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September 8, 2011

VIA HAND DELIVERY

Ms. Renné Vance
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

RE: In the Matter of Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct
Docket Nos. E-2, Sub 998; E-7, Sub 986

Dear Ms. Vance:

Enclosed for filing in the referenced docket please find the following documents:

- An original and 17 copies of the Testimony of Richard S. Hahn – (**Confidential Version**). ***This document contains confidential information and should be filed under seal.***

- An original and 13 copies of the Testimony of Richard S. Hahn (**Public Version**).

By copy of this letter and enclosure, I am serving all parties of record with a copy of the **Public Version** of Mr. Hahn's testimony. Copies of the Confidential Version will be provided upon request to parties who have executed appropriate confidentiality agreements.

Sincerely,

Robin G. Dunn

Robin G. Dunn

RGD
Enclosures
cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 998
DOCKET NO. E-7, SUB 986

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application of Duke Energy Corporation	)	
And Progress Energy, Inc. to Engage in a	)	TESTIMONY OF
Business Combination Transaction and	)	RICHARD S. HAHN
And Address Regulatory Conditions and	)	
Codes of Conduct	)	

PUBLIC VERSION

PUBLIC VERSION

**TESTIMONY OF
RICHARD S. HAHN**

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Exhibits

I. Introduction

Q. Please state your name and business address.

A. My name is Richard S. Hahn. I am a Principal Consultant with La Capra Associates, Inc. My business address is La Capra Associates, One Washington Mall, Boston, Massachusetts 02108.

Q. On whose behalf do you testify in this proceeding?

A. I am testifying on behalf of Environmental Defense Fund, the Sierra Club, the South Carolina Coastal Conservation League, and Southern Alliance for Clean Energy (collectively, the "Clients").

Q. Please summarize your experience and qualifications.

A. I have a Bachelor's of Science in Electrical Engineering, a Master's of Science in Electrical Engineering, and a Master's in Business Administration. I have worked in the electric utility business for nearly 40 years. From 1970 to 2003, I worked at NSTAR Electric & Gas (formerly Boston Edison Company). During that time, I held many technical and managerial positions in both regulated and unregulated subsidiaries covering all aspects of utility planning, operations, regulatory activities, and finance. In 2004, I joined La Capra Associates. Since then, I have worked on projects related to mergers and acquisitions, asset valuations, market rules and prices analysis, and litigation support. I am a registered professional engineer in Massachusetts. My resume is provided in Exhibit RSH-1 to this testimony.

Q. What is your specific experience relative to mergers and acquisitions?

A. I have previously reviewed several merger and acquisition applications. These include the Exelon-Constellation merger, the FirstEnergy-Allegheny Energy merger, the Exelon-Public Service Enterprise Group merger, the FirstEnergy-GPU Energy merger, the

Exelon-NRG Energy acquisition, and the Constellation-FPL Group merger. The issues that I have addressed in my review of these mergers and acquisitions include market power analyses, synergies and estimates of savings, and the impact on ratepayers and the need for ratepayer protections.

Q. What is the purpose of your testimony in this proceeding?

A. Duke Energy Corporation ("Duke") and Progress Energy Incorporated ("Progress") (collectively, the "Applicants") have filed for approval of a merger of the two holding companies with the North Carolina Utilities Commission (the "Commission"). La Capra Associates has been retained by the Clients to review the proposed merger. This testimony provides the results of that review.

Q. Have you also reviewed the proposed settlement agreement between the Applicants and the Public Staff?

A. On August 30, 2011, I received a copy of a draft set of regulatory conditions and code of conduct agreed upon by the Public Staff and the Applicants. I received a revised version of the regulatory conditions the following evening, on August 31, 2011. On September 2, 2011, I received a copy of the proposed settlement agreement. I have read these documents, but have not had sufficient time to analyze them in detail. Therefore, in this testimony, which was largely completed prior to receipt of these draft documents, I offer my preliminary assessment of the agreement reached by the Public Staff and the Applicants.

Q. Please summarize the application filed in this proceeding.

A. The Applicants filed an application to engage in a business combination transaction (the "Application"). Under the proposed transaction, Duke will acquire Progress in an all-stock swap. The proposed merger is at the holding company level: Progress will become a subsidiary of Duke, and, following the merger, the board of directors of the new Duke

Energy ("the merged entity") will consist of 11 directors designated by Duke and 7 directors designated by Progress.

Q. What is the stated rationale for the merger?

A. The Applicants offer several expected merger impacts as a rationale for approval by the Commission:[1]

1) Financial benefits arising from the advantages of a larger, more diversified company;
2) Centralized management of the Applicants' two nuclear fleets;[2]
3) Direct and immediate operational and rate benefits to customers;
4) Additional integration benefits to be realized over time;
5) Creating the largest utility in the country headquartered in the Carolinas; and
6) No diminution of effective state regulation.

Q. What does the Application state about the status of Duke Energy Carolinas, LLC and Progress Energy Carolinas, LLC after the merger?

A. The Application states that the Applicants' Carolinas electric utility subsidiaries, Duke Energy Carolinas, LLC ("DEC") and Progress Energy Carolinas, LLC ("PEC"), will not be merged into a single legal entity at the time of the merger. However, the Applicants state that there will be significant coordination of operations following the merger, including centralized economic dispatch of PEC's and DEC's generation assets through the joint dispatch agreement ("JDA") and the creation of the joint open access transmission tariff ("OATT"). According to the filing, DEC and PEC will be merged at some point in the future, but only after the Applicants resolve numerous issues, including determination of business practices, operating procedures, equipment specifications,

1 Application at 6-7.
2 See Dir. Testimony of Rogers and Johnson at 9, lines 15-16 (May 20, 2011).

uniform rate schedules, service regulations, and computer systems.[3] In another forum, Applicants have stated that they will not consolidate tariffs until a "convergence in rates" has occurred.[4] Thus, it appears that DEC and PEC will maintain separate rates and tariffs, but the field / back office operations will be consolidated so as to achieve merger synergies.

II. Summary of Findings and Conclusions

Q. Can you summarize the results of your review of the proposed merger?

A. My testimony in this proceeding can be summarized as follows.

- The Application does not provide sufficient information for the Commission to adequately review the merger. To the extent information has been provided about expected costs and benefits of the merger, it is not clear that North Carolina would enjoy benefits commensurate with the expected costs. In particular, the adverse impact of job losses would hit North Carolina particularly hard, with no explicit mitigation strategy proposed by the Applicants.
- The benefits from a JDA between PEC and DEC, which are cited as key benefits of the merger, are more uncertain than they are portrayed in the Application and could be achieved without a merger of the holding companies.
- As proposed, the merger would have a number of adverse impacts on the environment, including increased emissions from coal-fired generation.
- The merger would result in the creation of a dominant procurer of renewable energy in North Carolina, with market power that would not necessarily support the lowest cost option and would limit the pool of renewable energy developers.

3 Application at 4.
4 See transcript of hearing #11-11171 before the Public Service Commission of South Carolina, page 33.

- The merger would pose a significant risk to ratepayers, particularly because the proposed ring-fencing provisions are inadequate.
- There is a significant gap in rates between DEC and PEC ratepayers, and it is not clear from the application that adequate provisions are in place to ensure that benefits from the merger would be enjoyed equally across all North Carolina ratepayer groups.
- While the Public Staff settlement contains important provisions that protect ratepayers, this agreement does not appear to address many of the adverse impacts of this merger, particularly on issues that are important to my Clients.

In short, additional conditions and provisions should be established to address these adverse impacts before this merger is approved.

Q. Please provide your key findings and recommendations concerning the adequacy of the Application.

A. The Application falls short of what is required by the Commission and lacks information that is typically provided in merger applications. In particular, there is insufficient quantification of expected merger costs and benefits on which to judge the merits of the application, or to impose conditions to avoid excessive harm to any parties. In addition, the cost benefit analysis ("CBA") does not specify an allocation of benefits across rate classes or jurisdictions. I recommend that the Applicants be required to file a complete and adequate CBA before the Commission approves the merger.

Q. Please provide your key findings and recommendations concerning the merger's expected impact on jobs.

A. A large share of anticipated merger savings will come from cutting jobs. A disproportionate share of the job cuts will likely be in the Carolinas, the only area where the DEC and PEC service territories are contiguous and the location of both corporate headquarters. The job impacts would hit North Carolina the hardest, but resulting savings will be allocated in part to other states. North Carolina will have an estimated loss of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] jobs representing [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] of the company-wide total. The applicants have offered no specific plan to mitigate the negative impacts of the merger on North Carolina jobs, and I recommend that the Commission require such a mitigation plan as a condition of merger approval. Conditioning the approval of the merger on additional investment in energy efficiency and the clean energy sector would generate additional jobs to offset reductions resulting from the merger and would be an important component of any mitigation plan.

Q. Please provide your key findings and recommendations concerning the JDA.

A. Achieving benefits from joint dispatch is just as feasible and practical without a merger as it is with a merger. Furthermore, the JDA as proposed does not maximize the potential economic benefits of joint dispatch because it does not create a single balancing authority area ("BAA") for DEC and PEC. Finally, the analysis of JDA benefits done by Compass Lexecon on behalf of the Applicants does not appropriately model the system as it would operate under the proposed JDA, and therefore the estimate of JDA benefits is unreliable. I recommend that the Commission not accept benefits from the JDA as a justification for the merger because the same benefits could be achieved without a merger. I further recommend that the language of the JDA be revised to base the joint dispatch on a single BAA, and if necessary, that the Commission require the Applicants to provide an updated economic analysis of the revised JDA. If the Commission does not believe a single BAA is desirable, at a minimum, the Applicants should be required to conduct modeling that accurately simulates the proposed JDA.

Q. Please provide your key findings and recommendations concerning environmental impacts of the merger.

A. The merger would likely have several adverse impacts on the environment. In my opinion, it is appropriate to consider environmental impacts of the merger in the approval process. The merger would result in a single holding company whose Carolinas operating companies will be required to procure new renewable energy to satisfy REPS requirements. The merged entity could exert excessive market power and favor its own or affiliate projects to the possible detriment of ratepayers and renewable energy development. In addition, coal blending strategies that are at the heart of planned fuel synergies savings cited in the application will result in higher emissions and more coal combustion residue per unit of energy generated. Finally, the JDA will result in increased reliance on coal-fired generation—estimated in the Compass Lexecon analysis to be an increase of 9.5 million MWH over the first five years after the merger.

To address these negative impacts, I recommend that the Commission require a procurement process for renewables that is independent, transparent and project neutral. I also recommend that the Commission require an environmental mitigation plan that matches increases in coal-generation with increases in clean, emission-free resources such as wind and energy efficiency.

Q. Please provide your key findings and recommendations concerning ring-fencing provisions in the proposed merger.

A. The Application provides insufficient commitments to protect DEC and PEC ratepayers from the risk of exposure to parent and affiliate financial distress. Even as modified by the Public Staff settlement, the proposed ring-fencing measures leave the holding company with complete flexibility to set limits internally on transactions that could drain cash and impair equity. This flexibility is anomalous when compared to ring-fencing provisions set by commissions across the country in past merger approvals. For example, PEC dividend payments are not restricted, and limiting DEC's dividend payments to cumulative retained earnings does not provide adequate protection. Advance notice to the Commission of these transactions or subsequent credit rating downgrades may not leave sufficient time to raise capital and repair the damage, so ratepayers may still be harmed. Instead, the ring-fencing provisions should include preventive measures to ensure that retained earnings are reinvested and adequate capital is maintained so that the utility is able to thrive. With preventive ring-fencing measures in place, the utility should be able to protect its credit rating even if its affiliates experience distress. This is because the rating agencies look to preventive ring fencing provisions, rather than corporate management discretion, to establish whether the utility is vulnerable to the bankruptcy of an affiliate.

To provide adequate benefits to ratepayers, I recommend implementing a suite of inter-related ring-fencing provisions and ex-ante components including:

- Modifications to existing limits on dividend payments;
- Improved capital structure combined with a minimum equity ratio;
- Establishment of an independent member of the boards of directors of DEC and PEC;
- Additional restrictions regarding the use of money pools; and
- Establishment of a special purpose entity ("SPE") between regulated subsidiaries and the parent holding company.

Q. Please provide your key findings and recommendations concerning the difference in rates between PEC and DEC.

A. The Application does not provide a forecast or analysis of future rates, nor an estimate of how or when this rate gap would be sufficiently "closed" to facilitate combining DEC's and PEC's separate tariffs into a single set of tariffs. This is of particular concern because there is currently a significant difference between the rates of DEC and PEC, driven by differences in their generation mix. In 2010, PEC's rates were 15% higher for residential rates and 26% higher for commercial rates. It will take several years to close the rate gap because the generation mix of each utility is not likely to change in the short term. Merger approval should be expressly conditioned to avoid creating "winners and losers" among ratepayers, and instead to ensure that all ratepayer groups in each company benefit from the proposed merger.

III. Standard for Approval

Q. Please describe your understanding of the standard that the Applicants must meet before the Commission can approve this merger.

A. I am not a lawyer, so I do not offer a legal opinion. I am advised by counsel, however, that the Commission reviews a proposed merger to determine whether it is justified by the "public convenience and necessity." N.C. Gen. Stat. § 62-111(a).

It is my understanding that under North Carolina law, the public convenience and necessity standard is a relative or elastic standard, and that the Commission has broad discretion in determining whether to approve a merger. The Commission may inquire into all aspects of anticipated service and rates raised by the proposed merger. To aid in this analysis, the Commission requires merger applicants to file a market power analysis and a CBA. In prior merger proceedings, the Commission has considered three broad criteria: 1) that the merger will have no known adverse impact on rates and service; 2) that ratepayers are protected as much as possible from potential harm; and 3) that ratepayers will receive enough benefit from the merger to offset any potential costs, risks, and harms.

Given the elastic nature of the public convenience and necessity standard, it is appropriate for the Commission to take into account qualitative considerations of harms, risks and benefits to ratepayers when determining whether to approve a merger and under what conditions to do so. Of particular interest to the groups on whose behalf I am testifying are considerations related to the environment and clean energy. One of the general policies of the Commission is "[t]o encourage and promote harmony between public utilities, their users and the environment." N.C. Gen. Stat. § 62-2(5). In addition, in enacting the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), the North Carolina General Assembly declared that it is the policy of the State:

> To promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that will do all of the following:
>
> a. Diversify the resources used to reliably meet the energy needs of consumers in the State.
> b. Provide greater energy security through the use of indigenous energy resources available within the State.
> c. Encourage private investment in renewable energy and energy efficiency.
> d. Provide improved air quality and other benefits to energy consumers and citizens of the State.

N.C. Gen. Stat. § 62-2(10) a.-d. In light of these policies and the costs and risks to ratepayers of environmental harms, I believe that it is appropriate for the Commission, as a part of its evaluation of the proposed merger, to consider whether the merger poses any harm, risks or costs to ratepayers due to its environmental impact or otherwise impedes the State's clean energy policies, and to impose conditions if necessary to mitigate such harms, risks and costs, and advance those policies for the public interest.

Q. Do you believe that the merger, as proposed, complies with the Commission's approval standard?

A. No, for several reasons:

- The Application falls short of what is required by the Commission and lacks information that is typically provided in merger applications.
- In the Application, benefits are offered only from the JDA and fuel procurement. However, a merger may not be required to achieve these savings.
- No comprehensive CBA was performed, as required by the Commission. No estimates are offered of other benefits normally achieved through a merger, such as elimination of duplicate positions, operational synergies, IT synergies, et cetera. The Applicants identified such savings in responses to data requests, but not in their filings with the Commission. Further, the Application did not include an estimate of the costs to achieve these synergies—these costs were also identified in responses to data requests but were not formally proposed to the Commission via the Application.
- The Application provides no assessment of the merger's impact on the environment. My analysis of the Applicants' responses to data requests indicates that the merger will cause an increase in coal plant emissions that is not mitigated in any way, and a potential adverse impact on renewable energy development.
- The ring-fencing provisions are inadequate to protect ratepayers of the regulated affiliates; and
- The Applicants have provided no assessment of rate impacts from the merger.

I discuss each of these points in detail in the ensuing sections, along with my recommendations for additional conditions and provisions should be established to address these adverse impacts before this merger is approved.

IV. The Cost-Benefit Analysis Does Not Accurately Quantify the Costs and Benefits of the Proposed Merger

Q. What are the expected costs to achieve the merger cited in the filing?

A. The Applicants provide very little information about expected cost to achieve ("CTA") the merger and the benefits described in the filing. The only quantified CTA provided was a $51 million dollar cost over five years to implement the Applicants' coal blending strategy. The Applicants also state that they expect to incur unspecified upfront costs to achieve long-term savings through combined information technology ("IT") systems, supply chain functions, generation operations, corporate and administrative programs, and inventories.

Q. What are the expected benefits of the merger that have been quantified by the Applicants?

A. The Applicants' filing quantifies only two areas of expected benefits over the five-year period following the merger: $364 million dollars in fuel savings as a result of centralized economic dispatch of PEC's and DEC's generation assets through a JDA, and $331 million in additional fuel savings from the sharing and implementation of best practices for fuel procurement and use.

Q. What other expected benefits of the merger are cited in the filing?

A. In addition to the fuel savings mentioned above, the Applicants cite several other non-quantified benefits they expect to be realized through the merger. These include:

1) Increased size and diversity of the combined company, giving it the financial strength to obtain capital for investment in modernization of its plant, equipment, infrastructure and service offerings;

2) The elimination of multiple transmission charges for retail and wholesale customers in the Carolinas through the creation of a joint OATT for DEC's and PEC's three BAAs;

3) Reduced reserve margins through greater coordination of the PEC and DEC systems;

4) Future cost savings from combining and assimilating Duke's and Progress' IT systems, supply chain functions, generation operations, corporate and administrative programs, and inventories; and

5) The benefit for the Carolinas from having the largest utility in the nation headquartered in Charlotte, with a significant presence in Raleigh.

The Applicants assure the Commission, in their filing, that the expected cost savings do not depend on any involuntary workforce reductions and that the merger will not reduce the Commission's authority to regulate the service quality and rates of PEC and DEC.

