STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1026

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy	)	DIRECT TESTIMONY OF
Carolinas, LLC, for an Adjustment	)	WILLIAM B. MARCUS
of Rates and Charges Applicable to	)	FOR NC WARN
Electric Utility Service in North Carolina	)	

Q. WOULD YOU PLEASE STATE YOUR FULL NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is William B. Marcus. I am the Principal Economist, JBS Energy, Inc. 311 D Street, West Sacramento, CA 95695.

Q. IN WHAT CAPACITY ARE YOU APPEARING BEFORE THIS COMMISSION?

A. I am appearing as a witness on behalf of the North Carolina Waste Awareness and Reduction Network ("NC WARN"). NC WARN is interested in this proceeding because many of its members are customers of Duke Energy Carolinas, LLC ("DEC") and concerned about rising costs of electricity. NC WARN and its members are also concerned about the operation and construction of expensive nuclear plants and polluting fossil fuel plants.

Q. PLEASE SUMMARIZE YOUR PAST WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have 35 years of experience in the analysis of regulated gas and electric utilities. I have been a consultant at JBS Energy for 29 years; prior to that time, I worked for another consulting firm, for the California Energy Commission in progressively responsible positions as an economist, and for the Kennedy School of Government at Harvard as a casewriter. I hold an A.B. degree magna cum laude in economics from Harvard and an M.A. in economics from the University of Toronto. I have testified before approximately 40 regulatory bodies and courts in the United States and Canada.

Earlier this year, I testified in North Carolina in the Progress Energy rate case in NCUC Docket E-2, Sub 1023. Last year, I supplied a statement to the NC Utilities Commission (the "Commission") on behalf of NC WARN's petition for rulemaking on rate allocation methods in NCUC Docket E-100, Sub 135. I also previously testified in North Carolina on two occasions in the early 1980s.

My summary CV is attached to this testimony as Exhibit WBM-1.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

1 A. My testimony addresses several revenue requirement issues for DEC
2 including dues, donations, sponsorships, advertising, survey research, and
3 stock-based compensation.
4 I also address DEC's cost of service and rate allocation, for generation,
5 distribution, and other areas, such as treatment of major account
6 representatives and survey research in the cost allocation.
7 I describe alternative allocation measures that are fair and reasonable,
8 and which more rationally reflect both the demand for electricity as well as
9 energy needs. In rate cases, the rate allocation methodologies approved by
10 the Commission may not result in fair and reasonable rates, especially if the
11 summer coincident peak ("SCP") methodology is approved.
12 Lastly, I present an alternative cost of service study which shows
13 residential class costs should be reduced by an estimated $149 million from
14 the study presented by DEC.
15
16 **SECTION I -- REVENUE REQUIREMENT ISSUES**
17 **Q. WILL YOU SUMMARIZE YOUR RECOMMENDATIONS**
18 **REGARDING REVENUE REQUIREMENTS?**
19 A. I recommend the following reductions to revenue requirements totaling
20 $30,002,000 (at the DEC level before allocation to North Carolina).
21 $24,889,000 for stock-based compensation

1 $2,035,000 for image and other advertising

2 $1,361,000 of dues and donations to the Nuclear Energy Institute

3 $633,000 of Edison Electric Institute dues and donations

4 $621,000 for improper political and charitable contributions and

5 sponsorships

6 $275,000 for non-recurring survey research expenditures

7 $188,000 in Chamber of commerce dues

8 I also recommend that the Commission reduce 50% of directors' and officers'

9 (D&O) liability insurance by 50% (the amount is undetermined herein

10 because DEC has not answered NC WARN DR 1-106 filed on April 21, 2013).

11 Several of these costs are clearly inappropriate for "above the line" cost

12 recovery. Counsel has informed me that G.S. 62-310 allows the Commission

13 to bring legal action for monetary penalties for violations of the Public

14 Utilities Act, and in several instances I discuss below, penalties should be

15 considered for the most egregious violations.

16 It should also be noted that there are other inappropriate costs which

17 DEC attempts to charge to ratepayers, and which will be described in

18 testimony by the Public Staff and other intervenors. NC WARN supports

19 these reductions.

1 *I.A. Political Sponsorships and Charitable Donations*

2 **Q. WHAT IS THE ISSUE REGARDING SPONSORSHIPS AND**

3 **CHARITABLE DONATIONS BEING CHARGED TO RATEPAYERS?**

4 A. The response to NC WARN DR 1-90 (Exhibit WBM-2) contains some

5 seriously troubling information. DEC has identified $904,695 in

6 sponsorships and donations charged to ratepayers, $479,041 paid directly by

7 DEC, and $751,466 paid by other Duke entities who allocated $425,653 to

8 DEC.

9 **Q. IS THE CHARGING OF SPONSORSHIPS TO RATEPAYERS *PRIMA***

10 ***FACIE* UNREASONABLE UNDER DEC'S OWN ACCOUNTING**

11 **GUIDELINES?**

12 A. Yes. Exhibit WBM-3 contains the full response to NC WARN DRs 1-86

13 through 1-88. Attachments to this exhibit include several different

14 documents given by DEC's accounting staff to employees in its advertising

15 departments. All of them contain something similar to the following

16 information:

Figure 1: Excerpt from Duke Document "FERC Charging Guidance – Advertising, Bill Inserts, Donations & Sponsorships"

DONATIONS & SPONSORSHIPS - Require the accounts indicated below.

ACCOUNT REQUIRED	DONATION & SPONSORSHIP DESCRIPTION
0426100	Donations for charitable, social or community welfare purposes
0426400	Expenditures that are for civic, political & related activities
0426400	Sports related sponsorships

Moreover, DEC's training for advertising accounting notes the appropriate accounts for advertising that is political in nature, noting that "If we don't get it right… The commission can fine the company – potentially in the $millions." (Attachment 2 to NC WARN DR 1-87, p. 3)

Q. DOES DEC VOUCH FOR THE INTEGRITY OF ITS ACCOUNTING?

A. Yes. In testimony of Danny Wiles, on page 5, DEC states:

> Duke Energy Carolinas maintains and relies upon an extensive system of internal accounting controls and audits by both internal and external auditors. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management's authorization and are recorded properly.
>
> The system of internal accounting controls is reviewed annually, tested, and documented by the Company to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that the Company's financial statements are materially accurate.

Q. DESPITE ALL THE TRAINING, ALL THE WARNINGS, ALL THE INTERNAL AND EXTERNAL AUDITS, AND ALL THE ASSURANCES OF ACCURACY, HAS DEC ACCOUNTED PROPERLY FOR SPONSORSHIPS?

A. Clearly not. The response to NC WARN 1-90 proves it. Many sponsorships were charged to accounts paid by ratepayers, including $250,000 to Account 913 (product advertising). Most individual transactions were charged to Accounts 921100 and 921200, with several to other A&G

1 accounts (923000 and 930200). These accounts are paid "above the line", by

2 ratepayers according to the question, and there were no pro forma

3 adjustments made to remove these expenses.

4 **Q. HAVE YOU ANALYZED THESE COSTS IN DETAIL?**

5 A. Reviewing the company's actions, we start with $273,000 of clearly

6 partisan politics charged to ratepayers.

7 **Table 1: Partisan Political Sponsorships and Donations**

Acct.	Partisan Political Sponsorships/Donations		DEC Direct
921200	SOUTH CAROLINA SENATE DEMOCRATIC CAUCUS		$2,500
923000	SOUTH CAROLINA SENATE DEMOCRATIC CAUCUS		$5,000
921200	SOUTH CAROLINA SENATE REPUBLICAN CAUCUS		$2,500
921200	REPUBLICAN STATE LEADERSHIP COMMITTEE		$25,000
921200	SC BUSINESS AND INDUSTRY POLITICAL		$5,000
921200	SC HOUSE REPUBLICAN CAUCUS		$2,500
921200	SC SPORTSMENS CAUCUS		$1,250
921200	SOUTH CAROLINA HOUSE DEMOCRATIC CAUCUS		$2,500
921200	SOUTH CAROLINA LEGISLATIVE BLACK CAUCUS		$1,750
921200	PALMETTO LEADERSHIP COUNCIL *		$2,500
921200	NORTH CAROLINA LEGISLATIVE BLACK CAUCUS		$10,000
		Duke Donations	Allocation from Duke
921200	DEMOCRATIC GOVERNORS ASSOCIATION	$100,000	$55,650
921200	DEMOCRATIC GOVERNORS ASSOCIATION	$200,000	$112,600
921200	CONGRESSIONAL BLACK CAUCUS FOUNDATION	$50,000	$27,825
921200	CONGRESSIONAL HISPANIC CAUCUS INSTITUTE	$20,000	$11,130
921200	NATIONAL REPUBLICAN CLUB OF CAPITOL HILL	$10,000	$5,630
	Total DEC:		**$273,335**
* Political Action Committee associated with the Republican House Speaker in			
	in South Carolina		

8

9 We then move on into political organizations that lobby, write model

10 legislation supporting specific causes, and otherwise engage in political

11 activity, even though they might not claim that 100% is lobbying. Ratepayers

should not pay for these organizations. The largest are the Carolina Business Coalition, Inc. (which on its website has a purely political agenda)[1], the American Legislative Exchange Council, which drafts legislation for Republican state legislators across the country, and various other chambers of commerce and business lobbying groups. There is $165,000 in this category.

Table 2: Lobbying and Public Policy Organizations

		Lobbying and Public Policy Organizations		DEC Direct
921200		CAROLINA BUSINESS COALITION INC		$100,000
921100		AMERICAN LEGISLATIVE EXCHANGE COUNCIL		$2,500
921200		AMERICAN LEGISLATIVE EXCHANGE COUNCIL		$5,000
921200		AMERICAN LEGISLATIVE EXCHANGE COUNCIL		$12,500
921200		SOUTH CAROLINA MANUFACTURERS ALLIANCE		$4,000
921200		SOUTH CAROLINA MANUFACTURERS ALLIANCE		$3,133
921200		NORTH CAROLINA CHAMBER		$3,000
921200		NORTH CAROLINA CHAMBER		$10,000
921200		SC SPORTSMENS CAUCUS		$1,250
921200		SC BUSINESS AND INDUSTRY POLITICAL		$5,000
921200		SOUTH CAROLINA MANUFACTURERS ALLIANCE		$2,610
923000		NATIONAL FEDERATION OF INDEPENDENT BUSINESS		$5,000
923000		NATIONAL FEDERATION OF INDEPENDENT BUSINESS		$5,000
			Duke Donations	Allocation from Duke
		BUSINESS INSTITUTE FOR POLITICAL ANALYSIS	$5,000	$2,783
		BUSINESS INSTITUTE FOR POLITICAL ANALYSIS	$5,000	$2,783
		Total DEC:		**$164,557**

DEC charged charitable contributions above the line as well (as well as below the line corporate contributions and contributions from its foundations). Some of these donations may also serve political purposes, or as a perquisite for top executives and guests. For instance, DEC ratepayers

[1] http://www.carolina-business.org/issues/

1 paid for $28,000 in donations made to the Consortium of Catholic
2 Academies, which enabled Duke governmental affairs staff to lobby
3 politicians in the annual Boehner-Lieberman –Williams (renamed Boehner-
4 Feinstein-Williams) dinner, in Washington, D.C. Part of the $32,000 in DEC
5 ratepayers share of donations to the Kennedy Center were for seats at the
6 Kennedy Honors Weekend ($18,000 to Duke and $10,017 to DEC ratepayers
7 as their share of 4 seats.) Of the $91,016 of charitable donations, at least
8 $62,583 were made to charities in Washington DC, thanks to funding that
9 DEC wants to collect from its ratepayers.
10 DEC made donations to organizations ("think tanks") focused on
11 strategic and international relations, which essentially are donations with a
12 political bent. One of them was specifically to fund a study of nuclear power
13 in the US. The largest donations were made to a group that was founded by
14 former President Nixon. DEC ratepayers are expected to bear a portion of
15 those costs so that Duke Energy can have a foreign policy.

