redacted] – [redacted] ¢ / kwhr decrease in total avoided cost rates between proposed vs. last approved PEC rates, roughly [redacted] – [redacted] ¢ /

> kwhr or a [redacted] of the total change was driven by <u>lower avoided capacity rates</u>. Most of this ([redacted] – [redacted] ¢ / kwhr was driven 50:50 by the two changes: <u>Unit ratings:</u> Increased by roughly [redacted]% - [redacted]% across winter & summer ratings.
>
> | CT Rating/unit | Summer | Winter |
> |---|---|---|
> | CSP 27, 5000F | [redacted] | [redacted] |
> | CSP 29, 7FA (proposed) | [redacted] | [redacted] |
>
> [and] <u>CT useful life</u>[.]

Ex. C at P126-P127. In sum, PEC's and DEC's CT ratings change had a significant effect on their proposed rates, accounting – for example – for approximately [redacted] – [redacted] ¢/kWh or [redacted] of PEC's overall decline in its proposed avoided cost rates.[13]

PEC's and DEC's CT rating change merits Commission scrutiny for at least two reasons: First, the generic summer rated [redacted] MW single-unit CT[14] used jointly by PEC and DEC in this proceeding is substantially larger than the CTs either company used as an input for its (a) 2010 avoided cost rate calculations *or* (b) its 2012 IRP reserve margin calculations.[15] Second, the economies of scale being achieved by the ratings change are inconsistent with what the *2012 GTW Handbook* indicates is achievable.

In DEC's 2012 IRP, it notes that

> [a]s part of the NCUC's approval of the 2010 IRP, [DEC] and [PEC] were ordered to perform a quantitative analysis of the utilities' respective reserve margins and to provide the study results in the companies' 2012

[13] PEC acknowledges that the changed CT rating "was a significant driver in the decrease in the avoided capital costs for PEC." Ex. D at P3 (PEC response to NCSEA Data Request 1-3).

[14] A "peaker" plant facility is assumed to be comprised of 4 individual CT units. Multiplying the single unit rating of 201 MW by four accounts for the [redacted] MW rating that appears in some PEC/DEC internal emails and email attachments that are quoted or referenced in this filing.

[15] With regard to PEC, [redacted] MW is also substantially larger than any CT the utility actually plans to add to its fleet in the near future – as evidenced by PEC's representations in its 25 June 2012 confidential filing in this docket.

> IRPs. . . . [DEC and PEC separately] hired Astrape, a consultant that specializes in reserve margin analysis, to perform the quantitative analys[e]s.

The [Public] Duke Energy Carolinas Integrated Resource Plan (Annual Report), p. 85, Commission Docket No. E-100, Sub 137 (4 September 2012). To enable Astrape to produce study results, both PEC and DEC had to provide Astrape with generic CT characteristics for use in calculating the carrying cost of capacity. PEC directed Astrape to use a CT with a summer capacity rating of [redacted] MW, while DEC directed Astrape to use a CT with a summer capacity rating of [redacted] MW. Ex. F at P2-P3, P5-P6 (excerpts from Astrape Study Reports). Despite use of these lower-rated CTs as inputs for their 2012 IRP reserve margin studies, PEC and DEC chose not to use the lower-rated CTs in this proceeding.[16] This is inconsistent with their past practice. In a data request, NCSEA asked, "[D]id you[, in 2008 and 2010,] use the same generic CT characteristics for both your calculation of avoided costs and your preparation of the IRP you filed the same year[?]" Ex. D at P12, P14. PEC and DEC both confirmed that "[t]he generic CT characteristics applied in the avoided cost calculations matched those in IRP docket nos. E-100, Sub 127 and E-100, Sub 117." *Id.* Beyond the fact that it has been PEC's and DEC's practice, it seems appropriate that IOUs be required to use consistent assumptions in a given biennium's IRP and avoided cost proceedings.[17]

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[16] PEC deviated from its past practice by using a higher rated CT *and* by using a gas rating for the CT for the first time. Ex. C at P83 (19 October 2012 email noting "that this is the first time we have switched to a gas rating for the peaker for PEC. [redacted] proposed the change and felt he could explain it with the joint PEC & DEC review").

[17] Indeed, PEC and DEC acknowledge at least some need for consistency across dockets in this very proceeding. For example, PEC and DEC were faced with the question of whether to use a [redacted]% or a [redacted]% escalation rate. *See* Ex. C at P141, P143 (28 September 2012 email from PEC's Lead Regulatory Specialist for Utility Regulatory

Beyond the fact that PEC's and DEC's use of a higher-rated CT in this proceeding is inconsistent with their recent past practices, the results they have achieved by inputting a higher-rated CT seem to defy what the *2012 GTW Handbook* indicates is to be expected:

> Beyond [150 MW], the $/kW curve more or less remains flat regardless of size. The higher cost of materials and manufacturing for the larger and more advanced (high firing temperature) units negates any economies of scale that might have been realized.

Ex. E at P4.

For the foregoing reasons, the Commission should examine the appropriateness of the use of a higher-rated CT as an input and, if it deems such use inappropriate, require PEC and DEC to use as inputs CTs with ratings similar to those that were used by the companies in their 2012 IRP reserve margin studies.

2. *The Assumed Useful Life of a CT Should Continue To Be 25 Years for PEC and 30 Years for DEC.*

As already mentioned, PEC's and DEC's sharp drops in proposed rates are based on sharply lower per kW construction costs – even though CTs are generally more

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Planning, [redacted]). PEC and DEC chose the [redacted]% rate to be consistent with the DEC IRP. In a 20 September 2012 email, PEC's Lead Regulatory Specialist for Utility Regulatory Planning, [redacted], wrote: "[redacted] – [redacted] confirmed that the escalation rate applied in the DEC IRP was [redacted]%, and is appropriate to use for both PEC and DEC avoided cost filings. This rate would apply to both construction and O&M costs." Ex. C at P40. Similarly, in a set of 29 October 2012 comments, Duke employee [redacted] wrote: "Capital costs for the "peaker" unit, which is a [redacted] MW Simple Cycle CT were provided by [redacted] and [redacted] in the IRP and Analytical department. The CT fixed O&M expenses that are used in this study were also provided by [redacted] and [redacted] [in the IRP and Analytical department]. . . . The escalation rate for Fuel and O&M ([redacted]%) was provided by [redacted] in the IRP department. The escalation rate is the same rate being used for the IRP." Ex. C at P133.

expensive to build now than they were at the time of the 2010 avoided cost proceeding. PEC and DEC were able to, in essence, create the lower per kW construction costs by increasing the useful life of the "average" CT they used to model their avoided costs. Because the longer lived CT used to derive PEC's and DEC's sharply lower proposed avoided cost rates is significantly different from (1) the CTs each separately used to derive their 2010 avoided cost rates and (2) the "generic" CTs each separately used as an input for its 2012 IRP, the Commission should scrutinize the useful life change and consider directing both PEC and DEC to use CT useful lives consistent with those used in their 2010 avoided cost proceedings and 2012 IRP filings.

PEC's past practice has been to use 25 years as the useful life for a CT; DEC's past practice has been to use 30 years as the useful life for a CT. Ex. D at P3-P4 (PEC and DEC responses to NCSEA Data Request 1-3). However, DEC's and PEC's "development of common inputs . . . resulted in a change in the life of a CT for both companies. Based on a review of each company's new depreciation study, a book life of 35 years was determined to be appropriate for a CT[.]" *Id.*

PEC's and DEC's respective 10- and 5-year extensions of the useful life of the CT used to calculate their avoided cost rates was very impactful. In a 30 October 2012 email, PEC's Lead Regulatory Specialist for Utility Regulatory Planning, [redacted], explained the impact on PEC's proposed rates: "Of the roughly [redacted] – [redacted] ¢ / kwhr decrease in total avoided cost rates between proposed vs. last approved PEC rates, roughly [redacted] – [redacted] ¢ / kwhr or a quarter of the total change was driven by <u>lower avoided capacity rates</u>. Most of this ([redacted] – [redacted] ¢ / kwhr was driven 50:50 by the two changes: <u>Unit ratings</u> . . . [and] <u>CT useful life</u>: Increasing the useful life from 25 years to 35 years lowered annual carrying costs." Ex. C at P126-P127. In short, PEC's and DEC's CT useful life change had just as significant an effect on their proposed rates as the CT ratings change, accounting – for example – for approximately [redacted] – [redacted] ¢/kWh or another [redacted] of PEC's overall decline in its proposed avoided cost rates.

PEC's and DEC's CT useful life change merits Commission scrutiny for several reasons: First, as evidenced by the email timeline below, the joint PEC/DEC decision to adopt a 35-year useful life was made during the 16 days leading up to the filing deadline, involved quite a bit of indecision, and is not actually based on a figure in either company's depreciation study. Second, the 35-year useful life adopted jointly by PEC and DEC in this proceeding is inconsistent with the useful lives of the CTs each company used as an input for its (a) 2010 avoided cost rate calculations *and* (b) its 2012 IRP reserve margin calculations.

The reasonableness of the 35-year useful life is called into question by a reading/review of internal PEC/DEC emails that were sent between 15 October 2012 and 1 November 2012, the day the sharply lower proposed rates were filed with the Commission:

Date of Email/ Attachment	**Author of Email/ Attachment**	**Excerpt/Summary**	**Exhibit C at P**
15 Oct. 2012	[redacted]	Attachment entitled "Corporate Standard Assumptions for Long-Range Generic Planning – Carolinas" indicates a 30 year book life as of 10/9/2012.	P58-P59
17 Oct. 2012	[redacted]	"Here is my draft CSP 28 calculation – still a work in progress. I plan to change the useful life of the CT from 25 years to 30 years . . . but I wanted to compare rates first to the currently filed PEC rates which use a 25 year life." Attachment indicates analytical use of a 25 year useful life by PEC.	P144, P147
18 Oct. 2012	[redacted]	"I am looking for a useful life estimate for a new CT. . . . For the last several years, the useful life of a CT has been assumed to be 25 years[.] . . . I wanted to check if there is a better estimate, in light of the new depreciation study, or	P75-P76

		if there is newer information available. Currently, DEC is going through this same process on their tariff, and they have been using 30 years. This round though, PEC and DEC will both use the same CT technology and cost assumptions, and the same useful life. My counterpart in DEC researched this same question, and has not found a conclusive finding pinpointing the life of a new. CT. Lacking additional information, we are leaning towards using one of the two (likely 30 years), but wanted to be sure we are not missing some information to do otherwise."	
18 Oct. 2012	[redacted]	"Here is the draft CSP 29 calculation for your review. . . . I have changed the life of the CT from 25 years to 30 years to be consistent with DEC. [redacted] and I have not heard anything more definite of this term from Accounting either. This extension of the CT life by 5 years contributed to over a third of the overall_decline in avoided capacity rates for PEC."	P62
23 Oct. 2012	[redacted]	"What's happening with this? I spoke with [redacted] only briefly. Is anyone proposing to change the CT life in the avoided cost calculations? It would seem like there is a range of reasonable number of years life for a CT. I would stick to what we have right now instead of trying to change it."	P94
24 Oct. 2012	[redacted]	"I was not planning on changing it. Duke's new depreciation study rate equates to approx. 33 years. Duke's folks would not give me a useful life."	P94
24 Oct. 2012	[redacted]	"[redacted] did call back and indicate that he was fine with our using the 40 year useful life for the CT in our avoided cost filing, if that is part of our filed depreciation study. He did want to have consistency between PEC and DEC on this assumption though. [redacted] – do you[or] [redacted] see issues with applying the 40 year life, or would be worth setting up a call to talk about it with [redacted]?"	P102
24 Oct. 2012	[redacted]	"I think there might be issues for DEC using a 40 year life. When I spoke with the DEC fixed asset group, they said they had no backup for a useful life. The DEC depreciation study does not list useful lives. They did say the new useful life that will be used equates to 33 years. I did ask about talking with the depreciation consultant but they did not feel at that time, that would be of any use. They did not believe the consultant utilizes data that would be of any use."	P103-P104
24 Oct. 2012	[redacted]	Attachment indicates analytical use of a 30 year useful life by PEC.	P98, P101
25 Oct. 2012	[redacted]	"I will send the 30 vs. 40 year useful life CSP files next, cc: to [redacted] and [redacted]."	P112
25 Oct. 2012	[redacted]	"Just fyi – switching the useful life of the CT from 30 to 40 years reduced the all- in avoided cost rate by [redacted] – [redacted] **cents / kwhr**. I have not heard any more about the DEC useful life question, and can check back with the other folks." Attachments contain comparison analytical use of 30 year and 40 year useful lives.	P103, P108-P110
25 Oct. 2012	[redacted]	"[redacted]- have you made a call on the expected life yet? I would think we simply want to be consistent with what you will be using in strategist, so I think it's your call."	P114

25 Oct. 2012	[redacted]	"I support PEC use of a 40yr life but I think it is up to DEC&PEC asset accounting groups to come up with supporting information with respect to consistent depreciation studies."	P113
26 Oct. 2012	[redacted]	"Not sure who the best contact is for the DEC depreciation study so I'll start with you! We utilized a 40 year life assumption for new(er) CTs based on information from PEC resource planning and the depreciation consultants experiential data from other utilities. Regulatory is working on a filing and wanted to know how the life assumption PEC has used compares to DEC's life assumption for new(er) CTs in the most recent study."	P123-P124
26 Oct. 2012	[redacted]	"I have attached below a draft package of the PEC avoided cost tariff CSP – 29 to be filed by November 1st for your review. . . . We are still reviewing one of the assumptions in the tariff, and hope to close that out next Monday, which may change the tariff rates slightly. . . . [T]he tariff rates in this package reflect a 40 year useful life for the CT. We're hoping the useful life question can be resolved by Monday. Applying a 40 vs. 30 year useful life assumption decreased overall avoided cost rates (capacity + energy) by [redacted] – [redacted] cents / kwhr."	P115
29 Oct. 2012	[redacted]	"From the perspective of the study we have many lives along the survivor curve for each of the utility accounts across the CT/Other spectrum . . . . [redacted] does not provide a 'composite' projected life for all of CT."	P123
29 Oct. 2012	[redacted]	Attachment indicates analytical use of a 40 year useful life by PEC.	P116, P121
29 Oct. 2012	[redacted]	"I spoke to [redacted] this afternoon about the estimated life of a CT facility for our avoided cost filings. He is comfortable with using 35 years, and he will assist us in responding to questions from the Public Staff if they arise."	P138
30 Oct. 2012	[redacted]	"Both tariffs now reflect the 35 year useful life assumption, and the all-in rates are 1% to 6% apart between the 2 utilities." Attachment indicates analytical use of a 35 year useful life by PEC.	P126, P129
31 Oct. 2012	[redacted]	"So now the question is: what is the life assumption for other technologies (CC, Coal, Nuclear, etc)? Duke Progress currently uses 25 years for CC and 40 years for coal and nuclear."	P138

The emails and attachments quoted and cited in the table above evidence PEC's and DEC's rather gossamer foundation for the selection of 35 years as the useful life of an "average" CT. This selection appears to have been someone's "call" – a call that on the eve of filing stood at odds with the two companies' assumed 25 year useful life for combined cycle plants.

In addition to scrutinizing the 35 year useful life because of PEC's and DEC's internal indecision, there is another reason to question it: The inconsistency it creates between this docket and the 2012 IRP. In DEC's 2012 IRP, it notes that

> [a]s part of the NCUC's approval of the 2010 IRP, [DEC] and [PEC] were ordered to perform a quantitative analysis of the utilities' respective reserve margins and to provide the study results in the companies' 2012 IRPs. . . . [DEC and PEC separately] hired Astrape, a consultant that specializes in reserve margin analysis, to perform the quantitative analys[e]s.

The [Public] Duke Energy Carolinas Integrated Resource Plan (Annual Report), p. 85, Commission Docket No. E-100, Sub 137 (4 September 2012). To enable Astrape to produce study results, both PEC and DEC had to provide Astrape with generic CT characteristics for use in calculating the carrying cost of capacity. While it is unclear what useful life PEC directed Astrape to use, DEC directed Astrape to use a CT with a 30 year useful life. Ex. F at P6 (excerpt from DEC Astrape Study Report).

Given the lack of a firm foundation for the 35 year useful life and its inconsistency with DEC's 2012 IRP reserve margin inputs (and likely with PEC's as well), the Commission should consider implementing [redacted]' 23 October 2012 suggestion: *"[S]tick to what we have right now instead of trying to change it."* Ex. C at P94 (emphasis added).

> 3. *DEC Should Have Used the Full Estimated Owner's Contingency Costs That Were Included in the Sargent & Lundy Engineering Study DEC Commissioned.*

"DEC and PEC each individually commissioned third party engineering firms to provide cost estimates for new generation options including estimates for the installed cost of a gas fired simple cycle peaker." Ex. D at P3-P4 (PEC and DEC responses to

NCSEA Data Request 1-3). DEC commissioned a Sargent & Lundy ("S&L") engineering study. The S&L study estimated contingency costs associated with the construction and operation of a CT at [redacted]% – equal to $[redacted]. Ex. C at P5 (spreadsheet contains figure and footnote 3 indicates the analysis "[u]sed S&L contingency of [redacted]% as included in the estimate provided").

DEC chose to disregard the S&L estimate and instead set contingency costs for a DEC CT at roughly [redacted]% – equal to $[redacted]. Ex. C at P64 (per spreadsheet attached to PEC Lead Regulatory Specialist for Utility Regulatory Planning [redacted]'s 18 October 2012 email); *see* Ex. C at P1-P2 (a 4 September 2012 [redacted] email states: "[redacted] told me to use [redacted]% total contingency because that is what both Buck and Dan River look like they will come in at in the end with a combination of Shaw and Duke contingency. This is what is included 'Normalized A' tab. I have a concern that the S&L estimate could be provided as backup or requested by the Public Staff, therefore, I have done a separate normalized cost in 'Normalized B' tab which uses the S&L contingency in the normalized estimates as a dollar value.").

The contingency costs included in DEC's CT cost calculus are less than half the amount estimated by S&L. The lower-by-half DEC estimate was then averaged with the PEC estimate to arrive at "average" CT costs. Had the S&L contingency cost estimate been used, the contingency costs for the PEC/DEC "average" CT would have increased from $[redacted] to $[redacted]. *See* Ex. C at P64. This would have resulted in the proposal of higher avoided cost rates than were actually proposed. The Commission should scrutinize DEC's decision to deviate from the estimate it received from the engineering firm and should consider directing DEC to use S&L's estimate of contingency costs.[18]

4. *DEC Should Have Included Transmission System Upgrade Costs So As To Be Consistent with Its IRP Assumptions.*

"In calculating the avoided capital costs, DEC adopted the assumption that PEC has used in prior filings of including only transmission and natural gas infrastructure costs related to the avoided simple cycle peaker and not to include an estimate of system related costs on the gas and transmission systems." Ex. D at P4 (DEC response to NCSEA Data Request 1-3).

As evidenced by the email timeline below, it was not a unanimous decision within DEC to break from its past practice and exclude system upgrade costs:

Date of Email/ Attachment	Author of Email/ Attachment	Excerpt/Summary	Exhibit C at P
4 Sept. 2012	[redacted]	"[redacted] is uncomfortable with the assumption that the system upgrade costs should not be included in the Avoided Cost and is following up further."	P1
3 Oct. 2012	[redacted]	"I know we still have to discuss the transmission aspect but for now I would like to start working with 'inside the fence' costs that have been developed[.]"	P44
4 Oct. 2012	[redacted]	"$[redacted]/ kw construction cost for total [redacted]mw capacity. . . . You also mentioned this excludes transmission costs, and we can talk about this. My recollection was that it would be reasonable to add it as an avoided cost for QFs that supplied into our distribution system, not transmission."	P43
15 Oct. 2012	[redacted]	"Last when we talked, you were expecting to add avoided transmission costs to this estimate."	P61
15 Oct. 2012	[redacted]	"The CT costs that have been provided have the appropriate transmission costs included for the construction of the associated switchyard and connection to the grid. With respect to avoided system upgrade costs there are no system avoided upgrade costs. In short, when a QF provider connects to the transmission system they do not avoid upgrade costs on behalf of the retail customer. While they	P60

[18] NCSEA is unable to determine whether PEC – for its CT costs – used a contingency cost significantly different from the estimate in its engineering study. To the extent the contingency costs PEC used are significantly different from those it was provided by its engineering firm, the Commission should scrutinize PEC's reduction as well.

		pay for any system upgrade costs the QF customer is then refunded for the upgrades over time. The only reason the QF customer pays up front, subject to a refund, is to ensure the upgrade costs are not incurred without the benefit of the actual generation project. In short retail customers ultimately pay for any system upgrades a new QF customer imposes on the system and as such there is no avoided benefit. This conclusion has been reached after discussing this issue with transmission planning. It should be noted that there could be an avoided benefit for an EE resource when load is reduced. This would be an issue for EE cost effectiveness or other related load reducing programs or rates. I only mention this because I believe there is still a need to develop a 'generic $/kW avoided transmission cost' for certain types of economic analysis even though it does not apply to the avoided cost rate calculation."	

The Commission should scrutinize DEC's exclusion of system upgrade costs for at least two reasons.[19] First, as evidenced by the email quotes above, the exclusion of these costs made one employee "uncomfortable" and ran counter to what another employee thought was "reasonable[.]" Second, the exclusion of these costs appears to be at odds with DEC's past practice, including its practice in connection with its 2012 IRP. Specifically, in DEC's 2012 IRP, it notes that

> [a]s part of the NCUC's approval of the 2010 IRP, [DEC] and [PEC] were ordered to perform a quantitative analysis of the utilities' respective reserve margins and to provide the study results in the companies' 2012 IRPs. . . . [DEC and PEC separately] hired Astrape, a consultant that specializes in reserve margin analysis, to perform the quantitative analys[e]s.

The [Public] Duke Energy Carolinas Integrated Resource Plan (Annual Report), p. 85, Commission Docket No. E-100, Sub 137 (4 September 2012). To enable Astrape to produce study results, DEC had to provide Astrape with generic CT characteristics for use in calculating the carrying cost of capacity. DEC directed Astrape to use a CT with a

[19] The Commission should also examine whether PEC's practice of excluding transmission system upgrade costs is appropriate.

capital cost – "including transmission upgrades" – of $[redacted]/kW. Ex. F at P5-P6 (excerpt from DEC Astrape Study Report).

Coupled with inclusion of S&L's estimated contingency costs, inclusion of system upgrade costs in DEC's CT cost analysis would have brought the $/kW for a CT closer to $[redacted], Ex. C at P3-P4 (compare the spreadsheet on P3 to the spreadsheet on P4), and would have significantly affected the averaging of PEC's and DEC's CT costs, resulting in the proposal of higher rates than DEC actually proposed. *See* Ex. C at P64.