Q. What is your understanding of the Commission's requirement of a CBA?

A. The Commission has ordered that applicants seeking authority to engage in mergers or other business combinations must file a cost-benefit analysis that includes:

a. A comprehensive list of all material areas of expected benefit, detriment, cost and savings over a specified period (e.g., three to five years) following consummation of the merger and a clear description of each individual item in each area;

b. A quantification of each individual item (or an explanation as to why a quantification cannot be made) specifying whether it is an annually recurring amount, a single cumulative amount, or a one-time cost or saving;

c. An allocation or assignment of each quantified amount to the merging utilities and their affiliates by regulatory jurisdiction; and

d. Copies of all analyses of expected benefits, detriments, costs and savings related to the merger that are filed with other state and federal agencies.[5]

Q. Do you believe these requirements are adequate for considering merger costs and benefits?

A. Yes. I believe that a CBA conforming to the above requirements would provide adequate information on costs and benefits for the Commission to judge whether to approve the merger, and if so under what conditions. I believe the Commission's order is a good outline for the necessary components of a CBA that allows for sufficient review of the justifications for a merger.

Q. In your opinion, have the Applicants filed a CBA that meets the above requirements?

A. No, they have not. The current Application does not meet the Commission's requirements: it does not provide sufficient information concerning the savings, including the costs to achieve such savings, and costs of the merger. A comparison to previous merger applications highlights these deficiencies. In the Duke – Cinergy Merger application, for example, $2.1 billion in gross savings were identified over the first five years after the merger. Costs to achieve were estimated, and net savings were allocated. This formed the basis of a $117.5 million rate reduction by DEC as a condition of approval of the merger. A similar analysis has not been filed with the Commission in this proceeding.

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[5] Order Requiring Filing of Analysis at 7, NCUC Docket No. M-100, Sub 129 (Nov. 2, 2010).

The Application cites Exhibit 5, the "Fuel Synergies Review," as responsive to the Commission's requirements regarding CBA. Exhibit 5 documents expected savings and costs associated with changes in fuel procurement and use. The only other benefit that is quantified in the filing is the $364 million in fuel savings from the JDA. There are no other costs to achieve the merger quantified in the filing. While the Application discusses in general how the benefits will be allocated between North Carolina and South Carolina, it does not provide specific information as to how such allocation will be performed across rate classes within DEC and PEC. In my opinion, the CBA is incomplete, insufficient, and does not comply with Commission requirements.

Q. Did the Applicants perform additional cost-benefit analysis that was not discussed in the Application filed with the Commission?

A. Yes. In response to Public Staff Data Request Number 1, Items 1-6 and 1-9, the Applicants made available summary materials from two CBA studies done for merger planning purposes.

The Applicants engaged the services of Booz & Company to consult on matters of potential merger savings and CTA. Booz prepared an Executive Summary of its findings[6] and a summary document containing itemized savings and CTA[7] (the "Booz study"), both of which are dated November 8, 2010. According to the Booz study, the potential 10-year total savings resulting from the merger are over [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]. The estimated cost to achieve these savings is [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL], and [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] in savings are attributed to pre-merger initiatives, leaving a net potential savings of [BEGIN CONFIDENTIAL

6 CIFGUR Data Request Item 2-2, attachment *CF 2-2.01*.

7 CIFGUR Data Request Item 2-2, attachment *CF 2-2.02*.

[redacted] END CONFIDENTIAL] resulting from the merger. These savings do not appear to include the PEC and DEC fuel savings resulting from the JDA that are quantified in the Applicants' filing. Figure 1 provides a comparison of the potential costs and benefits quantified in the Booz study with the costs and benefits cited by the Applicants in their January 8, 2011 filing.

Figure 1
Comparison of CBA from November 8, 2010 Booz Study and the January 8, 2011 Application
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The 5-year net merger savings identified in the Booz study are nearly [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] than the savings claimed in the Application.

After the merger agreement was signed, the Applicants conducted a study of non-fuel O&M cost savings through the newly-formed Integration Project Management Office. As of August 5, 2011, the report on this study dated June 1, 2011 ("June 1st Study") was the most current consolidated analysis of expected non-fuel O&M synergies.[8] According to the report, the Applicants have scaled down their estimates of potential savings, but they remain considerable. Figure 2 below compares the non-fuel O&M savings potential identified in the November 2010 Booz & Co. study with the revised estimates in the June 1st study. By the third year post-merger (the last for which estimates are made in the June 1st study), annual savings estimates have reached [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] of the estimated savings in the November study.

Figure 2

Comparison of projected non-fuel O&M savings ($ millions) in November 2010 Booz & Co. study and June 1st study.

[BEGIN CONFIDENTIAL

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[8] Applicants' response to SELC Data Request No. 4, Item 4-8. After I completed my analysis of the June 1st results, the Applicants subsequently released an updated study dated August 17th. The results from this updated study, which are not as detailed as the results provided from the June 1st study, do not appear to differ from the June 1st study in any way that would cause any of my underlying arguments to change.

Q. What is your opinion of the cost benefit analysis results in the June 1st Study?

A. I do not have enough information to fully evaluate the results of the June 1st Study. However, these savings are not claimed in the Applicants' filing with the Commission, and therefore cannot provide grounds for approval of the merger application.

Q. Why does it matter that the Applicants' CBA results were not included in the application?

A. It is not sufficient for the Applicants to have merely conducted a series of their own internal CBAs that are not incorporated in the Application. For the Commission to approve the merger application, it must have the Applicants' best estimate of all expected benefits and costs associated with the merger, as well as their expected allocation across entities and jurisdictions, in order to properly assess whether the merger meets the Commission's standard.

Even when a merger generates net benefits, there are still winners and losers. For example, cost savings that are achieved by eliminating jobs may benefit ratepayers, but they will also harm the jurisdiction in which jobs had been located (even if the jobs are eliminated through voluntary attrition). Moreover, a fuel blending practice that saves ratepayers money could also increase harmful emissions that negatively impact the air quality of a region. Such tensions are inherent in mergers, which is why it is important for the Applicants to clearly indicate which specific benefits they intend to pursue, and at what cost. Only then can the Commission determine whether the benefits are likely to outweigh the expected costs, and how to ensure that the benefits are distributed in the public interest.

Q. What can you determine from the Booz study and the June 1st study about the distribution of costs and benefits in North Carolina?

A. Based on the supporting materials provided with both the Booz study and the June 1st study, it is apparent that [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] In fact, the Applicants have indicated that more than [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] This estimate of job losses is roughly consistent with a press release issued by Duke and Progress on September 2, 2011, which states that DEC and PEC currently estimate that between 1,000 and 1,300 employees will be based in downtown Raleigh once the merger is complete, compared to approximately 2,000 today.[10]

Q. What are your recommendations regarding the CBA?

A. The Commission should require that the Applicants submit a CBA as part of their filing that meets the requirements set forth by the Commission order in Docket No. M-100, Sub 129. If the Applicants intend for one of the studies that have been offered in response to data requests to serve as their CBA, they must explicitly state that so that the Commission can judge the merger based on the specific savings measures the Applicants intend to pursue. Without this critical information, it will be very difficult for the Commission to ensure that the benefits due to the merger truly outweigh the costs and that they are properly allocated.

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9 Confidential Responses to SELC Data Request No. 5, Item 5-15.

10 Even if the Applicants make good on their promise to avoid any involuntary job losses on an individual basis, the loss of job positions still impacts the region and its economy.

V. The Proposed Merger Would Cost North Carolina Jobs

Q. What does the Application state regarding the merger's impact on jobs?

A. As discussed above, the Application does not address this issue in detail. Typically, the elimination of jobs generates a major share of the cost savings from a merger. In this case, it is clear that workforce reductions will be relied on to generate significant savings. Due to the inadequacy of the CBA analysis detailed in the previous section, however, it is not clear specifically where and how the Applicants intend to achieve savings through workforce reductions.

The Applicants have stated:

> Over time, Progress and Duke do expect their combined workforces to be reduced compared to continued operation as unaffiliated companies. To the maximum extent possible, the companies will manage these reductions through normal retirements, employee attrition, possible voluntary retirement programs and similar measures, rather than through forced layoffs.[11]

Regardless of whether the workforce reductions are voluntary or involuntary, the loss of jobs will have adverse impacts on North Carolina. Even when a position is eliminated through normal retirement or attrition, its loss still affects job seekers who would have filled the open position.

Q. What have you learned from data requests about areas of potential job impacts?

A. As I discussed in the previous section, the Applicants have provided two internal studies assessing potential merger savings: the November 2010 Booz study and the June 1st study.

The Booz study indicated that about [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] might be possible as a result of the merger, including [BEGIN CONFIDENTIAL [redacted]

[11] Application at 13.

[redacted] END CONFIDENTIAL]. Although the study does not detail where these job reductions would occur, it is clear that the Carolinas would be hit hardest. First, corporate headquarters for both Duke and Progress are located in North Carolina. [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] Furthermore, the Carolinas is the only area where control areas of the two merging companies are adjacent. In one of the supporting documents for the study [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] Figure 3 reproduces the estimates used in the Booz study.[13]

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12 [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL.]

13 Document CF 2-2.01, responsive to CIGFUR DR 2, Item 2-2, at 10.

Figure 3

Baseline Comparison of Preliminary Staffing Reduction Estimates in Booz Study

[BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL]

The June 1st study identifies up to [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] in annual labor savings by the third year after the merger[14] based on the elimination of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] An estimated [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] of the eliminated

[14] Analysis Phase_Savings and CTA_6-01-11.xls, Detail Savings tab. Provided in response to Staff DR No. 1, Item 1-9.

jobs would be from North Carolina.[15] Figure 4 below reproduces the estimated impacts on FTEs by the third year after the merger:

Figure 4

Preliminary Staffing Reduction Estimates (Year 3 Post-merger) in June 1st Study

[BEGIN CONFIDENTIAL

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

END CONFIDENTIAL]

Q. Have the Applicants made estimates of job losses public?

A. Only very recently. A press release issued by Duke and Progress on September 2, 2011 states that DEC and PEC currently estimate that between 1,000 and 1,300 employees will be based in downtown Raleigh once the merger is complete, compared to approximately 2,000 today.[16]

[15] Confidential Response to SELC Data Request No. 5, Item 5-15.

[16] Press Release, Duke Energy and Progress Energy announce North Carolina merger settlement with N.C. Public Staff, (Sept. 2, 2011), https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Duke+Energy+and+Progress+Energy+announce+North+Carolina+merger+settlement+with+N.C.+Public+Staff&pubdate=09-02-2011.

Q. Are projected workforce reductions reasons to reject a merger?

A. No, they are not. As I stated previously, elimination of duplicate jobs is common to almost all mergers and can create benefits for ratepayers. However, the lost jobs represent a cost for some. With unemployment in North Carolina hovering near 10%, (up from 3% in 2009) and state debt above $6 billion, the potential loss of so many jobs in the next few years could harm the state's already struggling economy. I recommend that as conditions for approval of this merger, the Commission seek ways to ensure that some benefits of the merger are used to mitigate the harm it causes the public through the adverse impact on jobs, especially in North Carolina.

Q. What are your recommendations to address the adverse impact on jobs?

A. First, the Applicants should be required to file with the Commission their most current analysis of the expected North Carolina workforce reductions from the merger, with quantitative estimates of the savings they expect to achieve as a result. With this information, the Commission can take steps to ensure that some of the cost savings that result from the merger are used at least in part to mitigate harm from job losses. One way to do this is to require new investment that will create new jobs in North Carolina's growing clean energy sector. The Commission could establish a condition for the approval of the merger that required DEC and PEC to increase the amount of local renewable energy and / or energy efficiency resources in their portfolios. This action would not only provide in-state employment opportunities to offset the job losses from the merger, but it would also have environmental benefits, as discussed in further detail below in Section VII of my testimony.

VI. The Joint Dispatch Agreement Will Result in Minimal Savings and Could Be Accomplished Without the Proposed Merger

Q. Please briefly describe the Joint Dispatch Agreement proposed by the Applicants.

A. According to the Applicants' filing, specifically the testimony of Mr. Weintraub, the JDA is a voluntary agreement between DEC and PEC that will allow their generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest reasonable cost, consistent with DEC's and PEC's reliability and contractual obligations and applicable laws and regulations.[17]

Q. Have the Applicants provided an analysis of the expected savings from the JDA?

A. The Applicants provide an analysis of the JDA performed by Dr. Kalt of Compass Lexecon. This analysis was performed using the DAYZER power system simulation model. The results of this analysis yielded $364 M in savings over five years, ranging from 1% to 2.5% per year. Figure 5 below is an excerpt from the Application showing those results.

Figure 5

JDA Excerpt from Application

Exhibit No. 2
ESTIMATED COST SAVINGS ASSOCIATED WITH DUKE AND PROGRESS JOINT DISPATCH
Base Case ($mm)

		2012	2013	2014	2015	2016
Estimated Cost - No Joint Dispatch		$3,871	$4,110	$4,426	$4,465	$4,715
Estimated Cost - With Joint Dispatch		$3,833	$4,061	$4,361	$4,368	$4,599
Savings	$	$38	$49	$64	$97	$116
	%	1.0%	1.2%	1.6%	2.2%	2.5%

	'12-'16
Cumulative Savings	$364

[17] Dir. Testimony of Weintraub at 3.

. **Do you agree that it makes sense for DEC and PEC to enter into a JDA?**

A. Yes. A properly designed JDA should reduce production costs for both DEC and PEC by lowering fuel and other variable operating costs, such as environmental reagent costs.

Q. **Do you agree with the Applicants that while a JDA is theoretically possible without a merger, it is not realistic?**

A. No. I believe that it is both practical and realistic for DEC and PEC to enter into a JDA without a merger. Public Staff Data Request 3-3 asks the Applicants to explain why a JDA could not be implemented absent a merger. The response discusses the obligations of DEC and PEC to operate their respective systems for the benefit of their native load customers, but does not actually explain how a JDA without a merger would adversely affect those obligations.

Q. **Dr. Kalt states that a JDA is not possible without a merger due to real-time operational constraints and transaction costs. Do you agree?**

A. No. In fact, there are numerous examples where independent, vertically integrated utilities similar to DEC and PEC have entered into mutually beneficial JDAs. Prior to the creation of competitive electricity markets in the Northeast and Mid-Atlantic, the New England Power Pool, the New York Power Pool, and PJM all operated power pools with central dispatch of all generators to meet all loads that lowered each pool participant's annual production costs through sharing arrangements. Under these arrangements, each utility was responsible for planning and operating its own system for the benefits of its own customers, and acquiring the resources necessary to reliably serve load. The savings from central dispatch vastly outweighed any costs incurred in implementing the joint dispatch.

Q. How do you respond to Dr. Kalt's statement that a JDA requires the sharing of competitive generation operating costs and a level of cooperation that is not practical or realistic between unaffiliated entities?

A. I disagree. A JDA requires that each utility share information on fuel costs, heat rates, and other data points required to dispatch the generation to meet the loads. Such information is already publicly available, as both DEC and PEC include such information in the annual Form 1 reports that are submitted to the Federal Energy Regulatory Commission ("FERC"). Figure 6 below is an excerpt from DEC's 2010 FERC Form 1 for its Belews Creek Coal plant, which is available on FERC's website at http://elibrary.ferc.gov/idmws/search/fercadvsearch.asp. This schedule shows annual generation, non-fuel operating costs, heat rate, cost of fuel purchased, and cost of fuel burned. Similar schedules are available for every power plant operated by DEC and PEC.

Figure 6

Data for the Belews Creek Coal Plant

item	plant	Fuel 1	Fuel 2
Plant Name	Belews Creek		
Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam		
Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		
Year Originally Constructed	1974		
Year Last Unit was Installed	1975		
Total Installed Cap (Max Gen Name Plate Ratings-MW)	2,160		
Net Peak Demand on Plant - MW (60 minutes)	2,299		
Plant Hours Connected to Load	8,479		
Net Continuous Plant Capability (Megawatts)	0		
When Not Limited by Condenser Water	2,220		
When Limited by Condenser Water	0		
Average Number of Employees	188		
Net Generation, Exclusive of Plant Use - KWh	14,711,130,000		
Cost of Plant: Land and Land Rights	21,881,889		
Structures and Improvements	234,987,637		
Equipment Costs	1,487,811,370		
Asset Retirement Costs	11,062,367		
Total Cost	1,755,743,263		
Cost per KW of Installed Capacity (line 17/5) Including	813		
Production Expenses: Oper, Supv, & Engr	3,524,499		
Fuel	554,077,306		
Coolants and Water (Nuclear Plants Only)	0		
Steam Expenses	13,334,678		
Steam From Other Sources	0		
Steam Transferred (Cr)	0		
Electric Expenses	1,073,831		
Misc Steam (or Nuclear) Power Expenses	6,449,453		
Rents	28,784		
Allowances	11,387		
Maintenance Supervision and Engineering	4,611,615		
Maintenance of Structures	4,402,017		
Maintenance of Boiler (or reactor) Plant	15,582,812		
Maintenance of Electric Plant	10,581,580		
Maintenance of Misc Steam (or Nuclear) Plant	819,755		
Total Production Expenses	614,497,717		
Expenses per Net KWh	0.0418		
Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Coal	Oil
Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Tons	Barrels
Quantity (Units) of Fuel Burned		5,548,894	61,603
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		12,253	137,552
Avg Cost of Fuel/unit, as Delvd f.o.b. during year		96.37	91.501
Average Cost of Fuel per Unit Burned		97.33	90.176
Average Cost of Fuel Burned per Million BTU		4.004	15.609
Average Cost of Fuel Burned per KWh Net Gen		0.037	0
Average BTU per KWh Net Generation		9,288	0

The Form 1 reports also provide considerable detail on wholesale purchases and sales. The information needed to implement a JDA is largely publicly available now; neither Dr. Kalt's testimony nor any information provided in responses to our discovery requests identifies any specific competitive concern regarding the disclosure of this information between DEC and PEC in the absence of a merger. Furthermore, to the extent that DEC and PEC wished to avoid the sharing of this data, the JDA could be implemented by an independent third party. Thus, it is clear that the sharing of generation operating costs is not an obstacle to the implementation of a JDA without a merger.