Table 3: Charitable Contributions and Sponsorships

Acct.	Charitable Donations		DEC
921200	NCSL FOUNDATION FOR STATE LEGISLATURES		$1,250
921100	NEW ORLEANS SCHOOL OF		$58
921200	PALMETTO COUNCIL (BOY SCOUTS)		$750
		Duke Donations	Allocation to DEC
921200	WASHINGTON EMPOWERED AGAINST VIOLENCE	$5,000	$2,783
921200	CONSORTIUM OF CATHOLIC ACADEMIES (Wash DC)	$25,000	$13,913
921200	CONSORTIUM OF CATHOLIC ACADEMIES (Wash DC)	$25,000	$14,075
921200	AFRICAN AMERICAN NETWORK	$700	$496
921200	AFRICAN AMERICAN NETWORK	$60	$42
921200	AFRICAN AMERICAN NETWORK	$232	$164
921200	AFRICAN AMERICAN NETWORK	$275	$195
921200	AFRICAN AMERICAN NETWORK	$250	$177
921200	AFRICAN AMERICAN NETWORK	$250	$177
921200	AFRICAN AMERICAN NETWORK	$188	$133
921200	AFRICAN AMERICAN NETWORK	$750	$531
921200	AFRICAN AMERICAN NETWORK	$3,000	$2,125
921200	AFRICAN AMERICAN NETWORK	$1,000	$708
921200	AFRICAN AMERICAN NETWORK	$1,200	$850
921200	AMERICAN ASSOCIATION OF BLACKS IN ENERGY	$25,000	$13,913
921200	AMERICAN ASSOCIATION OF BLACKS IN ENERGY	$1,000	$563
921200	APPALACHIAN WILDLIFE FOUNDATION	$677	$381
921200	THE JOHN F KENNEDY CENTER	$18,000	$10,017
921200	THE JOHN F KENNEDY CENTER	$25,000	$13,913
921200	THE JOHN F KENNEDY CENTER	$14,000	$7,882
921200	THE WATERFALL FOUNDATION	$5,000	$2,783
921200	WINSTON-SALEM URBAN LEAGUE	$500	$354
921200	AMERICAN ASSOCIATION OF BLACKS IN ENERGY	$5,000	$2,783
Total DEC			**$91,016**

Table 4: International Relations Donations and Sponsorships

Acct.	International Relations Donations	Duke Donation	Allocation to DEC
921200	CENTER FOR STRATEGIC & INTERNATIONAL STUDIES	$25,000	$13,913
921200	CENTER FOR THE NATIONAL INTEREST	$30,000	$16,695
921200	CENTER FOR THE NATIONAL INTEREST	$75,000	$41,738
921200	WORLD AFFAIRS COUNCIL OF CHARLOTTE	$20,000	$11,130
Total DEC			**$83,476**

1 Athletic donations were included in both accounts 913001, and 921200.
2 The biggest was a sponsorship for advertising for the Charlotte Bobcats
3 ($250,000). There was another $463 allocated to DEC ratepayers for the
4 Central Intercollegiate Athletic Association. The accounting memo says that
5 these costs belong in Account 426.4, below the line.
6 In addition to these donations there were garden-variety problems. A bill
7 for the Commonwealth Worldwide Limousine service ($133.14 to DEC), $920
8 from DEC ratepayers on repeated occasions to the Capital City Club, a
9 private club, and a bill for $2,714 for the former CEO of DEC's country club
10 dues charged to ratepayers (NC WARN 2-23), where there may be more,
11 since only the one bill over $2,500 was provided to us, and a luncheon paid
12 for by DEC for EEI at the NASCAR hall of Fame that was not necessary to
13 provide utility service ($4,827 to DEC ratepayers).
14 **Q. WHAT IS THE TOTAL AMOUNT THAT WAS IMPROPERLY**
15 **ACCOUNTED FOR?**
16 A. By my estimate, of the $904,695 that Duke Energy charged above the line
17 for sponsorships, $871,441 was improper ($250,000 for the Bobcats and
18 $621,441 for political contributions, donations, and club dues that ratepayers
19 should not pay for). This is 96% of the money requested.

Q. WHAT IS YOUR ANALYSIS OF THIS PROBLEM?

A. This is a pervasive problem in parts of the organization that should know better. By looking at the invoices attached to Exhibit WBM-2 it appears that the office of the CEO of Duke Energy and both the state and federal governmental affairs offices literally "never got the memo" that was contained in Exhibit WBM-3 which said that, "If we don't get it right … The commission can fine the company – potentially in the $millions."

Q. ARE THERE OTHER PROBLEMS WITH DEC'S ACCOUNTING?

A. Yes. DEC cannot access information on the spending of ratepayer money on meals and entertainment. Here is the response to NC WARN 2-20:

Request: Following up on response to WARN 1 93, please confirm that there are costs of tickets to sporting, cultural, or musical events in the base year 2011 for which rate recovery is requested in this rate case, but accounting records are not identified in such a way that DEC can identify cost of any tickets to sporting, cultural, or musical events. If you cannot confirm this point, please explain in detail, including all information upon which you relied in order not to confirm the point, and identify any accounting records on which you relied to reach the conclusion that you could not confirm this point.

Response: We confirm that there is no unique or specific code block in our accounting system for these types of costs and, therefore, we are not able to separately identify them.

Duke cannot even answer the most elementary question – whether the governmental affairs departments, which have been shown to charge political contributions and politically related charitable contributions to ratepayers – have spent money on meals and entertainment for elected or

appointed officials or political party senior officials. Here is WARN 1-97, (to which DEC has simply not responded):

Please identify the cost of meals or entertainment provided to elected or appointed officials of the local governments, state governments, or the federal government or official of a state or national political party for which ratepayer recovery is requested above the line in the Test Year. Identify each individual item requested and provide vouchers or other support for all such costs. Include costs allocated from Duke's affiliated companies by specific affiliate as well as costs incurred directly by Duke.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should start by disallowing $871,441 just to make ratepayers whole. But disallowance of the expense is clearly not enough. If it was not for NC WARN, the utility could have gotten away with this flagrant abuse from the highest levels of the company for years.

In this case, the most serious violations are when DEC seeks recovery from ratepayers of costs that it knows are clearly outside of what is allowable to be recovered in a rate case. The fact that these violations (except for the Bobcats sponsorship) largely came from governmental affairs offices and the CEO's office, which should conduct themselves at the highest level of ethical probity, is an aggravating factor. DEC knew it could be fined millions for conduct like this, and it <u>should</u> be fined millions. The penalty should be equivalent in scope to reducing the rate of return on common equity by at least five basis points ($3.1 million to Duke shareholders and $5.3 million to Duke ratepayers after income tax gross-up) as an explicit deterrent.

I.B. Image Advertising Charged to Ratepayers

Q. WHAT IS YOUR CONCERN ABOUT IMAGE ADVERTISING?

A. Duke Energy as a whole and DEC seem to have a relatively expansive definition of the type of advertising that ratepayers should pay for.

Q. **WILL YOU DESCRIBE DEC'S UNDERSTANDING OF THE ACCOUNTING FOR ADVERTISING?**

A. Energy efficiency advertising for DEC is assigned to Account 557 and then reclassified to Energy efficiency accounts. The remainder is shown in the table below, which is extracted from Attachment 1 to NC WARN DR 1-87.

Figure 2: Accounting for Advertising

ACCOUNT DERIVED FROM PROCESS	ADVERTISING DESCRIPTION
0909650	Informational & Instructional; Health & Safety related; Provide Environmental Protection & Conservation Encouragement
0913001	Promoting or Retaining Service; Sales related advertising excluding the sale of merchandise
0930150	Corporate in Nature, promote Good Will, Improve image, Cost of Service & Other General advertising
0426400	Political in nature
0426510	Non-Recoverable, classified as "Below the Line"

Donations and sponsorships are not considered to be advertising in the DEC accounting attachments, though as discussed above, at least some DEC departments do not observe this rule.

1 While the definitions generally follow the uniform system of accounts,
2 many state commissions and FERC limit what can be charged. The
3 Commission should remember that DEC is a monopoly in its service area in
4 the Carolinas, so it does not need to sell anything. The promotion of
5 goodwill and corporate image should not be done at the expense of
6 monopoly ratepayers. Shareholders benefit from good will and corporate
7 image. Shareholders should pay to burnish that image.

8 **Q. DO OTHER COMMISSIONS LIMIT UTILITY ADVERTISING**
9 **EXPENSES?**

10 A. Yes. As one example, the Federal Energy Regulatory Commission does
11 not allow general advertising (FERC Account 930.1) as part of the cost of
12 service in the Midwest System Operator's (MISO) formula rate tariff.
13 California has circumscribed ratepayer funding of utility advertising for
14 about 35 years, and Arkansas routinely disallows anything that looks like
15 image advertising.

16 **Q. WHAT IS YOUR RECOMMENDATION?**

17 A. I recommend disallowing all of the costs in Accounts 913 and 930.1 as
18 image, brand, and product advertising that are unnecessary for a monopoly
19 utility. There is $1,521,000 in Account 913[2] and $514,000 in Account 930.1,[3]

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[2] NC WARN DR 1-85.

[3] Public Staff DR 25-02.

1 including a $250,000 sponsorship of the Charlotte Bobcats basketball team in
2 Account 913 identified in NC WARN DR 1-90. Both of these figures are at
3 the total company level. The total amount for DEC is $2,035,000.[4]

4 ***I.C. Dues Inappropriately Charged to Ratepayers***

5 **Q. WHAT WAS DEC'S ALLOCATION OF EDISON ELECTRIC**
6 **INSTITUTE EEI DUES?**

7 A. In 2012, Duke paid $2,060,404 to the Edison Electric Institute (EEI) for
8 dues. This included payment for Regular Activities "Core", "Industry
9 Issues", "Restore Power (mutual assistance) and a contribution to the Edison
10 Foundation. The response to NC WARN 1-90 seems to indicate that
11 $1,351,218 was allocated to DEC in Account 930.21.

12 **Q. WHAT IS EEI'S LEVEL OF QUESTIONABLE EXPENDITURES?**

13 A. I believe that it is about 47% as I will explain below. However, as a
14 preface, I must note that EEI has been trying to reduce the information given
15 to regulators on its expenses and activities since 2005. Essentially, EEI's
16 reduction in transparency is making it harder for utilities to bear their
17 burden of proof on the reasonableness of EEI dues. Therefore, this testimony
18 must build up an estimate from the information that is available.

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[4] Of this amount in Account 930.1, $59,656 is identified as economic development (PS DR 25-02) and might be considered for funding.

1 DEC's invoice from EEI noted that 26% of the Regular Activities dues
2 relate to influencing legislation, and that 36 percent of the Industry Issues
3 relate to influencing legislation. EEI spends money on many other things
4 that do not fit the narrow definition of lobbying but that ratepayers should
5 not pay for. EEI also spends money on legislative advocacy, regulatory
6 advocacy, marketing, public relations and advertising, donations, and club
7 dues. After a series of regulatory disallowances of significant parts of EEI
8 dues across the country, EEI has stopped issuing detailed information on its
9 budget, previously available under the auspices of the National Association
10 of Regulatory Utility Commissioners (NARUC).[5]
11 The most recent information on EEI expenditures that JBS Energy could
12 find was from an Oklahoma Gas and Electric (OG&E) rate case in Arkansas,
13 where OG&E filed the following information in response to an Arkansas
14 Public Service Commission (APSC) General Staff data request.

[5] Response to Initial Requests for Information (Question 65) of the Kentucky Attorney General (August 27, 2008) from Kentucky Public Service Commission Case No. 2008-00251 and 2007-00565 for Kentucky Utilities Company, found at http://psc.ky.gov/pscscf/2008%20cases/2008-00251/KU_Response%20to%20AG's%20Requests%20dated%20082708%20(Vol%201of3)_091108.pdf .