5. *DEC Should Have Used a Discount Rate That is Comparable To PEC's and DNCP's Discount Rates.*

PEC, DEC, and DNCP used discount rates to calculate their avoided cost rates.[20] A discount rate serves to "adjust[] costs in the future to render them comparable to values placed on current costs." Kammen, D.M. and S. Pacca, "Assessing the Costs of Electricity," *Annual Review of Environmental Resources*, vol. 29, p. 304 (2004).[21] Importantly, the discount rate represents an assumption. An IOU's assumed discount rate impacts its proposed avoided cost rates in the following way: The use of a lower discount rate results in a lower avoided capacity cost rate. *See* Ex. D at P9 (PEC response to NCSEA Data Request 2-6). In this case, the discount rate assumed by DEC is significantly lower than the discount rates assumed by PEC and DNCP and should be scrutinized to ensure that it is not unreasonably low.

[20] "Electricity costs for various current electricity generation technologies[, such as a peaker,] can be calculated using . . . equations . . . combined with [various pertinent] values . . . , *an appropriate discount rate*, and fuel cost information." Kammen, D.M. and S. Pacca, "Assessing the Costs of Electricity," *Annual Review of Environmental Resources*, vol. 29, p. 309 (2004) (emphasis added).

[21] The full article is accessible at http://josiah.berkeley.edu/2007Fall/ER200N/Readings/Kammen_2004.pdf (viewed on 10 January 2013).

PEC used a discount rate of [redacted]%. Ex. D at P9 (PEC response to NCSEA Data Request 2-6). DNCP used a discount rate of 8.53%. *Corrected Comments, Exhibits and Avoided Cost Schedules of DNCP*, Exhibits DNCP-5 & DNCP-6, Commission Docket No. E-100, Sub 136 (5 November 2012). Consequently, the discount rates selected by PEC and DNCP are [redacted]. DEC used a discount rate of [redacted]% – a rate approximately [redacted]% lower than [redacted]. Ex. D at P10 (DEC response to NCSEA Data Request 2-6). DEC's decision to assume a lower discount rate resulted in DEC proposing lower avoided cost rates than it otherwise would have. In a 29 October 2012 email, PEC's Lead Regulatory Specialist for Utility Regulatory Planning, [redacted], wrote:

> The avoided capacity rates for PEC are slightly higher than DEC, which may be largely driven by [th]e higher [weighted average cost of capital ("WACC")] in PEC's case. The PEC calculation uses an [redacted]% WACC based on the last awarded 12.75% ROE, while DEC's calculation uses a [redacted]% WACC based on the last awarded 10.50% ROE.

Ex. C at P116.[22] While the email accurately reflects that the Commission has held that "[t]he discount rate used to calculate avoided cost rates should reflect the utility's overall cost of capital"[23] (*i.e.*, the utility's WACC), it does not reflect how difficult it is to determine a WACC/discount rate. With regard to calculating the cost of equity capital (*i.e.*, "ROE") – which, together with cost of debt, is used to derive the overall cost of capital – a leading treatise, *Accounting for Public Utilities,* points out how unscientific

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[22] DNCP utilized an 8.53% discount rate in this proceeding. Its Commission-approved ROE at the time it filed its proposed rates was 10.70% – an ROE very similar to DEC's last awarded ROE. *Order Granting Rate Increase, Approving Fuel Charge Adjustment, and Approving Stipulation and Supplemental Agreement*, p. 9, Commission Docket Nos. E-22, Sub 459 and E-22, Sub 461 (13 December 2010).
[23] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, p. 9, Commission Docket No. E-100, Sub 106 (19 December 2007).

the various approaches are. For example, with regard to the discounted cash flow ("DCF") approach, the treatise notes that

> considerable disagreement centers around the validity of certain assumptions inherent in the DCF theory. Specifically, the assumption that investors' anticipated growth rates can be reasonably predicted into the long-term future, in the face of a constantly changing business environment, is strongly attacked by critics of the DCF approach. . . . [H]istoric factors (along with considerable judgment) commonly serve as the indicators utilized in predicting investor growth expectations. The validity of these indicators beyond the immediate future is seriously questioned by critics of the technique. . . . Critics are quick to point out that the approach is by no means scientific, in spite of such claims by its advocates.

Accounting for Public Utilities, § 9.05 at p. 9-15 (relevant excerpt attached as Ex. G, quote found at P5). Perusal of the testimony presented in DEC's last two rates cases offers further support for the proposition that precise calculation of an ROE or a WACC is nearly impossible. *See Order Granting General Rate Increase*, pp. 25-30, Commission Docket No. E-7, Sub 989 (27 January 2012); *see also Order Granting General Rate Increase and Approving Amended Stipulation*, Commission Docket No. E-7, Sub 909 (7 December 2009). This testimony also demonstrated how common it is to look at comparable companies to "obtain[] additional confidence with the mechanics and the results of[, for example,] the DCF technique. Ex. G at P6; *Order Granting General Rate Increase*, p. 26, Commission Docket No. E-7, Sub 989 (27 January 2012).

In this proceeding, NCSEA believes PEC, DNCP, and DEC should be viewed as comparable companies – indeed, PEC and DEC are both owned by the same parent holding company and trade under the same stock symbol. This should be resulting in a convergence of their discount rates over time, yet their proposed discount rates indicate that the opposite is occurring. In a 19 October 2012 email attachment, PEC's Lead

Regulatory Specialist for Utility Regulatory Planning, [redacted], provided a "comparison of PEC & DEC all in proposed rates (combined capacity & energy)[.]" Ex. C at P84, P87. A part of this comparison set out PEC's and DEC's 2010 avoided cost rates, including the discount rates/WACCs the companies used in 2010. PEC's WACC was [redacted]% for the 2010 proceeding and has risen to [redacted]% in this proceeding; DEC's WACC was [redacted]% for the 2010 proceeding and has decreased to [redacted]% in this proceeding. Ex. C at P87. The discount rate differential has increased from [redacted]% in 2010 to [redacted]% in 2012 despite the merger of PEC's and DEC's parent companies.

NCSEA believes DEC should be required to re-calculate its avoided cost rates using a higher discount rate that is more in line with PEC's and DNCP's discount rates. NCSEA recommends that the higher discount rate be [redacted]% and believes there is sufficient evidence in the record to support use of such a rate. First and foremost, despite DEC's representation that it "utilized the same method it has used in past filings and did not look at alternative assumptions[,]" Ex. D at P10 (DEC response to NCSEA Data Request 2-6), it appears as though DEC did consider using (or at least looked at) a [redacted]% discount rate. An appendix to the 29 October 2012 Comments of [redacted] indicates that DEC used a "Nominal After Tax Discount Rate for Capital" of [redacted]% for the 2010 proceeding – which is consistent with the 2010 discount rate disclosed in Ms. [redacted]'s 19 October 2012 email attachment; the attachment also indicates that DEC considered a "Nominal After Tax Discount Rate for Capital" of [redacted]% for the 2012 filing. Ex. C at P135. Beyond DEC's apparent consideration of this discount rate, NCSEA believes use of the [redacted]% discount rate appropriate as it will effectively maintain the 2010 PEC/DEC rate differential of [redacted]%.

DEC's use of a [redacted]% discount rate is significantly higher than the [redacted]% rate DEC actually used to calculate its proposed rates yet compares better to PEC's and DNCP's assumed discount rates, effectively [redacted] between [redacted]% and [redacted]%. Additionally, this higher discount rate is more consistent with (1) what DEC asserted its ROE should be – 11.5% – in its last rate case before it reached a settlement with the Public Staff, *Order Granting General Rate Increase*, p. 25, Commission Docket No. E-7, Sub 989 (27 January 2012), and (2) the ROE DEC is likely to request in its application for a rate increase filed in Commission Docket No. E-7, Sub 1026.

6. PEC and DEC Should Have Incorporated Hedging Costs Into Their Variable Fuel/Operating and Maintenance Costs.

"Electricity costs for various current electricity generation technologies can be calculated using . . . equations . . . combined with [various pertinent] values . . . , an appropriate discount rate, and fuel cost information." Kammen, D.M. and S. Pacca, "Assessing the Costs of Electricity," *Annual Review of Environmental Resources*, vol. 29, p. 309 (2004). NCSEA believes the costs of hedging are closely coupled with fuel cost and, as with fuel costs, should be factored into any Commission-approved avoided cost rates. PEC and DEC[24] appear to disagree as neither utility factored any natural gas hedging costs into its proposed rates. Ex. D at P7-P8 (PEC and DEC responses to NCSEA Data Request 2-2).

Hedging enables an electric supplier to reduce natural gas price volatility and provide greater price certainty for its customers. *See Affidavit of John Robert Hinton*, p. 3, Commission Docket No. E-2, Sub 1018 (11 September 2012). The attainment of

[24] NCSEA did not serve any data requests on DNCP and thus can only comment on PEC's and DEC's proposed rates.

reduced volatility and greater price certainty comes at a premium in the near-term and can result in net long-term costs as well. *Id.* at pp. 2-4. The costs associated with hedging can be substantial. For example, in 2012, PEC requested "recovery of $50 million for the net costs of its natural gas hedging program . . . equat[ing] to a total cost of approximately $19.44 per year for the typical residential customer who has an average monthly use of 1,000 kWh." *Id.* at p. 2. Even so, PEC and DNCP hedge as part of their natural gas procurement practices. *Id.* at p. 4 n1. And, despite the substantial net costs, the Commission wisely continues to see substantial benefit in reduced volatility and thus continues to view PEC's and DNCP's natural gas hedging as prudent. Given the prudency of PEC's and DNCP's hedging, DEC will – either directly or indirectly – engage in hedging during the 15- to 20-year window of time for which gas prices are being projected in this proceeding.[25]

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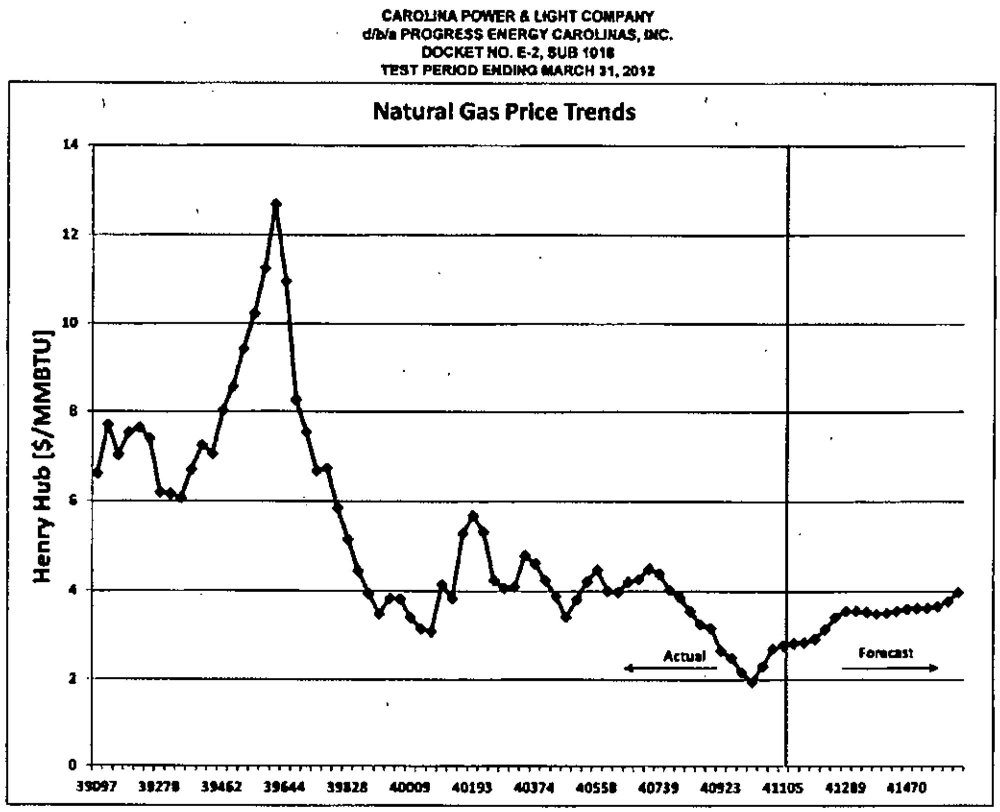
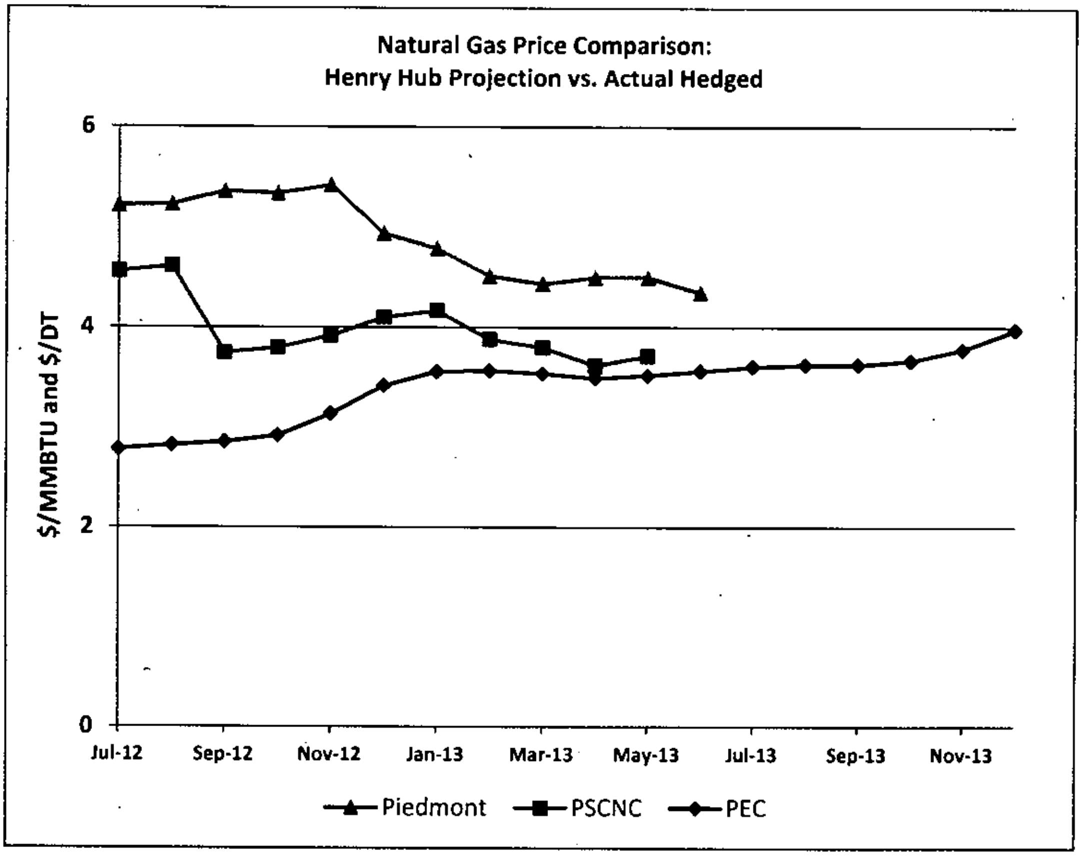
[25] Commission Rule R8-52(b) requires each electric public utility which uses fossil and/or nuclear fuel in the generation of electric power to file a Fuel Procurement Practices Report with the Commission. DEC, PEC, and DNCP file their Fuel Procurement Practices Reports in Commission Docket No. E-100, Sub 47A. DEC's 2004 Fuel Procurement Practices Report indicates on page 4 that "[g]as is burned only in peaking generation assets" and that DEC "employ[s] outside gas suppliers to provide a 'bundled' service to Duke's 'burner-tip'" including "risk management[.]" It is safe to assume DEC's suppliers engage in hedging and pass the costs along to DEC. Since filing the 2004 Report, DEC has added the Buck and Dan River CCs. DEC's use of natural gas as a fuel is projected to triple in the next five years. *See* Ex. C at P50, P53. As a result, DEC is considering altering its procurement practices: While DEC "does not currently employ a long-term hedging strategy [because t]he limited and unpredictable gas usage experienced in the past was not suitable for a long-term hedging program . . . [DEC is] continu[ing] to evaluate the feasibility of a hedging program, particularly with the increased gas consumption associated with the addition of the Buck and Dan River CCs." *Transcript of Testimony Heard on 12 June 2012*, p. 64, Commission Docket No. E-7, Sub 1002 (20 June 2012) (testimony of DEC witness Jessee).

A projection of hedging costs should be included in the IOUs' avoided cost rate calculus. Exclusion of hedging costs from the calculus can distort an avoided cost rate such that it no longer accurately represents the avoided energy cost. The potential for distortion can be illustrated by looking at two related graphs. First, PEC filed the following "Natural Gas Price Trends" graph on page 2 of Exhibit No. 2 to the testimony of Bruce Barkley in Commission Docket No. E-2, Sub 1018:



PEC's graph covers the period of time from January 2007 through December 2013 and depicts monthly Henry Hub gas prices. The "forecast" portion of the graph, prepared on or about 30 May 2012, covers the period of time from July 2012 through December 2013. The "forecast" portion of PEC's graph can be enlarged and the Henry Hub price projections graphed alongside the hedged costs of gas per dekatherm as reported in the beginning of June 2012 by Piedmont Natural Gas Company ("Piedmont")[26] and Public Service Company of North Carolina, Inc. ("PSCNC")[27]:



Piedmont's and PSCNC's hedged costs are substantially higher per dekatherm than PEC's unhedged projection of the Henry Hub price per mmBTU. While the comparison of two local distribution companies' hedged prices to PEC's projected Henry Hub price is perhaps imperfect, it does illustrate that, at any particular point in time, use of a projection of Henry Hub or NYMEX market price will under-account not only for delivery costs but also for the costs of hedging associated with a North Carolina utility's procurement of natural gas.

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[26] *May 2012 Hedging Status Report*, Commission Docket No. G-9, Sub 608 (7 June 2012).
[27] *May 2012 Hedging Status Report*, Commission Docket No. G-5, Sub 530 (5 June 2012).

If hedging costs are factored in, PEC's and DEC's proposed rates will likely be higher – perhaps up to half a cent per kilowatt hour higher. In a 2002 study, researchers at the Lawrence Berkeley National Laboratory concluded:

> If consumers are risk averse and prefer stable over volatile prices, then the cost of hedging is one that natural gas generators – or similarly, those that purchase natural gas-fired generation – must bear. Conversely, and more to the point of this paper, 0.5¢/kWh can be considered the approximate hedge value that investments in renewable energy provide relative to variable-price, gas-based electricity contracts. Therefore, assuming that consumers value price stability and that regulators and utilities seek to compare various electricity generation sources on equal grounds when making resource decisions, *this hedging cost should either be added to the cost of variable-price gas contracts or credited as a benefit to fixed-price renewable energy investments.*

Bolinger, M., R. Wiser, and W. Golove, "Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices," p. 13, Lawrence Berkeley National Laboratory (June 2002) (emphasis added).[28] NCSEA believes the Commission should order PEC and DEC to incorporate a projection of natural gas hedging costs into their overall avoided energy cost calculus.

NCSEA SUPPORTS THE RENEWABLE ENERGY GROUP'S ARGUMENTS

NCSEA urges the Commission to adopt the outcomes advocated for by the Renewable Energy Group with respect to (1) adjusting the performance adjustment factor for solar and wind, (2) addressing the "cut-off" dates embedded in the IOUs' proposed rate schedules, and (3) amending the IOUs' standard contract terms and conditions.

[28] The full article is accessible at http://eetd.lbl.gov/EA/EMp/reports/50484.pdf (viewed on 10 January 2013).

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing Comments by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 7th day of February, 2013.

Michael D. Youth
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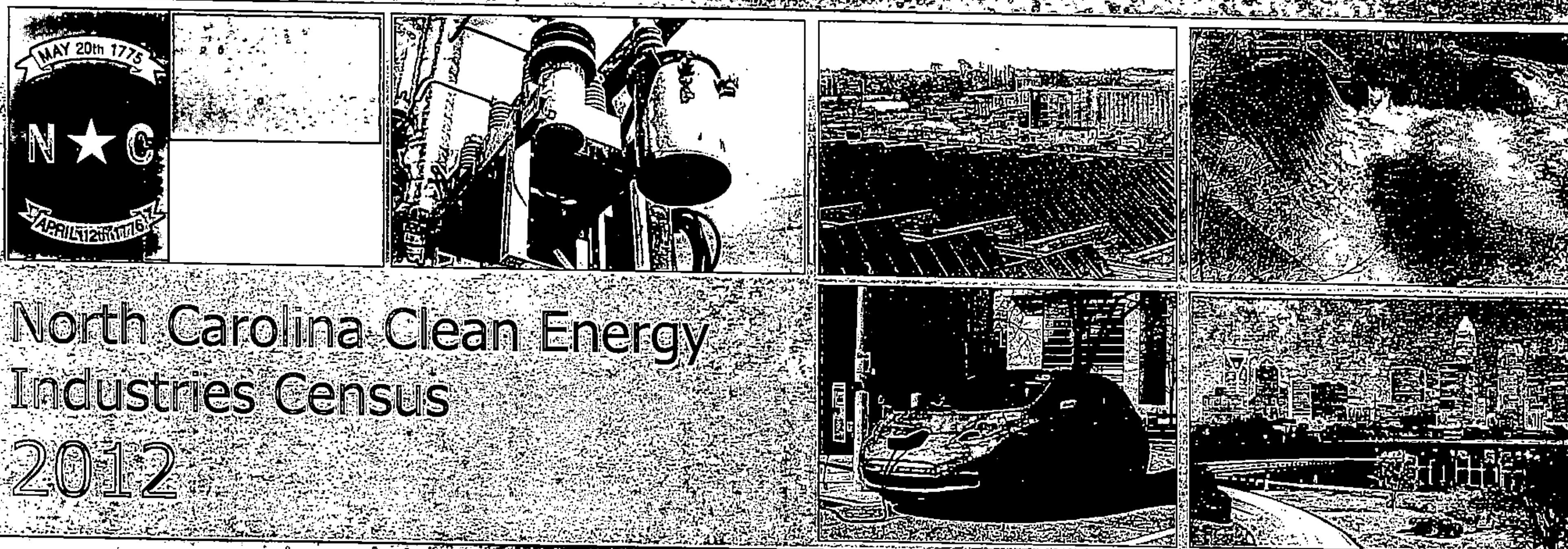
NOTE: READERS MAY NOTICE GAPS IN THE PAGE NUMBERS FOR PUBLIC VERSION EXHIBITS C, D, & F. THE MISSING PAGES HAVE BEEN REDACTED IN THEIR ENTIRETY.