Q. Do you have any concerns with the proposed JDA itself?

A. Yes, I have a number of concerns. There appear to be discrepancies between the language of the JDA and the Application, and it seems that the analysis performed by Compass Lexecon may not accurately simulate the JDA as written. Certain assumptions may cause the Compass Lexecon analysis to underestimate the savings from a JDA, and other assumptions may result in over-estimating the JDA savings. In addition, the Compass Lexecon analysis indicates that the JDA will result in an increase in the output of coal units, thereby increasing emissions. This concern regarding increased emissions is discussed in Section VII of my testimony along with recommendations on mitigation through investments in clean energy sources.

Q. Please explain your concern regarding the discrepancies between the system modeled in the Compass Lexecon analysis and the systems described in the DEC and PEC IRPs.

A. The Compass Lexecon analysis models a much different system for DEC and PEC than is contained in each company's 2010 integrated resource plan ("IRP"). As shown in Figure 7 below, the loads modeled by Compass Lexecon are considerably higher than those contained in the 2010 DEC and PEC resource plans,[18] while total resources are about the same. This causes the reserve margins in the Compass Lexecon study to be approximately zero in 2016. Under this assumption of higher loads, both systems will be considerably short of capacity, and it is likely that opportunities to create savings due to joint dispatch would be limited in the modeling. Therefore, the assumptions made

[18] 2011 IRPs were filed on September 1, 2011, which did not afford sufficient time for review prior to the filing of this testimony.

regarding loads may cause the Compass Lexecon analysis to underestimate the JDA savings.

Figure 7

IRP Summary Comparison

Load Comparison

	2012	2013	2014	2015	2016
Duke - IRP	17,759	17,974	18,280	18,605	18,990
Duke - Cap Balance Worksheet	19,824	20,130	20,536	20,962	21,454
Difference	2,065	2,156	2,256	2,357	2,464
PEC - IRP	11,884	12,857	13,084	13,253	13,415
PEC - Cap Balance Worksheet	13,734	14,108	14,435	14,691	14,932
Difference	1,850	1,251	1,351	1,438	1,517

Resource Comparison

	2012	2013	2014	2015	2016
Duke - IRP	20,958	21,429	21,464	20,850	20,861
Duke - Cap Balance Worksheet	21,087	22,508	22,508	21,428	21,428
Difference	129	1,079	1,044	578	567
PEC - IRP	14,839	15,712	15,753	15,269	15,398
PEC - Cap Balance Worksheet	15,833	16,981	16,377	15,854	14,916
Difference	994	1,269	624	585	-482

Reserve Margin

	2012	2013	2014	2015	2016
Duke - IRP	18%	19%	17%	12%	10%
Duke - Cap Balance Worksheet	6%	12%	10%	2%	0%
Difference					
PEC - IRP	25%	22%	20%	15%	15%
PEC - Cap Balance Worksheet	15%	20%	13%	8%	0%
Difference					

Additionally, the testimony of Mr. Weintraub states that the system of the merged entity will be dispatched as a single system.[19] As I understand it, Compass Lexecon analyzed the JDA as if the combined resources and loads of DEC and PEC post-merger will be dispatched as a single BAA. However, the JDA itself contains provisions that are at odds with this interpretation. In fact, the JDA specifically states that it is not intended or shall not be construed as providing or requiring a single integrated electric system or creating a

[19] Dir. Testimony of Weintraub at 3.

single BAA.[20] Failing to account for this provision of the JDA would likely cause the Compass Lexecon study to overestimate the savings from joint dispatch. I am concerned that, as a result of the difference between the JDA and the assumptions made by Compass Lexecon, the Applicants' filing overstates the JDA's benefits to ratepayers. Because certain assumptions contained in the Compass Lexecon analysis may cause it to both under- and over-estimate the JDA savings, I am concerned about the accuracy of the analysis and its applicability to the JDA.

Q. What are the benefits of a JDA based upon a single BAA?

A. A JDA based upon a single BAA has several advantages. This arrangement, which can be considered a "tight power pool," can achieve the maximum benefits of central dispatch. Such an approach allows for the sharing of planning reserves and operating reserves, which would result in lower costs to the ratepayers of each company without compromising the ability and requirement of each utility to plan for and maintain its own resource portfolio and operate its own resources for the benefit of its own customers. Also, in my experience, resources within a BAA are dispatched to optimize production costs. Each BAA first commits the generation needed to be on-line to meet operating requirements, and then dispatches the units that are on-line to achieve the lowest possible production costs. Economic exchange opportunities are typically explored after the dispatch has been established. Transactions between BAAs are not automatically identified, but rather are scheduled based upon advanced bilateral transactions or opportunities or economic interchange after the intra-BAA dispatch has been established. So if DEC and PEC are not operated as a single BAA, it is possible that the JDA might not capture the maximum amount of benefits possible.

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20 See section 3.2(a) of the JDA.

Q. Can you illustrate this concept by way of a simple example?

A. Power system simulation software that implements a security constrained unit commitment and economic dispatch is complex. However, I have created a simplified example of this process using spreadsheets. Consider two hypothetical utilities, designated as Company A and Company B, each with a resource mix as shown in Figure 8. Both companies have 800 MW of total resources, including nuclear and gas turbine ("GT") peaking capacity. Company A has coal resources and Company B has natural gas-fired combined cycle resources. Both systems have peak loads of 700 MW, resulting in a 14% planning reserve margin.

Figure 8

Unit Characteristics for Example Dispatch

COMPANY A						
unit	max MW	min MW	no load costs	incr var costs	full load $	full load rate
Nuclear-A	250.00	50.00	250.00	5.00	1,250.00	5.00
Coal-A	300.00	60.00	3,000.00	40.00	12,600.00	42.00
CT-A	250.00	25.00	2,500.00	90.00	22,750.00	91.00
total capacity	800.00	135.00	5,750.00	40.00	36,600.00	

Company B						
unit	max MW	min MW	no load costs	incr var costs	full load $	full load rate
Nuclear-B	200.00	40.00	240.00	6.00	1,200.00	6.00
CC-B	400.00	80.00	6,000.00	60.00	25,200.00	63.00
CT-B	200.00	20.00	2,400.00	100.00	20,400.00	102.00
total capacity	800.00	140.00		60.00	46,800.00	

Figure 9 below shows what happens when these two companies are dispatched separately, and then dispatched jointly as a single BAA. The loads of each company are assumed to be 350 MW. In the separate dispatch scenario, Company A's nuclear and coal capacity must be committed, resulting in production costs for one hour of $5,850. In this scenario, Company B must commit its nuclear and natural gas combined cycle capacity, resulting in production costs for one hour of $11,400. Thus, the sum of production costs for the two separate dispatches is $17,250.

Under a joint dispatch as a single BAA, however, Company B's natural gas combined cycle capacity is not committed. Rather Company A has underutilized coal capacity that can be dispatched to meet Company B's load. In this scenario, the joint dispatch yields production costs of $13,050, which equals savings of $4,200 or 24% as compared to the stand-alone dispatch results.

Figure 9

Example: Benefits of a JDA for a Single BAA

COMPANY A												
unit	max MW	min MW	no load costs	incr var costs	full load $	full load rate	Commit?	min mw dispatch	range dispatch	total MW dispatch	cost	cost per mwh
Nuclear-A	250.00	50.00	250.00	5.00	1,250.00	5.00	1	50.00	200.00	250.00	1,250.00	5.00
Coal-A	300.00	60.00	3,000.00	40.00	12,600.00	42.00	1	60.00	40.00	100.00	4,600.00	46.00
CT-A	250.00	25.00	2,500.00	90.00	22,750.00	91.00		0.00	0.00	0.00	0.00	N/A
total capacity	800.00	135.00	5,750.00	40.00	36,600.00			110.00	240.00	350.00	5,850.00	16.71
load	350.00							240.00		OK		
Company B												
unit	max MW	min MW	no load costs	incr var costs	full load $	full load rate	Commit?	min mw dispatch	range dispatch	total MW dispatch	cost	cost per mwh
Nuclear-B	200.00	40.00	240.00	6.00	1,200.00	6.00	1	40.00	160.00	200.00	1,200.00	6.00
CC-B	400.00	80.00	6,000.00	60.00	25,200.00	63.00	1	80.00	70.00	150.00	10,200.00	68.00
CT-B	200.00	20.00	2,400.00	100.00	20,400.00	102.00		0.00	0.00	0.00	0.00	N/A
total capacity	800.00	140.00		60.00	46,800.00		120.00	120.00	230.00	350.00	11,400.00	32.57
load	350.00						230.00	230.00		OK		
									A plus B	700.00	17,250.00	24.64
Joint Dispatch A&B												
unit	max MW	min MW	no load costs	incr var costs	full load $	full load rate	Commit?	min mw dispatch	range dispatch	total MW dispatch	cost	cost per mwh
Nuclear-A	250.00	50.00	250.00	5.00	1,250.00	5.00	1	50.00	200.00	250.00	1,250.00	5.00
Nuclear-B	200.00	40.00	240.00	6.00	1,200.00	6.00	1	40.00	160.00	200.00	1,200.00	6.00
Coal-A	300.00	60.00	3,000.00	40.00	12,600.00	42.00	1	60.00	190.00	250.00	10,600.00	42.40
CC-B	400.00	80.00	6,000.00	60.00	25,200.00	63.00		0.00	0.00	0.00	0.00	N/A
CT-A	250.00	25.00	2,500.00	90.00	22,750.00	91.00		0.00	0.00	0.00	0.00	N/A
CT-B	200.00	20.00	2,400.00	100.00	20,400.00	102.00		0.00	0.00	0.00	0.00	N/A
total capacity	1,600.00	275.00		40.00	83,400.00			150.00	550.00	700.00	13,050.00	18.64
load	700.00							550.00		OK	4,200.00	24%

Figure 10 illustrates what happens with a joint dispatch of separate BAAs for Companies A and B. In this scenario, all of the capacity that was committed in the stand-alone dispatches for each company is also committed in the joint dispatch. Because Company B's natural gas combined cycle capacity is committed in this dispatch, it is dispatched at minimum load and Company A's coal capacity is dispatched less. Savings from the joint dispatch with separate BAAs is $1,400 or 8% in this one hour, or less than half of what the savings would be for the joint dispatch with a single BAA, which were $4,200 or 24%.

Figure 10

Example: Benefits of a JDA with Separate BAAs

COMPANY A												
unit	max MW	min MW	no load costs	incr var costs	full load $	full load rate	Commit?	min mw dispatch	range dispatch	total MW dispatch	cost	cost per mwh
Nuclear-A	250.00	50.00	250.00	5.00	1,250.00	5.00	1	50.00	200.00	250.00	1,250.00	5.00
Coal-A	300.00	60.00	3,000.00	40.00	12,600.00	42.00	1	60.00	40.00	100.00	4,600.00	46.00
CT-A	250.00	25.00	2,500.00	90.00	22,750.00	91.00		0.00	0.00	0.00	0.00	N/A
total capacity	800.00	135.00	5,750.00	40.00	36,600.00			110.00	240.00	350.00	5,850.00	16.71
load	350.00							240.00		OK		
Company B												
unit	max MW	min MW	no load costs	incr var costs	full load $	full load rate	Commit?	min mw dispatch	range dispatch	total MW dispatch	cost	cost per mwh
Nuclear-B	200.00	40.00	240.00	6.00	1,200.00	6.00	1	40.00	160.00	200.00	1,200.00	6.00
CC-B	400.00	80.00	6,000.00	60.00	25,200.00	63.00	1	80.00	70.00	150.00	10,200.00	68.00
CT-B	200.00	20.00	2,400.00	100.00	20,400.00	102.00		0.00	0.00	0.00	0.00	N/A
total capacity	800.00	140.00		60.00	46,800.00		120.00	120.00	230.00	350.00	11,400.00	32.57
load	350.00						230.00	230.00		OK		
									A plus B	700.00	17,250.00	24.64
Joint Dispatch A&B												
unit	max MW	min MW	no load costs	incr var costs	full load $	full load rate	Commit?	min mw dispatch	range dispatch	total MW dispatch	cost	cost per mwh
Nuclear-A	250.00	50.00	250.00	5.00	1,250.00	5.00	1	50.00	200.00	250.00	1,250.00	5.00
Nuclear-B	200.00	40.00	240.00	6.00	1,200.00	6.00	1	40.00	160.00	200.00	1,200.00	6.00
Coal-A	300.00	60.00	3,000.00	40.00	12,600.00	42.00	1	60.00	110.00	170.00	7,400.00	43.53
CC-B	400.00	80.00	6,000.00	60.00	25,200.00	63.00	1	80.00	0.00	80.00	6,000.00	75.00
CT-A	250.00	25.00	2,500.00	90.00	22,750.00	91.00		0.00	0.00	0.00	0.00	N/A
CT-B	200.00	20.00	2,400.00	100.00	20,400.00	102.00		0.00	0.00	0.00	0.00	N/A
total capacity	1,600.00	275.00		60.00	83,400.00			230.00	470.00	700.00	15,850.00	22.64
load	700.00							470.00		OK	1,400.00	8%

This example illustrates the benefits of creating a single BAA in performing the joint dispatch. For this reason, the JDA should be revised to allow for a single BAA in the joint dispatch of DEC's and PEC's resources. This revision would maximize savings for North Carolina ratepayers.

Q. Are there other reasons to base the JDA on a single BAA?

A. The Applicants have stated their intention to combine their OATTs into a single OATT. An OATT provides for different types of transmission service. The most common type of service provided is Network Transmission Integration Service ("NTIS"), where the loads of a vertically integrated utility within the BAA are designated as network loads and the resources of that same utility within the BAA are designated as network resources. In the dispatch process, all network resources are centrally dispatched to meet all loads, subject to any transmission constraints that exist within the BAA. NTIS allows each utility to use the transmission system seamlessly as load levels and the output of generators change from hour to hour, without the necessity of obtaining individual transmission paths between loads and resources. This arrangement can be contrasted against the transmission service for transactions between neighboring BAAs. For inter-BAA transactions, point-to-point transmission is used, and specific transport quantities and specific points of receipt and points of delivery must be specified. For this reason, an OATT is almost always associated with a single BAA, which provides another reason to base the JDA on a single BAA.

Q. Are there any disadvantages to establishing a single BAA?

A. I cannot think of any disadvantages. The JDA is essentially a voluntary contract that establishes the terms and conditions for wholesale power purchases and sales between DEC and PEC. Some may be concerned that establishing a single BAA or a tight power pool would trigger FERC jurisdiction. In my opinion, however, the JDA would already be subject to FERC jurisdiction as currently written because it is clearly directed at wholesale purchases for resale between DEC and PEC. That said, it is unlikely that FERC would spend much time reviewing the JDA. This is because the JDA is a voluntary agreement between two willing, vertically integrated utilities with the vast majority of their activities subject to state regulation. Revising this agreement to reflect the joint dispatch of a single BAA would not change this fact. Because both DEC and PEC will still be subject to regulation and oversight by the Commission, my suggested revision to base the JDA on a single BAA would not compromise state jurisdiction. Moreover, a JDA based upon a single BAA does not require that DEC and PEC combine their planning process into one, nor does it require that DEC and PEC combine their retail rate tariffs. Each Company can still develop its own IRP, operate and maintain its own assets for the benefit of their own customers and shareholders, and maintain independent rate schedules for each retail service territory.

Q. Is it possible to establish a single BAA when there are severe transmission constraints between the incumbent BAAs?

A. Yes. Most transmission systems have constraints of some kind. These constraints are considered and accounted for when the security constrained unit commitment and dispatch process is implemented. A lack of transmission between the incumbent BAAs will limit the economic benefits that can be realized through a JDA, but such limitations will exist regardless of whether the JDA is based upon multiple BAAs or a single BAA. Transmission constraints notwithstanding, it is still the case that a single BAA provides the best possible savings opportunities within those constraints.

Q. Are there any concerns that a JDA based upon a single BAA could result in ratepayers of the low cost provider inappropriately subsidizing ratepayers of the high cost provider?

A. A properly designed dispatch agreement should reduce costs for both DEC and PEC and therefore reduce costs for ratepayers at both companies as well. Figure 11 below illustrates how the joint dispatch savings would be allocated to each of Company A and B under a JDA in which units are dispatched in a single BAA. The JDA proposed in this proceeding allocates the savings based upon actual hourly generation in the joint dispatch, so I have used that same method to allocate savings in the hypothetical example discussed above. Because Company A produces 71% of the hourly generation, it receives 71% of the $4,200 savings from the joint dispatch, or $3,000. Company B receives 29% of the savings, or $1,200. Thus while the total JDA savings is 24%, Company A, which is the low cost provider, saves 51%, while Company B, the high cost provider saves 11%. In essence, in this one-hour example, Company A is selling 150 MW of coal capacity that is underutilized in the standalone dispatch to Company B at $60.00 per MWH, which is well above the cost to produce that additional power, which is $40.00 per MWH. These infra-marginal revenues are credited back to Company A's ratepayers via the fuel charge. Company B purchases Company A's underutilized coal capacity at $60.00 per MWH, but avoids the commitment and dispatch of natural gas combined cycle capacity that costs $68.00 per MWH. Both Companies save money under this example of a JDA based upon a single BAA. Company A, the low cost provider, actually has its cost advantage increased, not decreased, which can be a suitable reward for having low cost capacity.

Figure 11

Example: JDA Savings Allocation

scenario	Company A	Company B	Sum
loads, mw	350.00	350.00	700.00
standalone dispatch			
#units committed	2	2	4
mw committed	550	600	1,150
mw gen	350	350	700
cost $	$6,100	$11,800	$17,900
cost per mwh	$17.43	$33.71	$16.29
joint dispatch before billing			
#units committed	2	1	3
mw committed	550	200	750
mw gen	500	200	700
cost $	$12,100	$2,800	$14,900
billing adjustments			
% of hourly gen	71%	29%	
mw purchased	($150)	$150	
cost / (revenue) $	($8,143)	$8,143	
cost / (revenue) per mwh	$54.29	$54.29	
joint dispatch after billing adj			
net mw gen	350	350	
net cost $	$3,957	$10,943	$14,900
net cost per mwh	$11.31	$31.27	$19.96
$ savings from joint dispatch	$2,143	$857	$3,000
% savings from joint dispatch	35%	7%	17%

Q. Is there ever an instance where a JDA does result in ratepayers of the low cost provider subsidizing ratepayers of the high cost provider?