Table 5: Edison Electric Institute Expenses for Core Dues Activities
% of Dues For the years 2005 – 2009 (Unaudited)

Operating Expense Category	2005	2006	2007	2008	2009
Legislative Advocacy and Policy Research	26.4%	25.7%	16.2%	14.4%	21.9%
Public Relations	7.7%	8.8%	2.2%	2.0%	2.4%
Advertising	1.7%	1.3%	0.9%	2.3%	2.3%
Marketing	3.7%	3.9%	0.0%	0.0%	0.0%

Where no more recent information is available, JBS uses the final year of EEI's published expenses, covered by core dues in 2009.

The only information on core dues activities that DEC provided on its EEI invoice is that 26% of core dues are used for legislative advocacy. In addition, from the 2009 budget figures, advertising (2.3%) and public relations (2.4%) should be removed from DEC's request. Finally, in EEI's final budget report by NARUC categories in 2005, 16.5% of expenses were for Regulatory Advocacy. This also belongs below the line. In total, 47.2 percent of DEC's core EEI dues should be disallowed.[6]

EEI states that 35% of its Industry Issues program is influencing legislation. That amounts to $64,445 that should be accounted below the line. The $30,000 donation to the Edison Foundation is a donation, and should be included in FERC Account 426.1, below the line.

[6] 26% for legislative advocacy plus 2.3% for advertising plus 2.4% for public relations plus 16.5% for regulatory advocacy equals 47.2%.

Q. GIVEN THIS INFORMATION, WHAT IS THE APPROPRIATE ADJUSTMENT FOR EEI DUES?

A. EEI dues should be reduced by $633,000, as summarized in Table 6, based on the percentage adjustments discussed above.

Table 6: Calculation of NC WARN Adjustment for EEI Dues

			% shareholder	disallow
Regular Activities		$ 1,841,276	47.20%	$ 869,082
Industry Issues		$ 184,128	36.00%	$ 66,286
Restore Power (mutual aid)		$ 5,000	0.00%	$ -
Contribution to Edison Foundation		$ 30,000	100.00%	$ 30,000
Total		$ 2,060,404	46.85%	$ 965,368
Allocate to DEC		$ 1,351,218	46.85%	$ 633,091

Q. WHAT IS DEC REQUESTING THAT RATEPAYERS PAY FOR THE NUCLEAR ENERGY INSTITUTE?

A. DEC's paid NEI dues of $2,712,247 in the Test Year (Account 524) per NC WARN DR 1-90. DEC actually was invoiced in January 2012 for $2,759,416 plus an additional $10,000 to NEI's Foundation for Nuclear Studies as a charitable contribution (according to an invoice provided with NC WARN DR 1-90). The difference in test year payments and the invoice received appears to be that DEC pays NEI quarterly and paid two quarters at 2011 rates and two at 2012 rates. The cost is contained in Account 524 (a nuclear expense account).

Q. WHY DOES DEC STATE THAT RATEPAYERS SHOULD FUND NEI?

A. DEC gives the following explanation:

1 Nuclear Energy Institute (NEI) – NEI, with member participation, develops
2 policy on key legislative and regulatory issues affecting the industry. The
3 NEI's objective is to ensure the formation of policies that promote beneficial
4 uses of nuclear energy and technologies in the United States and around the
5 world.[7]

6 **Q. WHAT IS NEI'S MISSION STATEMENT?**

7 A. NEI explains its own mission succinctly:

8 **NEI's Mission:** The Nuclear Energy Institute (NEI) is the policy organization
9 of the nuclear energy and technologies industry and participates in both the
10 national and global policy-making process.
11
12 NEI's objective is to ensure the formation of policies that promote the
13 beneficial uses of nuclear energy and technologies in the United States and
14 around the world.[8]
15
16 **Q. HOW MUCH OF NEI'S MONEY IS SPENT ON LOBBYING?**

17 A. It depends on the definition of lobbying. Using an extremely narrow
18 definition, NEI estimates 3.5%.[9] However, questions have been raised
19 regarding lobbying disclosure forms and the definition of lobbying. NEI's
20 method of disclosure excludes "grass-roots" lobbying activities, [10] which
21 other organizations consider as lobbying.

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[7] NC WARN DR 1-90 (Dues Attachment)

[8] http://www.nei.org/aboutnei/

[9] See invoice provided with NC WARN 1-90.

[10] Greenwire, Lobbying Disclosure Forms Don't Tell Full Story www.eenews.net 10/26/2009.

1 **Q. WHAT ARE SOME OF NEI'S OTHER ACTIVITIES THAT IT DOES**

2 **NOT CONSIDER TO BE LOBBYING THAT RATEPAYERS SHOULD**

3 **NOT PAY FOR?**

4 A. A large number of NEI activities are documented in Exhibit WBM-4.

5 NEI engages in significant public relations activities that do not fit its narrow

6 definition of lobbying and has created several "grass-roots" front groups to

7 advance its mission. Funding for NEI supports an array of organizations

8 promoting nuclear power.

9 Three organizations are not mentioned on the NEI website but either

10 identify NEI as a funder or sponsor or have been tied to NEI through other

11 government documentation. These are Clean and Safe Energy Coalition

12 ("founded and solely funded by the Nuclear Energy Institute"), Clean

13 Energy America, and Alliance for Energy and Economic Growth (sponsored

14 jointly by NEI and other organizations such as the US Chamber of

15 Commerce).[11] Essentially, NEI is hiding its political activities behind other

16 "front" organizations.

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[11] http://casenergy.org/our-coalition/about-the-coalition/ ; see also http://www.ucsusa.org/news/press_release/christine-todd-whitman-patrick-moore-0415.html; http://www.cleanenergy4america.org/clean-energy-mission.html http://www.yourenergyfuture.org/aboutUs.htm and http://www.yourenergyfuture.org/files/2010/AEEGPrincipals.pdf; http://www.cleanenergy4america.org/ This web page states: "Clean Energy America is sponsored by the Nuclear Energy Institute."

1 There is also no reason why DEC ratepayers should pay to conduct

2 polling and opinion research on nuclear power through NEI.[12] Public

3 opinion research is a cornerstone of NEI's activities with surveys conducted

4 on a regular basis about 6 months to a year apart.

5 There is again no reason for DEC ratepayers to pay for public relations

6 and glossy flyers to support nuclear power.[13] It is also inappropriate for

7 DEC ratepayers to pay for a public relations campaign, to teach Belarussian

8 children (who live near the real nuclear disaster of Chernobyl) not to fear

9 nuclear power.[14] DEC ratepayers should not pay to develop image

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[12] See http://www.nei.org/resourcesandstats/Documentlibrary/Publications/Perspective-on-Public-Opinion/Perspective-on-Public-Opinion,-April-2013. The description of this item on NEI's "Resources and stats" webpage says "Latest public opinion data shows an upward trend in public's favorable attitudes toward nuclear energy."

[13] http://www.nei.org/resourcesandstats/documentlibrary/protectingtheenvironment/flyers/nuclear-energy-powering-sustainable-economies-worldwide and http://www.nei.org/resourcesandstats/documentlibrary/protectingtheenvironment/flyers/nuclear-energys-indispensable-role-in-global-climate-change-strategy.

[14] http://www.nei.org/resourcesandstats/publicationsandmedia/insight/insightaugustseptember2007/belarusianchildrenlearnabcsofnuclearenergy

1 advertising supporting nuclear power[15] (print and radio, including past

2 sponsorship of the Washington Capitals National Hockey League team).[16]

3 NC WARN opposes the use of ratepayer money to publicize and promote

4 the opinion that nuclear energy is a required piece of any climate change

5 strategy and touting the need for new nuclear plants. [17] Many North

6 Carolina ratepayers disagree with this perspective – some because they

7 believe nuclear power is too slow and expensive to help with climate change,

8 and some because they do not believe in the human role in climate change.

9 DEC is proposing to force both of these disparate sets of ratepayers to fund

10 political views that they oppose through electricity rates.

11 **Q. WHAT IS YOUR RECOMMENDATION?**

12 A. NC WARN understands that NEI plays a technical role in cost reduction

13 in the industry. That is why we reluctantly agree that ratepayers could fund

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[15] http://www.nei.org/resourcesandstats/Documentlibrary/Reliable-and-Affordable-Energy/Advertising/Print-Ad,-Clean-Air,-2013, http://www.nei.org/resourcesandstats/Documentlibrary/Reliable-and-Affordable-Energy/Advertising/Print-Ad,-Jobs,-2013 http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/advertising/ad-on-production-of-nuclear-energy-around-the-clock-2010/

[16] Radio Ad, MD and VA, Washington Capitals, 2009-2010 - "MD and VA" is a 30-second ad that will air during the local radio broadcast of all Washington Capitals games in the 2009-2010 season. Game audio will also be streamed live on the team's official Web site, washcaps.com. The ad promotes the "nuclear. clean air energy" message and is part of NEI's corporate sponsorship program with the Washington Capitals. http://www.nei.org/resourcesandstats/documentlibrary/newplants/audio/washington-capitals-radio-ad---md-and-va/

[17] http://www.nei.org/publicpolicy/neipolicypositions/ and http://www.nei.org/keyissues/newnuclearplants/needfornewnuclearplants/ and http://www.nei.org/newsandevents/businessleaders (this document not included in attachments because it does not format for printing)

1 half of its budget despite its rampant advocacy and public relations activities
2 that go beyond the narrow definition of lobbying. But by asking ratepayers
3 to fund 100% of NEI (not even reducing the amount by the paltry 4% for
4 lobbying), DEC is asking the Commission to force ratepayers to subsidize
5 political views repugnant to many of them, through advocacy, public
6 relations, advertising, and other similar activity.

7 The Commission should fund a maximum of half of NEI's costs with
8 ratepayer money. NC WARN also disallows the foundation donation, which
9 under Duke Energy's accounting guidelines, should have been classified
10 below the line to Account 426.1. NC WARN's minimum disallowance is
11 $1,362,000 (half of the $2,713,000 requested less $10,000 for the foundation).

12 **Q. HOW MUCH DOES DEC PAY FOR CHAMBER OF COMMERCE**
13 **DUES?**

14 A. The amount is $188,000, all in Account 930.2.

15 **Table 7: DEC Chamber of Commerce Dues[18]**

North Carolina Chamber of Commerce	$65,483
South Carolina Chamber of Commerce	28,900
Greenville Chamber of Commerce	13,105
Greensboro Chamber of Commerce	10,845
Catawba County Chamber of Commerce	10,000
Greater Durham Chamber of Commerce	10,000
Spartanburg Area Chamber of Commerce	7,727
Cherokee County Chamber of Commerce	5,550
Greater Raleigh Chamber of Commerce	5,000
Chapel Hill-Carrboro Chamber of Commerce	3,090

[18] NC WARN DR 1-92.

Hillsborough-Orange County Chamber of Commerce	3,000
York County Regional Chamber of Commerce	3,000
Carolina Corridor Chamber of Commerce (Alamance County)	2,360
Anderson Area Chamber of Commerce	2,306
Lancaster County Chamber of Commerce	2,100
Wilkes Chamber of Commerce	1,774
Thomasville Area Chamber of Commerce	1,667
Greenwood Chamber of Commerce	1,616
Chester County Chamber of Commerce	1,500
Stanly County Chamber of Commerce	1,190
46 Miscellaneous Items (less than $1,000)	7,932
TOTAL ACCOUNT 0930230	$188,145

Q. WHAT IS YOUR RECOMMENDATION REGARDING CHAMBER DUES?

A. Chambers of commerce are political organizations, whose costs should not be allowed for recovery from ratepayers. This is consistent with regulatory practice in Arkansas and California. The $188,000 should be adjusted out of rates.

I.D. Customer Survey Research

Q. WILL YOU COMMENT ON CUSTOMER SURVEY RESEARCH?

A. Duke Energy has increased its spending on customer survey research from $1,152,000 in 2009 ($170,000 for specific surveys and $882,000 in general support) to $2,543,000 in the Test Year ($953,000 for specific surveys and $1,592,000 in general support). Of this cost $943,000 is allocated to DEC. NC WARN DR 1-83 and its attachment are Exhibit WBM-5.