EXHIBIT A



North Carolina Clean Energy Industries Census 2012

NC Sustainable Energy Association

October 2012

Rich Crowley

NORTH CAROLINA'S CLEAN ENERGY INDUSTRIES CENSUS

Key 2012 Findings and Definitions

- **North Carolina's clean energy sector accounts for over 15,200 full-time equivalent (FTE) employees as of September, 2012.**
- **Full-time equivalent employment in North Carolina's clean energy sector grew by approximately 3% since September, 2011.**
- **In 2012, the clean energy sector conservatively generated over $3.7 billion in North Carolina annual gross revenue from clean energy activities.**
- **NCSEA conservatively estimates that at least 1,100 companies are currently conducting business in the clean energy sector in 2012.**
- **Companies maintained nearly 1,400 offices across 86 of North Carolina's 100 counties.**
- **In addition to strong roots in North Carolina markets, over 200 companies indicate that they provide products and services to the national and international marketplace.**
- **A common theme among respondents was the importance of stability and predictability to the clean energy industry. Clean energy companies want laws and regulations that allows them to focus resources on developing their business, rather than reformulating their business plans in reaction to policy changes.**

For the purposes of the North Carolina Clean Energy Industries Census, "clean energy" is defined as energy efficiency or renewable energy. The starting point for this definition is North Carolina's landmark 2007 Renewable Energy and Efficiency Portfolio Standard law, the first of its kind in the Southeast. As this is a North Carolina specific report, coupled with the absence of a national definition of clean energy, the North Carolina Sustainable Energy Association believes utilizing this state statue is an appropriate starting point for defining the scope of our study. As such, this report does not consider nuclear energy, nor does it directly consider fossil-based combined heat and power.

Unlike national reports that use industry classification codes to model companies in the broader "green" economy, the North Carolina Clean Energy Industries Census uses confidential direct responses from North Carolina clean energy companies. Consequently, the North Carolina Clean Energy Industries Census does not evaluate green jobs, but rather looks at a critical element (clean energy), which is a sub-section of the larger "green" economy.

Table of Contents:

This report presents both key findings from data collected through the 2012 Census and aggregate industry trends distilled from the 2010 through 2012 participant responses. All employment numbers are reported as full-time equivalent employees. A brief methodology can be found at the back of this report. Readers interested in the report methodology, or who wish to review a copy of the 2012 Census questions, should visit the North Carolina Sustainable Energy Association's (NCSEA) website at **www.energync.org**. Readers with additional questions about the findings in this report or the underlying data should contact NCSEA's Market Intelligence team via email at info@energync.org, with the subject line *"2012 Census – Additional Information Request"*.

Throughout this report, key findings from the 2012 Census are identified in the text using the **bold blue font,** and company comments from the 2012 Census participants can be identified by the use of ***yellow or red colored italics.***

Acknowledgements: The North Carolina Sustainable Energy Association would like to thank all of the companies that responded to the 2012 Census, as well as those who have participated in the past three years. Additional thanks to the Center for Urban Affairs and Community Services at North Carolina State University for assistance in programming and administering the Census. This report was made possible through the generous support of the Energy Foundation. GIS software was made available though a grant from the Environmental Systems Research Institute (ESRI).

EXHIBIT B

Progress Energy Carolinas

Integrated Resource Plan

Appendix D
Alternative Supply Resources
NC REPS Compliance Plan

September 2012

PROGRESS ENERGY CAROLINAS, INC.'S
2012 REPS COMPLIANCE PLAN

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VII. CURRENT AND PROJECTED AVOIDED COST RATES

The current and projected avoided cost rates represent the annualized avoided cost rates for Cogeneration and Small Power Producer (CSP) Schedule CSP-27, approved in the Commission Order issued in Docket No. E-100, Sub 127 in August 2011.

Table 7: Annualized Capacity and Energy Rates (cents per KWh)

	2012 (Current)	2013 (Projected)	2014 (Projected)
Variable Rate	5.786¢	5.786¢	5.786¢
5 Year	6.184¢	6.184¢	6.184¢
10 Year	6.816¢	6.816¢	6.816¢
15 Year	7.286¢	7.286¢	7.286¢

VIII. PROJECTED TOTAL NORTH CAROLINA RETAIL AND WHOLESALE SALES AND YEAR-END NUMBER OF CUSTOMER ACCOUNTS BY CLASS

The tables below show the actual and projected retail sales for PEC and the Wholesale Customers.

Table 8: Retail Sales for Retail and Wholesale Customers

year	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast
Retail MWh Sales	37,353,311	36,868,966	37,255,920	37,708,885
Wholesale MWh Sales	155,584	155,568	155,982	156,398
Total MWh Sales	37,508,895	37,024,535	37,411,902	37,865,283

Table 9: Retail and Wholesale Year-end Number of Customer Accounts

year	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast
Residential Accts	1,115,346	1,126,564	1,137,912	1,151,075
General Accts	181,666	185,011	188,420	192,762
Industrial Accts	2,069	2,090	2,110	2,131

IX. PROJECTED ANNUAL COST CAP COMPARISON OF TOTAL AND INCREMENTAL COSTS, REPS RIDER, AND FUEL COST IMPACT

Table 10 shows the projected compliance costs for contracted resources by calendar year. The cost cap data is based on the number of accounts as reported above.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET E-100, SUB 137

In the Matter of Investigation of the Integrated Resource Plan in North Carolina for 2012	) DUKE ENERGY CAROLINAS, LLC'S 2012) RENEWABLE ENERGY & ENERGY) EFFICIENCY PORTFOLIO STANDARD) COMPLIANCE PLAN

P4

DUKE ENERGY CAROLINAS, LLC'S
2012 RENEWABLE ENERGY AND ENERGY EFFICIENCY
PORTFOLIO STANDARD ("REPS") COMPLIANCE PLAN

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IV. COST IMPLICATIONS OF REPS COMPLIANCE PLAN

A. CURRENT AND PROJECTED AVOIDED COST RATES

The current and projected avoided cost rates represent the annualized avoided cost rates in Schedule PP-N (NC), Distribution Interconnection, approved in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* issued in Docket No. E-100, Sub 127 (July 27, 2011).

Table 2: Annualized Capacity and Energy Rates (cents per KWh)

	2012 (Current)	2013 (Projected)	2014 (Projected)
Variable Rate	5.48¢	5.48¢	5.48¢
5 Year	5.63¢	5.63¢	5.63¢
10 Year	6.28¢	6.28¢	6.28¢
15 Year	6.63¢	6.63¢	6.63¢
20 Year (extrapolated)	7.02¢	7.02¢	7.02¢
25 Year (extrapolated)	7.42¢	7.42¢	7.42¢

B. PROJECTED TOTAL NORTH CAROLINA RETAIL AND WHOLESALE SALES AND YEAR-END NUMBER OF CUSTOMER ACCOUNTS BY CLASS

The tables below reflect the inclusion of the Wholesale Customers in the Compliance Plan. See Section V for more information regarding Wholesale Customer compliance.

Table 3: Retail Sales for Retail and Wholesale Customers

year	2012	2013	2014
Retail MWh Sales	55,966,071	54,678,204	55,169,132
Wholesale MWh Sales	3,496,738	3,409,456	3,510,277
Total MWh Sales	59,462,809	58,087,660	58,679,409

Note: The MWh sales reported above are those applicable to REPS compliance years 2012 – 2014, and represent actual MWh sales for 2011, and projected MWh sales for 2012 and 2013, respectively.

Table 4: Retail and Wholesale Year-end Number of Customer Accounts

year	2012	2013	2014
Residential Accts	1,743,155	1,780,837	1,794,511
General Accts	235,086	238,602	242,701
Industrial Accts	5,392	5,533	5,543

Note: The number of accounts reported above are those applicable to the cost caps for compliance years 2012 – 2014, and represent the actual number of accounts for year-end 2011, and the projected number of accounts for year-end 2012 and year-end 2013, respectively.

DOMINION NORTH CAROLINA POWER 2012 REPS COMPLIANCE PLAN

Pursuant to North Carolina Utilities Commission ("NCUC") Rule R8-67 (b), Virginia Electric & Power Company d/b/a Dominion North Carolina Power ("Company") submits its Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plan in accordance with N.C.G.S. § 62-133.8 (b), (c), (d), (e) and (f), and the aforementioned NCUC Rule R8-67(b). The REPS Compliance Plan covers the current (2012) and immediately subsequent two calendar years (2013-2014). This North Carolina REPS Compliance Plan is an addendum to the Company's 2012 Integrated Resource Plan ("IRP").

As indicated in the Company's REPS Compliance Report filed on August 10, 2012, the Company has met its 2011 REPS requirement.

1.1 RENEWABLE ENERGY REQUIREMENTS

An overview of North Carolina's REPS requirements and Virginia's Renewable Energy Portfolio Standard ("RPS") goals are provided in Chapter 4, Section 4.3 of the Company's 2012 Integrated Resource Plan ("2012 Plan") filed simultaneously with this addendum.

1.2 COMPLIANCE PLAN

In accordance with Rule R8-67 (b) (i), the Company describes its planned actions to comply with G.S. 62-133.8 (b), (c), (d), (e), and (f) for each year.

<u>The Company</u>

The Company plans to meet North Carolina's statutory goals through the year 2021 and thereafter with a REPS Compliance Plan that includes the use of Renewable Energy Certificates ("RECs"), energy efficiency ("EE") and new company-generated renewable energy where economically feasible. North Carolina General Statute § 62-133.8(d) sets the initial compliance target for solar in years 2010 and 2011 as 0.02% of the previous year's baseline load, with overall REPS compliance beginning in 2012, along with swine waste and poultry waste set-asides. The Company began implementing the energy efficiency programs in North Carolina by introduction of the Residential Lighting Program in May 2011 and the other approved programs in June 2011. These programs will contribute to the overall REPS goals, subject to approval by the NCUC.

On September 22, 2009, the NCUC issued an order on the Company's motion for further clarification in Docket No. E-100, Sub 113 ruling that the Company is allowed to utilize out-of-state RECs to meet all of its REPs requirements per G.S. 62-133.8(b)(2)(e). Therefore, in accordance with such order, the Company plans to meet DNCP's obligations with a mix of purchased out-of-state RECs, in-state RECs, qualified energy efficiency programs, and qualified

1.6 AVOIDED COST RATES

In accordance with Rule R8-67 (b) (v), the Company provides the following statement regarding the current and projected avoided cost rates for each year.

Figure 1.6.1 identifies the projected avoided energy and capacity cost from the Biennial Determination of Avoided Costs Rates for Electric Utility Purchases from Qualifying Facilities – 2010 proceeding E-100, SUB 127 before the North Carolina Utilities Commission. Avoided energy and capacity cost as used in the 2012 IRP are given below in Figure 1.6.2.

Figure 1.6.1 PROJECTED AVOIDED ENERGY AND CAPACITY COST (from E-100 sub 127)

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2012	52.31	40.09	20.23
2013	54.84	41.19	8.41
2014	60.13	45.22	18.27

Figure 1.6.2 PROJECTED AVOIDED ENERGY AND CAPACITY COST (from NC 2012 IRP)

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Capacity Price ($/kW-Year)
2012	44.39	29.51	20.05
2013	47.22	33.80	8.30
2014	50.38	37.97	30.58

1.7 TOTAL & PROJECTED COSTS

In accordance with Rule R8-67 (b) (vi), the Company provides the projected total and incremental costs anticipated to implement the REPS Compliance plan for each year.

<u>The Company</u>

The Company's projected costs for 2012-2014 are expected to consist of the sum of the costs required to comply with solar, swine, poultry and other general renewable requirements. Outside legal costs, NC RETS system development costs and ongoing user fees and APX Environmental Management Account system development costs could also be incurred. Figure 1.7.1 outlines the Company's Compliance Cost Summary for RECs procurement from 2012 to 2014.

EXHIBIT C

Fentress, Kendrick C

From: [redacted]
Sent: Tuesday, September 04, 2012 8:24 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Simple Cycle Estimate Comparison Update

See corrections below. I meant to correct in the original email but got interrupted several times and just sent it.

[redacted]
Engineering Manager, CTCC Projects
Duke Energy
[redacted]ffice
[redacted]cell

From: [redacted]
Sent: Tuesday, September 04, 2012 8:02 AM
To: [redacted]
Cc: [redacted]
Subject: Simple Cycle Estimate Comparison Update

[redacted],

Please find the attached spreadsheet comparison of 4x7FA simple cycle with two versions of normalizing the costs. A similar spreadsheet was reviewed with Glen Snider, Bobby McMurry, John Umstead, John Robinson and Dan Roeder. I have summarized the key points below:

1. [redacted]
2. Changes to the DEC 2012 Estimate: I have deleted the $35 million spreadsheet error and th[redacted] multiplication factor. I deleted the multiplication factor after comparing the total cost to the Rockingham estimate from 2008. I did not look at the combined cycle estimates from which this factor was developed. The DEC2 2012 estimate compares well to the Rockingham estimate and the factor could imply escalation from 2008 to 2012. However, based on a general feel of costs over that time frame, [redacted] and I believe that early 2008 when the Rockingham estimate was developed was the high point of material and construction costs and current costs should be the same or lower. I have confirmed this via indices such as the Turner Building Cost Index.
3. Electric Transmission and Interconnect Costs: Pe[redacted]'s direction, I have only included the cost of the on-site switchyard and the tie-in. PEC had an estimated cost of roughly $[redacted] million for this. Duke System Planning provided a cost of [redacted] for this portion of the costs in the Rockingham System Interconnect Study. I used [redacted] in the estimate[redacted] is uncomfortable with the assumption that the system upgrade costs should not be included in the Avoided Cost and is following up further.
4. Gas Transmission and Interconnect Costs: PEC does not include any Transco or Piedmont costs in the capital portion of their avoided costs. We agreed that the cost of the onsite M&R station should be in the capital cost but I get the feeling that we were talking past each other because they later came back and said that no Piedmont costs are included in the capital Avoided Cost. To me, this would imply that it should be then included in the FOM costs. I believe that [redacted] is also following up on this. I have included $[redacted] for the on-site M&R station in the estimate.
5. Owner's Costs - Our overall owner's costs were not much different so I used $[redacted] across the board.

6. Contingency - [redacted]'s direction was that the capital cost for avoided cost purposes should be reflective of a 50/50 chance of meeting or exceeding the cost during execution whereas a board approval estimate may be [redacted]%. With that in mind [redacted] told me to use [redacted]% total contingency because that is what both Buck and Dan River look like they will come in at in the end with a combination of Shaw and Duke contingency. This is what is included "Normalized A" tab. I have a concern that the S&L estimate could be provided as backup or requested by the Public Staff, therefore, I have done a separate normalized cost in "Normalized B" tab which uses the S&L contingency in the normalized estimates as a dollar value.
7. Plant Output – I normalized the outputs for the $/KW calculations since there were minor differences in temperature and elevation assumptions but the plants had the same equipment.

My understanding is that [redacted] would like to use an average normalized costs PEC and DEC with sufficient backup. I think we are close but need to finalize assumptions.

I had planned to be off today hiking around waterfalls but due to weather I will be working from home this morning and tomorrow morning. If you have any questions call my cell phone or set up a teleconference.

[redacted]
Engineering Manager, CTCC Projects
Duke Energy
[redacted] office
[redacted] cell

Fentress, Kendrick C

From: [redacted]
Sent: Wednesday, September 12, 2012 10:11 AM
To: [redacted]
Subject: RE: Avoided Cost Filing

[redacted]

We will need to work with [redacted] and [redacted] to ensure we have a common process in place to get delivered gas costs to the plants (delivered coal as well). Also I am assuming we are modeling dispatch based on replacement fuel costs and as such do not include contracted fuel for the avoided cost calc. Is that your understanding?

Best Regards,

[redacted]

From: [redacted]
Sent: Tuesday, September 11, 2012 5:56 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Avoided Cost Filing

I hope to have a common gas price by the end of the week, so modeling could begin next week.

We spoke to the rates area this morning and we are going to try to have the following common cost.

- CT capital cost and Fixed O&M cost (I have a meeting on Thursday to hopefully come to a agreement)
    - Transmission and maybe Gas cost adders
    - Life of Asset
- CT block size
- Common escalation rate
    - We are going to run by [redacted]
- Common Natural Gas Cost
    - I need to schedule something but most of the work has been done

As you can see we still have a lot of moving parts, schedule a call for Friday morning and hopefully we will have a path forward.

[redacted]
Integrated Resource Planning
[redacted]

From: [redacted]
Sent: Tuesday, September 11, 2012 4:14 PM
To: [redacted]
Cc: [redacted]
Subject: Avoided Cost Filing

[redacted]

I hear tha[redacted]wants the modeling work on the Avoided Cost filing to be complete by Sept. 30th.
To do that [redacted]need to get the gas price forecast as soon as possible.
We will be using this study to pass[redacted]s knowledge to[redacted], so we don't want to rush too much.

What is the expected delivery date for the gas price?

Thanks,

[redacted]
email:[redacted]

P-7

Fentress, Kendrick C

From: [redacted]
Sent: Friday, September 14, 2012 11:31 AM
To: [redacted]
Subject: Re: [redacted]ices

No problem I am on it

From: [redacted]
Sent: Friday, September 14, 2012 11:30 AM
To: [redacted]
Subject: FW:PEC/DEC Gas Prices

[redacted] as you can see with the attached image spot gas is only traded out about 3 years. Do you have anybody that can give us a quote from a broker or over the counter specific counterparty that can give us a 5 year market price. I really don't want to use the spot price when there are no trades?

Below is the note [redacted] sent to me earlier.

[redacted]

The table below shows the NYMEX natural gas trading for yesterday. You can see the volume (last column) drops off quickly about 18 months out. I also checked with Sequent Energy's forward trader and he confirmed that you can trade on the NYMEX about 3 years out and beyond that you typically trade over the counter with a specific counterparty. Let me know if you have questions.

Thanks,

[redacted]

[redacted]

Integrated Resource Planning

[redacted]

Fentress, Kendrick C

From: [redacted] (Marketing Employee [redacted]
Sent: Monday, September 17, 2012 1:39 PM
To: [redacted]
Cc: [redacted]
Subject: RE: request for HH gas quotes

[redacted]

We can provide a bid//offer curve based on Friday's close.

I will call to discuss but I've to JP Morgan who deals with trades out the curve and here is general indications for bid / offers:

2013 and 2014 – [redacted] cents
2015 and 2016 – [redacted] cents
2017 and 2018 – [redacted] cents

Some of this depends on the day, how much activity is occurring, and should be viewed as indicative. The further you go out the less liquid it gets. I want to call another bank and see if they are in the same range.

The numbers I used for getting these indications was ~ [redacted] day.

Hope this helps. If you need these, [redacted] can put this together.

[redacted]

From: [redacted]
Sent: Monday, September 17, 2012 11:18 AM
To: [redacted]
Cc: [redacted]
Subject: request for HH gas quotes

[redacted]

As you know we are filing an avoided cost rate on November 1 for both DEC and PEC. As part of that filing we are seeking to use a common gas price forecast for both DEC and PEC. I would like to use the market for the first 5 years based on broker quotes, nymex or whatever source you are comfortable with. From there we will either blend to the fundamentals in order to go out 15 years or if the market quotes align with the fundamentals we may go straight to the fundamentals for cal 2018. The modeling group needs to start modeling tomorrow and finish by week's end to stay on schedule with the work that needs to be done to support this filing. Would you please provide your best estimate of mid-market HH gas prices by calendar year for the years 2013, 2014, 2015, 2016 and 2017. I would like to discuss your thoughts on liquidity for 2016 and 2017 if you have a moment. Thanks so much for your help with respect to this request.

Best Regards,

[redacted]
Director, Carolinas Resource Planning and Analytics
Duke Energy
526 South Church Street
Charlotte, NC 28202

Fentress, Kendrick C

From: [redacted]
Sent: Wednesday, September 19, 2012 4:57 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Please update HH gas prices for use in the avoided cost filings at DEC and PEC

Chris,

Where can I find the DEC fundamental curve?
See [redacted]'s request below.

Thanks,
[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 4:40 PM
To: [redacted]
Cc: [redacted]
Subject: Please update HH gas prices for use in the avoided cost filings at DEC and PEC

[redacted]

Current calendar HH gas prices for the front years are provided in this spreadsheet. Please use these for nominal calendar values and shape them into monthly prices using the monthly shapes in the fundamentals database. Remember to use consistent HH gas prices between DEC and PEC throughout the analysis based on these prices and then based on the DEC fundamental curves 2019 and beyond.

Please call me on my cell phone and/or conference with Chris if you have any questions.

Thanks
[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 2:32 PM
To: [redacted]
Subject: RE: NYMEX vs. JPM offers

How does this look? I hope I did the interpolation correctly.

--
[redacted]
Duke Energy - Strategy & Planning
Integrated Resource Planning
[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 2:03 PM
To: [redacted]
Subject: FW: NYMEX vs. JPM offers

[redacted],

Would you please put a 2013 through 2019 comparison together comparing the fundamental prices currently being used compared to the prices below with a one year interpolation in 2018 to the fundamentals in 2019.

Thanks so much.

[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 1:43 PM
To: [redacted]
Subject: [redacted]: NYMEX vs. JPM offers

These are the Cal indicative offers I requested from JPM, let me know if you need anything else. Jim

From: [redacted]
Sent: Wednesday, September 19, 2012 1:41 PM
To: [redacted]
Cc: [redacted]
Subject: NYMEX vs. JPM offers

Jim,

Circled up with John with regards to the indicative calendar strip pricing. Please see the current mid-market NYMEX levels, as well as our current indicative offers. As you can see, the NYMEX pricing and our offers are generally in line.

Should you need anything else, please don't hesitate to reach out.

	NYMEX (mid market)	JPM Offer
Cal13	[redacted]	[redacted]
Cal14	[redacted]	[redacted]
Cal15	[redacted]	[redacted]
Cal16	[redacted]	[redacted]
Cal17	[redacted]	[redacted]

Thanks,

[redacted] | Analyst | Energy Derivative Sales and Structuring | J.P. Morgan [redacted] 10th Floor, New York, NY 10179 | T: [redacted] F: [redacted] | M: [redacted] | AOL/Yahoo: yrubinjpmc

and is not intended as such. This material is for the general information of our clients and is a "solicitation" only as that term is used within CFTC Rule 1.71 and 23.605 promulgated under the U.S. Commodity Exchange Act.