A. In a well-designed JDA, such a situation should not occur. Figure 12 below examines the same dispatch analysis as depicted in the above Figures 9 through 11, but over a wide range of loads, from 300 MW to 700 MW. Note that for most load levels, the savings are positive for both companies. Company A, the low cost provider, was consistently allocated a high share of the savings, retaining and enhancing its cost advantage over Company B. Savings are zero at loads of 550 MW and 600 MW, but at these load levels, the generation for each company is the same as it would have been in stand-alone dispatches. So, no power is bought or sold during these hours. None of the load levels result in savings for one company and higher costs for the other company. This indicates that a joint dispatch with a single BAA will benefit both parties.

Figure 12

JDA Savings Summary

Load for each Company A & B MW	Savings due to Power Pool Company A	Company B	Sum
700	2%	1%	2%
650	1%	1%	1%
600	0%	0%	0%
550	0%	0%	0%
500	5%	2%	3%
450	12%	4%	7%
400	19%	6%	10%
350	35%	7%	17%
300	35%	9%	18%

Q. What do you recommend regarding the proposed DEC - PEC JDA?

A. While a JDA does not require a merger, a properly designed JDA will provide benefits to both DEC and PEC. I recommend that the language of the JDA be revised to reflect a single BAA, so that the benefits to ratepayers are consistent with those claimed in the Applicants' testimony. A JDA with a single BAA will provide the maximum benefits to North Carolina ratepayers, and provide no economic disadvantages. As a condition of approving the merger, DEC and PEC should be required to modify the proposed JDA to reflect a single BAA.

<u>VII. The Proposed Merger Would Harm the Environment and Renewable Energy Development</u>

Q. Is it appropriate for the Commission to consider environmental issues in determining whether the proposed merger is justified by the public convenience and necessity?

A. Yes, it is. As I noted earlier in this testimony, it is my understanding that the Commission has broad discretion to take qualitative considerations into account in evaluating the proposed merger. Since it is the Commission's and the State's policy to encourage energy generation that is in harmony with the environment, and because the environmental impacts of the merger could harm ratepayers, I believe that it is appropriate to consider environmental impacts in the approval process and to impose conditions to mitigate adverse impacts if necessary.

Q. What are the primary environmental concerns that are raised by the proposed merger?

A. The Application does not explicitly address environmental considerations. However, a careful examination of the information provided by the Applicants has raised three significant concerns:

- One concern is the effect that the merged entity's market dominance will impact the procurement of renewable energy to satisfy REPS requirements.
- Second, much of the fuel synergies savings used to justify the merger rely on coal blending practices that will result in increased utilization of less efficient, higher-polluting coal.
- Third, joint dispatch of the DEC and PEC systems is expected to result in higher reliance on coal-fired generation, and thus greater emissions.

Q. Please elaborate on the concerns you have regarding the impact the merger will have on renewable procurement in the State.

A. Effectively, the merger will reduce the market for renewable energy to meet the North Carolina REPS requirements to one buyer, with the potential to substantially curtail the opportunities for independent renewable energy projects in the state. Although DEC and PEC should be in a position to develop renewable power within their regulated markets and have an opportunity to earn a fair return on these investments, it is imperative for there to be an open process that does not favorably bias DEC, PEC, or their affiliates or exclude participation by other developers.

Q. How do DEC and PEC currently plan to satisfy their REPS requirements?

A. Both DEC and PEC plan to maximize the amount of energy efficiency and out-of-state resources they use for compliance. For the remainder of the requirement, DEC plans to satisfy its requirements with a mix of company-owned resources and energy and renewable energy certificate ("REC") purchases. PEC plans to satisfy the remainder of its requirements with energy and REC purchases. For its company-owned resources, DEC plans to pursue co-firing and repowering projects to burn biomass fuel at its existing coal plants and to install solar PV on some of its property as part of its distributed solar program.

Q. What opportunities does the current system afford renewable energy developers?

A. Renewable energy developers have the ability to sell bundled energy or RECs from their projects to either PEC or DEC. Because PEC's strategy has been to procure its REPS compliance through requests for proposals ("RFPs") and has not thus far used any of its own resources for compliance, these RFPs create an open market for renewable developers. DEC's heavy reliance on company-owned resources does not provide the same open market environment. Thus, developers trying to sell power to DEC are essentially competing against DEC's own resources.

Q. How will opportunities for renewable energy developers be affected by the merger?

A. It is unclear how opportunities for renewable energy developers will be affected in the near term by the merger of the holding companies. There are two possibilities. The first is that after the merger of DEC and PEC, there will be only one entity procuring new renewable energy for REPS compliance. There is no information in the Application regarding future procurement strategy, but it is likely that the procurement strategy will include a mix of bundled energy and REC procurement and utility owned resources.

Under this scenario, the number of buyers of renewable energy has been reduced to one from two as a result of the merger, which creates the potential for the exercise of market power. The second possibility is that DEC and PEC continue separate renewable energy procurement processes if the merger is approved. Even if PEC continues the RFP-focused procurement process is has employed thus far, it will have an affiliate (DEC) who can compete in that process. Post-merger, developers could be left with only one potential buyer for their output, and it will mean that there will no longer be a market open to renewable developers in which they are not competing with utility-owned or affiliate resources. Under either possible outcome, the merger would have an adverse impact on the development and procurement of renewable energy in North Carolina.

Q. Will the Municipal Power Agencies or Electric Membership Corporations serve as an alternative buyer for renewable energy?

A. The Municipal Power Agencies (MPAs) and Electric Membership Corporations (EMCs) will serve as alternative buyers for the set-asides (solar, poultry and swine), but beyond the set-asides, the MPAs and EMCs are allowed to satisfy all of their REPS requirements with existing resources and energy efficiency. This means that the MPAs and EMCs, who are much smaller than DEC or PEC, are not likely to be competing with the merged entity for new renewable energy facilities.

Q. Will Dominion serve as an alternative buyer for renewable energy?

A. No. Dominion is allowed to, and is likely to, satisfy all of its REPS requirements with out of state RECs.

Q. What are the potential impacts of having one potential buyer competing directly or with affiliates with third party projects for renewables to meet REPS requirements?

A. A single company with a portfolio requirement and no requirement to solicit the best or most cost-effective projects can exert market power and favor its own or affiliate projects to the possible detriment of ratepayers. A single-procurer market with affiliates active in the market for renewables creates an exclusive barrier to entry, stifles competition and does not foster a process that guarantees the lowest cost or most favorable—from a technology or experience perspective—projects are built. A single buyer with affiliate interests could well cause unaffiliated renewable developers to forego North Carolina development activities and, instead seek opportunities in other state markets where there are open and transparent processes with competitive bidding and affiliate transaction rules.

Q. Is there precedent established elsewhere for competitive solicitations where affiliate interests are involved?

A. Yes, in similar wholesale market circumstances, FERC has developed mechanisms to address competitive procurements in which the buyer has competing affiliated interests. In FERC Opinion No. 473, "Opinion and Order Affirming Initial Decision in Part, Denying Requests for Rehearing and Announcing New Guidelines for Evaluating Section 203 Affiliate Transactions," FERC states in its determination: "the Commission continues to believe that affiliate acquisitions by their very nature raise concerns about the potential for discriminatory treatment in favor of the affiliate's plant, which can undermine competition and harm the public interest."[21] FERC also says, "[w]e believe that affiliate preference, or the possibility thereof, whether in market-based or cost-based PPAs or in asset acquisitions, harms competition" and cites a Southern California Edison case (106FERC 61,183). FERC states: "Affiliate preference could discourage non-

[21] Federal Energy Regulatory Commission. Opinion No, 473: *Opinion and Order Affirming Initial Decision in Part, Denying Requests for Rehearing and Announcing New Guidelines for Evaluating Section 203 Affiliate Transactions.* Docket Nos. EC03-53-000 and EC03-53-001, July 29, 2004, page 16, paragraph 47.

affiliates from adding supply in the local area, harming wholesale competition and, ultimately, wholesale customers."[22]

Q. Are there established standards for competitive solicitations involving affiliate transactions?

A. Yes. FERC presents guidelines in Opinion 473. FERC states that, "a competitive solicitation through a formal RFP in future section 203 cases is likely to be the most effective way to show that an affiliate transaction is not marred by affiliate abuse."[23] FERC gives the following guidelines for a solicitation process:

> a) Transparency: the competitive solicitation process should be open and fair.
> b) Definition: the product or products sought through the competitive solicitation should be precisely defined.
> c) Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.
> d) Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.[24]

Q. What do you recommend for a renewable energy procurement process in North Carolina if the merger is approved?

A. As a starting point, I would recommend a procurement process that follows FERC's guidelines above the portion of REPS compliance that would have been handled by PEC and DEC pre-merger. Under this approach, the procurement for renewables will be independent, transparent and project neutral; energy developers will have the same opportunities that they had pre-merger; and risk to ratepayers will be mitigated. Further, the Commission may want to consider approaches employed in other states, such as resource specific tariffs made available to smaller developers to provide opportunities for renewable generation development at the lowest cost.

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22 Id. at 18, note 40.
23 Ibid., Page 24, paragraph 67.
24 Ibid., page 25.

Q. **Regarding other environmental impacts, what specific concerns do you have related to the Applicants' proposed fuel synergies strategy?**

A. I am concerned that coal plant emissions will likely increase as a result of the Applicants' plans to increase the use of coal blending by DEC and PEC. Coal blending involves mixing lower quality coal with higher quality coal. The lower quality coal has a higher ash content, higher sulfur content and lower heating value. Consequently, it has higher emissions and more toxic coal combustion waste per unit of energy produced. The Applicants have offered no quantification of the expected emissions impact of coal blending.[25]

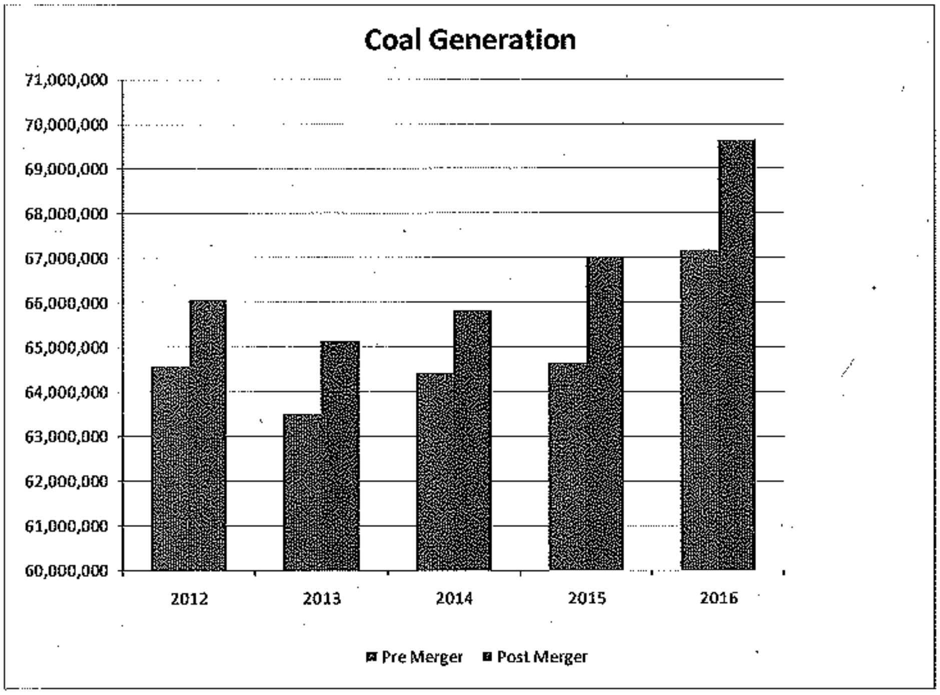
Q. **Please elaborate on your concern that the JDA will result in increased coal generation.**

A. According to the details underlying the Compass Lexecon analysis of the JDA, the merger will result in increased coal generation when compared to the sum of DEC's and PEC's coal generation pre-merger. Figure 14 below provides the MWH generation by coal pre-merger and post-merger from 2012 to 2016 for the base case assumptions. The increase amounts to 9.5 million MWH over the 5-year period.

25 See Response to SELC Data Request 2, Item 2-41.

Figure 14

Coal Generation Pre and Post Merger per Application



Q. Do you agree with Compass Lexecon's analysis that shows increased coal generation as a result of joint dispatch?

A. Yes, I believe that is a reasonable estimate. I conducted an independent analysis using AURORAxmp modeling software. AURORAxmp is a power system simulation model similar to the DAYZER software used by Compass Lexecon, which is a proprietary model not available to my firm. My analysis was intended to replicate the analysis performed by Compass Lexecon with the inputs and assumptions provided and obtained very similar results. The Compass Lexecon analysis showed that the merger caused in increase in coal generation of approximately 9.5 million MWH over the 2012 to 2016 period. My analysis yielded a similar estimate.

Q. What are your concerns related to increased coal generation resulting from joint dispatch?

A. I anticipate that increased coal-fired generation under the JDA will cause increased emissions of nitrogen oxides ("NOx"), sulfur dioxide ("SOx") and carbon dioxide

("CO_2"). In responses to data requests, the Applicants acknowledged that they did not attempt to quantify these increases. Data request SELC 2-41 asked the Applicants to provide emissions of NOx, SOx, and CO_2 emissions for both the pre-merger and post merger (or joint dispatch) simulations. The response simply stated that "No analyses of NOx, SOx and CO_2 emissions were performed as part of the joint dispatch analysis." However, increased coal generation will result in higher emissions. This increase in emissions as a result of the merger will adversely impact ratepayers in the form of environmental compliance costs, and will impact all North Carolina citizens in the form of health costs. However, the increased emissions from coal generation will not be mitigated by other aspects of the merger.

Q. **What is your recommendation to mitigate this adverse merger impact?**

A. One way to mitigate the increased reliance on coal generation is for the Commission to condition approval of the merger on additional use of cleaner resources such as wind, solar or energy efficiency. As a condition of approving the merger, the Applicants also should be required to develop and submit for approval a plan to mitigate the increased emissions that will result under the JDA. Such mitigation measures could take the form of additional in-state renewable energy projects and additional energy efficiency investments. The Applicants should be directed to work with interested stakeholders to develop and propose a plan to mitigate the adverse environmental impacts from the merger.

Q. **Is it feasible to add renewable energy or energy efficiency measures over and above the levels required by the state's REPS policy?**

A. Yes, it is. La Capra Associates recently performed a study on behalf of the North Carolina Energy Policy Council of the state's REPS policy and the resource potential for future compliance.[26] Our analysis showed ample, cost-effective resources available. For instance, our analysis showed 750 MW of practical wind power potential in the eastern part of the state (excluding off-shore waters).[27] Our modeling of REPS compliance predicted that only 16% of the total potential would be used to meet REPS requirements.[28] Similarly, our study found that the economic potential for energy efficiency measures is more than double the expected REPS compliance levels.[29]

VIII. The Proposed Ring-fencing Provisions Are Insufficient to Protect Ratepayers

Q. Are you concerned that the proposed merger may pose risks to ratepayers?

A. With the increased size and scale of the proposed "new Duke" holding company come additional affiliates and a more complex corporate structure. Hence, there is a greater need to ensure that each regulated utility — and its ratepayers — is protected against adverse consequences from the actions of its affiliates. "Ring-fencing" provisions are a significant protective feature in many state public utility commission orders involving utility holding company mergers over the last decade. Exhibit RSH-2 provides a list of recently approved merger cases I have reviewed. The Commission has recognized the need for effective ring fencing in the Regulatory Conditions and Codes of Conduct established at the time of prior mergers involving DEC and PEC. The Regulatory Conditions and Codes of Conduct established for those prior mergers may have been sufficient at the time that they were approved, but they require revisions and additional ring-fencing provisions to provide adequate protection for this proposed merger.

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26 North Carolina Energy Policy Council. *North Carolina's renewable energy policy: A look at REPS compliance to date, resource options for future compliance, and strategies to advance core objectives.* June 2011.

27 Ibid., 34.

28 Ibid., 2.

29 Ibid., 2.

Q. What is "Ring Fencing"?

A. Ring fencing is intended to protect ratepayers of regulated entities from risk in the business activities of unregulated affiliates or from other regulated affiliates. From a regulatory perspective, ring fencing is defined as a mechanism to insulate or "isolate the utility from the negative financial impacts created by affiliates" to ensure that utilities maintain strong credit ratings and avoid cross-subsidization of non-regulated subsidiaries.[30] Ring fencing includes "techniques used to insulate the credit risk of an issuer from the risks of affiliate issuers within the corporate structure."[31]

Q. Why is adequate ring fencing important?

A. Effective ring-fencing provisions are required to provide adequate protections for ratepayers in North Carolina. The fundamental purpose of ring fencing is to establish affiliate rules that cause a utility subsidiary to have greater value to the holding company as a thriving going concern than it would have when consolidated in bankruptcy with the parent. If the holding company's investment strategies under-perform or fail, causing access to debt and equity markets to diminish, the holding company's regulated subsidiaries may be called upon to help support the non-regulated holding company's strategy, either directly, for example, through dividend payments to the parent, or indirectly through other means.

To establish adequate ring-fencing provisions, it is necessary to hypothesize potentially extreme scenarios under which the prospect of bankruptcy or liquidation is considered. Even if such extreme scenarios might seem unlikely, the future is uncertain, and there are several examples in the electric power industry where growth pressures

30 Briefing on Ring-Fencing, Oregon Public Utility Commission, Bryan Conway, 2003.

31 Ring-Fencing Mechanisms for Insulating a Utility in a Holding Company System, NARUC Subcommittee on Accounting and Finance, 2003, p.1.

combined with inadequate ring-fencing provisions led to a utility deciding to file for bankruptcy protection. Two notable examples are Public Service Company of New Hampshire in 1998, whose bankruptcy filing was precipitated by cost over-runs for the Seabrook Nuclear Power Plant, and later Pacific Gas and Electric Company in 2001, whose filing was precipitated by conditions in the wholesale electricity trading market. Exhibit RSH-3 presents a list of recent utility bankruptcy filings. Short of bankruptcy, events resulting in even a modest change in a firm's credit rating can have measurable effects on the availability and cost of credit.[32] This degree of exposure is not fully captured in the quantitative analysis found in quarterly and annual reports and must be mitigated through ring-fencing provisions.