1 DEC has also changed its accounting for these surveys, moving the costs
2 from the administrative and general accounts (88% of all costs in 2009, with
3 the remainder mostly in energy efficiency, and only 0.5% in customer service
4 and information) to Account 910, a customer service and information
5 account which is allocated as customer-related and assigned 86% to
6 residential customers.
7 Upon reviewing the materials, it is first apparent that the ordinary
8 residential and small business customer satisfaction survey that Duke
9 conducts every year has increased in cost from $111,000 in 2009 to $286,000
10 (total cost) in 2012. The Test Year also contains a significant block of non-
11 recurring costs inasmuch as it has the costs of THREE residential customer
12 surveys in it, which is clearly unrepresentative. The Test Year contains a part
13 of the cost of the 2011 survey, a non-recurring pilot survey using the new
14 2012 methodology, AND the 2012 survey. While it is questionable whether
15 ratepayers should pay for any of these surveys, there should be general
16 agreement that in a representative test year, ratepayers should pay for only
17 one of these surveys, not three. Leaving in only the recurring 2012 survey
18 reduces total Duke Energy costs by $426,000 and DEC costs by $158,000.
19 Duke Energy has started to run duplicative separate residential and small
20 business surveys (customer satisfaction and national benchmark surveys),
21 which it did not run in 2009. Ratepayers should also not pay for two surveys

1 of the same or very similar issues. Duplicative survey costs that should be
2 removed are $125,000 (Duke Energy) or $43,000 for DEC. After removing
3 non-recurring and duplicative costs, the remaining cost of specific surveys is
4 reduced by $201,000 (for DEC) from $353,000 to $152,000.
5 The value to ratepayers of increased general support of $611,000 from
6 2009 to the Test Year is not explained. We recommend removing half of the
7 amount not associated with energy efficiency or $199,000 Duke Energy
8 ($74,000 for DEC).
9 Finally, the reassignment of these costs to Account 910, rather than an
10 administrative and general account, where DEC used to assign these costs in
11 2009, is inappropriate. DEC management is receiving the information.
12 Customers are not getting service or information. The transfer of these costs
13 from A&G expenses to customer service and information expenses
14 essentially makes residential and small business customers pay for 98% of
15 this corporate overhead that is only tangentially related to service.
16 Residential Customers shouldn't be handed 86% of the bill for the privilege
17 of being interrupted at dinner time by a DEC survey researcher or
18 telemarketer.
19 The results of NC WARN's recommendations on surveys are given
20 below. Note that the energy efficiency survey research costs, which we did

not adjust, are removed from the general rate case through other adjustments to Account 557.

Table 8: NC WARN Adjustment for Survey Research Costs

		NC WARN		
	DEC Request	Adjustment	Reclassification	Recommendation
EE (557)	129,607	0	0	129,607
910	811,820	(274,581)	(537,239)	0
A&G	1,933	(306)	537,239	538,865
Total	943,359	(274,887)	0	668,472

I.E. Stock-Based Compensation

Q. WHAT IS DEC REQUESTING FROM RATEPAYERS TO FUND STOCK-BASED COMPENSATION?

A. According to NC WARN DR 1-104, DEC is requesting $24,889,999 in stock-based compensation. This is by itself 5.6% of DEC's proposed rate increase. Exhibit WBM-6 contains the response to NC WARN DR 1-104.

Q. WHY SHOULD REGULATORS CARE ABOUT EXECUTIVE COMPENSATION IN GENERAL AND STOCK-BASED COMPENSATION IN PARTICULAR?

A. There is a fundamental difference between a competitive unregulated company and a regulated company in the effect of executive compensation on consumers. The literature on executive compensation is related to the "agency" problem; managers have incentives to act in their own best

interests, but when running a company they are acting as agents of shareholders. Executive compensation contracts are viewed under two schools of thought (with the truth possibly being between the two):[19] (1) "optimal contracting approach" that directors , who are themselves also agents of stockholders, will develop contracts that will align managers' incentives with those of shareholders; and (2) the view that executive compensation is strongly affected by "managerial power," i.e., managers have significant power (through the appointment of directors to their prestigious and lucrative posts, among other things) to influence their own pay packages.

The literature often presents executive compensation issues as if the issue relates only to executives and shareholders, although other stakeholders can occasionally be affected by compensation policies. But a utility regulator has to examine issues more carefully because, for utility companies, executive compensation is not just a tug-of-war between shareholders and executives, it also involves a third party, ratepayers. Regulated utilities often consider executive compensation to be a normal business expense that is paid by ratepayers.

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[19] This discussion is extracted from Lucian Arye Bebchuk and Jesse M. Fried, "Executive Compensation as an Agency Problem," *Journal of Economic Perspectives* (Vol. 17 No. 3) Summer 2003, 71-92.

1 At least in non-regulated corporations, which do not provide essential
2 services like utilities or health insurance, the trade-off between executive pay
3 and profit becomes an item largely of interest to shareholders. The price of
4 goods and services traded in competitive markets does not have a specific
5 component that rises when executives are paid more. Profits go up or down
6 depending both on the pay package and competence of the executives. It is
7 the job of the Board of Directors to balance these competing interests of
8 shareholders and executives. It is likely that if compensation gets out of line
9 with performance, the results are more likely to be some combination of cost-
10 cutting leading to lower pay for line workers (or a smaller number of
11 workers), lower shareholder profits, and possibly disgruntled shareholders.
12 The case of a regulated utility is different because the utility specifically
13 requests inclusion of the executive salaries as a "business expense." The
14 theoretical tension between management and shareholders regarding
15 executive pay is clearly attenuated if the full test year executive salary
16 expense can be included in rates charged to ratepayers, as DEC suggests in
17 this case. Managers, directors, and shareholders can all agree to reach into
18 ratepayers' pockets to increase executive pay, since the money is not coming
19 from shareholders' profits.
20 Without close scrutiny by regulators, ratepayers can only hope that the
21 executive officers improve shareholder value by cutting costs and being

1 productive (so that rates might decline by more than the executive
2 bonuses)— rather than asking regulators for rate "relief" to increase profits
3 or engaging in other practices that are likely to increase rates while
4 enhancing shareholder rewards.

5 A regulatory commission must therefore ask broader questions, not just
6 whether the compensation is similar to that requested by other utilities, and
7 is appropriate to attract and retain talented managers, but also (1) whether
8 offering compensation similar to that of other utilities is just and reasonable
9 in light of the methods by which compensation is set; (2) whether the
10 "talent" that is being attracted and retained is necessary for the efficient
11 operation of a regulated utility which benefits ratepayers; and (3) whether
12 the compensation, in particular stock-based incentive compensation, aligns
13 the interests of utility management not only with its shareholders but with
14 its ratepayers.

15 **Q. IS THERE A CLEAR RELATIONSHIP BETWEEN EXECUTIVE PAY**
16 **AND PERFORMANCE?**

17 A. At the highest level, it is reasonable to assume that the level of executive
18 compensation affects the ability of a company to attract and retain qualified
19 individuals. For example, one will probably not find a good CEO of a large
20 public company if one is only willing to pay $150,000. However, the link
21 between higher pay and improved performance is not at all clear. For

example, it is not clear that that a company will always get more talent for $2.5 million than $2 million or even for $10 million, for example.

The former President of Harvard University, Derek Bok, wrote *The Cost of Talent* in 1993 (before the recent burgeoning of executive pay) suggesting that relationships between pay and performance might be difficult to discern.[20] Other empirical information from the finance literature suggests that performance and pay packages are not closely related. Cooper, Gulen, and Rau have found that firms with CEOs who receive the highest levels of pay, and particularly higher levels of cash-based and stock-based incentives, earn abnormally low stock market returns.[21] Another study by Moody's links higher executive compensation (and particularly higher incentive compensation) with higher rates of defaults and bond rating downgrades after controlling for overall corporate performance.[22]

Q. WHY IS IT PARTICULARLY PROBLEMATIC FOR RATEPAYERS TO FUND STOCK-BASED COMPENSATION?

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20 Krugman, Paul. Review of "The Cost of Talent," by Derek Bok. Available: www.pkarchive.org/economy/Bok.html.

21 Michael J, Cooper, Huseyin Gulen, and P. Raghavendra Rau, "Performance for Pay? The Relationship between CEO Incentive Compensation and Future Stock Price Performance," May 2010. Working paper, available at SSRN: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1572085

22 Kenneth Bertsch and Chris Mann, Moodys, Special Comment: CEO Compensation and Credit Risk, July, 2005. http://www.moodys.com/cust/content/content.ashx?source=StaticContent/Free+pages/Credit+Policy+Research/documents/current/2003600000426617.pdf

1 A. The response to NC WARN 1-104 part c indicates that for performance
2 stock (70% of the total grant to executives), the only factor used in
3 determining the amount of performance shares issued is the stock price
4 relative to other companies on the Philadelphia Exchange Utility Index. The
5 number of shares handed out is unaffected by real corporate performance
6 either financially or as related to customer service and reliability. It is
7 entirely based on the stock price. The remaining shares (30% for executives
8 and more for other staff) are simply worth more when the price goes up.
9 More important, while prudent management, cost cutting, paying
10 attention to customers, and other items may have some impact on the stock
11 price, those impacts are very attenuated. The stock price is not highly
12 correlated with corporate performance. It may respond to productivity, but
13 it also responds to other factors. These include the success of management in
14 raising rates to customers in rate cases like the current one, the performance
15 of unregulated affiliates; and the ability of management to take other creative
16 steps on behalf of shareholders such as pursuing strategic mergers and
17 acquisitions, or alternatively even breaking up their company if the sum of
18 the parts is worth more than the whole.
19 **Q. WOULD SHAREHOLDERS THEORETICALLY BE INDIFFERENT TO**
20 **PAYING OUT MORE CASH OR GRANTING PERFORMANCE SHARES**
21 **OR RESTRICTED STOCK?**

A. No, they would not. Shareholders would prefer providing at least some executive compensation in performance shares or other stock-based compensation for three reasons. First, performance shares to a greater extent and restricted stock to a lesser degree focus executives on what is important to the shareholders – the share price and other aspects of financial performance. Second, unlike cash compensation, these shares require no immediate cash outlays by the company and do not directly affect the company's cash flow. Performance shares and restricted stock are paid by issuing treasury shares. While stock is diluted, the company does not need to pay cash either to make the up-front promises or to issue the shares at the end of the period.[23] Third, performance share payments are greater when stock and corporate performance is good and shareholders can afford to share largess with executives and less (or even zero) when stock prices are low or corporate performance is worse.

Q. IS THE VALUE OF PERFORMANCE SHARES KNOWN AND MEASURABLE AT THE TIME THAT THEY ARE GRANTED?

A. No, it is not known, even though it might be theoretically measurable on a statistical basis using actuarial or other estimating techniques. Performance shares are just slips of paper. The number of shares granted is

[23] A company may use cash to buy back stock to support its stock price, but the decision to buy back stock is independent of the decision to issue performance shares.

1 not known in advance, nor is the value of the shares at the time when they
2 vest. Whether an option will close in the money or not is also not known.
3 The actual value that executives will receive from performance shares will be
4 less if the stock price or corporate performance is low and higher if the stock
5 price or corporate performance is better. Unlike performance shares,
6 restricted stock has a value as it vests.

7 **Q. IN PRACTICE, CAN THE VALUE OF A UTILITY'S PERFORMANCE**
8 **SHARES AND STOCK OPTIONS EVER BE DIFFERENT THAN THE**
9 **AMOUNTS ESTIMATED ON ITS BOOKS OF ACCOUNT?**

10 A. For restricted and performance shares, a utility will reduce its accruals if
11 the stock price falls (or increase them if it rises). This means that the value of
12 the stock somewhat cushioned by ratepayers. Ratepayers could easily pay
13 more than was actually required if the stock values were estimated at a time
14 when prices were rising and stock prices subsequently fell (*e.g.*, if a
15 Commission hypothetically had included performance stock in rates in the
16 2006 rate case and the stock was finally awarded at the end of 2008).
17 Moreover, the number of these shares is estimated in advance, so that if DEC
18 were to underperform its Philadelphia Utility Index Peer Group, the
19 amounts on its books could exceed ultimate outlays.