Fentress, Kendrick C

From: [redacted]
Sent: Thursday, September 20, 2012 8:19 AM
To: [redacted]
Subject: RE: Please update HH gas prices for use in the avoided cost filings at DEC and PEC

[redacted] and [redacted] are just starting to work on their part. [redacted] just delivered the HH gas prices for the avoided cost runs. [redacted] is going to shape the annual market prices into monthly. After that, I have to get with [redacted] to get delivered gas prices for DEC. Hopefully, I will start making some runs this afternoon.

--
[redacted]
Duke Energy - Strategy & Planning
Integrated Resource Planning
[redacted]

From: [redacted]
Sent: Thursday, September 20, 2012 7:45 AM
To: [redacted]
Subject: Fw: Please update HH gas prices for use in the avoided cost filings at DEC and PEC

[redacted] what is the status of avoided cost [redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 04:57 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Please update HH gas prices for use in the avoided cost filings at DEC and PEC

[redacted]

Where can I find the DEC fundamental curve?
See [redacted]s request below.

Thanks,
[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 4:40 PM
To: [redacted]
Cc: [redacted]
Subject: Please update HH gas prices for use in the avoided cost filings at DEC and PEC

[redacted]

Current calendar HH gas prices for the front years are provided in this spreadsheet. Please use these for nominal calendar values and shape them into monthly prices using the monthly shapes in the fundamentals database. Remember to use consistent HH gas prices between DEC and PEC throughout the analysis based on these prices and then based on the DEC fundamental curves 2019 and beyond.

Please call me on my cell phone and/or conference with [redacted] if you have any questions.

Thanks

[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 2:32 PM
To: [redacted]
Subject: RE: NYMEX vs. JPM offers

How does this look? I hope I did the interpolation correctly.

--
[redacted]
Duke Energy - Strategy & Planning
Integrated Resource Planning
[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 2:03 PM
To: [redacted]
Subject: FW: NYMEX vs. JPM offers

[redacted]

Would you please put a 2013 through 2019 comparison together comparing the fundamental prices currently being used compared to the prices below with a one year interpolation in 2018 to the fundamentals in 2019.

Thanks so much.

[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 1:43 PM
To: [redacted]
Subject: FW: NYMEX vs. JPM offers

These are the Cal indicative offers I requested from JPM, let me know if you need anything else. Jim

---

From: [redacted]
Sent: Wednesday, September 19, 2012 1:41 PM
To: [redacted]
Cc: [redacted]
Subject: NYMEX vs. JPM offers

[redacted]

Circled up with [redacted] with regards to the indicative calendar strip pricing. Please see the current mid-market NYMEX levels, as well as our current indicative offers. As you can see, the NYMEX pricing and our offers are generally in line.

Should you need anything else, please don't hesitate to reach out.

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	NYMEX (mid market)	JPM Offer
Cal13	[redacted]	[redacted]
Cal14	[redacted]	[redacted]
Cal15	[redacted]	[redacted]
Cal16	[redacted]	[redacted]
Cal17	[redacted]	[redacted]

Thanks,

[redacted] | Analyst | Energy Derivative Sales and Structuring | **J.P. Morgan** | [redacted] 10th Floor, New York, NY 10179 | T: [redacted] | F: [redacted] | M: [redacted] | AOL/Yahoo: yrubinjpmc

Fentress, Kendrick C

From: [redacted]
Sent: Thursday, September 20, 2012 10:33 AM
To: [redacted]
Cc: [redacted]
Subject: RE: HH gas prices for use in the avoided cost filings at DEC and PEC
Attachments: Henry Hub Gas Price_Composite Curve for 2012 Avoided Cost.xlsx

All,

Per [redacted]s instructions below, the attached spreadsheet contains the composite Henry Hub price curve through 2036. Please apply this Henry Hub forecast to DEC and PEC transportation adders as appropriate.

Thanks,

[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 4:40 PM
To: [redacted]
Cc: [redacted]
Subject: Please update HH gas prices for use in the avoided cost filings at DEC and PEC

[redacted]

Current calendar HH gas prices for the front years are provided in this spreadsheet. Please use these for nominal calendar values and shape them into monthly prices using the monthly shapes in the fundamentals database. Remember to use consistent HH gas prices between DEC and PEC throughout the analysis based on these prices and then based on the DEC fundamental curves 2019 and beyond.

Please call me on my cell phone and/or conference with [redacted] if you have any questions.

Thanks

[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 2:32 PM
To: [redacted]
Subject: RE: NYMEX vs. JPM offers

How does this look? I hope I did the interpolation correctly.

--
[redacted]
Duke Energy - Strategy & Planning
Integrated Resource Planning
[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 2:03 PM
To: [redacted]
Subject: FW: NYMEX vs. JPM offers

[redacted]

Would you please put a 2013 through 2019 comparison together comparing the fundamental prices currently being used compared to the prices below with a one year interpolation in 2018 to the fundamentals in 2019.

Thanks so much.

[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 1:43 PM
To: [redacted]
Subject: FW: NYMEX vs. JPM offers

These are the Cal indicative offers I requested from JPM, let me know if you need anything else[redacted]

From: [redacted]
Sent: Wednesday, September 19, 2012 1:41 PM
To: [redacted]
Cc: [redacted]
Subject: NYMEX vs. JPM offers

[redacted]

Circled up with [redacted] with regards to the indicative calendar strip pricing. Please see the current mid-market NYMEX levels, as well as our current indicative offers. As you can see, the NYMEX pricing and our offers are generally in line.

Should you need anything else, please don't hesitate to reach out.

	NYMEX (mid market)	JPM Offer
Cal13	[redacted]	[redacted]
Cal14	[redacted]	[redacted]
Cal15	[redacted]	[redacted]
Cal16	[redacted]	[redacted]
Cal17	[redacted]	[redacted]

Thanks,

[redacted] | Analyst | Energy Derivative Sales and Structuring | **J.P. Morgan** | [redacted]0th Floor, New York, NY 10179 | T: [redacted] | F: [redacted] M: [redacted] AOL/Yahoo: yrubinjpmc

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[redacted]

From: [redacted]
Sent: Tuesday, January 15, 2013 11:38 AM
To: [redacted]
Subject: [redacted]

[redacted]

From: [redacted]
Sent: Friday, September 21, 2012 8:24 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Avoided Cost Filing

[redacted]/[redacted] the [redacted]%/year rate is correct. [redacted]

From: [redacted]
Sent: Thursday, September 20, 2012 2:39 PM
To: [redacted]
Cc: [redacted]
Subject: Avoided Cost Filing

Hi [redacted],
It was a pleasure talking with you.
Please feel free to call me if you have any questions as you review the ECC and fixed charge calculation from the PEC avoided cost file.

[redacted] – [redacted] confirmed that the escalation rate applied in the DEC IRP was [redacted]%, and is appropriate to use for both PEC and DEC avoided cost filings.
This rate would apply to both construction and O&M costs.

[redacted] please correct if I mis- stated the rate or if it should be any different.
Thanks!

[redacted]

Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone: [redacted] *Voicenet* [redacted]

From: [redacted]
Sent: Tuesday, October 02, 2012 12:02 PM
To: [redacted]
Cc: [redacted]
Subject: Avoided Fuel Cost for CSP with StartCost from Sep 2012 IRP_to [redacted] xlsx

[redacted]

Please find attached the avoided energy cost for the 2012 Avoided Cost filing.
We have supplied annual, on-peak, and off-peak avoided energy values for 2013 through 2031.
Values for 2013 through 2026 are highlighted.

The avoided energy cost includes variable O&M this time, so you probably should not add any additional variable O&M.
Other components of the avoided energy cost include fuel, SO2 and NOx allowances, startup O&M, and purchased energy.

Please contact me if you have questions.

Thanks,
[redacted] << File: Avoided Fuel Cost for CSP with StartCost from Sep 2012 IRP_to [redacted] xlsx >>

P41

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:24 AM
To: [redacted]
Subject: FW: Avoided Fuel Cost for CSP with StartCost from Sep 2012 IRP_to[redacted]xlsx

---

From: [redacted]
Sent: Tuesday, October 02, 2012 12:27 PM
To: [redacted]
Cc: [redacted]
Subject: FW: Avoided Fuel Cost for CSP with StartCost from Sep 2012 IRP_to[redacted]xlsx

Thanks [redacted], [redacted]
I will check back with you with a list of the supporting data files that the public staff requests.

[redacted] – the avoided energy costs are now included in the incremental energy costs.
(I will zero out the separate VOM input in the avoided cost file with a note)

On a ¢/ kwhr basis, compared to the 2010 CSP filing, incremental energy seems to be [redacted] lower on peak, and roughly [redacted] lower off- peak.
This translates to a roughly [redacted]% - [redacted]% decline in avoided incremental energy costs.

[redacted]

From: [redacted]
Sent: Tuesday, October 02, 2012 12:02 PM
To: [redacted]
Cc: [redacted]
Subject: Avoided Fuel Cost for CSP with StartCost from Sep 2012 IRP_to[redacted].xlsx

[redacted]

Please find attached the avoided energy cost for the 2012 Avoided Cost filing.
We have supplied annual, on-peak, and off-peak avoided energy values for 2013 through 2031.
Values for 2013 through 2026 are highlighted.

The avoided energy cost includes variable O&M this time, so you probably should not add any additional variable O&M. Other components of the avoided energy cost include fuel, SO2 and NOx allowances, startup O&M, and purchased energy.

Please contact me if you have questions.

Thanks,

[redacted]

From: [redacted]
Sent: Monday, January 14, 2013 3:33 PM
To: [redacted]
Subject: FW: CT costs

Can you print for me with attachments?

From: [redacted]
Sent: Thursday, October 04, 2012 10:55 AM
To: [redacted]
Cc: [redacted]
Subject: FW: [redacted]

[redacted],

Thanks for forwarding the peaker construction costs,
I'm guessing these are listed in columns I – K of the "Normalized A" worksheet, listing the $[redacted]/kw construction cost for total [redacted]mw capacity.

I'd like to confirm the following related items, and we can talk through some of these if that's easier. Also, if any of these are best confirmed with someone else, let me know and I can check in with them.

- Technology
- Number of units / site ,greenfield or brownfield
- Seasonal ratings per unit (the PEC avoided cost calculation uses a seasonal blend of construction and fixed o&M rates)
- Construction spending curve – I'd also like to confirm whether this is an overnight cost (that needs escalation adjustments in the revenue requirements) or not.
- Fixed O&M cost / kw –mo (2012$)
- Useful life

You also mentioned this excludes transmission costs, and we can talk about this. My recollection was that it would be reasonable to add it as an avoided cost for QFs that supplied into our distribution system, not transmission. Currently- most of PEC QFs I believe are supplying into the transmission system.

[redacted]

Simple Cycle Capital Compariso...

From: [redacted]
Sent: Thursday, October 04, 2012 8:21 AM

P43

To: [redacted]
Subject: CT costs

[redacted]

Per my voicemail please call with any questions.

Best Regards,
[redacted]

From: [redacted]
Sent: Wednesday, October 03, 2012 3:05 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Updated Spreadsheet

[redacted]

My last spreadsheet is attached. We agreed to use the Normalized A tab. [redacted] concurred with this.

[redacted]
Engineering Manager, CTCC Projects
Duke Energy
[redacted] office
[redacted] cell

From: [redacted]
Sent: Wednesday, October 03, 2012 2:24 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Updated Spreadsheet

Hello [redacted]

Sorry for the long winded voicemail. Could you send me the agreed upon new build CT numbers that we came up with in our last meeting. I know we still have to discuss the transmission aspect but for now I would like to start working with the "inside the fence" costs that have been developed using both the Burns and Mac and S&L studies.

Thanks again and please feel free to call my cell phone if you would like to discuss.

Best Regards,

[redacted]
Director, Carolinas Resource Planning and Analytics
Duke Energy
526 South Church Street
Charlotte, NC 28202

Office [redacted]
Cell [redacted]

From: [redacted]
Sent: Wednesday, August 29, 2012 12:55 PM
To: [redacted]
Cc: [redacted]
Subject: Updated Spreadsheet

Please see attached spreadsheet where I have added a third worksheet called "Review" with normalization based on parameters suggested by [redacted]

[redacted]
Engineering Manager, CTCC Projects
Duke Energy
[redacted] office
[redacted] cell

P45

[redacted]

From: [redacted]
Sent: Tuesday, January 15, 2013 11:58 AM
To: [redacted]
Subject: FW: Avoided cost files
Attachments: Avoided Costs 2012.xlsx

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[redacted]

From: [redacted]
Sent: Thursday, October 11, 2012 4:22 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Avoided cost files

[redacted]

Here are the avoided energy costs for 2012. It is my understanding that the costs for a new CT should be finalized tomorrow.

[redacted]
Duke Energy - Strategy & Planning
Integrated Resource Planning
[redacted]

From: [redacted]
Sent: Thursday, October 11, 2012 9:49 AM
To: [redacted]
Subject: Avoided cost files

Just checking to see when you thought I would get the avoided cost files from your group? I know [redacted] has been on vacation and it looks like [redacted] is going on vacation so I wanted to check.

[redacted]

P49

Fentress, Kendrick C

From: [redacted]
Sent: Monday, October 15, 2012 8:18 AM
To: [redacted]
Cc: [redacted]
Subject: Car_Generic Unit Char with Gas 2012.xlsx
Attachments: Car_Generic Unit Char with Gas 2012.xlsx

Hi [redacted]
Do you have an update to the avoided peaker costs that need to be applied to the avoided cost filing.
I am finalizing my analysis and reviewing numbers this week, and would like to send the updated tariff for internal review by end of this week.

Last when we talked, you were expecting to add avoided transmission costs to this estimate.
Thanks!

[redacted]

<<Car_Generic Unit Char with Gas 2012.xlsx>>

[redacted]

From: [redacted]
Sent: Monday, October 15, 2012 3:25 PM
To: [redacted]
Subject: FW: Inclusion of appropriate transmission costs in the avoided cost rate

I did get a response from [redacted] that no additional incremental avoided transmission costs need to be added to the avoided cost calculation. So what I have received to date is OK.

From: [redacted]
Sent: Monday, October 15, 2012 1:56 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Inclusion of appropriate transmission costs in the avoided cost rate

[redacted] and [redacted],

The CT costs that have been provided have the appropriate transmission costs included for the construction of the associated switchyard and connection to the grid. With respect to avoided system upgrade costs there are no system avoided upgrade costs. In short, when a QF provider connects to the transmission system they do not avoid upgrade costs on behalf of the retail customer. While they pay for any system upgrade costs the QF customer is then refunded for the upgrades over time. The only reason the QF customer pays up front, subject to a refund, is to ensure the upgrade costs are not incurred without the benefit of the actual generation project. In short retail customers ultimately pay for any system upgrades a new QF customer imposes on the system and as such there is no avoided benefit. This conclusion has been reached after discussing this issue with transmission planning.

It should be noted that there could be an avoided benefit for an EE resource when load is reduced. This would be an issue for EE cost effectiveness or other related load reducing programs or rates. I only mention this because I believe there is still a need to develop a "generic $/kW avoided transmission cost" for certain types of economic analysis even though it does not apply to the avoided cost rate calculation. We should keep the Wednesday meeting to discuss the methodology for this calculation as Jeff still needs some input for his project. To that end I will forward Jeff the meeting request so he can hear the discussion first hand.

Please feel free to call or email if you have any further questions.

Best Regards,

[redacted]

Director, Carolinas Resource Planning and Analytics

Duke Energy
526 South Church Street
Charlotte, NC 28202

Office [redacted]
Cell [redacted]

From: [redacted]
Sent: Monday, October 15, 2012 8:18 AM
To: [redacted]
Cc: [redacted]
Subject: Car_Generic Unit Char with Gas 2012.xlsx

Hi [redacted], [redacted],
Do you have an update to the avoided peaker costs that need to be applied to the avoided cost filing.
I am finalizing my analysis and reviewing numbers this week, and would like to send the updated tariff for internal review by end of this week.

Last when we talked, you were expecting to add avoided transmission costs to this estimate.
Thanks!

[redacted]

<< File: Car_Generic Unit Char with Gas 2012.xlsx >>

P61

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:24 AM
To: [redacted]
Subject: FW: Draft PEC Avoided Cost file (CSP 29)

From: [redacted]
Sent: Thursday, October 18, 2012 12:10 PM
To: [redacted]
Cc: [redacted]
Subject: Draft PEC Avoided Cost file (CSP 29)

[redacted]
Here is the draft CSP 29 calculation for your review. Overall avoided capacity rates have declined by [redacted]% - [redacted]%, and avoided energy rates declined by 14% - 29% when compared to the currently PEC CSP 27.

2012 AVOIDED
:OST using Gas Pe..

[redacted] - [redacted] will be back next week to review this, but here's my first cut if you'd like to compare to what you are getting. When you are close to your final version, you can send it on and I could compare the 2 utility rates at a high level.

<u>Key Drivers</u>

- **<u>Avoided Capacity Costs</u>:**
  - <u>Increased Capacity ratings</u>:
    While the construction costs of the average generic CT / site (GE 7FA machines) of $[redacted] per unit reflects a ≈[redacted]% annual escalation rate from the $[redacted]/ unit in the 2010 CSP 27, the [redacted]% to [redacted]% increase in CT ratings drove an overall [redacted]% decline in capacity costs / kw vs. the 2010 cost. Here's a comparison vs. the updated CT costs vs. costs in the last approved CSP 27 (you'll notice that fixed O&M costs also declined):

    Simple Cycle Costs.xlsx

    CT Costswith Gas-Final [redacted]%.x...
  - <u>Useful life of a CT</u>
    I have changed the life of the CT from 25 years to 30 years to be consistent with DEC [redacted] and I have not heard anything more definite of this term from Accounting either. This extension of the CT life by 5 years contributed to over a third of the overall decline in avoided capacity rates for PEC.

Note – overall I have tried to stay with the ½ year AFUDC & CPI calculation applied in the last filings, and with DEC's approach. If we do want to simplify it to zero AFUDC & CPI in the year of spending (or 2 years of AFUDC & CPI for a 3 year construction period), this will reduce the all in avoided capacity rates by another [redacted]% - [redacted]%. (I have included alternate revenue requirement sheets in the avoided cost file to compare this and other variations).

- **<u>Avoided Energy Costs</u>**: Delta Production costs including VOM fell by [redacted]% - [redacted]% on peak, and [redacted]% - [redacted]% off peak, mostly driven by the lower avoided energy costs (including VOM) over the 15 year term. If you compare fuel + VOM costs for the same years between the versions (e.g., 2013 vs. 2013...), the decline is [redacted] at [redacted]% - [redacted]% on peak and [redacted]% - [redacted]% off peak.
  Here's an annual comparison between versions:

  CSP 29 vs 27
  Avoided Energy.xl...

[redacted]
Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone: [redacted] *Voicene*[redacted]

Fentress, Kendrick C

From: [redacted]
Sent: Thursday, October 18, 2012 2:27 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Other AC energy questions
Attachments: Fuel Comparison 2010 and 2012.xlsx; Load Forecast Compare 2010 and 2012.xlsx

Here are the fuel price and load comparisons. For the loads, I included with and without energy efficiency since a lot of the changes since 2010 have been in EE.

The gas prices have dropped around 40% since the 2010 avoided cost filing. This is mainly due a greater supply of gas in the market. The coal prices haven't changed a lot, but we are now projecting different coal blending strategies for several of the units. The mix of generation has shifted to a lot more combined cycle. [redacted] and those units will be [redacted] In 2010, the [redacted] were projected to be [redacted].

Do you need anything else?

--
[redacted]
Duke Energy - Strategy & Planning
Integrated Resource Planning
[redacted]

From: [redacted]
Sent: Thursday, October 18, 2012 10:54 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Other AC energy questions

[redacted]

I need to get my draft out in the next day or do. Is there anyway I can get this information soon?

[redacted]

From: [redacted]
Sent: Friday, October 12, 2012 3:03 PM
To: [redacted]
Cc: [redacted]
Subject: Other AC energy questions

[redacted]

Can I get the load Comparison?
Also can I get an written explanation of the differences. In the past you have addressed the following points;

[redacted]

P75

From: [redacted]
Sent: Thursday, October 18, 2012 4:32 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Useful life of a Combustion Turbine

Let us do a little digging and get back with you. I do believe we have this we just need to go through the files. Thanks, [redacted]

[redacted] *CPA*
Manager, Regulatory and Property Accounting - PEC
Accounting Department - PEB 18
Progress Energy Service Company
[redacted]

From: [redacted]
Sent: Thursday, October 18, 2012 3:42 PM
To: [redacted]
Cc: [redacted]
Subject: Useful life of a Combustion Turbine

Hi [redacted]
I am looking for a useful life estimate for a new CT. I have talked with [redacted] in light of the new depreciation study, and while she could not find the useful life of a new CT, she suggested running it by you.

This relates to a PEC avoided cost tariff to purchase power from small qualified facilities to be filed with the NCUC on November 1st. The useful life of a CT drives the annual capacity cost in this tariff (based on the cost of an avoided peaker).

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Currently, DEC is going through this same process on their tariff, and they have been using 30 years. This round though, PEC and DEC will both use the same CT technology and cost assumptions, and the same useful life. My counterpart in DEC researched this same question, and has not found a conclusive finding pinpointing the life of a new CT.

Lacking additional information, we are leaning towards using one of the two (likely 30 years), but wanted to be sure we are not missing some information to do otherwise.

Do you have any information or suggestions on this?

Thanks!

[redacted]

Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone: [redacted] *Voicenet* [redacted]

Fentress, Kendrick C

From: [redacted]
Sent: Friday, October 19, 2012 1:28 PM
To: [redacted]
Cc: [redacted]
Subject: Capacity cost
Attachments: Scanned at ECII-0654001.pdf

I have attached the information we supplied to the Public Staff in 2010 regarding the development of the Company's capacity credits. Due to the fact that DEC's cost per KW in the current filing is [redacted] vs [redacted] in the 2010 filing, I am sure the Public Staff is going to want the differences detailed. I normally try to summarize issues like this in a document for [redacted] before filing.

Is there any way we can get documentation or explanation of the differences before October 29th?

If I can be of any help please let me know.

[redacted]

From: [redacted]
Sent: Monday, October 08, 2012 1:07 PM
To: [redacted]
Cc: [redacted]
Subject: Avoided Peaker Assumptions - Questions received during DEC avioded cost 2010 process

<<Scanned at ECII-0654001.pdf>>

[redacted]

-----Original Appointment-----
From: [redacted]
Sent: Monday, October 08, 2012 9:15 AM
To: [redacted]
Cc: [redacted]
Subject: Avoided Peaker Assumptions
When: Monday, October 08, 2012 2:00 PM-2:30 PM (GMT-05:00) Eastern Time (US & Canada).
Where: Call in line: [redacted] / [redacted]

Participant code: [redacted]

To confirm key assumptions around the avoided peaker:
1) Construction spending curve
2) Fixed O&M
3) Useful life

[redacted] - thanks for confirming the fuel type for the PEC avoided cost filing, which will be gas (also consistent with DEC).
[redacted]- I have you as an optional attendee.