Credit rating agencies and regulatory authorities recommend ring-fencing provisions in addition to strong corporate governance in mergers involving holding company structures to shield shareholders, bondholders, and customers of one affiliate from downside risk of another affiliate's failed capital expenditure plan or investment strategy. This is especially important for mergers at the holding company level where affiliates of the holding company include regulated utilities whose rates support strong cash flow, which in turn supports debt service obligations and thus continued financial independence.

Q. Isn't threshold corporate governance policy sufficient to mitigate any potential risk?

A. No. While many corporate governance policies address both affiliate transactions and a service company cost allocation to some degree, they do so only to a threshold level that amounts to a promise and <u>not</u> an actual commitment. Threshold governance gives the

[32] U.S. Supreme Court, Docket No. 10-871, General electric Co. v. Environmental Protection Agency, et al., Brief of Finance Professors and Scholars as Amici Curiae, pp. 3-6.

parent company freedom to decide if credit market conditions warrant a change to its policy, which then could expose the regulated utility to greater financial risk.

For this reason, ratings agencies prefer not to rely solely on corporate governance policies. According to Fitch, "[f]inancial restrictions imposed solely through internal corporate policies are a weaker method of isolating issuer risks relative to those mandated by law, regulation or contract because the corporation may adjust its policies at will."[33] Credit rating agencies' views on ring fencing have evolved in recent years, in the wake of collapse of Enron in 2001 and the credit crisis of 2008-2009, to include more explicit evaluation of affiliate exposure.[34]

Q. What level of affiliate exposure do ratings agencies examine in utility mergers?

A. Ratings agencies believe there is a need to evaluate the utility's rating in the context of the entire corporate family, called "linkage."[35] Ring-fencing measures should anticipate and prevent an event that might cause a credit downgrade for the utility subsidiary, rather than taking a more passive approach of hoping the utility and parent have the means to correct a potential downgrade event should it occur. It is difficult to make adequate plans after the damage has been done because credit rating downgrades can trigger a rapidly

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33 NARUC Subcommittee on Accounting and Finance, "Ring-Fencing Mechanisms for Insulating a Utility in a Holding Company System", http://www.regulationbodyofknowledge.org/documents/135.pdf Quote from a Fitch Ratings Special Report : Ratings Linkage within US Utility Groups, 08 April 2003, Bonelli, et al., p. 2 (subscription access required).

34 See American Public Power Association, "The Electric Utility Industry After PUHCA Repeal, What Happens Next?", October 2005, "However, the problems revealed in connection with the financial meltdown of significant players in the electric industry in 2001-2002 indicate that regulatory oversight has not been adequate. Enron is the prime example, but other energy companies as well used accounting techniques to hide debt and inflate revenues." p. 16, and Public Utilities Fortnightly, "The Constellation Experience: Ring-Fencing after the subprime meltdown", Scott Strauss and Peter Hopkins, August, 2010, "On the morning of Sept. 16, 2008, Constellation Energy (parent of Baltimore Gas & Electric), faced its own crisis arising, at least in part, from rumors concerning the company's alleged exposure to the Lehman bankruptcy," p. 37.

35 See Standard & Poor's "Methodology: Differentiating The Issuer Credit Ratings of a Regulated Utility Subsidiary and Its Parent", March 11, 2010: "Utilities subsidiaries' ratings are linked to the consolidated group's credit quality because of the financial linkage of the parent to the subsidiary.", as well as Fitch Ratings Report "Parent and Subsidiary Rating Linkage, Fitch's Approach to Rating Entities within a Corporate Group Structure," 14 July 2010.

unfolding cascade of events. In addition, utilities may have significant exposure to distressed affiliates through the use of corporate business services and contracts for critical intercompany transactions, such as cash management, and purchases of fuels and other supplies. Once distress materializes, the utility has little control over the magnitude of the dollar impact on cash flow and may have to take drastic measures that could affect service quality. Therefore, ratings agencies look favorably on preventive or "ex ante" ring fencing because it recognizes and addresses the un-insulated utility's -- and the regulator's -- limited ability to respond in a compressed time frame to preserve cash flow.[36] One frequently cited example of the benefits of preventive ring fencing is Portland General Electric's survival of Enron's bankruptcy because the Oregon Public Service Commission imposed a preventive ring fencing strategy.[37]

Q. Can you provide any relevant examples of why strong and effective ring-fencing provisions are necessary and desirable for this merger?

A. Yes. Progress Energy Florida ("PEF") has been experiencing problems with the Crystal River 3 Nuclear Power Station. During a 2009 outage to replace steam generator tubes, cracks were discovered in the containment vessel walls. Other issues surfaced during the containment wall repairs. The unit is not expected to return to service until 2014. PEF is exposed to considerable uncertainty regarding the recovery of the actual cost of the

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36 Fitch Ratings, U.S. Utilities Survey of State Public Service Commissions, February 2004, "Fitch expects a continuing trend of preventive ring-fencing efforts, introduced through PSC orders for rates, financing plans or merger approvals, in tandem with other forward-looking regulatory efforts, such as preapproval of construction expenditures or automatic rate-adjustment mechanisms," p. 2.

37 Two recent analyses of ring-fencing published in Public Utilities Fortnightly cite the strong provisions put in place by the Oregon Public Utility Commission as a condition of approving Enron's acquisition of Portland General Electric as a threshold or even a 'gold' standard for future merger applications by state commissions. See "Fencing in the Regulated Utilities", Dr. Fred Grygiel and John Garvey, August 2004, "While Enron's debt was downgraded to junk status, Portland General Electric's ratings were many notches higher as a result of the PUC's actions." p.1, as well as "The Constellation Experience: Ring-fencing after the subprime meltdown," Scott Strauss and Peter Hopkins, August, 2010, "PGE subsequently was spared consolidation into the Enron bankruptcy, an outcome that numerous commentators, including Standard & Poor's, stated was the result of the commission-imposed ring-fencing measures," p. 37.

repairs, plus potential replacement power costs incurred to purchase power or operate other less-economic generation. This uncertainty manifests itself in two ways. First, there is uncertainty regarding whether insurance will cover some of the actual repair costs and replacement power costs. Second, depending upon the outcome of the insurance re-imbursement, there is uncertainty regarding whether and how much of these costs will be deemed to be imprudent and therefore at risk of recovery from the Florida Public Service Commission. On July 1, 2011, Fitch Ratings announced a downgrade of PEF. While Fitch held the rating of the holding company parent and PEC stable, if this uncertainty for PEF turns into a large disallowance, it is possible that a further downgrade of PEF could also result in a downgrade of all affiliates.

Duke Energy Indiana ("DEI") faces a similar risk of cost disallowances due to cost overruns for a new coal gasification unit at the Edwardsport plant. When the plant was proposed in 2006, the project had an estimated cost of $1.985 billion. That cost estimate has been revised upwards several times, and DEI is now requesting IURC approval for a revised cost estimate of $2.88 billion. The Indiana Office of Utility Consumer Counselor filed testimony on July 14, 2011 recommending that the Indiana Utility Regulatory Commission deny DEI's request for cost recovery over $1.985 billion."[38] Cost overruns at two "new Duke" affiliates and the risk of subsequent commission disallowance of cost-recovery highlight the need for strong ring-fencing measures in this merger.

[38] Please see the Indiana Office of Utility Consumer Counselor (OUCC) web page for an overview of the case and links to pertinent documents: http://www.in.gov/oucc/2625.htm .

Q. What ring-fencing measures do DEC and PEC propose to establish for this merger?

A. If the merger is approved, the Applicants propose to implement a slightly revised version of the Regulatory Conditions and Code of Conduct from the 2005 Duke-Cinergy merger. Exhibit 6 of the Application provides a redlined version of these Regulatory Conditions and Code of Conduct, showing the proposed revisions. These Regulatory Conditions and Code of Conduct do contain some key structural and operational ring-fencing measures. However, while these ring-fencing provisions may have been adequate in 2006, I believe they are inadequate for this merger, as discussed in detail below.

Q. Describe the ring-fencing measures that are typically established to help insulate utilities and their ratepayers.

A. Ring-fencing mechanisms that are typically considered when evaluating a utility's credit rating on both a stand-alone basis and in the context of corporate family rating fall into two categories: structural and operational. Regulatory commissions and ratings agencies look for a package of structural and operational ring-fencing measures to demonstrate that the utility qualifies for even a single rating grade difference from the parent.[39]

Structural measures - These measures create the initial conditions for the utility subsidiary to be viewed by its creditors as a stand-alone company and lay the foundation to minimize exposure to parent financial distress. Structural measures include making sure that a regulated utility subsidiary:

- Maintains its own (i.e. separate from its parent)
  - corporate accounting and cash management systems
  - capital structure combined with a minimum equity ratio

[39] See Public Utilities Fortnightly, "Fencing in the Regulated Utilities: Credit-rating linkage harms certain power companies. Ring-fencing is the best answer for regulators." Dr. Fred Frygiel and John Garvey, August 2004, p. 2, for a discussion of structural versus operational ring-fencing policies.

  - o debt and preferred stock credit ratings
  - o independent member(s) on its board of directors;

- Obtains a non-consolidation opinion from an independent bankruptcy counsel that confirms the parent will not and cannot involuntarily file the utility into bankruptcy; and
- Maintains a special purpose entity between it and the parent to achieve greater ratings separation within the holding company structure to confirm -- for the benefit of lenders and credit rating agencies -- its intention to remain a limited purpose operating company.[40]

Operational measures - These measures govern how affiliates interact within the structural framework recognizing the possibility that affiliates may over reach on a transaction level. Conditioning merger approval on the adoption of operational ring-fencing measures requires active public utility commission oversight of:

- Affiliate transactions;
- Dividend payments to the parent company;
- Debt and equity issuances;
- Asset transfers and divestitures; and
- Ownership changes.

Q. In addition to the structural and operational provisions listed above, are there other measures that better insulate the regulated utility from other affiliates?

A. Yes. No combination of structural and operational ring-fencing measures will render a utility bankruptcy-proof or credit downgrade-proof because the ratings agencies may

[40] Stated another way, it helps to provide evidence of "limited commitment" to and "insulation" from a corporate parent and its weaker subsidiaries. See Standard & Poor's, "Differentiating the issuer Credit Ratings of a Regulated Utility Subsidiary and Its Parent," Todd A. Shipman and Solomon B. Samson, March 11, 2010, page 3.

believe that "the parent will weaken the utility's financial profile to some degree, if its own financial condition begins to slide."[41] The objectives served by a ring-fencing strategy are to minimize the impact of holding company investment strategies on ratepayers and make the utility bankruptcy-remote by maximizing its financial independence.[42] For this reason, rating agencies and other experts advise that the holding company should, in addition to implementing robust structural and operational provisions, ensure that ring-fencing measures do not contradict any regulation, order, contract term, law or especially provision of the Federal Bankruptcy Code, and consider whether any significant intercompany transaction, such as a loan or a service company contract, is "so critical to continuing operations (that it) may nullify all other ring-fencing efforts."[43]

Q. What is the role of state utility commissions in addressing ring fencing?

A. Due to changes in federal regulation of utility holding company mergers, credit rating agencies view state regulatory commissions as having a unique opportunity to address preventive ring-fencing provisions. As a NARUC subcommittee report states, "[w]hile according to the ratings agencies, state statutory authority is the preferable tool to properly insulate the regulated utility from no-regulated affiliate activities, any action that state regulators take that provides support (whether legal, regulatory, financial, or operational) to the utility and/or isolates the utility (most importantly financial

41 Standard & Poor's, "Differentiating the issuer Credit Ratings of a Regulated Utility Subsidiary and Its Parent", Todd A. Shipman and Solomon B. Samson, March 11, 2010, pp. 4-5.

42 For a good example of a recent merger where the public utility commission imposed a slate of ring-fencing as a condition of merger approval, see Pennsylvania Public Utility Commission, Docket No. A-2010-2176520 / 2176732, "Joint Application of West Penn Power, TRAIL Co. and FirstEnergy, February 24, 2011, "Motion of Commissioner Wayne E. Gardner."

43 This last observation about operational measures is taken from the Utah State Department of Commerce "Report on Ring-Fencing," September 2005, p. 18, while the preceding structural and operational measures are taken from various reports cited herein.

obligations) from its parent company will be positive from a credit rating standpoint. Only when sufficient regulatory insulations exist will the corporate credit rating (risk of default) of an operating company be separated from that of the holding company."[44]

The important role of state regulators in addressing ring fencing was highlighted in testimony by former Commissioner James Kerr before the U.S. Senate Committee on Energy and Natural Resources on behalf of the National Association of Regulatory Utility Commissioners.[45] Commissioner Kerr's testimony described how North Carolina reassessed its authority to review mergers following the enactment of the Energy Policy Act of 2005 ("EPAct 2005"), which repealed the Public Utility Holding Companies Act of 1935 ("PUHCA 1935"). Commissioner Kerr presented the view that North Carolina and other states should maintain the same authority and oversight they have always had. North Carolina's General Statutes give the commission authority to review and approve transfers of assets affecting a public utility.[46] When reviewing and approving a merger, however, many commissions include a list of stipulated terms or conditions agreed to by all parties that include ring-fencing provisions. In the Duke Energy-Cinergy merger example cited by Commission Kerr, the North Carolina Commission included such a list as an attachment to the order, and this list serves as the basis for the Applicants' revised Regulatory Conditions in the proposed Duke Energy-Progress Energy merger.[47]

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[44] "Ring-Fencing Mechanisms for Insulating a Utility in a Holding company system", NARUC Subcommittee on Accounting and Finance, "Possible Ring Fencing Measures", p. 11.

[45] Testimony of the Honorable James Y. Kerr, II, Commissioner, North Carolina Utilities Commission on Behalf of the National Association of Regulatory Commissioners on "Adequacy of State and Federal Regulatory Structures for Governing Electric Utility Holding Companies", May 1, 2008.

[46] N.C. General Statutes, 62-111.

[47] This list is included as Attachment A to Commissioner Kerr's testimony, http://www.naruc.org/Testimony/08%200501%20Kerr%20Testimony.pdf, as well as referenced in Docket No. E-7, Sub 795, "Application of Duke Energy Corporation for Authorization under G.S. 62-111 to Enter Into a Business Combination Transaction with Cinergy Corp. and for Approval of Affiliate Agreements

Q. Do you believe the regulatory conditions proposed by the Applicants contain adequate ring-fencing provisions?

A. No, I do not. I believe that additional and improved ring-fencing provisions are necessary to protect ratepayers.

Q. What additional ring-fencing provisions should be established as conditions of approval for this merger?

A. There are several key provisions that, in my view, are either lacking or inadequate in the proposed conditions, even as modified by the proposed Public Staff settlement. These relate specifically to the following areas, as discussed in more detail below.

- Modifications to existing limits on dividend payments;
- Improved capital structure combined with a minimum equity ratio;
- Establishment of an Independent Member of the Boards of Directors of DEC and PEC;
- Additional restrictions regarding the use of money pools; and
- Establishment of a special purpose entity between regulated subsidiaries and the parent.

Q. What is your concern regarding dividend payments?

A. Dividend payments are typically made to holders of common stock of regulated utility companies. When all of the shares of common stock are held by the parent holding company, the concern is that the parent holding company may use excessive dividends to withdraw cash from a regulated utility. The current and proposed Regulatory Condition No. 39, p. 22 of Applicants' Exhibit 6, states that "DEC shall limit cumulative distributions paid to Duke Energy Corporation subsequent to the Merger of Duke Energy

under G.S. 62-153. http://ncuc.commerce.state.nc.us/cgi-bin/docksrch.ndm/INPUT?COMPNUM=E-7&COMPSUB=795&PROC=Search&frmmnth=00&frmday=00&frmyear=****&numret=20.

Corporation and Cinergy Corp to (i) the amount of Retained Earnings on the day prior to the closure of such Merger, plus (ii) any future earnings recorded by Duke Power subsequent to such Merger."

I have two concerns here. First, there is no restriction proposed for PEC dividend payments. Second, limiting dividend payments to cumulative retained earnings is not much of a restriction. As of December 31, 2010, DEC had retained earnings of $5.21 billion, and PEC had retained earnings of $3.37 billion. After the merger, the combined retained earnings will be $8.58 billion. Even if DEC and PEC remained separate entities with their own set of books, each could write an extremely large dividend check to the parent company, assuming they had sufficient cash available. A large dividend check would reduce or eliminate available cash for reinvestment in regulated utility assets and have the effect of lowering the amount of equity in the regulated entity and increasing the portion of debt in the capitalization structure. This would harm ratepayers by causing the utility to implement additional financings or forego needed capital investments. A more reasonable limit on dividends should be established, and it should apply to both DEC and PEC.

Q. Have regulatory commissions established limits on dividends in approving other mergers?

A. Yes, please see Exhibit RSH-5 for a list of recent orders issued in several state jurisdictions across the country where approval for a regulated utility to merge with a holding company was conditioned upon dividend payment restrictions. Fifteen mergers were reviewed beginning with Enron's acquisition of Portland General in 1997 and extending through the present time. Of these fifteen, twelve did not involve Duke Energy or Progress Energy or their immediate predecessors. These twelve include the

PacifiCorp-Mid-American Energy 2005 merger, which was reviewed by no less than 6 states (four of which are covered in this Exhibit), National Grid's 2007 acquisition of Keystone Energy and Niagara Mohawk in New York State, MDU Resources 2007 acquisition of Cascade Natural Gas Corporation, the Maryland PSC's 2011 order approving the merger of FirstEnergy Corporation and Allegheny Energy (Potomac Edison), as well as the Pennsylvania PUC's order earlier this year approving FirstEnergy's acquisition of West Penn Power. These orders commonly adopted a stipulated condition allowing dividend payments to the parent company only if the utility subsidiary (and in one case the parent as well) maintained minimum interest coverage and equity ratios, and confirmed that such payment would not cause the utility's equity ratio or debt servicing capacity to fall below a minimum threshold. For example, the PacifiCorp-Mid-American Energy merger order tied dividend payments to the parent company to PacifiCorp maintaining a common equity ratio above 45% through 2011 and 44% thereafter. Maryland's PSC restricted dividend payments in the EDF-Constellation and FirstEnergy-Allegheny Power mergers to BG&E and Potomac Edison each demonstrating that they can maintain a 45% equity ratio. Tying approval to make distributions to thresholds for equity and debt servicing ratios addresses my concern expressed above to retain cash for reinvestment in the utility subsidiary and controlling the proportion of debt in the utility's capital structure.