20 **Q. AS A RESULT OF THIS ANALYSIS, WHAT DO YOU RECOMMEND**
21 **REGARDING STOCK-BASED COMPENSATION?**

1 A. Ratepayers should not fund any of it. As already noted, long-term
2 incentive compensation (a) is largely not a cash expense, (b) fluctuates in
3 value, (c) is concentrated in a few executives (no more than 2% of DEC
4 employees according to NC WARN DR 1-104c), and (d) does not provide
5 material ratepayer benefits or align the interests of shareholders and
6 ratepayers with its focus on stock prices and earnings per share. In fact, all
7 else being equal, larger rate increases from the utility's regulators would
8 increase the value of stock and increase the value of executive compensation.
9 Moreover, if stock prices drop, shareholders would be cushioned by the
10 provision of cash to cover the cost of performance stock. Long-term
11 incentive compensation also fluctuates dramatically in value over time
12 depending on the performance of the stock market. Any decline in DEC's
13 valuation in the rate-effective period will result in a reversal of its income
14 statement entry and a liability on its balance sheet being reduced even
15 though the amount ratepayers are paying for such stock would have been set
16 in the general rates. In other words, the Company will pay out less than it
17 was awarded in the rate case, based simply on the fact that its stock price
18 went south, and shareholders will pocket the rest.
19 **Q. ARE YOU AWARE OF ANY OTHER STATE COMMISSIONS THAT**
20 **DISALLOW STOCK-BASED COMPENSATION?**

1 A. Yes. At a minimum, it is disallowed in three states where I have worked

2 recently, Arkansas, Texas, and California. The Arkansas PSC found "no

3 substantial evidence of ratepayer benefit which would justify including these stock-

4 driven incentives in rates."[24] The Public Utilities Commission of Texas last

5 decided in Docket 39896 (Entergy Texas) agreeing with the ALJs' Proposal

6 for Decision (PFD), that

7 The ALJs conclude that ETI should not be entitled to recover its financially
8 based incentive compensation costs. Based upon prior Commission
9 precedents, the ALJs conclude that the issue is not, as ETI contends, whether
10 such incentives might provide any benefits to customers. The proper
11 question to be asked is whether they provide benefits most immediately or
12 predominantly to shareholders. Without a doubt, the primary purpose of
13 financially based incentives, such as incentives tied to earnings per share or
14 stock price, is to benefit shareholders, not ratepayers. Even construing Dr.
15 Harzell's testimony in the most generous light, any benefits that might
16 accrue to ratepayers would be merely tangential to that primary purpose.[25]
17
18 The PUCT went farther, denying rate case expense recovery for the attempt

19 to pursue recovery of financially based incentives because the precedent was

20 so settled against it. The ALJ's proposed decision states:

21 Simply put, the ALJ concludes that ETI did not act reasonably when it
22 incurred expenses litigating for recovery of its financially-based incentive
23 costs in the face of clear and consistent precedent to the contrary on the issue.

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[24] APSC Docket No. 06-101-U, Order No. 10 (June 15,2007), p. 68.

[25] ALJs Proposal for Decision, PUCT Docket No. 38986, pp. 168-169.found at http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=39896&TXT_ITEM_NO=764

1 As such, the ALJ recommends that ETI's expenses be cut by some amount to
2 account for this issue.[26]
3
4 The Commission even added a further $522,245 to the ALJs' disallowance of
5 $208,494 for rate case expenses in this area as a penalty.[27]
6 The California Public Utilities Commission (CPUC) disallowed ratepayer
7 funding in two previous decisions involving Southern California Edison
8 Company.[28] The latest decision on the topic (D. 13-05-010 regarding the
9 Sempra Energy utilities, San Diego Gas and Electric and Southern California
10 Gas Company) also disallowed stock-based compensation, as follows:

11 In deciding who should pay for the cost of long term compensation, we need
12 to examine whether ratepayers or shareholders benefit from such
13 compensation programs, and how the Commission has treated such costs in
14 the past. This type of compensation is stock-based, which means that when
15 employees are awarded these stock units, that the value of the stock units
16 will grow if the company's stock price increases. Since the long term
17 compensation of both SDG&E and SoCalGas are based on four years of
18 financial performance, these factors all point to benefits which accrue to
19 shareholders. However, this type of compensation also benefits shareholders
20 and ratepayers by attracting and retaining employees who are familiar with
21 the corporate culture and goals of the two companies. As the Applicants
22 point out, a financially strong company usually has lower borrowing costs,
23 which benefits ratepayers by lowering costs. With regard to the
24 Commission's past treatment of long term compensation, our review of the
25 decisions show that the Commission has generally disallowed long term
26 incentive compensation.

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[26] ALJ Proposal for Decision in PUCT Docket 40295, pp. 24-25.
http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=40295&TXT_ITEM_NO=67

[27] *Id.*, page 3

[28] *See* California Public Utilities Commission Decision No. 09-03-025, pp. 134-135; and Decision No. 12-11-051, pp. 451-452.

Although many companies offer long term compensation plans, that does not necessarily mean that ratepayers should have to pay for the costs of funding such a program. In considering whether such costs are reasonable, the benefit of this type of compensation plan clearly benefits the executives and shareholders if the value of the stock goes up. Since this stock-based compensation is tied to financial performance over a period of time, that clearly demonstrates that a premium is being placed on the companies' financial performance. In addition, the employees who received the stock-based compensation are already highly compensated through their base pay, and the short term incentive compensation. Another consideration is the cost to ratepayers, who see little benefit from such a program, but face increased costs if the cost of the long term incentive compensation program is included in the revenue requirement. Based on all these considerations, and given the state of the economy and the benefits that shareholders receive, it is reasonable to disallow ratepayer funding of the costs of the long term incentive compensation program for SDG&E in the amount of $10.148 million, and for SoCalGas in the amount of $5.361 million.[29]

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission disallow all LTIs (including stock options). The amount of the disallowance is $24,889,000.

I.F. Directors and Officers (D&O) Liability Insurance

Q. WHAT HAS DEC REQUESTED FOR D&O LIABILITY INSURANCE?

A. At this point, we do not know with any accuracy, because DEC has not answered NC WARN DR 1-106, which was filed on April 21.

Q. SHOULD THE ENTIRE COST OF THE D&O LIABILITY INSURANCE POLICY BE PAID BY RATEPAYERS?

[29] Decision No. 13-05-010, pp. 883-884.

1 A. No. It is not appropriate to assign 100% of the cost of D&O insurance to
2 utility ratepayers. Instead, it is reasonable to share the cost of this insurance
3 on a 50-50 basis between ratepayers and shareholders, since D&O insurance
4 is often called into play when shareholders of publicly traded companies sue
5 company management.

6 Ratepayers should pay a portion of D&O insurance because the existence
7 of the insurance does improve the ability to attract and retain qualified
8 directors and enables them to make decisions without fear of personal
9 liability. However, proceeds of insurance payouts do not flow to ratepayers,
10 but only to shareholders. D&O insurance provides a mechanism for
11 aggrieved shareholders to collect funds under certain circumstances. The
12 policies reduce the risk of common equity investment in the event of a bad
13 decision by management or directors.[30] Moreover, in the absence of such
14 insurance, many of the cases in which shareholders could collect funds
15 (related to inadequate or misleading disclosures to shareholders of material
16 company activities), would be below the line from the perspective of
17 ratepayers in any event.

18 I thus recommend that shareholders share in the cost of the policy
19 because not only do shareholders get the payoff from the insurance policy

[30] An academic article suggests that there are several means of protecting directors from personal liability, but D&O insurance "protects the shareholders' wealth more than the directors'." Boyer, M. Martin, Directors' and Officers' Insurance and Shareholder Protection (March 2005). Available at SSRN: http://ssrn.com/abstract=886504 .

1 when something goes wrong, but without the insurance, ratepayers would
2 not be liable in any event for at least significant portions of the payment to
3 shareholders.

4 **Q. ARE YOU SAYING THAT D&O INSURANCE IS DIFFERENT FROM**
5 **OTHER BUSINESS EXPENSES?**

6 A. Yes. The fundamental difference is that when the insurance pays a
7 settlement or claim, the recipient of the money is often aggrieved
8 shareholders. Ratepayers should not pay for a second income stream for
9 shareholders if something goes wrong.

10 **Q. HAVE OTHER STATE COMMISSIONS SHARED D&O INSURANCE**
11 **BETWEEN RATEPAYERS AND SHAREHOLDERS?**

12 A. Yes. In its Orders in four contested cases,[31] the Arkansas Public Service
13 Commission (PSC) adopted the 50-50 sharing of these expenses based on the
14 rationale given above. Excerpts from two decisions are quoted below:

15 The news (T. 1040) is replete with stories about companies experiencing
16 lawsuits by shareholders. The Commission agrees with the AG that more
17 often than not it is the current shareholders who sue management and
18 who receive a large portion of the proceeds from the D&O insurance
19 payouts. Accordingly, the Commission finds that Arkla's existing asset-
20 based allocation for D&O insurance should be maintained and that the
21 expense for D&O insurance should be shared on a 50-50 basis between
22 shareholders and ratepayers.[32]
23

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[31] Arkansas PSC Docket Nos. 02-227-U, 04-121-U, 04-176-U, and 06-101-U.

[32] (Arkansas PSC Docket No. 04-121-U, Order No. 16, page 40, September 19, 2005 http://www.apscservices.info/pdf/04/04-121-u_286_1.pdf)

The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer. [33]

Similarly in California the CPUC has required a 50-50 sharing of this cost since 1996.[34] The 1996 decision specifically cited information brought forward by the Commission's Division of Ratepayer Advocates that the bulk of lawsuits using this insurance were brought by shareholders and that the one such shareholder suit that Southern California Edison settled resulted in a below-the-line payment of amounts less than the policy deductible. The Commission concluded:

In D. 87-12-066, 26 CPUC 2d 392,422, we permitted these types of premiums to be recovered in rates. However, the statistics provided by DRA [Division of Ratepayer Advocates] from 1986-1993, which were not available in 1987 when we decided D. 87-12-066, illustrate that shareholders also benefit from this insurance. Therefore, we will allow half of the expenses requested by Edison for this item. By making this allocation, we are not implying that it is not necessary for Edison to maintain such insurance. To the contrary, we are funding half of the premium with ratepayer funds. However, to the extent

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[33] Arkansas PSC Docket No. 06-101-U Order No. 10, Page 70, June 15, 2007, footnote omitted, http://www.apscservices.info/pdf/06/06-101-u_303_1.pdf

[34] CPUC Decision No. 96-01-011 in Application No. 93-12-025 slip. op. at 140-141, January 15, 1996, regarding Southern California Edison Company; and California PUC Decision No. 00-02-046 in Application No. 97-12-020, slip op. at 309, February 17, 2000, regarding Pacific Gas and Electric Company.

that shareholders also benefit from this insurance, they should also share in the expense.[35]

The Public Utilities Commission of Nevada reversed a precedent from 1991 and adopted 50-50 sharing of this expense, stating that "in this instance, the Commission is persuaded by BCP [Bureau of Consumer Protection] that shareholders receive a tangible benefit from D&O liability coverage and should participate in its cost."[36]

The Connecticut Department of Public Utility Control has gone a step further, requiring ratepayers to pay just 25% of the cost of D&O insurance cost since 2006. Its January 27, 2006 Decision in Docket 05-06-04 (for United Illuminating).[37]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that DEC's D&O liability insurance expense be reduced by 50% in the test year by apportioning 50% of the costs to the shareholders. I will quantify my adjustment when DEC responds to NC WARN 1-106 filed by NC WARN on April 21, 2013.

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[35] CPUC Decision No. 96-01-011, p. 141.

[36] Public Utilities Commission of Nevada, Order in Docket 08-12002 (June 24, 2009), p. 149.

[37] Connecticut DPUC Decision in Docket 05-06-04 (United Illuminating Company) January 27, 2006, p. 47. The DPUC reconfirmed its precedent of allowing only 25% of D&O liability insurance in rates in its Decision in Docket 08-07-04 (United Illuminating Company) February 4, 2009 at page 43.