[redacted]

Duke Energy Carolinas, LLC's Responses to Public Staff's Economic Research Division
Data Request No. 1 Dated December 9, 2010
Docket No. E-100, Sub 127
Response Date: January 7, 2011

2. For purposes of the following questions, please refer to the development of the Company's capacity credits.

(D) Please identify the combustion turbine (CT) that underlies the proposed avoided capacity costs. This response should include the manufacturer, model number, the proposed number of CTs assumed to be located at the site, summer and winter ratings, primary fuel source, average heat rate, incremental heat rate, per unit start costs, and whether it is duct-fired and has dual-fuel capacity.

RESPONSE: See Confidential Attachment to Question 2-D – CT identification.pdf.

(E) Please identify the following cost components that support the installed cost of the CT used to develop the proposed capacity credit:

1. Plant Equipment and Installation
2. Engineering and Project Management
3. Administrative and General Expenses
4. Spare parts
5. Taxes
6. AFUDC
7. Property Acquisition
8. Gas Pipeline and connection
9. Electric Transmission connection
10. Total Project Cost
11. Total Project Cost per kW

RESPONSE: See Confidential Attachment to Question 2-E – Cost Components.pdf.

G. Please provide excerpts from the 2009-2010 "Gas Turbine World Handbook" that support the cost of the installed CT identified in this proceeding. A similar excerpt was provided to the Public Staff in a data request response in Docket No. E-100, Sub 87, that was supportive of the Company's installed CT costs.

RESPONSE: See Attachment to Question 2-G – Cost Components.pdf. Duke Energy generally does not utilize the Gas Turbine World Handbook for estimating project cost or performance when actual projects are underway that have similar costs or characteristics; however, the Company's Generic CT cost used in this proceeding is consistent with the "equipment-only" price of the PG7241FA model simple cycle CT reported in "Gas Turbine World, 2010 GTW Handbook" (GTW) at p. 51. Note that as stated in "Price Trends" section of the GTW (at p. 43) the prices are "equipment-only" prices and are generally accurate within plus or minus 5 percent of Original Equipment Manufacturer (OEM) competitive bid prices, depending on industry demand at the time of the bid. Thus, these price estimates are time and market dependant and do not include any additional add-on equipment or the necessary balance-of-plant equipment. Further, the GTW also states: "Keep in mind, for budget planning, that engineering and construction services for installation can add 60 to 100%" on top of "equipment-only" prices for simple cycle plants. (GTW at p. 48).

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:20 AM
To: [redacted]
Subject: FW: Draft PEC Avoided Cost file (CSP 29)

From: [redacted]
Sent: Friday, October 19, 2012 2:00 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Draft PEC Avoided Cost file (CSP 29)

Hi [redacted]
Here are comments from [redacted] & my notes on the CSP file.
Also – here's a link to the file: CSP - 29

([redacted] please add if I missed something)

- Variable O&M: As VOM is now combined with the fuel costs (and not broken out) in the "AC_Energy" sheet, we have some items that seem redundant. He also noted that the working capital adder for fuel was now being added to the combined fuel + VOM (we talked about this).
  Here are my suggestions – let me know what you think:
  - "Work Capital" sheet: Working capital allowance rates are broken for fuel vs. non- fuel prdn O&M. Now that fuel & VOM costs are combined, I could modify the calc. in the "Work Capital" sheet to get a single combined adder for the combined costs.
  - "Input Ranges": Delete the separate VOM input (E34) & working capital for O&M (E38) or zero them with comments to make it easier for Staff as they compare versions
  - "AC_Energy": delete the separate VOM column f (for now I have a footnote (2) on that page why this has zeros)

- Revenue Req. calcs.:
  - [redacted] and I both agreed that the "Cost of Service 2 year AFUDC " calculation looked cleaner and simpler than the 2.5 year being applied right now. This version simply treats each year of spend as if it happened at the end of the year, and a full year of afudc and CPI is applied in the next year.

  - Labeling on the rate base components was wrong (stale as to end of year vs. beg. Of year), and I have corrected them.

    Note : the npv vs. cpvrr test at the end of this sheet is for my review and I can remove it from the official version for the tariff

[redacted] also noted that this is the first time we have switched to a gas rating for the peaker for PEC.
[redacted] proposed the change and felt he could explain it with the joint PEC & DEC review.

P83

Also, Here is recent comparison of PEC & DEC all in proposed rates (combined capacity & energy), using draft files from [redacted]:

DEC vs PEC 2012 Filing.xlsx

[redacted]

From: [redacted]
Sent: Thursday, October 18, 2012 12:10 PM
To: [redacted]
Cc: [redacted]
Subject: Draft PEC Avoided Cost file (CSP 29)

[redacted]

Here is the draft CSP 29 calculation for your review. Overall avoided capacity rates have declined by [redacted]% - [redacted]%, and avoided energy rates declined by 14% - 29% when compared to the currently PEC CSP 27.

<< File: 2012 AVOIDED COST using Gas Peakers.xlsx >>

[redacted] - [redacted] will be back next week to review this, but here's my first cut if you'd like to compare to what you are getting. When you are close to your final version, you can send it on and I could compare the 2 utility rates at a high level.

__Key Drivers__

- **__Avoided Capacity Costs__:**
  - __Increased Capacity ratings__:
    While the construction costs of the average generic CT / site (GE 7FA machines) of $[redacted] per unit reflects a ≈[redacted]% annual escalation rate from the $[redacted] / unit in the 2010 CSP 27, the [redacted]% to [redacted]% increase in CT ratings drove an overall 12% decline in capacity costs / kw vs. the 2010 cost. Here's a comparison vs. the updated CT costs vs. costs in the last approved CSP 27 (you'll notice that fixed O&M costs also declined):

    << File: Simple Cycle Costs.xlsx >> << File: CT Costswith Gas-Final 2.50%.xlsm >>
  - __Useful life of a CT__
    I have changed the life of the CT from 25 years to 30 years to be consistent with DEC. [redacted] and I have not heard anything more definite of this term from Accounting either. This extension of the CT life by 5 years contributed to over a third of the overall decline in avoided capacity rates for PEC.

Note – overall I have tried to stay with the ½ year AFUDC & CPI calculation applied in the last filings, and with DEC's approach. If we do want to simplify it to zero AFUDC & CPI in the year of spending (or 2 years of AFUDC & CPI for a 3 year construction period), this will reduce the all in avoided capacity rates by another [redacted]% [redacted]%. (I have included alternate revenue requirement sheets in the avoided cost file to compare this and other variations).

P84

- **Avoided Energy Costs**: Delta Production costs including VOM fell by [redacted]% - [redacted]% on peak, and [redacted]% - [redacted]% off peak, mostly driven by the lower avoided energy costs (including VOM) over the 15 year term. If you compare fuel + VOM costs for the same years between the versions (e.g., 2013 vs. 2013...), the decline is [redacted] at [redacted]% - [redacted]% on peak and [redacted]% - [redacted]% off peak.
  Here's an annual comparison between versions:
  << File: CSP 29 vs 27 Avoided Energy.xlsx >>

[redacted]
Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone: [redacted] *Voicenet* [redacted]

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:29 AM
To: [redacted]
Subject: FW: Useful life of a Combustion Turbine

From: [redacted]
Sent: Monday, October 22, 2012 10:34 AM
To: [redacted]
Subject: FW: Useful life of a Combustion Turbine

[redacted],

Here's information from [redacted] that lists a 40 year useful life for new CTs, in Appendix D2 of the recent PEC depreciation study. Sorry for the late timing of this input.

It sounds like the 30 year life used for the ECC in our current files should not be an issue.

Changing it to 40 per the study will certainly reduce the avoided capacity cost rate – we can talk when you get a moment.

[redacted]

Appendix D2.xls.xls

From: [redacted]
Sent: Monday, October 22, 2012 10:19 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Useful life of a Combustion Turbine

[redacted]

[redacted] has communicated with the depreciation consultant. PEC utilized a 40 year useful life expectation for our CTs in the depreciation study just filed with the NCUC and to be filed soon with SC ORS.

Thanks,

[redacted]

[redacted] *CPA*
Manager, Regulatory and Property Accounting - PEC
Accounting Department - PEB 18

Progress Energy Service Company
[redacted]

From: [redacted]
Sent: Friday, October 19, 2012 7:02 AM
To: [redacted]
Subject: RE: Useful life of a Combustion Turbine

[redacted]

Thanks – we are under a tight deadline though.
I have sent my calculations (with a 30 year life) for internal review, and they will be filed on November 1st for both PEC & DEC.

If the useful life needs to be different, I'd like to put in the change early next week (will check also with my DEC counterpart).

Thanks!

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Let us do a little digging and get back with you. I do believe we have this we just need to go through the files. Thanks, [redacted]

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Manager, Regulatory and Property Accounting - PEC
Accounting Department - PEB 18
Progress Energy Service Company
[redacted]

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Thanks!

[redacted]
Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone: [redacted] *Voicenet* [redacted]

Progress Energy Carolinas, Inc.
Generating Unit Retirement Data

PEC Generating Plants	Unit #	Fuel	Original In Svc Yr	Retirement date used in latest approved study	Est. Ret. Date	Est. Svc. Life	Sept. 2010 IRP Smr MW Cpcty Rtng
Steam							
Asheville	1	Coal	1964	2033	2031	67	191
Asheville	2	Coal	1971	2011	2033	62	185
Cape Fear - Retired	1	Coal	1923	2021	~1969		N/A
Cape Fear - Retired	2	Coal	1924	2020	~1969		N/A
Cape Fear - Retired	3	Coal	1942	2012	Cold standby		N/A
Cape Fear - Retired	4	Coal	1943	2012	Cold standby		N/A
Cape Fear	5	Coal	1956	2026	10/1/2012		144
Cape Fear	6	Coal	1958	2027	10/1/2012		172
Lee	1	Coal	1952	2032	9/1/2012		74
Lee	2	Coal	1951	2043	9/1/2012		77
Lee	3	Coal	1962	2038	9/1/2012		246
Mayo	1	Coal	1983	2036	2035	52	727
Robinson (SC)	1	Coal	1960	2037	10/1/2012		177
Roxboro	1	Coal	1966	2035	2032	66	369
Roxboro	2	Coal	1968	2037	2032	64	662
Roxboro	3	Coal	1973	2038	2035	62	693
Roxboro	4	Coal	1980	2020	2035	55	698
Sutton	1	Coal	1954	2013	12/1/2013		97
Sutton	2	Coal	1955	2015	12/1/2013		104
Sutton	3	Coal	1972	2037	12/1/2013		403
Weatherspoon	1	Coal	1949	2039	10/1/2011		48
Weatherspoon	2	Coal	1950	2031	10/1/2011		48
Weatherspoon	3	Coal	1952	2033	10/1/2011		75
Gas/Oil							
Asheville	1	Gas/Oil	1999	2035	2039	40	164
Asheville	2	Gas/Oil	2000	2035	2040	40	160
Blewett	1	Oil	1971	2017	2027	56	13
Blewett	2	Oil	1971	2017	2027	56	13
Blewett	3	Oil	1971	2017	2027	56	13
Blewett	4	Oil	1971	2017	2027	56	13
Cape Fear	1	Oil	1969	2012	2027	58	11
Cape Fear	2	Oil	1969	2012	2027	58	11
Cape Fear	3	Oil	1969	2012	2027	58	11
Cape Fear	4	Oil	1969	2012	10/1/2012	42	11
Cape Fear - Steam block only	1		1969	2012	3/31/2011	42	11
Cape Fear - Steam block only	2		1969	2012	3/31/2011	42	11
Darlington (SC)	1	Gas/Oil	1972	2031	2027	55	52
Darlington (SC)	2	Gas/Oil	1972	2031	2027	55	52
Darlington (SC)	3	Gas/Oil	1972	2031	2027	55	50
Darlington (SC)	4	Gas/Oil	1972	2031	2027	55	51
Darlington (SC)	5	Gas/Oil	1972	2031	2027	55	52
Darlington (SC)	6	Gas/Oil	1972	2031	2027	55	51
Darlington (SC)	7	Gas/Oil	1972	2031	2027	55	52
Darlington (SC)	8	Gas/Oil	1972	2031	2027	55	49
Darlington (SC)	9	Gas/Oil	1972	2031	2027	55	52
Darlington (SC)	10	Gas/Oil	1972	2031	2027	55	52
Darlington (SC)	11	Gas/Oil	1972	2031	2027	55	52
Darlington (SC)	12	Gas/Oil	1997	2032	2037	40	118
Darlington (SC)	13	Gas/Oil	1997	2032	2036	39	116
Lee	1	Oil	1968	2036	10/1/2012	59	12
Lee	2	Oil	1971	2036	10/1/2012	56	21
Lee	3	Oil	1971	2036	10/1/2012	56	21
Lee	4	Oil	1971	2036	10/1/2012	56	21
Morehead City	1	Oil	1968	2012	10/1/2012	59	12
Richmond	1	Gas/Oil	2001/02	2036	2041	40	162
Richmond	2	Gas/Oil	2001/02	2036	2041	40	167
Richmond	3	Gas/Oil	2001/02	2036	2041	40	169
Richmond	4	Gas/Oil	2001/02	2036	2041	40	163
Richmond	6	Gas/Oil	2001/02	2036	2041	40	159
Richmond	1	Gas/Oil	2002	2036	2042	40	470
Richmond	2	Gas/Oil	6/1/2011	N/A	2051	40	600
Robinson (SC)	1	Gas/Oil	1968	2012	2027	59	15

PEC Generating Plants	Unit #	Fuel	Original In Svc Yr	Retirement date used in latest approved study	Est. Ret. Date	Est. Svc. Life	Sept. 2010 IRP Smr MW Cpcty Rtng
Roxboro	1	Gas/Oil	1968	2031	Retired 12/1/2007		N/A
Sutton	1	Gas/Oil	1968	2012	2027	59	11
Sutton	2	Gas/Oil	1969	2012	2027	58	24
Sutton	3	Gas/Oil	1969	2012	2027	58	26
Sutton	1	Gas/Oil	12/1/2013	N/A	2053	40	625
Wayne County	1	Gas/Oil	2000	30 yr. rate (3.38%) used	2040	40	177
Wayne County	2	Gas/Oil	2000	30 yr. rate (3.38%) used	2040	40	174
Wayne County	3	Gas/Oil	2000	30 yr. rate used	2040	40	173
Wayne County	4	Gas/Oil	2000	30 yr. rate used	2040	40	170
Wayne County	5	Gas/Oil	2009	30 yr. rate used	2049	40	169
Wayne County	1	Gas/Oil	1/1/2013	N/A	2053	40	920
Weatherspoon	1	Gas/Oil	1970	2012	2027	57	33
Weatherspoon	2	Gas/Oil	1970	2012	2027	57	32
Weatherspoon	3	Gas/Oil	1971	2012	2027	56	34
Weatherspoon	4	Gas/Oil	1971	2012	2027	56	32
Nuclear							
Brunswick	1		1977	2036	9/8/2036	59	938
Brunswick	2		1975	2034	12/27/2034	59	920
Harris Unit	1		1987	2046	10/24/2046	59	900
Robinson (SC)	2		1971	2030	7/31/2030	59	724
Hydro							
Blewett (Technically 6 "units")	1	Hydro	1912	2037	2058	146	22
Marshall (Technically 2 "units")	1	Hydro	1910	2035	2050	140	4
Tillery (Technically 4 "units")	1	Hydro	1928	2042	2058	130	87
Walters (Technically 3 "units")	1	Hydro	1930	2042	2034	104	112

Planned Designated Generation - Sept. 2011 IRP

Wayne County		Gas/Oil	1/13		2053	40	920
Sutton Plant		Gas/Oil	12/13		2053	40	625

[redacted]

93

From: [redacted]
Sent: Tuesday, October 23, 2012 3:48 PM
To: [redacted]
Cc: [redacted]
Subject: FW: Useful life of a Combustion Turbine

Hi [redacted]

Here is recent information I received from [redacted] that the useful life of a new CT is estimated as 40 years per PEC's recently filed depreciation study with the NCUC.
This came from additional review and follow – up with their consultant.

My current analysis uses an ECC based on 30 years, and extending it another 10 years will reduce the avoided capacity cost further (I will estimate the impacts tomorrow).
However, [redacted] wanted to run this by you as it affects resource modeling assumptions, and by extension - the current avoided cost analyses.

[redacted]

From: [redacted]
Sent: Monday, October 22, 2012 10:34 AM
To: [redacted]
Subject: FW: Useful life of a Combustion Turbine

[redacted]

Here's information from [redacted] that lists a 40 year useful life for new CTs, in Appendix D2 of the recent PEC depreciation study. Sorry for the late timing of this input.
It sounds like the 30 year life used for the ECC in our current files should not be an issue.
Changing it to 40 per the study will certainly reduce the avoided capacity cost rate – we can talk when you get a moment.

[redacted]

[redacted]

From: [redacted]
Sent: Tuesday, January 15, 2013 11:20 AM
To: [redacted]
Subject: FW: Useful life of a Combustion Turbine

From: [redacted]
Sent: Wednesday, October 24, 2012 8:33 AM
To: [redacted]
Subject: RE: Useful life of a Combustion Turbine

I was not planning on changing it. Duke's new depreciation study rate equates to approx 33 years. Duke's folks would not give me a useful life.

-----Original Message-----
From: [redacted]
Sent: Tuesday, October 23, 2012 09:30 PM Eastern Standard Time
To: [redacted]
Subject: RE: Useful life of a Combustion Turbine

What's happening with this? I spoke with [redacted] only briefly. Is anyone proposing to change the CT life in the avoided cost calculations? It would seem like there is a range of reasonable number of years life for a CT. I would stick to what we have right now instead of trying to change it.

From: [redacted]
Sent: Monday, October 22, 2012 10:37 AM
To: [redacted]
Subject: FW: Useful life of a Combustion Turbine

[redacted]

[redacted]

[redacted]

From: [redacted]
Sent: Monday, October 22, 2012 10:34 AM
To: [redacted]
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[redacted]

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<< File: Appendix D2.xls.xls >>

From: [redacted]
Sent: Monday, October 22, 2012 10:19 AM
To: [redacted]
Cc: [redacted]
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[redacted] has communicated with the depreciation consultant. PEC utilized a 40 year useful life expectation for our CTs in the depreciation study just filed with the NCUC and to be filed soon with SC ORS.

Thanks,

[redacted]

[redacted] *CPA*

Manager, Regulatory and Property Accounting - PEC

Accounting Department - PEB 18

Progress Energy Service Company

[redacted]

From: [redacted]
Sent: Friday, October 19, 2012 7:02 AM
To: [redacted]
Subject: RE: Useful life of a Combustion Turbine

[redacted]

Thanks – we are under a tight deadline though.

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[redacted]

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Cc: [redacted]
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Let us do a little digging and get back with you. I do believe we have this we just need to go through the files. Thanks, [redacted]

[redacted] *CPA*

Manager, Regulatory and Property Accounting - PEC

Accounting Department - PEB 18

Progress Energy Service Company

[redacted]

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Cc: [redacted]
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Do you have any information or suggestions on this?

Thanks!

[redacted]

Lead Regulatory Specialist

PEC Utility Regulatory Planning

Duke Energy

Phone:[redacted] *Voicenet*[redacted]

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:17 AM
To: [redacted]
Subject: FW: 2012 AVOIDED COST using Gas Peakers.xlsx

From: [redacted]
Sent: Wednesday, October 24, 2012 9:12 AM
To: [redacted]
Subject: 2012 AVOIDED COST using Gas Peakers.xlsx

[redacted]

Just to close out, here's the CPVRR ratio for the construction spending assumptions:

1) Assumed mid - year spending: [redacted]'s format = [redacted]
2) Assumed mid - year spending: ECC model format = [redacted] (similar to DEC calc. by [redacted]
3) Assumed end of year spending: ECC model format = [redacted]

Currently I've applied method 2) in the file, let me know if you're OK with switching to method 3).
As we talked yesterday, switching from method 2) to 3) reduces the all in rate (capacity + energy) by 0[redacted]–[redacted] cents/ kwhr.

2012 AVOIDED
:OST using Gas Pe..

[redacted]

[redacted]

From: [redacted]
Sent: Wednesday, October 24, 2012 10:44 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Useful life of a Combustion Turbine

P102

Hi [redacted]

[redacted] did call back and indicate that he was fine with our using the 40 year useful life for the CT in our avoided cost filing, if that is part of our filed depreciation study.
He did want to have consistency between PEC and DEC on this assumption though.

[redacted] – do your [redacted] see issues with applying the 40 year life, or would be worth setting up a call to talk about it with [redacted]?

[redacted]

From: [redacted]
Sent: Tuesday, October 23, 2012 3:48 PM
To: [redacted]
Cc: [redacted]
Subject: FW: Useful life of a Combustion Turbine

Hi [redacted]

Here is recent information I received from [redacted] that the useful life of a new CT is estimated as 40 years per PEC's recently filed depreciation study with the NCUC.
This came from additional review and follow – up with their consultant.

My current analysis uses an ECC based on 30 years, and extending it another 10 years will reduce the avoided capacity cost further (I will estimate the impacts tomorrow).
However, [redacted] wanted to run this by you as it affects resource modeling assumptions, and by extension - the current avoided cost analyses.

[redacted]

From: [redacted]
Sent: Monday, October 22, 2012 10:34 AM

[redacted]

From: [redacted]
Sent: Monday, January 14, 2013 3:33 PM
To: [redacted]
Subject: FW: Useful life of a Combustion Turbine

[redacted]

From: [redacted]
Sent: Thursday, October 25, 2012 12:47 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Useful life of a Combustion Turbine

Just fyi – switching the useful life of the CT from 30 to 40 years reduced the all- in avoided cost rate by [redacted] – [redacted] cents / kwhr. I have not heard any more about the DEC useful life question, and can check back with the other folks.

For reference, here are the avoided cost files for both life assumptions.

<u>30 year life rate file</u>:
The first tab in this file compares rates from the 30 vs. 40 year calculations.

2012 AVOIDED
COST Gas Peakers ..

<u>40 year life rate file</u>:

2012 AVOIDED
COST Gas Peakers ..

[redacted]

From: [redacted]
Sent: Wednesday, October 24, 2012 2:20 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Useful life of a Combustion Turbine

I think there might be issues for DEC using a 40 year life. When I spoke with the DEC fixed asset group, they said they said they had no backup for a useful life. The DEC deprecation study does not list useful lives. They did say the new useful life that will be used equates to 33 years. I did ask about talking with the depreciation consultant but they did not feel at that time, that would be of any use. They did not believe the consultant utilizes data that would be of use.