Q. What is your specific recommendation regarding dividend policy?

A. Dividends are typically less than annual net income, with the other portion of net income re-invested back into the regulated utility. Therefore, annual dividends should be capped at the level of annual net income, unless specifically approved by the Commission, to ensure that excess amounts of cash are not inappropriately diverted to the parent company. This restriction should apply to both DEC and PEC.

Q. What is your concern regarding capitalization structure?

A. Regulated utilities typically maintain a balance capitalization structure with approximately equal parts debt and equity. If this structure has excessive debt, the regulated utility becomes too highly leveraged, and its credit rating may be downgraded, which would lead to higher borrowing costs. If this structure has excessive equity, rates may be higher than necessary, as equity financing is more expensive than debt. In my experience, most regulated utilities have equity ratios ranging from 40% to 60%.

Q. Have regulatory commissions established limits on capital restructures in approving other mergers?

A. Yes, please see Exhibit RSH-5 for a list of recent orders issued in different state jurisdictions across the country where the application for a regulated utility to merge with a holding company was conditioned upon the utility subsidiary maintaining a common equity ratio above a specified threshold for a specified duration. For example, the Pennsylvania PUC in its order approving FirstEnergy's acquisition of West Penn Power, required the utility subsidiaries to each maintain equity ratios above 40% for five years following the merger. If they fail to do so, the utilities must file a 12 month plan to cure this deficiency or face dividend restrictions. National Grid's KeySpan and Niagara Mohawk utility subsidiaries must not allow their respective debt-to-total capital ratios exceed 56% for over a 12 month period, as reported each calendar quarter. (This is the same as requiring the equity ratio to remain above 44%.) The commissions intend this provision to be an adjunct to the dividend restriction condition because it allows them to address equity erosion by other means.

Q. What is your specific recommendation regarding capital restructure?

A. The Commission should include as a new Regulatory Condition that DEC and PEC maintain an equity ratio at 40% or higher, unless otherwise explicitly approved by the Commission. This is only slightly higher than the 35% minimum equity ratio established by the Kentucky Commission in Case No. 2001-00124.

Q. Why do you recommend requiring an independent member on the boards of directors of each of the utility operating subsidiaries, DEC and PEC?

A. A condition requiring an independent member of the boards of directors of DEC and PEC—that is, a member who is not an employee of the parent holding company or any of its affiliates—will provide additional protection for ratepayers in the event that the parent company or other affiliate faces bankruptcy. This is because such a condition would require that the independent director consent to a board vote to allow the utility subsidiary to be filed into bankruptcy with its parent or affiliate. If the independent board member is independent, he or she is free to make such a decision solely based on the interest of the regulated utility's ratepayers. Exhibit RSH-5 provides a summary of recent orders approved in different state jurisdictions across the country where the application for a regulated utility to merge with a holding company was conditioned upon the inclusion of an independent director on the regulated utility's board of directors. The independent director provision often requires that any board vote to file for bankruptcy or be consolidated in bankruptcy with an affiliate must be unanimous. But for orders where a unanimous vote has not been required, the commission has specified that a majority vote must include the consent of the independent director. Many of these orders required the independent director's assent to take other actions, such as an agreement to be merged or pledge assets. Included among the orders summarized in Exhibit RSH-5 is the order issued by the Kentucky Public Service Commission on August 2, 2011, which conditioned approval of this proposed merger on, among other ring-fencing provisions, the requirement that "Duke's post-merger Board of Directors will include at least one non-employee member who is a customer of either Duke Kentucky, Duke Ohio, or Duke Energy Indiana."[48] While the requirement in the Kentucky order calls for an independent director at the holding company level, this was done to ensure that the mid-west customers of Duke had some representation in Duke's governance, and it illustrates the principle of and benefits from independent directors. The Maryland PSC conditioned its approval of EDF International's acquisition of Constellation Energy Group (parent of Baltimore Gas & Electric Company) upon the appointment of an independent member to the board of directors of the Special Purpose Entity (SPE) that CEG agreed to set up as a merger approval condition.[49] This further illustrates the effective use of independent directorships as a ring-fencing measure.

Q. What is your concern with participation in a money pool?

A. Of particular concern is DEC's and PEC's use of utility money pools, as described in the utility money pool agreement provided in the Applicants' response to SELC Data Request Set 3, Item 3-38. Although the use of money pools is not uncommon, its use does not meet the test of ex-ante ring fencing and raises critical issues of both financial

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48 Commonwealth of Kentucky before the Public Service Commission, Case No. 2011-00124, Appendix B, Regulatory Commitments, No. 48, page 10, August 2, 2011. Regulatory Commitment No. 48 requires an independent member of the holding company board of directors who is a non-employee and a customer of one of the mid-west utility affiliates mentioned.

49 Public Utilities Fortnightly, "The Constellation Experience: Ring-fencing after the subprime meltdown.", August 2010, "One year later [following the subprime credit crisis], testifying in support of the EDF acquisition before the Maryland Public Service commission (MDPSC), Constellation executives acknowledged that (it had) insufficient ring-fencing measures surrounding BGE to mitigate against the likelihood that a court would involuntarily consolidate BGEinto a Constellation bankruptcy "... [due to its exposure to a Lehman bankruptcy and the "financially-challenging" construction of a third nuclear reactor at Calvert Cliffs] ... In addition, Constellation controlled a majority of the seats on the board of directors of BGE .. and could direct BGE to file a voluntary petition for bankruptcy together with a Constellation filing." p. 38, 41.

independence (risk of consolidation in event of bankruptcy) and non-regulated affiliate access to utility subsidiary liquid assets. As one expert has testified before the Washington Utilities and Transportation Commission in 2005 regarding the PacifiCorp-Mid-American Energy merger application:

> Holding company money pools, where companies deposit or borrow cash on a daily basis provides a linkage between the financial operations of regulated and unregulated firms in the holding company. For example, a cash-rich utility operation could lend the holding company money pool \$50 million and a cash-poor competitive generator could borrow that same \$50 million from the money pool, at a short-term debt rate. In effect, the regulated utility is lending money to the unregulated operation even though there is no security or pledge of assets offered by the utility. Such a transaction, I believe, would also pass muster with regard to a prohibition of lending to Mid-American Energy or its affiliates because in the action I've described, PacifiCorp's \$50 million contribution could be characterized as "simply participating in the corporate money pool" and not specifically lending to any entity directly. Such a characterization would not be untrue but would mask the actual financial linkage of the regulated and unregulated subsidiaries.[50]

Q. What do you recommend regarding DEC's and PEC's participation in money pools?

A. Money pools allow participants to exchange short-term funds. A more effective way to insulate a regulated utility from potential adverse impacts from affiliates would be to require that regulated utility to maintain its own independent short-term debt and lines of credit. In the Duke-Cinergy merger, the Commission allowed the use of a money pool, but restricted the participants in that pool, prohibiting loans to and borrowings from Duke Energy Corporation and Cinergy Corporation. See Regulatory Condition #48. In proposed Regulatory Condition # 42, the Applicants modify that language to include a prohibition on money pool transactions with Progress Energy, Inc. This proposed Regulatory Condition does not prohibit money pool transactions with other unregulated

[50] WUTC, Docket No. UE-051090, Pacificorp Mid-American Merger Application, Direct Testimony of Stephen G. Hill, November 18, 2005, pp. 22-23.

affiliates of DEC and PEC. If the Commission is going to allow participation by DEC and PEC in a money pool, it should be conditioned upon having only regulated utilities participate in the money pool. This will mitigate the risk that potential poor financial performance of an unregulated affiliate will adversely impact DEC or PEC.

Q. Why do you recommend establishing a special purpose entity between DEC and PEC and the parent holding company?

A. A special purpose entity (SPE) establishes and maintains the necessary degree of separateness that credit rating agencies are looking for when evaluating the credit-worthiness of the utility subsidiaries on a stand-alone basis. In other words, a SPE is a "firewall" between the subsidiary and its parent. As noted by Fitch Ratings, "[a] special purpose subsidiary created to hold passive financial assets for a securitization can achieve complete credit isolation and bankruptcy remoteness."[51] Because the rating agencies look to evaluate the utility's isolation from parent and affiliate distress, all else being equal, an SPE can help to improve credit ratings, which can lead to lower cost of debt. The Applicants have provided a simplified organization chart illustrating the structure of the proposed post-merger entity, presented in Exhibit RSH-6 below, which shows that while Duke Energy ("HoldCo") will retain the Progress Energy intermediate holding company, no such SPE will exist between DEC and the rest of the corporate family.

The Applicants, in their response to Public Staff Data Request No. 16 (page 5) state that "Given the extent of [their proposed] regulatory conditions that would be in place, the SPE seems unwarranted." This response is presented in Exhibit RSH-7. The distinctive feature of the ring-fencing provisions recommended in this testimony, and sought by the credit rating agencies, as cited above, is that they are inter-related and

[51] Fitch Ratings, "U.S. Utilities Survey of State Public Service Commissions", February 2004, "The Aim and Sources of a Ring-Fence," p. 2.

imposed as a group, including that the SPE that holds no debt, owns 100% of the equity of the utility subsidiary, the utility maintains a minimum equity ratio, and includes an independent member on its board of directors whose vote is required to allow the utility to be filed into bankruptcy. The Maryland PSC expressed the belief in its EDF – Constellation (BG&E) order that, taken together, these provisions reinforce the regulated utility's separateness from any parent or affiliate facing financial distress to such a degree that they "not only will protect BGE against financial catastrophe at the hands of its parent, but will strengthen BGE in ways that will yield more for ratepayers in the long term than any rebate."[52] In their response to response to Public Staff Data Request No. 16, the Applicants have suggested that the significant expense associated with transferring and recording of assets outweighed benefits. By contrast, the strong statement from the Maryland PSC affirms the value of ring-fencing at the time of the merger and for the long-term.

Q. Have regulatory commissions required a special purpose entity in connection with other mergers?

A. Yes, please see Exhibit RSH-5 for a list of recent regulatory commission orders where the application for a regulated utility to merge with a holding company was conditioned upon the establishment of a SPE between the utility subsidiary and the parent holding company. For example, the Washington commission ("WUTC") required an SPE in all three mergers reviewed, including MDU-Cascade Natural Gas (2007) and Puget Sound Energy-PPW Holdings (Macquarie Capital Corp, 2008), The WUTC, along with the Idaho commission, also approved an SPE as part of the 2005 PacifiCorp-Mid-American

[52] Maryland Public Service Commission, Order 82407, Case No. 9173, Constellation Energy Group (parent of Baltimore Gas & Electric), MidAmerican Energy Holdings (Phase I – 2008), EDF International (Phase II - 2009), October 30, 2009, p. 5.

Energy acquisition. Five of the twelve (non-Duke/Progress Energy-related) orders reviewed required a SPE, with these five orders pertaining to four separate merger applications. The PacifiCorp-Mid-American Energy merger appears more than once in this list because it required commission approval in several states. The PacifiCorp-Mid-American Energy multi-state settlement included a set of stipulations to be adopted across all states in which the post-merger entity would operate, including ring-fencing provisions but not an SPE. However, each state commission could append its own unique provisions, with the WUTC and the Idaho PUC requiring an SPE, or amend a common stipulation to be more restrictive, as the WUTC commission did by adding a senior unsecured long term debt credit rating threshold to the dividend payment restriction. Because of these state-specific provisions, this merger appears more than once in the recommendation tables in Exhibit RSH-5.

IX. The Rate Impacts of the Proposed Merger Could Result in "Winners and Losers"

Q. Are the Applicants offering to reduce rates as a result of the merger?

A. No. As explained in the Application, DEC's and PEC's current plans to construct new generating units will cost over $5 billion. To recover these costs, DEC and PEC are planning to file one or more general rate cases for both utilities in the 2011-2013 timeframe, and acknowledge that these rate cases will seek rate increases. Although the Applicants claim that merger savings will help offset these rate increases, they are not offering lower rates as one of the benefits of the merger.[53] Unlike the Duke-Cinergy merger where Duke was required to implement a one-year across the board decrement to rates for North Carolina retail customers in the amount of $117.5 million, no specific savings mechanism is offered in this merger application.

[53] Application at 14.

Q. Do you have any concerns about the possible impacts of the merger on rates?

A. Yes, I do. There is currently a significant difference between the rates of DEC and PEC. I am concerned that there could be "winners and losers" as a result of the eventual merger of DEC and PEC. In other words, that merger may cause rates to go up for some customers and down for other customers.

Q. How do the DEC and PEC rates compare?

A. As shown in Figure 16 below, DEC's rates are currently significantly lower than PEC's.

Figure 16

Rate Comparison for DEC and PEC

2010 Average Revenue (cents per KWH sold)			
Class	DEC	PEC	% difference
Residential	8.9	10.2	15%
Comm & Ind	6.2	7.9	26%

Q. What is the basis of the current DEC and PEC rate differentials?

A. Information on rate differentials was not provided in the Application itself. However, I was able to examine FERC Form 1 2010 data, which shows each company's historic costs for plant in service and operation and maintenance ("O&M"). These items of cost represent the largest components of cost-based electric rates, so I would expect a strong correlation between these costs and current rates. Figure 17 below provides a comparison of net plant costs and O&M costs per MWH of sales to ultimate customers. PEC has, in aggregate, lower plant costs per MWH, but higher O&M costs, particularly fuel costs.

Figure 17

Cost Summary for DEC and PEC

	$ per MWH Sales to Ultimate Customers		
Item	DEC	PEC	DIFF
NET ELECTRIC PLANT IN SERVICE			
Steam Production	$37.33	$33.68	
Nuclear Production	$34.88	$42.93	
Hydraulic Production	$13.60	$1.06	
Other Production	$7.35	$13.96	
subtotal	$93.16	$91.63	($1.53)
Transmission	$17.74	$21.27	$3.54
Distribution	$62.88	$54.97	($7.90)
subtotal	$173.77	$167.88	($5.90)
O&M COSTS	$48.18	$69.56	$21.38
Non-Fuel O&M	$26.42	$34.11	$7.70
Fuel Costs	$21.76	$35.44	$13.68

Figure 18 below provides a breakdown of the sources of energy deployed by each company. Both DEC and PEC have large portions of their energy supply portfolio in coal. DEC has a greater share of nuclear and hydro, and PEC has a greater reliance on natural gas and oil. This supports the conclusion that fuel cost differences, which in turn are based upon differences in generation mix, are the key driver of the rate differentials between DEC and PEC.

Figure 18

Energy Portfolio for DEC and PEC

	DEC		PEC	
Item	MWH	% of total	MWH	% of total
SOURCES OF ENERGY				
Steam - Coal	39,602,035	44%	30,527,715	49%
Nuclear	43,443,278	48%	21,623,668	35%
Hydro-Conventional	1,880,416	2%	608,018	1%
Hydro-Pumped Storage	2,967,185	3%	0	0%
Natural Gas / Oil	608,468	1%	5,429,327	9%
Less Energy for Pumping	(3,656,154)	-4%	0	0%
Purchases	4,790,025	5%	4,011,820	6%
Net Exchanges	290,188	0%	0	0%
Transmission by Others	96,651	0%	(26,381)	0%
TOTAL	90,022,092	100%	62,174,167	100%

Figure 19 below shows per unit costs of fuel burned in 2010 by fuel type. PEC has a lower cost for coal but higher costs for natural gas. These differences provide additional support for the conclusion that the generation mix is the key driver in rate differentials.

Figure 19

Fuel Cost Comparison for DEC and PEC

Row Labels	Units	Units Burned	Annual Cost of Fuel Burned	Cost per Unit
Coal	tons	28,684,336	$2,567,232,080	$89.50
DEC		15,547,600	$1,430,900,551	$92.03
PEC		13,136,736	$1,136,331,529	$86.50
Gas	MCF	35,387,560	$226,560,566	$6.40
DEC		6,990,560	$36,915,593	$5.28
PEC		28,397,000	$189,644,973	$6.68
Nuclear	MWH	65,066,945	$359,567,442	$5.53
DEC		43,443,278	$224,670,344	$5.17
PEC		21,623,668	$134,897,098	$6.24
Oil	BBLs	1,915,636	$169,404,747	$88.43
DEC		188,255	$17,355,590	$92.19
PEC		1,727,381	$152,049,157	$88.02
Grand Total			$3,322,764,835	

Q. Have the Applicants provided an assessment of the impact of the merger on rates?

A. No, not to my knowledge. The Applicants have offered estimates of savings due to the merger from the JDA and fuel procurement practices, as well as an estimate of cost allocation and savings between North Carolina and South Carolina using theoretical allocation ratios. The Applicants' witness Sasha Weintraub discusses allocation of JDA savings between DEC and PEC on pages 9-12 of his direct testimony. However, the Applicants have not provided a detailed assessment of how these estimated savings or other identified savings, net of any costs to achieve these savings, will be allocated between and among the rate classes within each jurisdiction.

Q. What do you conclude from your independent assessment?

A. The current generation mix of each utility is the key driver of the current rate differentials. As noted in the above section that discussed the JDA, although both DEC and PEC should benefit from the JDA, the JDA is unlikely to narrow the gap between the DEC and PEC production costs because the generation mix of each utility is not likely to change in the short term. Due to the choice of hourly generation as the allocator for joint dispatch savings, it is possible that the JDA may actually increase, not decrease the production cost difference.

Q. What is the significance of an increase in the difference between the DEC and PEC production costs?

A. The Applicants state that DEC and PEC will likely remain as separate entities with separate rate tariffs for several years until numerous operational issues are addressed, including uniform rate schedules.[54] DEC and PEC have indicated that they will not seek to merge until the difference in rates between the two entities has closed, or at least narrowed.[55] However, the Application does not provide a forecast or analysis of future rates nor an estimate of how or when this rate gap would be sufficiently "closed" to facilitate combining DEC's and PEC's separate tariffs into a single set of tariffs.