SECTION II -- COST ALLOCATION

II.A. Generation Cost Allocation

Q. WILL YOU DISCUSS THE ORGANIZATION OF THIS SECTION ON COST ALLOCATION?

A. First, I discuss the issues of generation planning and develop an allocation for production (generation) plant. Then I review distribution cost allocation issues. I then review other issues (such as assignment of 86% of the cost major account representatives, who serve large non-residential customers, to the residential class, and allocation of economic development and marketing costs) and present the results of my recommended cost of service study, which reduces residential costs by $152 million relative to DEC.

Q. WHAT ARE THE REASONS FOR THE CONSTRUCTION OF GENERATING PLANTS?

A. The allocation of generation costs on the summer coincident peak ("SCP") method proposed by DEC allocates all costs based on the demand by the various rate classes during the 15-minute summer peak. However, this does not reflect the reasons why generation is built. The "need for generation" essentially must be broken down into two separate questions. The first is <u>how much</u> generation is required. The second is <u>what kind</u> of generation is required, because there are a variety of generating technologies

1 with varying capital costs. Generation with lower capital costs tends to have
2 higher variable costs, such as fuel, and vice versa.

3 **Q. WHAT ARE THE CAUSES FOR NEED FOR GENERATION?**

4 A. The amount of generation is generally calculated based on meeting the
5 system coincident peak load with a reserve margin adequate to cover periods
6 of system stress caused by generating plant outages. System stress does not
7 just occur in the peak hour of the year but can occur in a considerable
8 number of hours when loads are high. Stress can occur even in non-peak
9 months when large generating plants are taken down for maintenance and
10 there is the potential for other units to then suffer forced outages.

11 **Q. WHAT ARE THE ISSUES RELATED TO RELIANCE ON**
12 **CONCIDENT PEAK?**

13 A. The use of a single coincident month's peak (1 CP), the method proposed
14 by DEC, is rarely used because it does not reflect actual use and system
15 stress. Most summer peaking jurisdictions, such as Texas, do not use a single
16 coincident peak month for establishing peak demand but often instead use 3
17 CP or 4 CP. Jurisdictions with higher levels of winter demand often use 6 CP
18 (the six highest months including two or three winter months) or even a 12
19 CP. The Federal Energy Regulatory Commission (FERC) tends to use 12 CP
20 to allocate transmission costs unless systems are extremely peaked, and has
21 laid out a number of tests as to whether 12 CP is reasonable.

1 **Q. WHAT OTHER METHODS OF RATE ALLOCATION ARE USED BY**

2 **OTHER UTILITIES?**

3 A. Marginal cost jurisdictions, such as Nevada, spread generation demand

4 costs using loss of load probability (LOLP), which includes not just high

5 peak hours in both seasons but probabilities of load loss due to forced

6 outages when units are on maintenance. The LOLP method spreads loads

7 outside single peak hours in a month.

8 Other methods can be used to reflect the fact that high loads in a number

9 of hours can theoretically contribute to system stress peak. One such

10 method is the Peak Contribution Allocation Factor (PCAF), also referred to

11 as the Probability of Peak (POP). This method assigns diminishing amounts

12 of capacity costs in each hour with load in excess of 80% of the peak. Thus

13 the peak hour is weighted 19 times as much as an hour with 81% of the peak

14 load, but some weight is given to all high load hours. Pacific Gas and

15 Electric Company uses PCAF. NV Energy uses the same method, which it

16 calls POP, to allocate transmission and distribution costs. Southern

17 California Edison and San Diego Gas and Electric assign equal weight to

18 each of the top 100 hours of the year.

19 Q. **DO ENERGY REQUIREMENTS EXPLAIN WHY SPECIFIC TYPES OF**

20 **GENERATION ARE BUILT**?

1 A. Yes, the choice of generating plants is generally based on attempting to
2 minimize total system costs taking into account fuel costs, fuel diversity, and
3 sustained energy use, while maintaining reliability, responding to
4 uncertainties, and meeting constraints caused by generation lead times.
5 There is a significant energy-related component to the choice of what to
6 build. As pointed out by DEC in the conclusions to its Integrated Resource
7 Plan, September 1 2012, at page 89, the results of DEC's IRP analysis
8 "suggest that a combination of additional base load, intermediate and
9 peaking generation, renewable resources, EE, and DSM programs is required
10 over the next twenty years to meet customer demand reliably and cost-
11 effectively." NCUC Docket E-100, Sub 137. In the testimony of DEC
12 Witness, Phillip O. Stillman, DEC maintains that the purpose of its IRP
13 process is solely to meet its peak requirements plus a reserve margin.
14 Stillman testimony, p. 12. This contradicts how utilities actually plan for
15 and construct generation; meeting demand throughout the year is not based
16 simply on what meets peak demand.
17 **Q. HOW DOES A UTILITY DECIDE ON WHAT TYPE OF PLANT TO**
18 **CONSTRUCT?**
19 A. If a utility is building a plant that provides energy in a few hours at peak
20 or for reserves, it builds a peaking plant – low capital costs, high fuel costs. If
21 a utility needs energy around the clock, it builds baseload generation – much

1 higher capital costs, much lower fuel costs. For intermediate loads, the
2 utility builds a plant such as a combined cycle, which has capital costs and
3 fuel costs between the peaker and the baseload plant.

4 **Q. WHAT PART DOES FUEL MIX PLAY?**

5 A. Utilities also make choices of what to build based on fuel diversity as well
6 as absolute fuel costs, and choose a diverse mix of fuels in order to hedge
7 against both price and environmental risks associated with
8 overconcentration in specific fuels. One of the means of maintaining fuel
9 diversity is to acquire power from renewable resources, either by purchase
10 or ownership. Most renewables share characteristics with baseload
11 resources, high capital costs and zero or low fuel costs.

12 **Q. ARE GENERATING PLANT COSTS ENTIRELY CAUSED BY PEAK**
13 **LOADS?**

14 A. The clearest examples explaining why generating plant costs are not
15 entirely caused by peak loads come from units with extremely low fuel costs
16 – nuclear, hydro and wind. It is clear that a nuclear plant or hydro plant or
17 wind turbine is built to provide very cheap energy. With a high cost of
18 initial capital, significant fixed O&M, and ongoing capital additions, a
19 nuclear plant would only be cost-effective because it uses extremely
20 inexpensive fuel to provide energy, less than 1 cent per kWh. A utility will
21 also build hydro generation, which is far more expensive than equivalent

fossil generation, to gain free fuel (or in the case of pumped storage, use off-peak energy that is less expensive to save higher fuel costs during peak periods). A utility will spend the capital to build wind generation to save fuel and gain environmental benefits that are entirely related to the energy that the plant produces. Wind energy has limited firm capacity per unit of energy but provides energy with low variable costs and no fossil fuel use when the wind is blowing. The intent when the plants were built was clear – they were built to save expensive fuel and provide diverse fuel sources. The meeting of peak load remains an incidental.

Q. WERE THE PLANTS PROPOSED TO BE ADDED TO DEC'S RATE BASE BUILT SIMPLY TO MEET THE SUMMER CAPACITY NEEDS?

A. No, DEC has plants already in its rate base, and is constructing new plants, that meet demand and energy needs far beyond simply to meet the summer capacity hours in one or a few peak hours. The issue is the method the utility uses to allocate costs to consumers, because the construction and operation of the various generating units may not provide the cheapest form of capacity. A cost causation based on this rationale cannot possibly be squared with a cost allocation based entirely or almost entirely on summer peak demand for the full capital cost of a new plant, especially if the plant is a nuclear plant. The use of the SCP leads to residential and small business

1 classes picking up most of the financial burden for new baseload
2 construction.
3 This is unreasonable.
4 **Q. HOW DO YOU RESPOND TO DEC'S ARGUMENT FOR SCP/1CP?**
5 A. Cost causation is more than meeting the summer peak load only. The
6 amount of generation is planned to meet a level of reliability, often called
7 Loss of Load Probability or a related concept of Expected Unserved Energy.
8 This is the sum of the probabilities in all hours of the year that load can be
9 lost. Now in many off-peak hours, the probability is infinitesimally small,
10 but there are a significant number of hours where the Loss of Load
11 Probability is large enough to be taken into account. For example, an hour
12 that is 5% less than the peak load will have a significant amount of LOLP,
13 although less than the peak hour. Even an hour that is as much as 20% or
14 30% less than the peak might have a significant LOLP if maintenance of large
15 baseload generators is scheduled into that time frame. The dual summer and
16 winter peak of DEC means that its maintenance windows are more limited
17 than those of other utilities.
18 There is a trade-off between reliability and cheap energy that also plays
19 through the LOLP calculation and the choice of generating units and their
20 size as individual units. Consider a modern nuclear plant. It runs well, until
21 it doesn't, and then there is a large amount of energy forced out of service,

1 creating system stress. If we assume that a nuclear plant has a 5% forced
2 outage rate (a relatively low number), there is a 5% probability that the entire
3 1000 MW plant will not be operating. If the utility had built combined cycles
4 totaling 1000 MW with 4 combustion turbines and 2 steam turbines, all of
5 which had a 5% forced outage rate (high for a combined cycle), then the
6 probability of losing that entire 1000 MW to a forced outage would be just
7 over 1 in 10 million. In other words a nuclear plant requires more back-up
8 power than a combined cycle because of LOLP. It may have value if it can
9 produce cheap energy, but its capacity is worth less.
10 The bigger issue is the relation of capital spending to energy cost. A
11 nuclear plant has approximately 85-90% non-fuel costs and 10-15% fuel costs.
12 A combined cycle hypothetically running at the same capacity factor as a
13 nuclear plant (i.e., not dispatched down because other fuels are cheaper)
14 would have about 50% non-fuel costs and 50% fuel costs.
15 Let us assume, totally counterfactually, that the nuclear plant and the
16 combined cycle had the same total costs in dollars per kW when run at a
17 high capacity factor for purposes of illustration and argument. In this
18 illustration, let us also set aside the fact that the utility buys less reliability
19 with a nuclear plant than with a combined cycle of the same number of
20 megawatts. If we do that, the result is that the utility system as a whole is
21 largely indifferent between the nuclear plant and the combined cycle plant.

However, the interests of the rate classes diverge wildly. High load factor industrials would pay far less for the nuclear unit than for a combined cycle of equivalent total cost while residential and small business customers would pay far more. A peak demand-related allocation method in fact would encourage large commercial and industrial customers to promote the building of **more expensive** nuclear plants over cheaper non-nuclear alternatives because the nuclear units allow them to shift non-fuel costs, incurred to use the cheap fuel, onto other customer classes.

DEC's rationale for SCP/1CP is a results-oriented argument. Because the peak method charges industrials less, and as a matter of arithmetic a method containing an energy allocation would charge them more, the peak allocation is the right thing to do. It is extremely difficult to claim with a straight face that a nuclear plant should be allocated by peak demand and is constructed solely to meet the peak demand (when a combustion turbine plant that would meet the peak demand could be built at 15% of the cost or less of the nuclear plant, would have considerably lower operations and maintenance costs as well and would not have back-end massive costs of fuel disposal and decommissioning), unless the objective is to charge industrial customers less.

Q. ARE THERE ENERGY-RELATED COSTS OF RUNNING POWER PLANTS ON A DAY-TO-DAY BASIS THAT MANY COST ANALYSTS FAIL TO RECOGNIZE?

1 A. Operations, maintenance, and capital improvements to power plants
2 have energy-related reasons. Pollution control retrofits have been required
3 in the past and additional retrofits may be required in the future on many
4 baseload coal generation plants because they are used for many hours of the
5 year; if they were used for reserves only, retrofit requirements would be less
6 or non-existent.

7 Other items that some utilities classify as demand-related, including fuel
8 handling, ash disposal, water and consumable chemicals, and the leasing or
9 ownership of rail cars to deliver fuel to coal plants also are related to energy
10 production, not to meeting peak demand. DEC correctly treats these costs as
11 energy-related, in part because it does not own rail cars, though some
12 utilities do not.