Maybe we should have [redacted] contact his equivalent in the DEC group and to determine if a consistent life can be determined. I will be out Thursday and Friday, I will have access to email and will call into meetings but will not have access to the company share drives.

I have copied [redacted] on this email. Please copy [redacted] on all future emails regarding this topic.

[redacted]

From [redacted]
Sent: Wednesday, October 24, 2012 10:44 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Useful life of a Combustion Turbine

Hi [redacted]
[redacted] did call back and indicate that he was fine with our using the 40 year useful life for the CT in our avoided cost filing, if that is part of our filed depreciation study.
He did want to have consistency between PEC and DEC on this assumption though.

[redacted] – do your [redacted] see issues with applying the 40 year life, or would be worth setting up a call to talk about it with [redacted]?

[redacted]

From [redacted]
Sent: Tuesday, October 23, 2012 3:48 PM
To: [redacted]
Cc: [redacted]
Subject: FW: Useful life of a Combustion Turbine

Hi [redacted]
Here is recent information I received from [redacted] that the useful life of a new CT is estimated as 40 years per PEC's recently filed depreciation study with the NCUC.
This came from additional review and follow – up with their consultant.

My current analysis uses an ECC based on 30 years, and extending it another 10 years will reduce the avoided capacity cost further (I will estimate the impacts tomorrow).
However, [redacted] wanted to run this by you as it affects resource modeling assumptions, and by extension - the current avoided cost analyses.

[redacted]

From: [redacted]
Sent: Monday, October 22, 2012 10:34 AM
To: [redacted]
Subject: FW: Useful life of a Combustion Turbine

[redacted],
Here's information from [redacted] that lists a 40 year useful life for new CTs, in Appendix D2 of the recent PEC depreciation study. Sorry for the late timing of this input.
It sounds like the 30 year life used for the ECC in our current files should not be an issue.
Changing it to 40 per the study will certainly reduce the avoided capacity cost rate – we can talk when you get a moment.

[redacted]

<< File: Appendix D2.xls.xls >>

From: [redacted]
Sent: Monday, October 22, 2012 10:19 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Useful life of a Combustion Turbine

[redacted],

[redacted] has communicated with the depreciation consultant. PEC utilized a 40 year useful life expectation for our CTs in the depreciation study just filed with the NCUC and to be filed soon with SC ORS.

Thanks,
[redacted]

[redacted] CPA
Manager, Regulatory and Property Accounting - PEC
Accounting Department - PEB 18
Progress Energy Service Company
[redacted]

From: [redacted]
Sent: Friday, October 19, 2012 7:02 AM
To: [redacted]
Subject: RE: Useful life of a Combustion Turbine

[redacted]

Thanks – we are under a tight deadline though.
I have sent my calculations (with a 30 year life) for internal review, and they will be filed on November 1st for both PEC & DEC.

If the useful life needs to be different, I'd like to put in the change early next week (will check also with my DEC counterpart).

Thanks!

-[redacted]

From: [redacted]
Sent: Thursday, October 18, 2012 4:32 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Useful life of a Combustion Turbine

Let us do a little digging and get back with you. I do believe we have this we just need to go through the files. Thanks, [redacted]

[redacted] *CPA*
Manager, Regulatory and Property Accounting - PEC
Accounting Department - PEB 18
Progress Energy Service Company
[redacted]

From: [redacted]
Sent: Thursday, October 18, 2012 3:42 PM
To: [redacted]
Cc: [redacted]
Subject: Useful life of a Combustion Turbine

Hi [redacted]
I am looking for a useful life estimate for a new CT. I have talked with [redacted] in light of the new depreciation study, and while she could not find the useful life of a new CT, she suggested running it by you.

This relates to a PEC avoided cost tariff to purchase power from small qualified facilities to be filed with the NCUC on November 1st. The useful life of a CT drives the annual capacity cost in this tariff (based on the cost of an avoided peaker).

For the last several years, the useful life of a CT has been assumed to be 25 years, applied as a modeling assumption for this tariff as well as economic analysis and resource planning analysis. I have not seen the source of that life, but wanted to reach out to your group if there is a better estimate that should be applied for the life of a new CT. In prior years, this life was also run by [redacted] when he was in the Regulatory

Accounting group, and I wanted to check if there is a better estimate, in light of the new depreciation study, or if there is newer information available.

Currently, DEC is going through this same process on their tariff, and they have been using 30 years. This round though, PEC and DEC will both use the same CT technology and cost assumptions, and the same useful life. My counterpart in DEC researched this same question, and has not found a conclusive finding pinpointing the life of a new CT.

Lacking additional information, we are leaning towards using one of the two (likely 30 years), but wanted to be sure we are not missing some information to do otherwise.
Do you have any information or suggestions on this?
Thanks!

[redacted]
Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone: [redacted] *Voicenet:* [redacted]

P107

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:27 AM
To: [redacted]
Subject: FW: 2012 AVOIDED COST using Gas Peakers.xlsx

From: [redacted]
Sent: Thursday, October 25, 2012 12:14 PM
To: [redacted]
Subject: FW: 2012 AVOIDED COST using Gas Peakers.xlsx

[redacted]

I spent some time reviewing [redacted]'s calculation and found an error when I extended the book life to 30 years.
I have corrected it it in my email below - essentially the [redacted]/ installed cost ratio under Bob's method comes very close to the ratios under the ECC methods (#2) & 3) below).

I will send the 30 vs. 40 year useful life CSP files next, cc: to [redacted] and [redacted].
These will all reflect method 3 as we talked & I will delete the other rev. reqmt. methods except for [redacted]'s sheet in case we need it for Bob Hinton.

[redacted]

From: [redacted]
Sent: Wednesday, October 24, 2012 9:12 AM
To: [redacted]
Subject: 2012 AVOIDED COST using Gas Peakers.xlsx

[redacted]

Just to close out, here's the CPVRR ratio for the construction spending assumptions:

1) Assumed mid - year spending: [redacted]'s format = [redacted]
2) Assumed mid - year spending: ECC model format = [redacted] (similar to DEC calc. by [redacted])
3) Assumed end of year spending: ECC model format = [redacted]

Currently I've applied method 2) in the file, let me know if you're OK with switching to method 3).
As we talked yesterday, switching from method 2) to 3) reduces the all in rate (capacity + energy) by [redacted]-[redacted] cents/ kwhr.

2012 AVOIDED
:OST using Gas Pe..

[redacted]

From: [redacted]
Sent: Thursday, October 25, 2012 4:21 PM
To: [redacted]
Cc: [redacted]
Subject: FW: Avoided Cost Review

P113

[redacted]

Sorry I meant to send you the note below and copy [redacted] but you inadvertently got let off the list.

Thanks

[redacted]

From: [redacted]
Sent: Thursday, October 25, 2012 4:19 PM
To: [redacted]
Subject: RE: Avoided Cost Review

[redacted]

I support PEC use of a 40yr life but I think it is up to DEC&PEC asset accounting groups to come up with supporting information with respect to consistent depreciation studies. I will try and reach out to our project development group and see if the turbine vendors have any documentation or suggestions from their end.

I look forward to our discussion on Monday – have a great weekend.

[redacted]

From: [redacted]
Sent: Thursday, October 25, 2012 4:10 PM
To: [redacted]
Subject: RE: Avoided Cost Review

I also have a meeting from 10-11 on Monday, but otherwise am free in the morning. Please include [redacted].

From: [redacted]
Sent: Thursday, October 25, 2012 3:30 PM
To: [redacted]
Subject: Re: Avoided Cost Review

P114

I have a 10-11 on Mon but otherwise should be available. Please include [redacted]

[redacted] - have you made a call on the expected life yet? I would think we simply want to be consistent with what you will be using in strategist, so I think it's your call.

From: [redacted]
Sent: Thursday, October 25, 2012 02:42 PM
To [redacted]
Subject: Avoided Cost Review

[redacted] and [redacted],

[redacted] would like to have a review session on Monday to discuss the DEC and PEC filings along with some of the outstanding issues (e.g. when the old rates are suspended, CT life, differences in peak hour definitions, relationship to negotiated offering for larger than 5MW QFs etc..). I will be setting up a meeting and inviting both of you but I wanted to reach out and see who else you thought should be involved in the meeting. Also I wanted to ensure that Monday morning would work on the meeting request. I would envision about an hour meeting for us to look at the 2010 to 2012 comparison of the rates for DEC and PEC along with the general discussion on the related issues previously mentioned.

Please feel free to call or email if you have any questions.

Best Regards,
[redacted]

[redacted]
Director, Carolinas Resource Planning and Analytics
Duke Energy
526 South Church Street
Charlotte, NC 28202

Office [redacted]
Cell [redacted]

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:19 AM
To: [redacted]
Subject: FW: Draft CSP 29 Filing Package

From: [redacted]
Sent: Friday, October 26, 2012 3:52 PM
To: [redacted]
Cc: [redacted]
Subject: Draft CSP 29 Filing Package

Hi [redacted]

I have attached below a draft package of the PEC avoided cost tariff CSP -29 to be filed by November 1st for your review.

This includes the proposed attachments (changes tracked in most cases), as well as the confidential exhibits.

Overall avoided cost rates have declined in the 20% + range when compared to the currently approved tariff.

1) Cover Letter, filing statement with verification

Filing Cover Letter Draft 10-2...   NCUC Avoided Cost Filing State...

2) Attachments 1 – 4

Att 1 Redlined NC Schedule CSP...   Att 2 Clean NC Schedule CSP-29...   Att 3 Application for Standard...   Att 4 NC Terms and Conditions ...

3) Confidential Exhibits

Confidential Exhibits.pdf

Potential Change

We are still reviewing one of the assumptions in the tariff, and hope to close that out next Monday, which may change the tariff rates slightly.

Please let me know if you have any comments or questions as you review the package,

[redacted], [redacted] [redacted]– the tariff rates in this package reflect a 40 year useful life for the CT. We're hoping the useful life question can be resolved by Monday.

Applying a 40 vs. 30 year useful life assumption decreased overall avoided cost rates (capacity + energy) by [redacted]– [redacted] cents / kwhr.

Regards,

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:19 AM
To: [redacted]
Subject: FW: DEC vs. PEC avoided cost rates

From: [redacted]
Sent: Monday, October 29, 2012 9:20 AM
To: [redacted]
Cc: [redacted]
Subject: DEC vs. PEC avoided cost rates

For your reference, here is a comparison of proposed avoided cost rates between DEC vs. PEC.

- "Comparison Summary" sheet summarizes the all in rate differences between PEC & DEC, and also breaks out the average avoided capacity vs. energy pieces between the DEC and PEC calculation. Overall – the DEC all in rates appear higher, mostly driven by higher avoided energy rates in the DEC calculation.

  The avoided capacity rates for PEC are slightly higher than DEC, which may be largely driven by be higher WACC in PEC's case. The PEC calculation uses a [redacted]% WACC based on the last awarded 12.75% ROE, while DEC's calculation uses [redacted]% WACC based on the last awarded 10.50% ROE. There are other calculation differences that may contribute to or off-set this delta (30 vs. 40 year life, weighted average seasonal rating, etc.).

- "Comparison PEC 11.25ROE": At [redacted]'s request, I did run a scenario to estimate PEC's avoided cost rates at an 11.25% cost of equity applied in the WACC. As expected, PEC's avoided cost rates did decline – all in rates fell by 7 cents to 14 cents. This was largely driven by the avoided capacity which fell below DEC's avoided capacity rates.

- "Detail" worksheet lists rate details.

Comparison Summary

DEC vs PEC 2012 Filing Oct 29 ...

CSP -29 File

2012 AVOIDED :OST Gas Peakers ..

[redacted] – my comparison uses DEC avoided cost rates from the draft files you sent me on October 18th.

If these need to be updated, please send me the revised files and I can update the comparison
Thanks!

[redacted]

[redacted]
Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone: [redacted] *Voicenet* [redacted]

P117

Fentress, Kendrick C

From: [redacted]
Sent: Monday, October 29, 2012 10:58 AM
To: [redacted]
Subject: FW: Avoided Cost Review

FYI – from DEC property accounting:

From: [redacted]
Sent: Monday, October 29, 2012 10:55 AM
To: [redacted]
Subject: FW: Avoided Cost Review

From: [redacted]
Sent: Monday, October 29, 2012 10:46 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Avoided Cost Review

As a baseline, our last 4 Other Production Plant assets that went into service had the following life span in our latest depreciation study:

Mill Creek – [redacted] years
Lee – [redacted] years
Rockingham – [redacted] years
Buck – Combined Cycle – [redacted] years

[redacted]
Lead Accounting Analyst
Property Accounting
Duke Energy Corporation
550 South Tryon Street
Charlotte, N.C. 28202
Tel: [redacted]

From: [redacted]
Sent: Monday, October 29, 2012 10:34 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Avoided Cost Review

Thanks [redacted]. This would be an estimated life for new CTS rather than a composite. Our consultant used 40 as a baseline for new CTs. Does that help?

From: [redacted]
Sent: Monday, October 29, 2012 9:54 AM
To: [redacted]

P122

Cc: [redacted]
Subject: RE: Avoided Cost Review

[redacted]/[redacted] -

From the perspective of the study we have many lives along the survivor curve for each of the utility accounts across the CT/Other spectrum (341.Structures and Improvements -[redacted]yrs, 342.Fuel Holders, Producers, and Accessories [redacted]yrs, 343.Prime Movers -[redacted]yrs, 344.Generators [redacted]yrs, Accessory Electric Equipment -[redacted]yrs, Miscellaneous Plant Equipment [redacted]yrs). John Spanos does not provide a "composite" projected life for all of CT. Let me know if you would like to discuss.

Thanks!!!

[redacted]
Lead Accounting Analyst
Property Accounting
Duke Energy Corporation
550 South Tryon Street
Charlotte, N.C. 28202
Tel: [redacted]

From: [redacted]
Sent: Monday, October 29, 2012 8:02 AM
To: [redacted]
Cc: [redacted]
Subject: Fw: Avoided Cost Review

[redacted],

PEC folks have meeting this morning and were hoping to have an answer to the question below. Of you could provide one to [redacted] I would appreciate it. If you have questions let me know.

Thanks,
[redacted].

From: [redacted]
Sent: Friday, October 26, 2012 09:20 AM
To: [redacted]
Cc: [redacted]
Subject: FW: Avoided Cost Review

[redacted] – can you assist [redacted] with his question regarding our assumption in the DEC depreciation study. Thanks,

[redacted]

From: [redacted]
Sent: Friday, October 26, 2012 8:55 AM
To: [redacted]
Subject: FW: Avoided Cost Review

[redacted]

Not sure who the best contact is for the DEC depreciation study so I'll start with you! We utilized a 40 year life assumption for new(er) CTs based on information from PEC resource planning and the depreciation consultants experiential data from other utililities. Regulatory is working on a filing and wanted to know how the life assumption PEC has used compares to DEC's life assumption for new(er) CTs in the most recent study. Would you or the appropriate person be able to provide that information? I think the filing is due next week so if not a quick response, let me know so I can gauge their expectations. I have a call later this morning to discuss why we've had separate depreciation studies and that it is okay that we've used different assumptions in the past.

Thanks, [redacted]

From: [redacted]
Sent: Thursday, October 25, 2012 4:19 PM
To: [redacted]
Subject: RE: Avoided Cost Review

[redacted]

I support PEC use of a 40yr life but I think it is up to DEC&PEC asset accounting groups to come up with supporting information with respect to consistent depreciation studies. I will try and reach out to our project development group and see if the turbine vendors have any documentation or suggestions from their end.

I look forward to our discussion on Monday – have a great weekend.

[redacted]

From: [redacted]
Sent: Thursday, October 25, 2012 4:10 PM
To: [redacted]
Subject: RE: Avoided Cost Review

I also have a meeting from 10-11 on Monday, but otherwise am free in the morning. Please include [redacted].

From: [redacted]
Sent: Thursday, October 25, 2012 3:30 PM
To: [redacted]
Subject: Re: Avoided Cost Review

I have a 10-11 on Mon but otherwise should be available. Please include [redacted].
[redacted] have you made a call on the expected life yet? I would think we simply want to be consistent with what you will be using in strategist, so I think it's your call.

From: [redacted]
Sent: Thursday, October 25, 2012 02:42 PM
To [redacted]
Subject: Avoided Cost Review

[redacted] and [redacted],

[redacted] would like to have a review session on Monday to discuss the DEC and PEC filings along with some of the outstanding issues (e.g. when the old rates are suspended, CT life, differences in peak hour definitions, relationship to negotiated offering for larger than 5MW QFs etc..). I will be setting up a meeting and inviting both of you but I wanted to reach out and see who else you thought should be involved in the meeting. Also I wanted to ensure that Monday morning would work on the meeting request. I would envision about an hour meeting for us to look at the 2010 to 2012 comparison of the rates for DEC and PEC along with the general discussion on the related issues previously mentioned.

Please feel free to call or email if you have any questions.

Best Regards,
[redacted]

[redacted]
Director, Carolinas Resource Planning and Analytics
Duke Energy
526 South Church Street
Charlotte, NC 28202

Offic[redacted]
Cell[redacted]

P125

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:18 AM
To: [redacted]
Subject: FW: Avoided cost update

From: [redacted]
Sent: Tuesday, October 30, 2012 12:01 PM
To: [redacted]
Cc: [redacted]
Subject: Avoided cost update

All,
Here are the updated files reflecting the 35 year useful life assumption.
Please let me know if you have any questions. In the meanwhile, I will send [redacted] the updated PEC filing documents reflecting this version.

PEC avoided costs:
As expected avoided capacity rates and all in avoided cost rates increased slightly (0.03 -0.05 cent / kwhr) from the 40 year version.

2012 AVOIDED
COST Gas Peakers ..

DEC vs. PEC avoided cost comparison
Both tariffs now reflect the 35 year useful life assumption, and the all-in rates are 1% to 6% apart between the 2 utilities.

DEC vs PEC 2012
Filing Oct 30 ...

PEC avoided cost rate change:
I have also added a "Rate Comp" sheet in my file that details rate differences (¢ / kwhr) between the PEC avoided cost versions (CSP 29 vs. 27).
While [redacted] would give some more color around the decrease in avoided energy costs, here are some notes on key drivers underlying capacity rate declines.
Of the roughly [redacted] - [redacted] ¢ / kwhr decrease in total avoided cost rates between proposed vs. last approved PEC rates, roughly [redacted] – [redacted] ¢ / kwhr or a quarter of the total change was driven by lower avoided capacity rates.
Most of this [redacted] – [redacted] ¢ / kwhr) was driven 50: 50 by the two changes:

- Unit ratings: Increased by roughly [redacted]% - [redacted]% across winter & summer ratings.

CT Rating / unit	Summer	Winter

P126

CSP 27, 5000F	[redacted]	[redacted]
CSP 29, 7FA (proposed)	[redacted]	[redacted]

- CT useful life: Increasing the useful life from 25 to 35 years lowered annual carrying costs.

[redacted]
Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone [redacted] *Voicenet* [redacted]

[redacted]

From: [redacted]
Sent: Wednesday, January 09, 2013 11:18 AM
To: [redacted]
Subject: FW: Avoided cost
Attachments: Comments_on_Results 2012.docx

From: [redacted]
Sent: Wednesday, October 31, 2012 12:38 PM
To: [redacted]
Cc: [redacted]
Subject: RE: Avoided cost

[redacted],

[redacted] said to send you this information for the write up you are doing. If you have questions let me know.

[redacted]

From: [redacted]
Sent: Wednesday, October 31, 2012 9:41 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Avoided cost

[redacted],

Both PEC and DEC will be filing avoided cost tomorrow. PEC's filing will be about a 20% decrease in the rate and DEC's will be around a 10% – 15% decrease. Obviously, this will be of interest and concern to QFs. The new proposed rates for the two utilities are fairly comparable, with DEC being just slightly higher. The primary drivers for the decrease for PEC are – lower gas prices, higher ratings for the new avoided CT units without a significant increase in the total cost of the units (leading to lower per kw costs), and an increase in the assumed life of the avoided CT units from 25 years to 35 years.

[redacted] put the filing together for PEC and [redacted] for DEC.

[redacted], [redacted], and others – please feel free to add anything that you think would be helpful.

From: [redacted]
Sent: Wednesday, October 31, 2012 9:11 AM
To: [redacted]
Cc: [redacted]
Subject: RE: Avoided cost

[redacted] – PEC is filing a new avoided cost tomorrow. I believe the best resource for the type of discussion that you want to have is [redacted].

From: [redacted]
Sent: Wednesday, October 31, 2012 9:02 AM
To: [redacted] (Marketing Employee); [redacted]
Subject: Avoided cost

Are we filing a new avoided cost rate in N.C. tomorrow or soon? Do you know where I can get more information about it? It sounds like this will be a pretty big deal for QF owners.

[redacted]
Director-Regulated Utility and Customer Strategy Communications
Duke Energy
[redacted]
24-hour media line: 1-800-559-DUKE (3853)

Fentress, Kendrick C

From: [redacted]
Sent: Wednesday, October 31, 2012 1:36 PM
To: [redacted]
Subject: RE: Life of CT for avoided cost calculations

[redacted] is pursuing that with [redacted].

From: [redacted]
Sent: Wednesday, October 31, 2012 1:35 PM
To: [redacted]
Subject: RE: Life of CT for avoided cost calculations

So now the question is: what is the life assumption for other technologies (CC, Coal, Nuclear, etc)? Duke Progress currently uses 25 years for CC and 40 years for coal and nuclear.

From: [redacted]
Sent: Wednesday, October 31, 2012 1:10 PM
To: [redacted]
Subject: FW: Life of CT for avoided cost calculations

fyi

From: [redacted]
Sent: Wednesday, October 31, 2012 8:25 AM
To: [redacted]
Subject: FW: Life of CT for avoided cost calculations

FYI – [redacted], Director of Strategic Engineering will help with the support for the 35 year life for the GE 7FA for the avoided cost filing.
I believe he has worked closely with folks on the DEC depreciation study.

[redacted]

From: [redacted]
Sent: Monday, October 29, 2012 3:03 PM
To: [redacted]
Cc: [redacted]
Subject: Life of CT for avoided cost calculations

I spoke to [redacted] this afternoon about the estimated life of a CT facility for our avoided cost filings. He is comfortable with using 35 years, and he will assist us in responding to questions from the Public Staff if they arise. I told [redacted] that I would copy him on this note I am sending you to make it "official".