The "rate gap" will likely be closed only when significant changes in the generation mix occurs. Such changes seldom happen quickly, as generating units are long-lived assets. Although both DEC and PEC have significant capital investment plans, it does not appear that the production cost advantage currently enjoyed by DEC will change in the very near future. Therefore, it is likely that this rate differential between DEC and PEC will persist for quite some time.

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54 See Dir. Testimony of Rogers and Johnson at 7.
55 See Transcript of Hearing at 33, Public Service Commission of South Carolina (2011) (No. 11-11171).

Q. Is it possible that the allocation of other merger savings besides the production cost savings created by the JDA could narrow the rate differential?

A. While such an outcome might be theoretically possible, I would not expect that to occur. Merger synergies, such as savings from combining IT operations or T&D field forces, should be allocated such that both DEC and PEC benefit. Therefore, these merger savings alone are unlikely to narrow the gap.

Q. What do you recommend regarding rate impacts?

A. It is clear that DEC has substantially lower rates than PEC. It does not appear that the merger will close this gap in the very near future. Although the Applicants are planning to maintain separate rate schedules for PEC and DEC, the post-merger allocation of costs and savings should be performed in a manner that results in merger benefits being experienced by all customer classes. Merger approval should be expressly conditioned to avoid creating "winners and losers," and instead to ensure that all ratepayer groups in each company benefit from the proposed merger.

X. The Proposed Public Staff Settlement Agreement Does Not Address Certain Adverse Impacts Caused by the Merger

Q. What is your initial assessment of the settlement agreement between the Applicants and Public Staff?

A. I had very little time to review the agreement due to the fact that it was provided only two business days prior to the filing of this testimony. The agreement is based upon the existing Regulatory Conditions and Code of Conduct. The majority of the revisions in the draft settlement agreement appear directed at preserving state jurisdiction over the merged entity, eliminating to the maximum extent possible the potential for federal preemption, and ensuring the native retail customers continue to receive the benefits of the existing portfolio of power supplies. The draft settlement does adopt one of my recommendations, which is to limit participation in the money pool to regulated utility operating companies subject to state jurisdictions. These provisions provide important protections for North Carolina and should be adopted by the Commission.

Q. Does the draft settlement agreement address all of your concerns regarding this merger?

A. No, the draft settlement does not address several of my key concerns. For example:

- The draft settlement does not appear to contain any provisions to address the adverse environmental impacts from the increased coal generation and emissions caused by the merger.
- There do not appear to be any provisions to address the negative impact on jobs.
- The agreement preserves many of the existing ring-fencing provisions, which as discussed above, are not adequate. The additional conditions and provisions that I recommend here can and should be added to the provisions contained in the draft settlement agreement.
- Lastly, the draft settlement agreement specifically prohibits a JDA based upon a single BAA.[56] This is an issue that the Public Staff and I disagree on, and in the short time since I have received the draft settlement agreement, I have not had the opportunity to discuss these differences with the Public Staff. As I noted previously, a JDA based upon a single BAA will provide maximum benefits to North Carolina without compromising the principles and protections sought by the Public Staff, as I understand them. I continue to recommend a JDA based upon a single BAA.

XI. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

[56] See paragraph 4.1 of the draft settlement agreement.

Exhibit RSH 1
Resume of Richard S. Hahn

La Capra Associates

Richard S. Hahn

Principal Consultant

Mr. Hahn is a senior executive in the energy industry, with diverse experience in both regulated and unregulated companies. He joined La Capra Associates in 2004. Mr. Hahn has a proven track record of analyzing energy, capacity, and ancillary services markets, valuation of energy assets, developing and reviewing integrated resource plans, creating operational excellence, managing full P&Ls, and developing start-ups. He has demonstrated expertise in electricity markets, utility planning and operations, sales and marketing, engineering, business development, and R&D. Mr. Hahn also has extensive knowledge and experience in both the energy and telecommunications industries. He has testified on numerous occasions before the Massachusetts Department of Public Utilities, and also before FERC.

SELECTED EXPERIENCE – LA CAPRA ASSOCIATES

- Reviewed and analyzed a proposed retail rate increase by Fitchburg Gas and Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Spending Plan, and an accompanying recovery mechanism.
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Georgia, Vermont.
- Reviewed and analyzed damages claimed in litigation between a developer of renewable energy facilities and the owner of the host site.
- Evaluated the decision of PacifiCorp to acquire new generating resources in Utah. Filed testimony before the Public Service Commission of Utah.
- Served as a principal advisor and key team member in La Capra Associates' assessment of strategic options for Entergy Arkansas, Inc. subsequent to its withdrawal from the Entergy System Agreement.
- Conducted a study of non-transmission alternatives to a proposed substation and related transmission upgrades in Jay, Vermont.
- Reviewed and evaluated the construction of and cost recovery for a large cogeneration plant for a mid-west utility; utilized heat balance analysis to develop new cost allocators between steam and electric sales.
- Analyzed fuel costs, market sales and revenues, capacity position, and performance parameters for a large- mid-west utility.

- Performed a review and analysis of the proposed merger between FirstEnergy and Allegheny Energy. Provided expert testimony before the FERC and the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Performed a study of non-transmission alternatives to a proposed transmission project in the Lewiston-Auburn area of Central Maine Power Company's service territory. Testified before the Maine Public Utilities Commission.
- Analyzed a proposed plan by National Grid to procure 2011 default service power supplies and comply with Renewable Energy Standards. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to the Pennsylvania Office of Consumer Advocate in reviewing 2011 default service plans for Pennsylvania Electric Distribution Companies.
- Analyzed a purchase power agreement between National Grid and on offshore wind project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Reviewed and analyzed a proposed retail rate increase by Western Massachusetts Electric Company before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Capital Plan, and an accompanying recovery mechanism.
- Served as an advisor to the developer of a utility-scale Solar PV facility in Massachusetts.
- Evaluated a proposed Solar PV installation for a large retail customer in Massachusetts. Performed an analysis of the appropriate rate of return and its impact on facility electric costs and financial feasibility.
- Assessed the economic impact of an additional interconnection between ISO-NE and NYISO; analyzed impact on market prices and congestion.
- Reviewed and analyzed the capacity position of a large mid-west utility and the impact of that position on electric rates.
- Performed an economic evaluation of a proposed transmission line in New England. Assessed the project's ability to deliver renewable energy to load centers and the impact of the project on Locational Marginal Prices.
- Analyzed a proposed interconnection of a large new industrial load in Massachusetts. Evaluated proposed substation configuration and developed alternatives that achieved comparable reliability at lower costs. Assessed cost recovery options.
- Reviewed the Energy Efficiency and Conservation Programs proposed by Pennsylvania Power & Light and Philadelphia Electric Company in response to Act 129, Pennsylvania legislation that requires Electric Distribution Companies to achieve certain annual consumptions and demand reduction by 2013. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding program design, benefit cost analyses, and cost recovery.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Rhode Island Public Utilities Commission. Provided expert testimony before the Rhode Island Public Utilities Commission regarding the Company's proposed

Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan

- Reviewed and analyzed Time-of-Use rates proposed by Pennsylvania Power & Light. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding compliance with Commission requirements, rate design, cost recovery, and consumer education issues.
- Assisted in the review and analysis of a proposed retail rate increase by National Grid before the Massachusetts Department of Public Utilities. Provided expert testimony before the Massachusetts Department of Public Utilities regarding the Company's proposed Inspection & Maintenance Program, its Capital Plan, its Storm Funding Plan, and its Facilities Plan.
- Performed a review and analysis of the proposed merger between Exelon and NRG. Provided expert testimony before the Pennsylvania Public Utilities Commission regarding merger policy, benefits and market power issues.
- Reviewed the needs analysis and load forecast supporting a proposed Transmission Project in Rhode Island. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Performed an assessment of plans to procure Default Service Power Supplies for a Rhode Island utility. Provided expert testimony before the Rhode Island Public Utilities Commission.
- Served as an advisor to Vermont electric utilities regarding the evaluation of new power supply alternatives. Developed and applied a probabilistic planning tool to model uncertainty in costs and operating parameters.
- Conducted a review of Massachusetts electric utilities' proposal to construct, own, and operate large scale PV solar generating units. Served as an advisor to the Massachusetts Attorney General in settlement negotiations. Performed an analysis of the appropriate rate of return and its impact on ratepayer costs and financial feasibility. Provided expert testimony before the Massachusetts Department of Public Utilities.
- Served as a key member of a La Capra Associates Team evaluating wind generation RFPs in Oklahoma.
- Performed an assessment of plans to procure Default Service Power Supplies for Pennsylvania utilities. Provided expert testimony before the Pennsylvania Public Utilities Commission.
- Performed an assessment of a merchant generator proposal to construct, own, and operate 800 MW of large scale PV solar generating units in Maine.
- Analyzed proposed environmental upgrades to several existing coal-fired power plants in Wisconsin, including an economic evaluation of this investment compared to alternative supply resources. Provided expert testimony in three separate proceedings before the Public Service Commission of Wisconsin.
- Reviewed Pennsylvania Act 129 and Commission rules for Energy Efficiency Plans

- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Maine.
- Served as a key member of the La Capra Associates Team advising the Connecticut Energy Advisory Board (CEAB) on a wide range of energy issues, including integrated resources plan and the need for and alternatives to new transmission projects.
- Performed a study of non-transmission alternatives (NTAs) to a proposed set of transmission upgrades to the bulk power supply system in Vermont.
- Served as an advisor to the Delaware Public Service Commission and three other state agencies in the review of Delmarva Power & Light's integrated resource plan and the procurement of power supplies to meet SOS obligations.
- Served as an expert witness in litigation involving a contract dispute between the owner of a merchant powerplant and the purchasers of the output of the plant.
- Served as an advisor to the Maryland Attorney General's Office in the proposed merger between Constellation Energy and the FPL Group.
- Reviewed and analyzed outages for Connecticut utilities during the August 2006 heat wave. Prepared an assessment of utility filed reports and corrective actions.
- Conducted a study of required planning data and prepared forecasts of the key drivers of future power supply costs for public power systems in New England.
- Reviewed and analyzed Hawaiian Electric Company integrated resource plan and its DSM programs for the State of Hawaii. Prepared written statement of position and testified in panel discussions before the Hawaii Public Utility Commission.
- Assisted the Town of Hingham, MA in reviewing alternatives to improve wireless coverage within the Town and to leverage existing telecommunication assets of the Hingham Municipal Light Plant.
- Conducted an extensive study of distributed generation technologies, options, costs, and performance parameters for VELCO and CVPS.
- Analyzed and evaluated proposals for three substations in Connecticut. Prepared and issued RFPs to seek alternatives in accordance with state law.
- Performed an assessment of merger savings from the First Energy – GPU merger. Developed a rate mechanism to deliver the ratepayers share of those savings. Filed testimony before the PA PUC.
- Prepared long term price forecasts for energy and capacity in the ISO-NE control area for evaluating the acquisition of existing powerplants.
- Conducted an assessment of market power in PJM electricity markets as a result of the proposed merger between Exelon and PSEG. Developed a mitigation plan to alleviate potential exercise of market power. Filed testimony before the PA PUC.
- Performed a long-term locational installed capacity (LICAP) price forecast for the NYC zone of the NYISO control area for generating asset acquisition.
- Served as an Independent Evaluator of a purchase power agreement between a large mid-west utility and a very large cogeneration plant. Evaluated the implementation of

amendments to the purchase power agreement, and audited compliance with very complex contract terms and operating procedures and practices.

- Performed asset valuation for energy investors targeting acquisition of major electric generating facility in New England. Prepared forecast of market prices for capacity and energy products. Presented overview of the market rules and operation of ISO-NE to investors.
- Assisted in the performance of an asset valuation of major fleet of coal-fired electric generating plants in New York. Prepared forecast of market prices for capacity and energy products. Analyzed cost and operations impacts of major environmental legislation and the effects on market prices and asset valuations.
- Conducted an analysis of the cost impact of two undersea electric cable outages within the NYISO control area for litigation support. Reviewed claims of cost impacts from loss of sales of transmission congestion contracts and replacement power costs.
- Reviewed technical studies of the operational and system impacts of major electric transmission upgrades in the state of Connecticut. Analysis including an assessment of harmonic resonance and type of cable construction to be deployed.
- Conducted a review of amendments to a purchased power agreement between an independent merchant generator and the host utility. Assessed the economic and reliability impacts and all contract terms for reasonableness.
- Assisted in the development of an energy strategy for a large Midwest manufacturing facility with on-site generation. Reviewed electric restructuring rules, electric rate availability, purchase & sale options, and operational capability to determine the least cost approach to maximizing the value of the on-site generation.
- Assisted in the review of the impact of a major transmission upgrade in Northern New England.
- Negotiated a new interconnection agreement for a large hotel in Northeastern Massachusetts.

SELECTED EXPERIENCE – NSTAR ELECTRIC & GAS

President & COO of NSTAR Unregulated Subsidiaries

Concurrently served as President and COO of three unregulated NSTAR subsidiaries: Advanced Energy Systems, Inc., NSTAR Steam Corporation, and NSTAR Communications, Inc.

Advanced Energy Systems, Inc.

- Responsible for all aspects of this unregulated business, a large merchant cogeneration facility in Eastern Massachusetts that sold electricity, steam, and chilled water. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Steam Corporation

- Responsible for all aspects of this unregulated business, a district energy system in Eastern Massachusetts that sold steam for heating, cooling, and process loads. Duties included management, operations, finance and accounting, sales, and P&L responsibility.

NSTAR Communications, Inc.

- Responsible for all aspects of this unregulated business, a start-up provider of telecommunications services in Eastern Massachusetts. Duties included management, operations, finance and accounting, sales, and P&L responsibility.
- Established a joint venture with RCN to deliver a bundled package of voice, video, and data services to residential and business customers. Negotiated complex indefeasible-right-to-use and stock conversion agreements.
- Installed 2,800 miles of network in three years. Built capacity for 230,000 residential and 500 major enterprise customers.
- Testified before the Congress of the United States on increasing competition under the Telecommunications Act of 1996.

VP, Technology, Research, & Development, Boston Edison Company

- Responsible for identifying, evaluating, and deploying technological innovation at every level of the business.
- Reviewed Electric Power Research Institute (EPRI), national laboratories, vendor, and manufacturer R&D sources. Assessed state-of-the-art electro-technologies, from nuclear power plant operations to energy conservation.

VP of Marketing, Boston Edison Company

- Promoted and sold residential and commercial energy-efficiency products and customer service programs.
- Conducted market research to develop an energy-usage profile. Designed a variable time-of-use pricing structure, significantly reducing on-peak utilization for residential and commercial customers.
- Designed and marketed energy-efficiency programs.
- Established new distribution channels. Negotiated agreements with major contractors, retailers, and state and federal agencies to promote new energy-efficient electro-technologies.

Vice President, Energy Planning, Boston Edison Company

- Responsible for energy-usage forecasting, pricing, contract negotiations, and small power and cogeneration activities. Directed fuel and power purchases
- Implemented an integrated, least-cost resource planning process. Created Boston Edison's first state-approved long-range plan.

- Assessed non-traditional supply sources, developed conservation and load-management programs, and purchased from cogeneration and small power-production plants.
- Negotiated and administered over 200 transmission and purchased power contracts.
- Represented the company with external agencies. Served on the Power Planning Committee of the New England Power Pool.
- Testified before federal and state regulatory agencies.

EMPLOYMENT HISTORY

La Capra Associates, Inc. **Boston, MA**
Principal Consultant 2004 – present

Advanced Energy Systems, Inc. **Boston, MA**
President and COO 2001-2003

NSTAR Steam Corporation **Cambridge, MA**
President and COO 2001-2003

NSTAR Communications, Inc.
President and COO 1995-2003

Boston Edison Company **Boston, MA**

VP, Technology, Research, & Development	1993-1995
VP, Marketing, Boston Edison Company	1991-1993
Vice President, Energy Planning, Boston Edison Company	1987-1991
Manager, Supply & Demand Planning	1984-1987
Manager, Fuel Regulation & Performance	1982-1984
Assistant to Senior Vice President, Fossil Power Plants	1981-1982
Division Head, Information Resources	1978-1981
Senior Engineer, Information Resource Division	1977-1978
Assistant to VP, Steam Operations	1976-1977
Electrical Engineer, Research & Planning Department	1973-1976

EDUCATION

Boston College Boston, MA
Masters in Business Administration 1982

Northeastern University Boston, MA
Masters in Science, Electrical Engineering 1974

Northeastern University Boston, MA
Bachelors in Science, Electrical Engineering 1973

PROFESSIONAL AFFILLIATIONS

Director, NSTAR Communications, Inc.	1997-2003
Director, Advanced Energy Systems, Inc.	2001-2003
Director, Neuco, Inc.	2001-2003
Director, United Telecom Council	1999-2003
Head, Business Development Division, United Telecom Council	2000-2003
Elected Commissioner – Reading Municipal Light Board	2005-present
Registered Professional Electrical Engineer in Massachusetts	

Exhibit RSH-2
Merger Orders Reviewed

1. KY: 2011, Case No. 2011-00124, Joint Application of Duke Energy Corp, Progress Energy, Inc. for Approval of the Indirect Transfer of Control of Duke Energy Kentucky.
2. MD-1: 2011, Order No. 83788, Case No. 9233, FirstEnergy Corp, Allegheny Energy (Potomac Edison)
3. PA: 2010, Docket No. A-1010-2176520/2175732, West Penn Power, First Energy.
4. WA-1: 2008, Order 08, Docket U-072375, Puget Sound Energy, Puget Holdings consortium (including Macquarie Capital Corp.)
5. MD-2: 2009, Order 82986, Case No. 9173, Constellation Energy Group (parent of Baltimore Gas & Electric), MidAmerican Energy Holdings (Phase I), EDF International (Phase II).
6. NY: 2007, D06-M-0878, KeySpan Corp, National Grid PLC, (Niagara Mohawk, KEDNY, KEDLI)
7. WA-2: 2007, Docket No. US-061721, MDU Resources Group, Inc., Cascade Natural Gas Corp.
8. CA: 2006, CA, D06-02-03, Case 05-07-010, Pacificorp, MidAmerican Energy Corp.
9. ID: 2006, Order 29973, Case No. PAC-E-05-8, Pacificorp, MidAmerican Energy Corp.
10. OR-1: 2006, Order No. 06-121, UM 1209, Pacificorp, MidAmerican Energy Corp.
11. WA-2: 2005, Order No. 07, Docket UE-051090, Pacificorp, MidAmerican Energy Corp.
12. NC-1: 2005, Docket No. E-2, Sub 795, Duke Energy – Cinergy Corporation
13. SC: 2005, Order No. 2005-684, Docket No. 2005-210-E, Duke Energy – Cinergy Corporation
14. NC-2: series of interrelated dockets and orders for Carolina Power & Light – Florida Progress Corporation: E-2, Sub 844 (2004) incorporates revised regulatory conditions for the following dockets: E-2, Sub 753 (2002), E-2, Sub 760 (2000), G-21, Sub 377 (2000), E-2, Sub 740 (1999).
15. OR-2: 1997, Order No. 97-196, UM 814, Enron Corp, Portland General Electric

Exhibit RSH-3
List of Recent Utility Bankruptcy Filings [1]

Bankruptcies Of Utilities With First-Mortgage Bonds

Company	Year filed	Year emerged	Paid first mortgage bond coupons?
Entergy New Orleans Inc.	2005	Pending	No*
NorthWestern Corp.	2003	2004	Yes
Pacific Gas & Electric Co.	2001	2004	Yes
El Paso Electric Co.	1992	1996	Yes
Public Service Co. of New Hampshire	1988	1991	Yes

*Ceased payment for one year, but has resumed while still in bankruptcy.