13 NARUC recommends the assignment of Accounts, 512, and 513 relating
14 to boiler and electrical system maintenance of steam plants and portions of
15 Account 510 (and similar accounts 528, 530, and 531 for nuclear plants) as
16 energy-related because overhauls and the need for maintenance are caused
17 by sustained usage. Nuclear plants must be refueled, and base refueling
18 costs are necessary <u>because the fuel is used up</u> and the timing of refueling
19 intervals can change depending how intensively the plant is used. Similarly,
20 the cost of long-term service agreements on most combined cycle plants are
21 variable, because they are variable, as they are related to the hours of

1 operation of the plant or its subcomponents or energy-related phenomena
2 such as start-ups.
3 Finally, profits from off-system power sales are often treated as energy-
4 related and flowed back to customers through fuel adjustment clauses on an
5 energy basis. This is unreasonable if demand is entirely based on peak load,
6 because it assumes that the off-system sales were generated entirely by fuel
7 and that the unused plant capacity had no role in them. If cheap nuclear or
8 coal power can be sold profitably by DEC, then the money flows to reduce
9 the fuel adjustment clause rates based on energy use, so high load factor
10 customers get more of the money. So not only do peak users pay for a
11 disproportionate share of expensive nuclear capacity that was not built to
12 serve peak load, but they then have to give up a disproportionate amount of
13 profits from excess power, generated by the unused capacity which they
14 paid for, because of the energy allocator. Off-system sales of baseload power
15 allocated as energy-related would cause lower load factor customers to lose
16 twice. I do not object to passing off-system sales profits between rate cases
17 through the fuel adjustment clause for administrative convenience, but the
18 profits from those sales should be assigned to both demand and to energy
19 when setting the initial cost of service in a rate case.

Q. PLEASE PROVIDE EXAMPLES OF ALLOCATION METHODS THAT TAKE ENERGY INTO ACCOUNT FOR NON-FUEL COSTS OF UTILITY PLANTS.

A. There are several common allocation methods that take energy into account:

a. The Base – Intermediate - Peak (B-I-P) method uses different allocation methods for different types of plant to reflect the different causes for constructing them; a heavily energy-oriented method for baseload power; a method such as 12 CP for intermediate plant (combined cycles and older coal plants), and a more heavily peaked method for plants used for peaking and reserves.

b. The Summer Winter Peak and Average (SWPA) method advocated by the Public Staff in previous rate proceedings is a form of the Average and Peak Demand (APD) method. This method multiplies the system load factor by average demand (energy) and one minus the system load factor by a measure of peak demand. This method reflects in broad general terms that usage of power plants and the type of plants that are being built is based on sustained energy but the amount of generation is based on peak. As a matter of general principle, the APD method, including the SWPA, is one of several ways to recognize that relatively inexpensive peaking plants are built to

1 meet peak loads, but relatively expensive baseload facilities are constructed
2 instead of cheaper peaking plants to meet sustained energy loads.
3 c. The Plant Capacity Factor (PCF) method takes the APD analysis to the
4 individual plant level. Under this method, a baseload plant like a nuclear
5 plant running at an 85% capacity factor would be classified 85% to energy
6 and 15% to demand. A peaking plant running 2% of the time would be
7 classified 2% to energy and 98% to demand. This method produces an even
8 higher energy allocation than APD or SWPA because the most expensive
9 baseload power plants have the highest energy allocations.
10 d. The Peak Credit Method assigns costs equal to the fixed cost of a
11 combustion turbine (and possibly some fuel costs for a nominal capacity
12 factor such as 5%) as demand related. Additional costs associated with
13 utility baseload power plants above the cost of the peaker are assumed to
14 have been incurred to reduce energy costs and are energy-related. The
15 allocation of some peaker fuel costs as an offset to the higher fixed costs of
16 baseload generation addresses the concern of some parties that baseload
17 users may be overassigned costs of expensive fuel.
18 e. Hourly Load Methods
19 1. The Probability of Dispatch (POD) method assigns costs of both
20 capacity and energy based on hourly loads in the hours when plants are
21 dispatched for native load. A POD model allocates generation costs by

1 spreading the fixed costs of the various generation plants of a utility units
2 across the hours of the year as the units are operated, based on the usage of
3 those units by each customer class. Energy costs can be allocated generally
4 in the same way, although complications may arise from off-system sales.
5 Under the POD model, baseload plants, including capital, operations and
6 maintenance and energy, are allocated to users across the year, while
7 peaking plants are allocated to users in high load hours. A plant held for
8 reserves and not operated is allocated based on the peak. I requested
9 information from DEC to be able to use the POD method, but DEC does not
10 have hourly loads – even by time-of-use periods that it uses for pricing QF
11 power – except for customers with TOU meters.
12 2. The marginal cost method assigns the fixed costs of a combustion
13 turbine (with some possible adjustments) to capacity and other costs to
14 energy. These can be short-run marginal costs (e.g., market prices) or longer
15 run incremental costs (costs of combined cycle or coal generation). The total
16 marginal costs can then be trued up to total generation costs (fixed, fuel, and
17 purchased power), creating capacity-related and energy-related percentages
18 of cost. Capacity is usually allocated by a loss of load probability method
19 and energy based on hourly loads or loads in specific time periods to obtain
20 percentages of capacity and energy. Nevada and California use a short-run
21 marginal cost method. Utilities in the Pacific Northwest have traditionally

1 used a long-run incremental cost method. This method also requires loads
2 either hourly or by time of use – which DEC does not have.
3 f. The Average and Excess Demand (AED) computes demand in two
4 parts. The system load factor is multiplied by each class's average demand,
5 and the remaining excess demand (one minus the system load factor) is
6 allocated to each class based on its excess demand above the average. While
7 proponents of this method claim that it recognizes sustained energy use or
8 average demand in the calculation, the pure mathematics of the way the
9 method works, unlike APD or SWPA, is that it nearly always comes out very
10 close to a pure peak demand allocation. The only small differences from a
11 peak allocation arise from the treatment of classes, like streetlighting, which
12 would have negative excess demand which is typically zeroed out, and from
13 differences in the regulatory definitions of peak loads used to compute the
14 load factor and to compute the excess demand. The AED method typically
15 assigns a trivial amount to energy, somewhere between 0.5% and 5%,
16 depending on its construction, while giving the analyst a small fig leaf to
17 claim that energy is being considered in the allocation.
18 **Q. BASED ON YOUR REVIEW OF ALLOCATION METHODS, DO YOU**
19 **HAVE AN OPINION ON THE DEC PROPOSAL?**
20 A. The SCP/1CP method proposed by DEC is rarely used because the results
21 are often not fair or reasonable. The treatment of all of the generation

"fixed" costs as being related entirely to peak demand is contrary to economic theory. A significant relationship between generation fixed costs and energy usage arises from the principles of utility planning. A number of methods can be used to relate portions of generation "fixed" costs to energy. Even in states where fixed costs are considered demand-related, most states use multiple months of coincident peak demands or other methods to assign demand-related costs to multiple hours to recognize that peak loads are not driven by a single hour.

A single SCP method also is prone to gaming, where the utility can inform some of its larger customers that a peak event is likely to happen, so that they can partially self-interrupt for a short period of time and avoid the entire allocation of peak demand for their customer class for the entire year.

II.B. Preferred Allocation Method

Q. WHAT METHOD WOULD YOU HAVE CHOSEN IN THIS CASE IF DATA WERE AVAILABLE, AND WHY?

A. I would preferred to use an hourly load method such as the probability of dispatch method (which assigns both fixed and variable costs to loads based on when individual plants run), or a marginal cost method.

A number of utilities that are smaller than DEC have no problems collecting hourly load at the level of individual classes. A few examples are

1 Sierra Pacific Power and Nevada Power (the two NV Energy companies),
2 MidAmerican's operations in Iowa, and San Diego Gas and Electric
3 Company. The larger California utilities have hourly data at least at the level
4 of time-of-use periods, and PG&E uses hourly load data for both generation
5 and local distribution capacity cost allocation based on a weighted average of
6 the hours when load is within 20% of the peak.
7 DEC provided NC WARN with some hourly data by large customer class
8 on Monday, June 10, 2013, fifty days after we requested the information and
9 two days before the original testimony due date. However, the data
10 could only be used for general research on several points rather than for
11 allocation both because it was so late and because it did not divide each class
12 into its major subclasses (residential with and without space heating, small
13 and large general service, the three optional rates).
14 I report on some of this research after developing my recommended
15 allocation method, and in particular find that applying the existing hourly
16 load data to DEC's avoided costs would assign considerably less to the
17 residential class than even I am proposing below.
18 **Q. WHAT DO YOU RECOMMEND FOR USE IN THIS CASE GIVEN**
19 **THE INFEASIBILITY OF HOURLY LOAD METHODS?**
20 A. I have developed a modified version of the peak credit method, which
21 includes a limited amount of energy from peakers in the demand-related

1 costs so as to respond to the concerns raised by industrial customers in the
2 absence of hourly data.
3 **Q. PLEASE EXPLAIN YOUR CALCULATIONS.**
4 A. The peak credit method essentially compares the cost of baseload
5 generation to that of a combustion turbine, the cheapest form of capacity. If
6 only capacity is needed, a CT could be built. All other capacity is built to
7 meet energy needs.
8 To obtain the embedded cost of combustion turbines, we took
9 combustion turbine data from NC WARN DR 1-29 and 1-30 and from DEC's
10 2011 FERC Form 1. For the four modern pure combustion turbines (Lee,
11 Lincoln, Mill Creek, and Rockingham), the cost was $273 per kW for a
12 weighted average start date of 1999 – much later than the initial construction
13 of DEC's coal and nuclear units. For conservatism, the full value of $273 was
14 compared against the cost of coal and nuclear plants constructed much
15 earlier without applying inflation or deflation factors. Operations and
16 maintenance costs of the modern combustion turbines was $4.25 per kW-
17 year. The fuel cost was 4.14 cents/kWh in 2011-12, according to Stillman
18 Exhibit 4, and the modern peakers ran at a capacity factor slightly under 3%
19 in the Test Year.
20 Out of conservatism, this analysis assumes that a small portion of fuel is
21 demand-related – enough to operate a modern CT at a historical 5% capacity

1 factor. Treatment of this fuel as demand-related responds to the concern of
2 industrial customers that they are assigned too much fuel from peakers and
3 other units with expensive fuel. With a fuel cost of 4.14 cents/kWh
4 according to Stillman Exhibit 4, fuel at a 5% capacity factor is $18.13/kW-
5 year. We treat this potential peaker fuel cost as an offset to some of the
6 energy-related fixed costs of other generation.
7 The table below provides the capital costs of combustion turbine plants
8 owned by DEC. We use the data on modern CTs as the basis for calculating
9 the peaker cost.

Table 9: Combustion Turbine Capital Cost and Depreciation Reserve

						$/kW		
Gas Turbine Stations	**In Service Year**	**Gross Plant**	**Estimated Reserve**	**Net Plant**	MW	gross plant	reserve	net plant
Buck	1970	653,477,695	25,727,576	627,750,119	691	946	37	908
Buzzard Roost	1971	27,954,975	29,121,022	(1,166,047)	197	142	148	(6)
Dan River	1968	6,447,751	6,802,377	(354,626)	70	91	97	(5)
Riverbend	1969	13,335,201	13,498,577	(163,376)	101	132	133	(2)
Lee	2006	57,258,578	11,141,560	46,117,018	120	477	93	384
Lincoln	1995	392,388,467	254,980,687	137,407,780	1,443	272	177	95
Mill Creek	2002	252,264,911	89,597,690	162,667,221	936	270	96	174
Rockingham	2000	293,979,938	126,361,672	167,618,266	1,150	256	110	146
Total CTs		1,697,107,516	557,231,160	1,139,876,356	4,709	360	118	242
w/o Buck (CC and CT mixed partial 2011)		1,043,629,821	531,503,585	512,126,237	4,018	260	132	127
modern CTs only	1999	995,891,894	482,081,609	513,810,285	3,649	273	132	141

We calculated fuel and non-fuel O&M costs in total dollars and dollars per kW and estimated return, taxes, and depreciation based on 3% multiplied by gross plant (approximate depreciation) and 10% multiplied by net plant (approximate return and income taxes, implicitly taking deferred income taxes into account). Modern combustion turbines have a non-fuel O&M cost of $4.25 per kW-year and estimated depreciation, return, and taxes of $22.27.