P138

[redacted]

From: [redacted]
Sent: Wednesday, October 31, 2012 3:59 PM
To: [redacted]
Subject: RE: DEC & PEC Avoided Cost Filings

P139

Those are fine.

[redacted]

From: [redacted]
Sent: Wednesday, October 31, 2012 3:52 PM
To: [redacted]
Subject: DEC & PEC Avoided Cost Filings

[redacted] – can you confirm the 2 highlighted sections before I send this? Thanks.

Both DEC and PEC will file updates to their avoided cost rates with the NCUC tomorrow. These rates set the price at which DEC and PEC purchase power from qualifying facilities. The utilities have coordinated to ensure consistent inputs into the avoided cost calculations and, as a result, the proposed rates will be fairly consistent, with DEC's rates being just slightly higher than PEC's. However, PEC's filing will propose a **~20% decrease** compared to the current rates and DEC's filing will propose a **~10%-15% decrease**. This will not be popular among the qualifying facilities. In addition, PEC will be filing a motion to terminate the current long-term rates effective Dec 1, 2012, and only offer variable rates until the NCUC approves new rates. This change will make PEC's approach more consistent with DEC's, but will also be unpopular, especially given the significant decrease in the rates. Both DEC and PEC recover the cost of purchases from qualifying facilities from all retail and wholesale customers.

We will be making a similar filing in SC in the coming months.

Primary Drivers of the Decrease:

- Lower gas prices
- Higher ratings for the new avoided CT units without a significant increase in the total cost of the units, leading to lower per kw costs (PEC only, DEC used higher rating in last proceeding)
- Increase in the assumed life of the avoided CT units from 25 years to 35 years for PEC and from 30 years to 35 years for DEC.

Avoided Cost Background:
Under PURPA, utilities are required to purchase power from qualifying facilities in their service territories at avoided cost rates. We file updated avoided cost rates every two years and they are based on the "peaker method" (cost of a generic peaker/CT unit and a forecast of the utilities marginal energy/fuel costs). The generators can lock in the rates under 5-, 10- or 15-year contracts. The tariff is limited to small generators (3 – 5 MWs), but is also the basis for negotiating contracts with larger generators.

Please let us know if you have any questions.

[redacted] and [redacted]

P140

[redacted]

From: [redacted]
Sent: Tuesday, January 22, 2013 3:25 PM
To: [redacted]
Subject: FW: Variable O&M 2008 - June 2012.xlsx
Attachments: Variable O&M 2008 - June 2012.xlsx

[redacted]

From: [redacted] [mailto:[redacted]]
Sent: Friday, September 28, 2012 9:55 AM
To: [redacted]
Cc: [redacted]
Subject: FW: Variable O&M 2008 - June 2012.xlsx

The [redacted]% escalation rate has been in use this year for DEI, DEK, DEO, and DEC IRP type analysis. I've copied quite of a few of you just to be sure we're all moving down the road in an informed manner. If there are any concerns, suggestions, etc, certainly advise. [redacted]

From: [redacted]
Sent: Friday, September 28, 2012 8:09 AM
To: [redacted]
Cc: [redacted]
Subject: FW: Variable O&M 2008 - June 2012.xlsx

Hi Tim / Vivienne,

We have a new rate of [redacted]% for standard escalation rates for O&M and construction costs that will be applied in the avoided cost filing. This rate was used by the Resource Planning organization for the DEC IRP, and will be consistently applied for both PEC and DEC avoided cost filings.

Accordingly, I'll update the [redacted]% escalation rate in the VOM calculation below with the [redacted]% rate.

Please call me if you have any questions.

[redacted]

From: [redacted]
Sent: Friday, August 24, 2012 2:10 PM
To: [redacted]
Cc: [redacted]
Subject: Variable O&M 2008 - June 2012.xlsx

[redacted]

Attached is the 2012 VOM as we discussed earlier. As requested, I left the inflation rate at [redacted]%. Please let me know if you have any additional questions.

Kind Regards,

[redacted]

[redacted]

From: [redacted]
Sent: Friday, January 18, 2013 12:04 PM
To: [redacted]
Subject: FW: CSP 29
Attachments: 2012 AVOIDED COST using Gas Peakers.xlsx; Simple Cycle Costs.xlsx; CT Costswith Gas-Final[redacted]%.xlsm

Please print with attachments.

From: [redacted]
Sent: Wednesday, October 17, 2012 1:58 PM
To: [redacted]
Subject: CSP 29

Here is my draft CSP 28 calculation – still a work in progress.
I plan to change the useful life of the CT from 25 years to 30 years in cell E17 in the "Input Ranges" sheet (that will reduce the ECC and capacity costs), but I wanted to compare rates first to the currently filed PEC rates which use a 25 year life.

Also, for now I have used the revenue requirement calc. that layers 3 full years of afudc & cpi during the 3 year construction period (as if spending occurs beginning of each year and the CT is placed in service at the end of the year).

I have another tab that keeps it to 2 full years of afudc & cpi, which I can apply if that makes more sense. [redacted]'s method kept it in between at 2.5 years.

Key Changes

- Avoided Capacity Costs:

  - Increased Capacity ratings:

While the construction costs of the 4 CTs / site (GE 7FA machines) of $[redacted] (or $[redacted] per unit) reflect ≈ [redacted]% escalation rate from the $[redacted]/ unit in the 2010 CSP 27, the[redacted]% to[redacted]% increase in ratings caused on overall[redacted]% decline in capacity costs / kw vs. the 2010 cost. Here's a comparison vs. the 2010 filing & the revised 2012 CT cost file:

  - Final Capacity rates

The[redacted]% increase in fixed cost rates was somewhat muted by increase in the discount rate ([redacted]% to [redacted]% with the higher cap structure), etc., and the overall capacity rates decreased by[redacted]% to[redacted]% vs. the 2010 CSP 27.

- Avoided Energy Costs

[redacted]
Lead Regulatory Specialist
PEC Utility Regulatory Planning
Duke Energy
Phone: [redacted] *Voicenet* [redacted]

EXHIBIT D

Request Number: NCSEA PEC 1-2

Request:
Please provide a qualitative description of the impact of natural gas prices on Progress's proposed avoided cost rates. Please include a qualitative evaluation of whether Progress believes natural gas prices are the most significant driver of Progress's proposed avoided cost rates.

Response:
The avoided energy cost forecast has declined by approximately 22% on average over the forecast period of 2013 through 2027. The natural gas price forecast has declined by approximately 23% on average over the same period. In the previous avoided cost evaluation most of the avoided fuel cost is natural gas. In the 2012 evaluation most of the avoided fuel cost is natural gas after 2016. Therefore it is reasonable to say that the decline in natural gas price forecast is the most significant driver in the decline of avoided energy cost projections.

Request Number: NCSEA DEC 1-2

Request:
Please provide a qualitative description of the impact of natural gas prices on Duke's proposed avoided cost rates. Please include a qualitative evaluation of whether Duke believes natural gas prices are the most significant driver of Duke's proposed avoided cost rates.

Response:
The avoided energy cost forecast has declined by approximately 14% for the peak hours and 8% for the off-peak hours on average over the forecast period of 2013 through 2027. The natural gas price forecast has declined by approximately 25% on average over the same period. In addition, the coal price forecast has increased by approximately 8% on average. In the 2012 avoided cost evaluation, the avoided fuel costs are a mixture of coal and natural gas.

Request Number: NCSEA PEC 1-3

Request:
With respect to Commission Dockets E-100, Sub 127 and E-100, Sub 136 and Progress's involvement therein, please describe in qualitative terms any conscious change in Progress's definition of/calculation of "capital" for purposes of arriving at Progress's proposed avoided cost rates.

Response:
PEC did not change its definition of/calculation of "capital" for the purposes of arriving at the proposed avoided cost rates.

In terms of input data, prior to the merger, DEC and PEC each individually commissioned third party engineering firms to provide cost estimates for new generation options including estimates for the installed cost of a gas fired simple cycle peaker. After the merger, in the development of common inputs, the companies settled on an averaging of the two studies which resulted in slightly higher CT capital costs for PEC and slightly lower costs for DEC as compared to the individual studies. In addition, the unit rating for the peaker received from both third party engineering firms was higher than the rating PEC had used in its 2010 filing. This change was a significant driver in the decrease in the avoided capital costs for PEC. The development of common inputs also resulted in a change in the life of a CT for both companies. Based on review of each company's new deprecation study, a book life of 35 years was determined to be appropriate for a CT versus 25 years in the prior PEC avoided cost filing.

Request Number: NCSEA DEC 1-3

Request:
With respect to Commission Dockets E-100, Sub 127 and E-100, Sub 136 and Duke's involvement therein, please describe in qualitative terms any conscious change in Duke's definition of/calculation of "capital" for purposes of arriving at Duke's proposed avoided cost rates.

Response:
In calculating the avoided capital costs, DEC adopted the assumption that PEC has used in prior filings of including only transmission and natural gas infrastructure costs related to the avoided simple cycle peaker and not to include an estimate of system related costs on the gas and transmission systems.

In terms of input data, prior to the merger, DEC and PEC each individually commissioned third party engineering firms to provide cost estimates for new generation options including estimates for the installed cost of a gas fired simple cycle peaker. After the merger, in the development of common inputs, the companies settled on an averaging of the two studies which resulted in slightly higher CT capital costs for PEC and slightly lower costs for DEC as compared to the individual studies. The development of common inputs also resulted in a change in the life of a CT for both companies. Based on review of each company's new deprecation study, a book life of 35 years was determined to be appropriate for a CT versus 30 years in the prior DEC avoided cost filing.

PROGRESS ENERGY CAROLINAS
RESPONSE TO NCSEA Request 2
NCSEA 2-1
Date of Request: December 6, 2012

Request 2-1:
As part of PEC's 2012 Generation Reserve Margin Study, conducted by Astrape Consulting, PEC provided Astrape with generic combustion turbine characteristics. See attached CONFIDENTIAL Exhibit 1.

a. Please describe the impact on PEC's proposed avoided cost rates in CSP-29 of the use of the same generic combustion turbine characteristics and associated assumptions (e.g., discount rate) provided to Astrape, including whether the rates calculated using the information provided to Astrape would go up or down relative to the proposed CSP-29 rates as well as a quantification of any up or down impact on proposed CSP-29 rates.
b. If the rates calculated using the generic combustion turbine characteristics and associated assumptions (e.g., discount rate) provided to Astrape are different from those proposed by PEC in CSP-29, please explain how the Reserve Margin Study would be impacted if the information and assumptions used to calculate the proposed CSP-29 rates had been used to conduct the study.

Response:
The combustion turbine cost data used for the Avoided Cost filing was based on new third party studies, which are more current than the vintage 2011 data provided for the Astrape study. Since the Avoided Cost filing is simply based on more current CT data, the requested calculations were not performed and therefore are not available.

DUKE ENERGY CAROLINAS
RESPONSE TO NCSEA Request 2
NCSEA 2-1
Date of Request: December 6, 2012

Request 2-1:
As part of Duke's 2012 Generation Reserve Margin Study, conducted by Astrape Consulting, Duke provided Astrape with generic combustion turbine characteristics. See attached CONFIDENTIAL Exhibit 1.

a. Please describe the impact on Duke's proposed avoided cost rates in PP-N(NC) of the use of the same generic combustion turbine characteristics and associated assumptions (e.g., discount rate) provided to Astrape, including whether the rates calculated using the information provided to Astrape would go up or down relative to the proposed PP-N(NC) rates as well as a quantification of any up or down impact on proposed PP-N(NC) rates.
b. If the rates calculated using the generic combustion turbine characteristics and associated assumptions (e.g., discount rate) provided to Astrape are different from those proposed by Duke in PP-N(NC), please explain how the Reserve Margin Study would be impacted if the information and assumptions used to calculate the proposed PP-N(NC) rates had been used to conduct the study.

Response:
The combustion turbine cost data used for the Avoided Cost filing was based on new third party studies that are more current than the vintage 2011 data provided for the Astrape study. Since the Avoided Cost filing is simply based on more current CT data, the requested calculations were not performed and therefore are not available.

PROGRESS ENERGY CAROLINAS
RESPONSE TO NCSEA Request 2
NCSEA 2-2
Date of Request: December 6, 2012

Request 2-2:
Please explain how PEC's natural gas hedging costs are factored into PEC's proposed CSP-29 rates.

Response:
PEC did not include natural gas hedging costs into its proposed CSP-29 rates. Hedges are sunk costs and not appropriate for inclusion in CSP rates.

DUKE ENERGY CAROLINAS
RESPONSE TO NCSEA Request 2
NCSEA 2-2
Date of Request: December 6, 2012

Request 2-2:
Please explain whether Duke factored any natural gas hedging costs into Duke's proposed PP-N(NC) rates. If Duke did, please explain how such costs were factored in.

Response:
Duke did not factor any natural gas hedging costs or gains into the proposed PP-N(NC) rates as DEC currently has no hedges in place.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 136

In the Matter of:	)	
Biennial Determination of Avoided Cost Rates	)	**NCSEA'S THIRD SET OF**
for Electric Utility Purchases from Qualifying	)	**WRITTEN DISCOVERY**
Facilities - 2012	)	**REQUESTS TO PROGRESS**
	)	**ENERGY CAROLINAS, INC.**
	)	

INTERROGATORIES

1. In each of the past four biennial avoided cost dockets (E-100, Sub 100; E-100, Sub 106; E-100, Sub 117; and E-100, Sub 127) did you use the same generic CT characteristics for both your calculation of avoided costs <u>and</u> your preparation of the IRP you filed the same year?

Response:
After discussing and reaching agreement with NCSEA, Progress Energy Carolinas is responding to the question with regard to the previous two avoided cost and IRP dockets.

Yes. The generic CT characteristics applied in the avoided cost calculations matched those in IRP dockets nos. E-100, Sub 127 and E-100, Sub 117.

2. Follow-up to your response to NCSEA Data Request 2-1: While the calculations NCSEA requested were not performed and therefore are not available, please provide your best guess as to whether use of "the vintage 2011 data provided for the Astrape study" would have resulted in higher or lower proposed avoided cost rates than the data actually used.

Response:
Question was withdrawn.

3. In your 2012 IRP filed with the Commission, you indicate that you have not made a firm commitment to build a nuclear plant or participate in building a regional nuclear plant. Despite this absence of a firm commitment, have you included one or more nuclear plants in your forward cost model for determining energy credits? If so, is it true, if the low variable cost of a nuclear plant is included in the forward cost model and the plant is delayed, reduced or cancelled, that the avoided cost of energy will be understated as a result? If applicable, please explain why you chose to include one or more nuclear plants in your forward cost model despite the absence of a firm commitment?

Response:
The nuclear capacity that was part of PEC's 2012 IRP is included in PEC's 2012 avoided energy cost determination. Since nuclear capacity is base loaded, the energy from nuclear units would not be avoided by a 100 MW reduction to load, which is the standard for determining avoided energy cost. Therefore, it is not likely that the avoided energy cost would be understated if the nuclear capacity was delayed or canceled. PEC's rationale for including nuclear generation in its resource plan is discussed on pages 4 and 5 of its 2012 IRP.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 136

In the Matter of:	)	
Biennial Determination of Avoided Cost Rates	)	**NCSEA'S THIRD SET OF**
for Electric Utility Purchases from Qualifying	)	**WRITTEN DISCOVERY**
Facilities - 2012	)	**REQUESTS TO DUKE ENERGY**
	)	**CAROLINAS, LLC**
	)	

P13

INTERROGATORIES

1. In each of the past four biennial avoided cost dockets (E-100, Sub 100; E-100, Sub 106; E-100, Sub 117; and E-100, Sub 127) did you use the same generic CT characteristics for both your calculation of avoided costs <u>and</u> your preparation of the IRP you filed the same year?

Response:
After discussing and reaching agreement with NCSEA, Duke Energy Carolinas is responding to the question with regard to the previous two avoided cost and IRP dockets.

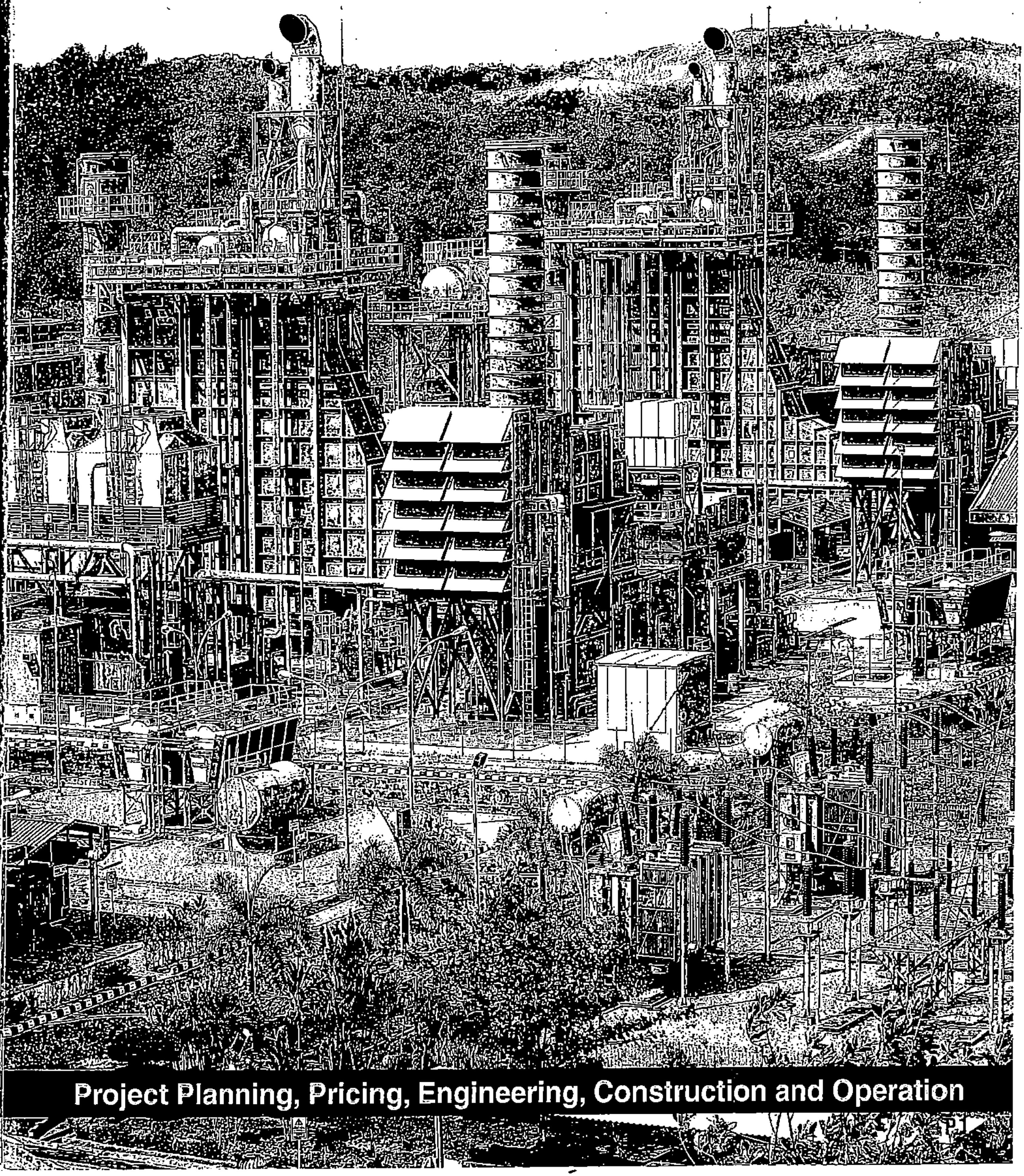
Yes. The generic CT characteristics applied in the avoided cost calculations matched those in IRP docket nos. E-100, Sub 127 and E-100, Sub 117.

EXHIBIT E

Gas Turbine World
2012 GTW Handbook

A Pequot Publication

Volume 29



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Gas Turbine Engineering

2012 Budget Plant Pricing

Performance Specs Guide

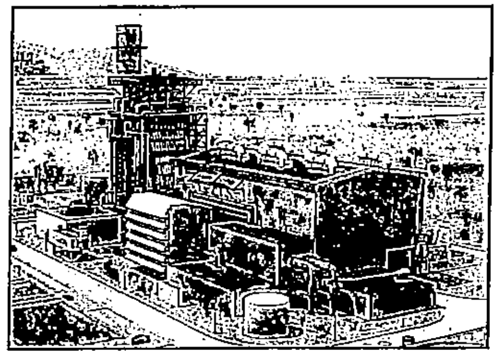
IGCC Power Generation

Orders and Installations

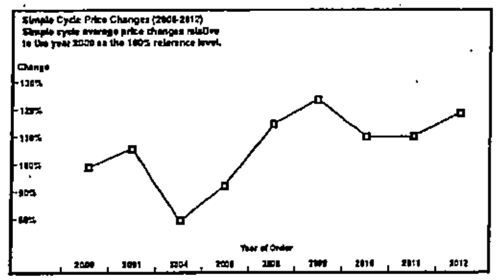
Industry Sources of Supply

On the Cover

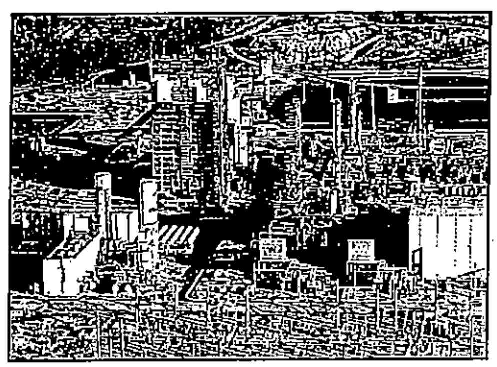
Repowered 2xRB211 combined cycle IPP plant in Indonesia rated at 85 MW and 52.6% efficiency, page 90



Engineering
Next generation combined cycle plants are able to reach full net rated output in less than 30 minutes of an overnight start and over 61% efficiencies, pages 6-30



Price trend
New gas turbine orders during 2012 are expected to reflect an increase of about 5 to 7% in price level compared with last year's gas turbine prices, pages 34-61



IGCC power
New era for 50/60Hz coal-based utility power plants will be marked by the scheduled commercial debut of a 618MW plant during 2012 in the US, pages 106-116

Gas Turbine World (USPS 9447600, ISSN 0746-4134) is published bimonthly in addition to the GTW Handbook annual by Pequot Publishing Inc. 654 Hillside Rd., Fairfield, CT 06824. Periodicals postage paid at Fairfield, CT 06824 and at additional mailing offices. Canada Post International Mail Product (Canadian Distribution) Sales Agreement No. 0747165. Printed in U.S.A.