[1] Table 2. From Standard & Poor's Archive Request for Comment: Proposed Update to U.S. Utility First-Mortgage Bond Issue Ratings Criteria, 30-May-2007, John W. Whitlock, Primary Credit Analyst.

Exhibit RSH-4
Latest Credit Ratings Issued by Major Credit Rating Agencies and Issue Date
(Provided as response to SELC Data Request No. 3, Item 3-29)

Standard & Poor's	Duke Energy	DE Carolinas	Progress Energy	PE Carolinas
Most Recent Report Date	January 2011	January 2011	June 2011	June 2011
Corporate Credit Rating	A-	A-	BBB+	BBB+
Senior Secured	N/A	A	N/A	A
Senior Unsecured	BBB+	A-	BBB	BBB+
Preferred Stock	N/A	N/A	N/A	BBB-
Short Term	A-2	N/A	A-2	A-2
Outlook	Stable	Stable	Watch Positive	Watch Positive

Moody's Investors Service	Duke Energy	DE Carolinas	Progress Energy	PE Carolinas
Most Recent Report Date	January 2011	January 2011	April 2011	April 2011
Issuer Rating	Baa2	A3	N/A	A3
Senior Secured	N/A	A1	N/A	A1
Senior Unsecured	Baa2	A3	Baa2	A3
Preferred Stock	N/A	N/A	N/A	Baa2
Short Term	P-2	N/A	P-2	P-2
Outlook	Stable	Stable	Stable	Stable

Fitch Ratings	Progress Energy	PE Carolinas
Most Recent Report Date	July 2011	July 2011
Issuer Default Rating	BBB	A-
Senior Secured	N/A	A+
Senior Unsecured	BBB	A
Preferred Stock	N/A	BBB+
Short Term	F2	F1
Outlook	Stable	Stable

Exhibit RSH-5

Recommendation I. Dividend Payment Restriction

State	Order Date	Order/Case/Docket	Merger	Condition / Stipulation	
				Number	Description
NY	2007	Case 06-M-0878	National Grid PLC, KeySpan Corp. (KEDNY, KEDLI, Niagara Mohawk)	JP 2, app 5, para 3	Utility subsidiary may not pay common dividends if unsecured bond rating (a) of utility subsidiaries falls to lowest level investment grade rating, and nationally recognized credit rating agency issues (b) utility rating downgrade or places on negative watch, or (c) if parent company rated lowest investment grade level or below.
WA-3	2005	UE-051090/Order 07	Pacificorp - MidAmerican Energy Corp. (MEHC)	Wa 24, App I, 2f.2	Pacificorp not allowed to declare or make any distribution to SPE PPW Holdings based on leverage and interest coverage thresholds OR if Pacificorp's senior unsecured long term debt is rated below BBB (S&P) and Baa2 (Moody's). *[Washington specific commitment]*
CA	2005	UE-051090/Order 07	Pacificorp - MidAmerican Energy Corp. (MEHC)	18 a,c	Multi-state settlement agreement and Consolidated List of Commitments include Pacificorp will not make any dividends to PPW Holdings that will reduce Pacificorp's common equity to Total Capital below 45.25% through 2011 and 44% thereafter.
ID	2006	Case PAC-E-05-8 / Order 29973	Pacificorp - MidAmerican Energy Corp. (MEHC)	18 a, c, I 35 same as Wa 24 above	Multi-state settlement agreement and Consolidated List of Commitments include Pacificorp will not make any dividends to PPW Holdings that will reduce Pacificorp's common equity to Total Capital below 45.25% through 2011 and 44% thereafter.
WA-2	2007	UG-061721/Order 06	MDU Resources Group - Cascade Natural Gas Corporation	28	Cascade will not make any dividend that will reduce common equity capital below 35% of Cascade's Total Adjusted Capital on a consolidated basis that includes its intermediate holding company.
PA	2010	Docket A-1010-2176520/2175732	West Penn Power, First Energy	12	Pennsylvania utility subsidiaries may not pay any dividend or cash distribution to the unregulated parent that will cause the utilities common equity ratio to decline below 40% of total capital.
OR-2	1997	UM 814, Order 97-196	Enron Corp., Portland General Electric	6	PGE shall not make any distribution to Enron that would cause PGE's equity capital to fall below 48% of total PGE capital.
WA-1	2008	U - 072375/Order 08	Puget Holdings, LLC - Puget Sound Energy (PSE)	36, 40	PSE shall not declare or make any distribution that would cause PSE's common equity ratio to fall below 44%.
MD-1	2008	Case No.9233/Order 83788	First Energy, Allegheny Energy Inc., Potomac Edison Co. d/b/a Allegheny Power	17	Potomac Edison shall not pay a dividend if its equity-to-total capitalization ratio has fallen below 45%, or would cause it to fall below that threshold, nor will it pay a dividend if any major credit rating agency has rated Potomac Edison below investment grade.
MD-2	2008	Case No. 9173/Order 82986	EDF International, Constellation Energy Group (CEG), Baltimore Gas & Electric Co. (BG&E)	2	BGE shall not pay dividends to CEG if, after the dividend payment, BGE's equity level would fall below 48%, not make any distribution to CEG if BGE's senior unsecured credit rating is rated by 2 of 3 major credit rating agencies below investment grade.

Exhibit RSH-5

Recommendation II. Minimum Equity Threshold

State	Order Date	Order/Case/Docket	Merger	Condition / Stipulation	
				Number	Description
NY	2007	Case 06-M-0878	National Grid PLC, KeySpan Corp. (KEDNY, KEDLI, Niagara Mohawk)	JP 2, app 5, para 5	Average Total Debt < 56% of Total Capital, excluding goodwil for 12 month period ending in a calendar quarter.
SC	2005	2005-210-E/2005-684	Duke Energy Corp. - Cinergy Corp.	3	55% Equity, 45% long-term Debt cpital structure remains in effect post merger and include actual capital structure of Duke for informational purposes, in Duke's quarterly surveillance reports.
WA-3	2005	UE-051090/Order 07	Pacificorp - MidAmerican Energy Corp. (MEHC)	Wa-11	MEHC and Pacificorp agree that SPE PPW Holdings LLC's (a) maintains no debt in its capital structure and (b) will not allow its common equity ratio to fall below 45.25% for 2011 and 44% thereafter on a consolidated basis.
ID	2006	Case PAC-E-05-8 / Order 29973	Pacificorp - MidAmerican Energy Corp. (MEHC)	I 21 a	MEHC and Pacificorp agree that SPE PPW Holdings LLC's (a) maintains no debt in its capital structure and (b) will not allow its common equity ratio to fall below 45.25% for 2011 and 44% thereafter on a consolidated basis.
PA	2010	Dkt A-1010-2176520/2175732	West Penn Power, First Energy	8	For a period of 5 years following merger if any Pennsylvania utility subsidiary's equity ratio falls below 40% must file 12 month plan to meet or exceed 40% or face restrictions on dividend payment to parent.
WA-1	2008	U - 072375/Order 08	Puget Holdings, LLC - Puget Sound Energy, Inc. (PSE)	35	PSE will have a common equity ratio of not less than 50% at merger closing, and at all times thereafter will have a common equity ratio of not less than 44%, except to the extent a lower equity ratio is established for ratemaking purposes by the Commission.
KY	2011	Case No. 2011-00124	Duke Energy Corp. - Progress Energy, Inc.	22	Applicants commit to maintain a capital structure for Duke Energy Kentucky which contains a minimum of 35% equity.

Exhibit RSH-5

Recommendation III. Independent Director

State	Order Date	Order/Case/Docket	Merger	Condition / Stipulation	
				Number	Description
KY	2011	Case No. 2011-00124	Duke Energy Corp. - Progress Energy, Inc.	48	Duke Energy Corporation commits to include on its post-merger Board of Directors at least one non-employee member who is a customer of either Duke Kentucky, Duke Ohio, or Duke Energy Indiana.
NY	2007	Case 06-M-0878	National Grid PLC, KeySpan Corp. (KEDNY, KEDLI, Niagara Mohawk)	p. 126	Establish a "Golden Share" with voting rights to an Independent Party whose vote would be required to (a) agree to allow the Utility subsidiary from being filed into bankruptcy precipitated by the parent company or an affiliate, or (b) agree to the Utility subsidiary commence its own voluntary bankruptcy, liquidation, or receivership proceeding.
WA-3	2005	UE-051090/Order 07	Pacificorp - MidAmerican Energy Corp. (MEHC)	App I, 2a	SPE PPW Holdings LLC's board of directors must include an independent director whose vote is required to merge, liquidate or sell its assets, consent to bankruptcy proceedings or file a voluntary petition to seek bankruptcy or reorganization. *[Washington specific commitment]*
ID	2006	Case PAC-E-05-8 / Order 29973	Pacificorp - MidAmerican Energy Corp. (MEHC)	App 1, 2a	Idaho PUC was party to a multi-state settlement agreement that resulted in a Consolidated List of Commitments including the Independent Director provision listed in WA-3 above.
WA-2	2007	UG-061721/Order 06	MDU Resources Group - Cascade Natural Gas Corporation	7	MDU Resources commits to establish SPE Equico with at least one Independent Director, whose consent is required to merge, liquidate or sell the assets of Equico, or to file for bankruptcy or consent to include Equico in bankruptcy proceedings.
WA-1	2008	U - 072375/Order 08	Puget Holdings, LLC - Puget Sound Energy, Inc. (PSE)	16	At least one director of PSE will be an Independent Director who is not a member, stockholder, director, officer or employee of Puget Holdings LLC or its affiliates (other than PSE), and whose vote is require to file PSE into bankruptcy or include PSE in bankruptcy.
MD-2	2008	Case No. 9173/Order 82986	Electricite de France International (EDF), Constellation energy Group (CEG), parent of Baltimore Gas & Electric Co. (BG&E)	4.b,c	The Board of Directors of the SPE will have one independent Director, and also will issue a "Golden Share" to a SPE administration company who is separate from the Independent Director. The vote in assent of each is required to approve a voluntary petition for bankruptcy by the SPE.

Exhibit RSH-5

Recommendation IV. Special Purpose Entity (SPE) in between Utility Subsidiary and Parent/Affiliates

State	Order Date	Order/Case/Docket	Merger	Condition / Stipulation	
				Number	Description
WA-3	2005	UE-051090/Order 07	Pacificorp - MidAmerican Energy Corp. (MEHC)	App I, 2e.1,4	Established PPW Holdings LLC as a SPE whose purpose is to purchase and own 100% of the capital stock of Pacificorp, is managed by its own separate board of directors, including an independent director, and which maintains its own set of books and records separate from the parent and the utility. *[Washington specific commitment]*
ID	2006	Case PAC-E-05-8 / Order 29973	Pacificorp - MidAmerican Energy Corp. (MEHC)	App 1, 2e. 1,4	Idaho PUC was party to a multi-state settlement agreement that resulted in a Consolidated List of Commitments including the SPE provision listed in WA-3 above.
WA-2	2007	UG-061721/Order 06	MDU Resources Group - Cascade Natural Gas Corporation	5	MDU Resources plans to cause all of the common stock of Cascade to be owned by Equico, which is established as a bankruptcy-remote special purpose entity (SPE).
WA-1	2008	U - 072375/Order 08	Puget Holdings, LLC - Puget Sound Energy, Inc. (PSE)	38	PSE is wholly owned by Puget Energy. The latter was acquired by Puget Holdings LLC, which itself is owned by an international consortium including Macquarie Capital Group. Puget Holdings agreed to establish a bankruptcy-remote SPE in between itself and Puget Energy called Equico, a Washington limited liability company that shall not have debt.
MD-2	2008	Case No. 9173/Order 82986	EDF International, Constellation Energy Group (CEG), parent of Baltimore Gas & Electric Co. (BG&E)	4.a	CEG shall form a bankruptcy remote, special purpose subsidiary (SPE) for the sole purpose of holding 100% of the equity shares of BGE.

Exhibit RSH-6
Simplified Organization Chart of Post-Merger Duke Energy
(Provided in SELC Data Response No. 2, Item 2-3, page 3 of 3)

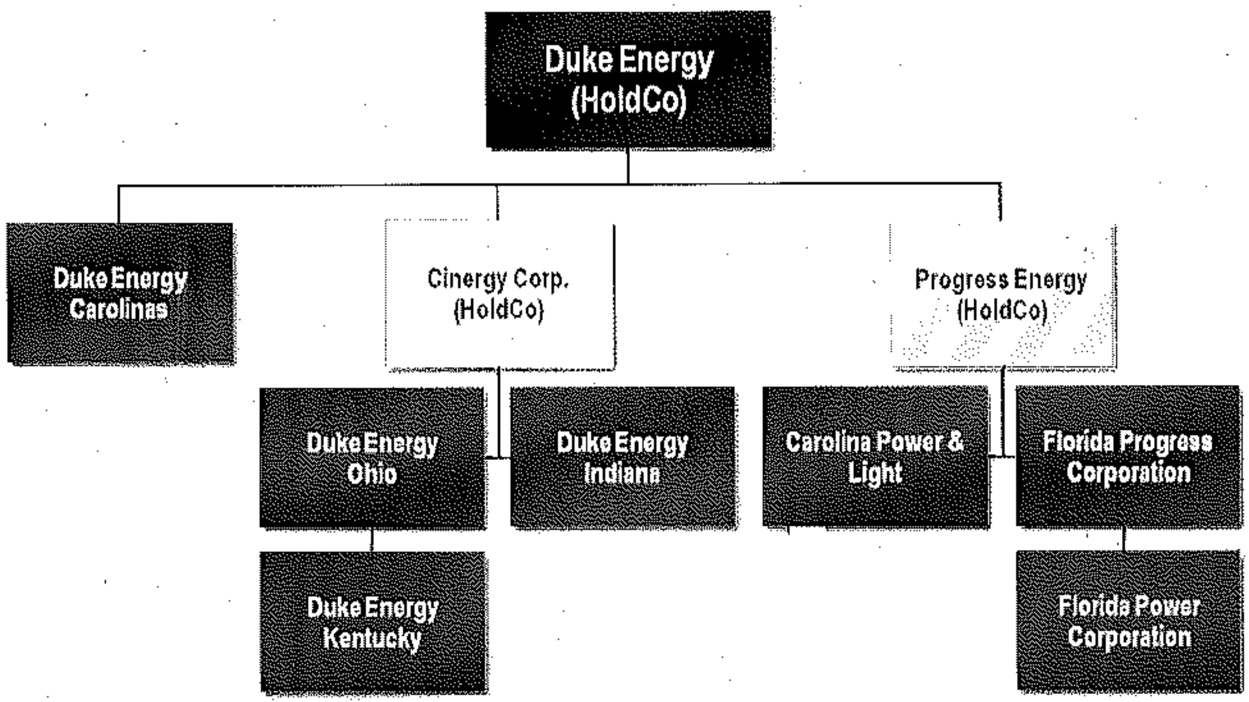

Exhibit RSH-7

Companies' Response to Public Staff Data Request No. 16 (a), pp. 4-5.

"Turning to the specific ring fencing tools identified by the Public Staff in its data request:

(a) A regulated utility being placed in a Special Purpose Entity (SPE) that is legally separate from the other affiliated regulated utilities, non-regulated affiliates and the parent holding company;

Research indicates that a SPE is a separate legal structure created by a firm to provide liquidity and/or obtain favorable external funding. Assets are isolated within the new entity, and securities issued by the entity are backed by these assets as collateral. Basically, while it can be a trust, corporation or LLC, its governance documents require that it be completely separate from all other legal entities. Typically, an SPE is used in connection with asset securitization or structured finance transactions to enable lower financing rates and to move the debt of the SPE off the balance sheet of the parent (Enron was infamous for its abuse of SPEs). The assets involved in the particular transaction that will provide the source of revenue and the collateral for the financing are transferred into the SPE to isolate them from the reach of creditors of the parent and affiliates. The transfer of all the regulated assets of DEC and PEC into an SPE would involve having to obtain the consent of existing lenders of DEC, PEC (including the trustee under the blanket PEC mortgage), PGN, and Duke, as well as the preferred shareholders, co-owners and significant counterparties (to the extent required under existing agreements), and significant expense to record assignments and transfers of record for all the assets involved, depending on how the transfer is structured. In addition, the governing documents (charter/bylaws) of an SPE are usually much more restrictive than an operating company's governing documents. Given the extent of the regulatory conditions that would be in place, the SPE seems unwarranted.

CERTIFICATE OF SERVICE

I certify that the persons on the docket service lists have been served with the Public Version of the Testimony of Richard S. Hahn on behalf of Environmental Defense Fund, the Sierra Club, the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 8th day of September, 2011.

Robin Dunn

Robin Dunn
Administrative Legal Assistant