Industry Price Trends

Gas Turbine Prices (2000-2012)

Influencing factors

In 2011, the US saw a flattening in total domestic electrical demand stabilized at around the 2,000 MW-hrs per day average during 2010, according to US government data. Generation additions were sluggish worldwide, with the exception of Brazil, India and China.

Globally, the main driver behind new capacity has been for peaking and grid back-up to support intermittent wind and solar power generation. Floods in various regions of the world and other natural catastrophes, most notably the devastating earthquake and tsunami in Japan, have also created demand for mobile gensets and relatively small packaged plants while new capacity is being built to replace lost capacity.

More steady growth is forecast for new simple cycle and combined cycle plants to make up for the retirement of old coal steam plants and scheduled shutdowns of nuclear power. Sustained growth, however, depends on world economies returning to normal and continued availability of low cost natural gas fuel.

Outlook for 2012

During the next 12 months, the level of new gas turbine orders is expected to firm up and reflect an increase in price level of about 5 to 7%, compared with 2011 prices.

According to last year's Federal Bureau of Statistics, the producer price index for "turbine generator sets" shipped for the first eight months of 2011 increased by around 4% over the same period in 2010.

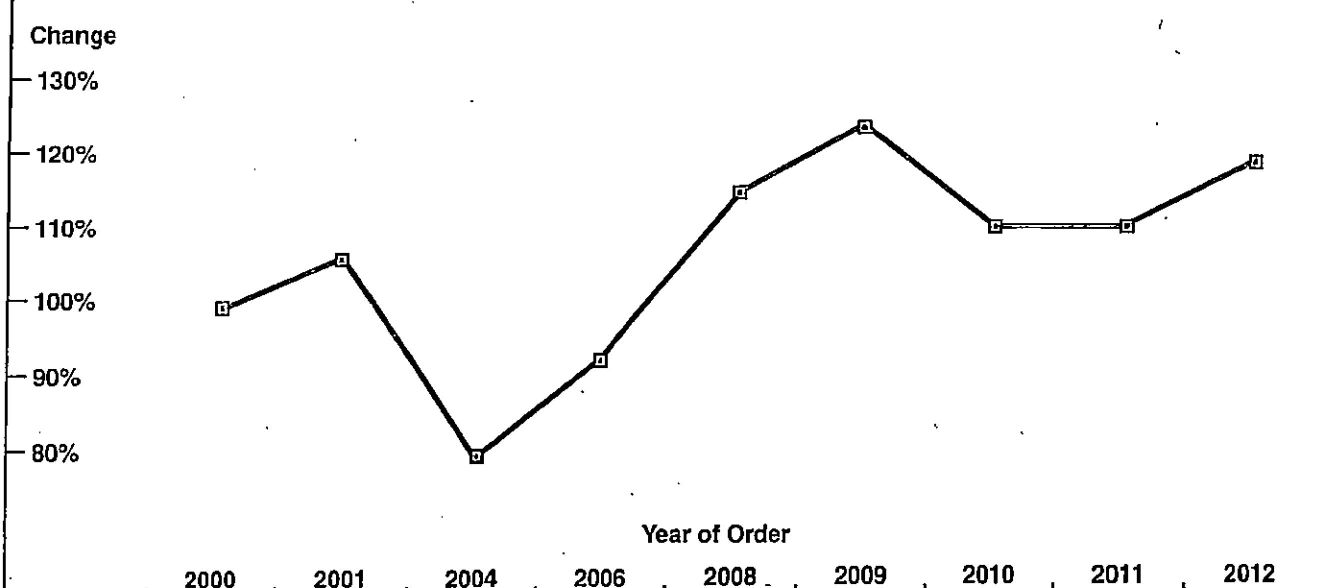
The power generation market is going through a significant structural change due to 1) economic problems in Europe which affect business worldwide, 2) major shifts into renewable energy requiring a restructuring of the generation mix to accommodate the variability of wind and solar generation, and 3) increasing supply of natural gas worldwide du to shale gas development and LNC trade growth.

Given these interactive market de velopments, and impact on gas tur bine supply and demand, Gas Turbin World has adjusted its original pric ing assessment and is forecasting continued rise in prices for new or ders during 2012 which should persis through 2014.

One important change from las year's gas turbine pricing outlook ha been the rapid development of shal gas in North America. With new tech nologies for extracting gas from tigh sands and shale, proven US reserve of natural gas have increased signifi cantly, driving down the price of nat ural gas.

As a result, natural gas fuel price in the US are predicted to range be tween \$3.00 and \$5.00 per MMBt over the next few years compare with \$2.00 to \$2.50 per MMBtu fo the cost of coal.

Simple Cycle Price Changes (2000-2012)
Simple cycle average price changes relative to the year 2000 as the 100% reference level.



and exhaust pressure drops combined could reduce power output by about 1.5 percent and increase heat rate by about 0.5 percent.

Nominally quoted prices are for design rating with power output measured across the generator terminals in order to include generator inefficiencies and gearing losses.

Specific project bid prices are usually quoted by OEMs with guarantees on net power and heat rate at site specific conditions (ambient temperature, elevation and relative humidity, as well as fuel composition). Quoted performance would include inlet and exhaust losses for specific equipment being quoted.

Bid quotes

Actual performance quoted and guaranteed by the gas turbine OEM will be for "new and clean" equipment condition with no allowance made for inevitable degradation in performance with usage.

Conservative OEMs tend to bid with some margin, i.e. with slightly higher heat rate and lower power output to allow for normal variations in manufacturing tolerances and test uncertainties.

Typically, with performance guarantees, there is a margin of 0.5 to 1% points on efficiency and power ratings which is why slightly better performance may initially be realized in actual service.

Several factors that enter into a given project price quote include number of units ordered (there are quantity discounts), scope of equipment supply, site specifics, duty cycle, geographic location and local market share position.

Changes in currency valuations also could play a significant role in quotation depending on which countries (i.e. currencies) are involved in the gas turbine manufacture, purchase, and installation.

Gas turbine gensets specially designed for onshore oil and gas pipeline operation typically are priced around 10% higher than industrial or utility power plants due to increased cost of specified packaging and safety requirements for such applications.

Offshore platform packages have an additional price premium. They require specialized mounts and housing, marine-resistant coatings and materials, and ultra efficient intake filter systems to handle salt-water laden air.

Scoping studies

This reference section of the GTW Handbook is useful for a preliminary assessment and evaluation of gas turbine prices. For project budget planning though, mind that engineering and construction services for installation can add 60 to 100% to total plant cost.

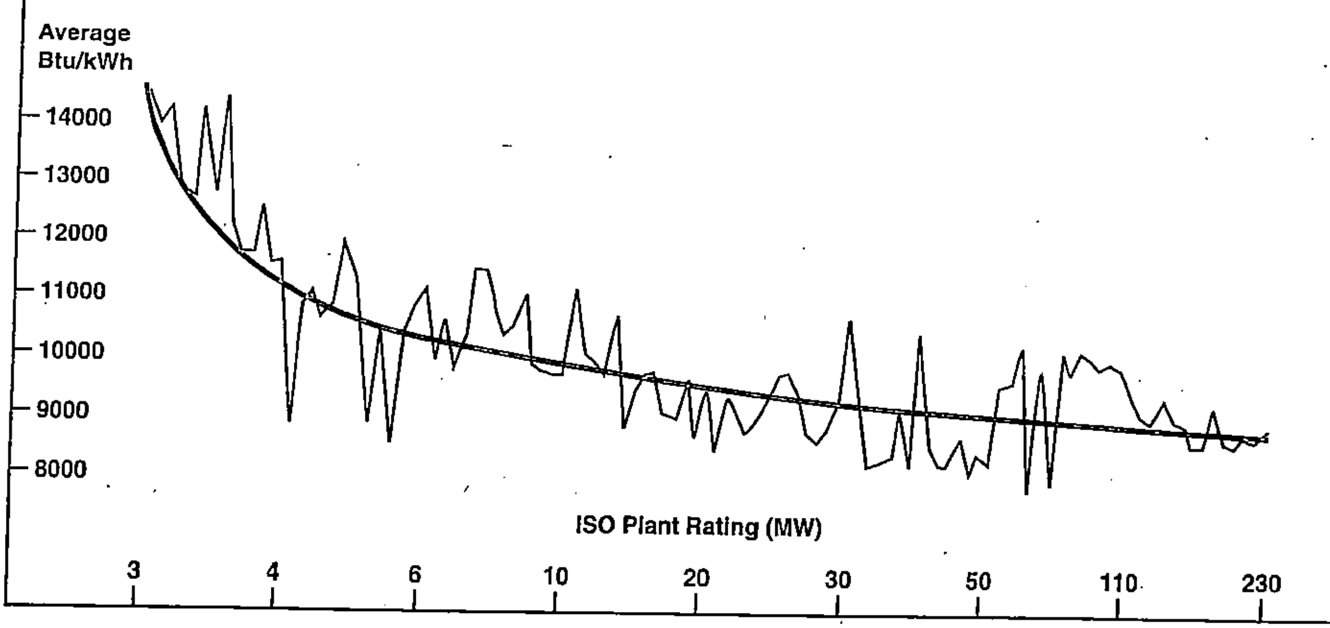
In general, prices are considerably higher in \$/kW for small gas turbines in the "under 20MW size range" than for larger units.

Above 20MW on up to around 150MW, the \$/kW price falls off considerably as economies of scale allow OEMs to reduce the manufacturing costs of larger machines.

Beyond that, the \$/kW curve more or less remains flat regardless of size. The higher cost of materials and manufacturing for the larger more advanced (high firing temperature) units negates any economies of scale that might have been realized. ■

2012 Simple Cycle Heat Rates (Btu/kWh vs MW)

There has been a marked drop of 400-450 Btu from around 11,500 Btu/kWh for small units below 3MW to an average 9000 Btu/kWh for aero technology units in the 4-6MW and 40-100MW size ranges.



P4

EXHIBIT F

2012

Progress Energy Carolinas 2012 Generation Reserve Margin Study

Astrape Consulting
8/17/2012

2012

Duke Energy Carolinas 2012 Generation Reserve Margin Study

Astrape Consulting
8/17/2012

EXHIBIT G

FILING INSTRUCTIONS

Accounting for Public Utilities

Publication 16 Release 29 November 2012

Check As Done

☐ 1. Check the Title page in the front of your present Volume 1. It should indicate that your set is filed through ~~Release Number~~ 28. If the set is current, proceed with the filing of this release. If your set is not filed through Release Number 28, DO NOT file this release. Please call Customer Services at 1-800-833-9844 for assistance in bringing your set up to date.

☐ 2. Separate this Release Number 29 package into the following groups of material:

- White Publication Table of Contents
- White Revision pages

☐ 3. Circulate the "Publication Update" among those individuals interested in the contents of this release.

attention are briefly reviewed in the following sections.

[2] Discounted Cash Flow

The discounted cash flow (DCF) method is intended to measure the return requirements of the utility stock as expressed by the market. The investor is presumed to value the stock by discounting to a present value the expected future cash flows at the rate of earnings required by the investor. The current earnings rate, when combined with the growth rate, establishes the price the investor will pay for the stock. Since the historic market price is a known factor in the DCF approach, the rate of earnings expected can presumably be established objectively by combining the stock price with the estimated growth rate to duplicate the discount rate implicit in the market price. The market expectations as produced by "k" in the formula below, after adjustments to compensate for marketplace phenomena such as market pressure and flotation costs for new issues, are assumed to represent the cost of equity capital as established by an objective party—the stock market. The formula and its components are:

$k = D/P + G$

k = discount rate (i.e., rate of earnings expected)

D = annual dividends

P = stock price

G = growth rate

As stated, "k" is the rate of earnings that the investor is seeking. This is the investor's earnings objective in pricing the stock ("P" in the formula) in view of the dividend and growth factors that are perceived. The dividends used ("D" in the formula) are either at the current rate or the rate anticipated for the coming year (experts differ on which is applicable). The stock price is at a recent time; an average over recent days, weeks, or months (again dependent upon the views of the one making the calculation). The growth factor estimate ("G" in the formula) is held to express the added future cash flows resulting either from the sale of the stock after expected growth in the market value or from future growth in dividends, or both.

While the D and P values require limited judgment (since they are essentially based on known data), the G value is purely subjective. It is based on forecasts of either what the company performance will be or what the market will do in future pricing of the stock. It is entirely prospective and is subject solely to the judgment of the prognosticator. Accordingly, the growth factor is the most controversial of all the DCF components, and experts often produce significantly different results in a rate case. The growth rate may be expressed by a measure of expected growth in book value, in dividends, or in earnings. Obviously, the three growth measures are interrelated, but even so, the growth rates may be assigned different values. In practice, the dividend growth rate is the factor utilized most often in the formula.

[3] Capital Asset Pricing Model

The capital asset pricing model approach measures the risk inherent in the stock of the utility. Once determined, this risk component is added to the going rate of interest on risk-free securities (e.g., U.S. Treasury bills) to establish the cost of equity for the utility. The risk component for a particular utility is determined by comparing the performance of the stock market over a period of time with the performance of the particular utility stock over that same period. The difference is considered to express the relative risk of the utility and is designated as the "beta" factor (see Chapter 9 for further discussion). To determine the utility's required return on common equity, the risk-free rate is added to the product of the beta factor times the difference between the market return and the risk-free rate. The formula is expressed as follows:

$R_j = R_f + b\,(R_m - R_f)$

R_j = required return

R_f = risk-free return

b = beta factor

R_m = market return

The required return may be further adjusted for market factors (e.g., market pressure and flotation costs) to produce the allowable rate of return on common equity.

[4] Bond Yield Risk Differential

Traditional capital costing theory holds that secured obligations (e.g., mortgage bonds) are less risky than are unsecured obligations (e.g., common stock). Accordingly, it is held that equity holders assess a risk premium that requires a higher return on equity than on bonds. On that premise, if the amount of the difference (i.e., risk premium) can be determined, the cost of equity can be established by adding the risk premium to readily ascertainable bond yields in the market. The bond yield risk differential approach is expressed by the following formula:

$k = B_y + R_p$

k = cost of equity

B_y = bond yields in the market

R_p = risk premium on the stock

Bond yields can be established without much difficulty, since both interest payments and market prices are readily available. The controversies concerning this method relate primarily to the amount of risk differential that may apply at a given time. As with other approaches, the equity cost results may be further adjusted for market that any such capital is not acquired on reasonable terms, since sales below book value necessarily dilute prior shareholders' investment.

The inability of the E-P approach to consider current and future market conditions, thereby ineffectively dealing with investors' expectations, has resulted in almost total abandonment of this rate of return technique. It is sometimes felt that the real value of the earnings-price approach is that it gives an indication of the minimum rate of return on common equity capital. Any allowed returns below this level are considered clearly unreasonable and inadequate.

§ 9.05 Discounted Cash Flow Method

The discounted cash flow (DCF) method for determining the "cost" of common equity differs from the earnings-price approach in one important respect. The DCF method attempts to consider certain aspects of investors' expectations regarding future earnings—namely, the expected cash flow from dividends and the expected market appreciation of stock.

The basic theory behind the DCF approach is that the market price an investor pays for a share of stock represents the present value of his expected future cash flows from both dividend yields and market value appreciation. This future cash flow is discounted at the individual investor's required rate of return or, in other words, at his "opportunity cost" of foregoing alternative uses for his funds. The actual stock price observed in the market is, in essence, an averaging of the different levels of returns required by individual investors at their personal discount rates.

Advocates of the DCF approach generally believe that when the technique is properly applied, it will correctly measure the "cost" of equity capital, after adjustment for market pressure and flotation costs. The level of earnings (and dividends) that result from using a DCF rate of return will force the market price of a stock in line with its book value over time, thereby maintaining the integrity of common equity capital.

The formula commonly utilized to measure the cost of common equity under the DCF theory is as follows:

$$k = D/P + G$$

k = current "cost" of common stock equity

D = dividends per share

P = market price per share

G = assumed growth rate

A simple illustration of the application of this formula is as follows:

Example:

Assume that the stock of a utility is currently paying an annual dividend of $2.00 per share and has a present market price of $24.00. Through certain calculations (discussed below), it is determined that the average anticipated growth rate for both dividends and market value is approximately 8 percent annually. With these data, the current cost of common equity capital is computed to be 16.33 percent ($2.00/$24.00 + 8%).

The major points in favor of the DCF approach include the ready availability of most of the required data and the simplicity of the actual calculations. More importantly, the DCF concept is designed to determine the "current" cost of capital by attempting to focus on both current investment yields and investor expectations regarding future returns.

On the other hand, considerable disagreement centers around the validity of certain assumptions inherent in the DCF theory. Specifically, the assumption that investors' anticipated growth rates can be reasonably predicted into the long-term future, in the face of a constantly changing business environment, is strongly attacked by critics of the DCF approach. As discussed below, historic factors (along with considerable judgment) commonly serve as the indicators utilized in predicting investor growth expectations. The validity of these indicators beyond the immediate future is seriously questioned by critics of the technique.

Furthermore, the ability to measure accurately any of the different variables required in the DCF formula is often questioned by those who criticize the approach. A tremendous amount of judgment is required in the measurement of each variable, with the decisions reached having the potential to affect greatly the ultimate product of the DCF process. Critics are quick to point out that the approach is by no means scientific, in spite of such claims by its advocates. Some of the more important problems encountered in measuring the required variables are analyzed briefly:

(1) *Current yield*— While the basic data are readily available to calculate the dividend yield (D/P), a decision must be made regarding which data to utilize. For instance, should the dividend rate and market price be measured at a point in time, or should an averaging technique be employed? If dividend rates and/or market prices are averaged, over what period should the averaging extend and what should be the frequency or interval of observations?

Another issue raised is the need to update dividend yield calculations from the test year date to the approximate date of the regulatory commission's order. When market prices of stock are erratic, updating may be considered necessary to establish a rate return based on the most current estimates of capital costs.

(2) *Growth*— As discussed above, predicting investors' growth expectations presents a major problem for the DCF approach. Three indices, dividends per share, earnings per share, and book value per share, are commonly used, either individually or in combination, to determine the growth percentage. Of course, substantial controversy exists over which one or combination of these factors most accurately reflects investors' future growth expectations and over the fact that each of these indicators requires the use of historic data to predict future expectations. In addition, growth, as envisioned in the DCF model, commonly has two components, dividends and market appreciation.

A question arises as to whether a different set of factors should be employed and whether a different analysis should be performed to predict the anticipated growth of these separate components.

Furthermore, each of the three indices noted above can be criticized for not necessarily being valid indicators of growth expectations, irrespective of their historic bias. If growth in dividends is utilized, this factor can be distorted in the short run by management decisions affecting dividend pay-out ratios. In the case of earnings per share, wide variations are often experienced over relatively short periods, a fact which, in many cases, may appear to indicate negative growth expectations. While it is generally felt that increases in book value per share is the most steady of these indices, this measure becomes distorted when utilities sell new shares of stock below book value. Dividends and earnings are more cash flow oriented than book value and are therefore more likely to be utilized by an investor in his individual return on investment analysis. In fact, dividends are the most commonly utilized measure, with the dividend growth estimate being tempered by earnings growth expectations (from which dividends must come).

Once an indicator or a combination of indicators has been selected, the mechanics of measuring the growth rate requires a decision as to which data should be utilized, similar to the current yield measurement problem. That is, over what period should observations be made and what frequency of observations is required in order to determine the appropriate growth trend?

In recognition of the historic bias and inherent problems associated with the various indicators, many regulatory commissions "massage" the results of the growth analysis in an attempt to deal with those growth rates that intuitively appear out of line. Techniques sometimes employed include the exclusion of observations that vary widely from the norm, downward adjustment of what appears to be abnormally high growth rates, and upward adjustment of low rates. Those who criticize the DCF approach believe this adjustment process clearly indicates that a major flaw is inherent in the discounted cash flow theory.

(3) *Comparable companies*— As a means of obtaining additional confidence with the mechanics and the results of the DCF technique, the comparable companies concept is sometimes incorporated into the analysis. This concept can be utilized in several different ways:

   (a) as a means of verifying that the various data (dividend yields and growth rates) utilized in the formula are reasonable;

   (b) as a means of establishing that a particular company's DCF cost of capital approximates that of comparable companies; and

   (c) as actual data in the DCF formula, through the process of calculating average variables from a representative group of companies (including the utility in question).

The problem of establishing an operational definition of comparable companies is discussed in section 9.02[1] andis equally applicable in those cases where the concept is employed as a component of the DCF measurement process.

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In summary, variations of the discounted cash flow approach are widely utilized today in spite of the many inherent problems. The technique is often defended under the premise that it represents a concept that at least attempts to predict future conditions expected to exist when the related rates are in effect. The inherent problems in the overall DCF concept have led most commissions accepting the method to interject various other considerations in the measurement process as a means of dealing with its vagaries. It is sometimes argued that any theoretical justification existing for the DCF approach is surely destroyed by the introduction of a variety of judgmental factors.

§ 9.06 Capital Asset Pricing Model

While the capital asset pricing model (CAPM) is also used to measure the cost of common stock capital, it defines "cost" somewhat differently than the E-P and DCF approaches. The cost of equity capital is viewed in terms of the return that *current* (as opposed to future) investors perceive they must receive in order to be compensated adequately for the risk they incur (relative to the risk of alternative investments available to them). In essence, the principle of comparable earnings is applied in measuring "comparable risk" factors to determine the cost of capital.

In this light, the CAPM is a measurement technique designed to relate the risk associated with an individual security to the return expected by investors on that security. This risk factor is measured in terms of the variability in rates of return on a particular common stock, relative to fluctuations in returns for the entire "market." It is through the process of determining relative risks that the market results (that is, investor returns) of an individual company are necessarily equated with those of comparable companies. To appreciate the pros and cons to the CAPM approach, it is necessary to outline the basic "investor risk" theory upon which the technique is developed.

[1] Risk Theory

According to CAPM theory, a return on investment is the compensation an investor receives for risk taking. This return actually has three components. They are (1) a pure rent cost, generally held to be in the 2–3 percent range, (2) an inflation allowance to compensate for the expected loss in purchasing power, and (3) a return that is compensation for risk. The first two components are combined to form a risk-free return requirement which is compensation for foregoing the opportunity to spend the money currently. The third component, compensation for risk, includes not only the potential for an investment to fare less well than others, but also the possibility of no return or even loss of the initial investment. The magnitude of this risk factor associated with a given common stock investment in comparison with alternative stock investments can be measured by their relative fluctuations in returns on investment over time.

While returns on investment relate to total cash flows from both dividends and market appreciation, the variations in these returns are largely the consequence of the market price fluctuations, since dividends have proven to be relatively stable over time. Market price variability can be divided into two categories. First, there are