Table 10: Combustion Turbine Fixed Cost

					Estimate of Return, Tax, Depr.	
Gas Turbine Stations	**In Service Year**	MW	non-fuel O&M	non-fuel	10% of net plant + 3% of gross plant	
				$/kW-yr	$	$/kW-yr
Buck	1970	691	467,822	0.68	82,379,343	$ 119.20
Buzzard Roost	1971	197	553,893	2.81	722,045	$ 3.67
Dan River	1968	70	58,499	0.83	157,970	$ 2.24
Riverbend	1969	101	8,786	0.09	383,718	$ 3.79
Lee	2006	120	740,430	6.17	6,329,459	52.75
Lincoln	1995	1,443	4,593,680	3.18	25,512,432	17.68
Mill Creek	2002	936	2,240,515	2.39	23,834,669	25.46
Rockingham	2000	1,150	7,933,665	6.90	25,581,225	22.24
Total CTs		4,709	16,597,290	3.52	164,900,861	35.02
w/o Buck (CC and CT mixed partial 2011)		4,018	16,129,468	4.01	82,521,518	20.54
modern CTs only	1999	3,649	15,508,290	4.25	81,257,785	22.27

The peak credit subtracted from coal and nuclear plants is thus $44.65 per kW (return and taxes of $22.27, O&M of $4.25, and $18.13 worth of fuel at a 5% capacity factor).

Coal and nuclear plant costs are given below – first capital costs and then O&M and estimated return, taxes, and depreciation (calculated in the same way – 3% of gross plant plus 10% of net plant). As is evident, the coal

1 and nuclear plants have fixed costs (non-fuel plus return) of $81.47 per kW
2 and $190.16 per kW respectively.
3 We analyzed hydro generation in the aggregate with a simplified
4 method. Pumped storage was assumed to be demand-related and
5 conventional hydro was treated as 50% energy and 50% demand without a
6 thermal plant offset, because some of it runs at relatively low capacity
7 factors.
8 We did not analyze the Buck combined cycle (because it does not have
9 an operational history and because it is so much newer than other
10 generation and would need inflation adjustments as a result). By doing so,
11 we left the combined cycle using a fixed-variable method. We do not
12 believe that these methods are necessarily correct, but the bulk of any
13 changes to cost classification under peak credit would come from coal and
14 nuclear generation.

Table 11: Capital Cost and Depreciation Reserve of Baseload Generation

						$/kW		
Fossil Steam	**In Service Year**	**Gross Plant**	**Estimated Reserve**	**Net Plant**	MW	gross plant	reserve	net plant
Dan River	1949	20,779,455	28,755,246	(7,975,791)	1,159	18	25	(7)
Allen	1957	1,021,098,859	361,764,400	659,334,460	1,155	884	313	571
Belews Crk	1974	1,803,737,718	968,003,663	835,734,055	2,160	835	448	387
Buck	1953	159,874,300	101,872,191	58,002,108	1,157	138	88	50
Cliffside	1972	903,262,731	158,389,705	744,873,026	571	1,582	277	1,305
Lee	1951	161,331,847	102,891,819	58,440,027	355	454	290	165
Marshall	1965	1,321,627,431	762,303,615	559,323,816	1,161	1,138	657	482
Riverbend	1952	248,175,641	235,967,366	12,208,275	466	533	506	26
Total		**5,619,108,527**	**2,691,192,759**	**2,927,915,768**	8,184	687	329	358
Nuclear								
Catawba	1985	799,751,301	374,746,028	425,005,273	464	1,724	808	916
McGuire	1981	2,543,415,890	1,392,726,594	1,150,689,296	2,441	1,042	571	471
Oconee	1973	2,427,490,241	911,430,295	1,516,059,946	2,667	910	342	569
Total	1978	**5,770,657,432**	**2,678,902,917**	**3,091,754,515**	5,571	1,036	481	555

Table 12: O&M and Fixed Costs of Baseload Generation

						Estimate of Return, Tax, Depr.	
			non-fuel O&M		non-fuel	10% of net plant + 3% of gross plant	
Fossil Steam	**In Service Year**	MW			$/kW-yr	$	$/kW-yr
Dan River	1949	1,159	7,920,522		6.83	(174,195)	$ (0.15)
Allen	1957	1,155	35,135,013		30.42	96,566,412	$ 83.61
Belews Crk	1974	2,160	56,402,009		26.11	137,685,537	$ 63.74
Buck	1953	1,157	7,074,432		6.11	10,596,440	$ 9.16
Cliffside	1972	571	26,117,221		45.74	101,585,185	$ 177.91
Lee	1951	355	9,264,136		26.10	10,683,958	$ 30.10
Marshall	1965	1,161	63,716,108		54.88	95,581,205	$ 82.33
Riverbend	1952	466	7,939,167		17.04	8,666,097	$ 18.60
Total		8,184	205,648,086		25.13	461,364,833	$ 56.37
Nuclear							
Catawba	1985	464	43,198,596		93.13	66,493,066	$ 143.35
McGuire	1981	2,441	249,581,449		102.26	191,371,406	$ 78.41
Oconee	1973	2,667	284,309,999		106.62	224,430,702	$ 84.16
Total	1978	5,571	577,090,044		103.59	482,295,174	$ 86.57

The results are summarized below. The modified peak credit proposed here, which includes $18.13/kW of fuel as demand-related to offset the fixed costs of baseload plants, classifies 62% of baseload plants (45% of coal generation and 77% of nuclear generation) and 50.2% of the DEC system as energy-related.

1 **Table 13: Calculation of Energy and Capacity Cost for Generation**

		fixed cost	fixed cost
	MW	$/kW-year	$'000
Total Coal	8,184	$ 81.50	$ 667,013
Peaker cost including 5% 2011 energy	8,184	$ 44.65	$ (365,416)
Gross energy-related cost	8,184	$ 36.85	$ 301,597
Total Nuclear	5,571	$ 190.16	$ 1,059,385
Peaker cost including 5% 2011 energy	5,571	$ 44.65	$ (248,749)
Gross energy-related cost	5,571	$ 145.51	$ 810,636
Total baseload	13,755	$ 125.51	1,726,398
Peaker cost including 5% 2011 energy	13,755	$ 44.65	$ (614,165)
Energy-related baseload	13,755	$ 80.86	$ 1,112,233
Less Actual CT fuel 2011-12 (demand-related offset)			(39,563)
Net Energy-related baseload plant with CT fuel offsets			1,072,670
% of baseload fixed cost plant energy-related			62.1%
50% of conventional hydro fixed cost to energy			48,814
Total energy-related classification			1,121,484
Fixed production plant (Stillman Exhibit 2)			2,136,256
approximate % energy-related			52.5%

2

3

By comparison to the modified method I recommend here, a raw peak credit method (without fuel) would classify approximately 79% of the non-fuel costs of baseload plant as energy-related and would results in 64% of the DEC system as being energy-related. Thus, calculations made to assure that high load factor customers do not overpay for peaker fuel reduces the energy classification by 14 points.

Q. HOW DO YOU PROPOSE TO ALLOCATE COSTS GIVEN THIS INFORMATION?

A. I propose to allocate 52.5% of the generation non-fuel costs by energy and 47.5% by demand. In addition, since I classified all combustion

1 turbine fuel as demand-related through offsetting other energy related
2 costs, for consistency, I treated fuel oil inventory as demand-related also.
3 I use the summer peak demand because it is available, even though I
4 do not believe that SCP is a good method, particularly, since (as DEC's
5 own data show) a shift of 300 MW and a shift of an hour later in the day
6 could change the residential allocation by 9 percentage points (from the
7 July 2011 value to the June 2012 value).[38] Because of the instability of
8 this method and its failure to recognize that the potential for loss of load
9 extends beyond any single peak hour, I would have preferred to use a
10 broader capacity method using hourly data to assign capacity costs to
11 customer classes. Either a Loss of Load Probability analysis or a peak
12 capacity allocation factor (PCAF) that assigns some weight to all hours in
13 excess of 80% of peak demand (diminishing as demand falls from 100%)
14 would have been more reasonable than SCP.
15 There were 504 hours within 80% of the system peak load. A PCAF
16 based on 80% of system load would have a few winter hours in the Test
17 Year, but most of the hours would be in the summer. In general, we were
18 able to determine that PCAF would have moved some costs to the
19 residential and lighting classes from the general service and small
20 industrial classes without affecting the optional class significantly relative

[38] Calculated from NC WARN DR 1-3.

to SCP. We can take that point into account judgmentally in the final recommendation on revenue allocation.

Q. WILL YOU DISCUSS THE JURISDICTIONAL ALLOCATION?

A. There is no reason why the jurisdictional allocation and the class allocation must mirror each other. I am aware of utilities where they do not match. I accept DEC's jurisdictional allocation so I neither trap nor double-recover costs, while applying the 47.5-52.5 production demand-energy allocation only to North Carolina jurisdictional loads.

Q. WHAT IS THE EFFECT OF USING THE 47.5-52.5 DEMAND-ENERGY ALLOCATION FOR GENERATION BASED GENERALLY ON THE PEAK CREDIT METHOD?

A. I prepared a cost of service study using DEC's revenue requirement for comparability and an equalized rate of return for all North Carolina customer classes as the starting point of my analysis. Under these assumptions (which I do not support but use only for comparability), the residential class revenue responsibility would be reduced by $54 million, from $2,362 million to $2,308 million.

Q. IF THE COMMISSION DOES NOT ADOPT YOUR DEMAND-ENERGY ALLOCATION, DO YOU STILL RECOMMEND ANY CHANGES?

1 A. Yes. I recommend that Accounts 512 and 513 (boiler and electric
2 maintenance for steam plants) and 530 and 531 (reactor and electric
3 maintenance for nuclear plants be classified as energy-related, consistent
4 with NARUC's analysis and consistent with a number of other utilities
5 including Entergy in various states and other Texas utilities. Classifying
6 these costs as energy-related would classify 30.4% of production O&M
7 expenses ($166 million) as energy-related based on 2011 FERC Form 1
8 data by individual production O&M account.

9 **Q. ARE YOU AWARE OF ANY OTHER STATES WHICH USE A**
10 **PEAK CREDIT OR OTHER ENERGY-RELATED METHOD FOR**
11 **ALLOCATING GENERATION COSTS?**

12 A. Yes. A number of other states with which I am familiar do so. The
13 peak credit method is used in Idaho, Washington, and Oregon, as well as
14 by Northern States Power (NSP) in Minnesota and the Dakotas, and by
15 Otter Tail Power and Minnesota Power in Minnesota. The Colorado PUC
16 requested a peak credit study in Public Service Company of Colorado's
17 next rate case.[39] The average and peak method is used in for NSP's
18 Wisconsin and northern Michigan jurisdictions, as well as in Arkansas

[39] NSP provided a very good description of generation cost allocation methods in its jurisdictions in the following document filed in Minnesota. http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/MN-Rate-Case-2013/vol-2C-2.pdf

since the mid 1980s. California and Nevada have used marginal costs, with a combustion turbine for capacity and marginal energy costs, for nearly 30 years. Wyoming uses 75% demand and 25% energy. A number of other states that I do not mention have retail competition, so that the classification of costs between energy and demand is not an issue.

Q. WILL YOU IDENTIFY THE PRINCIPAL CRITICISMS OF A PEAK-ORIENTED METHOD RAISED IN DEC'S TESTIMONY?

A. First, DEC suggests that high load factor customers are paying for too much expensive energy, and that this is a mismatch with their low payments for expensive capacity. Second, DEC suggests that an energy allocation of plant, including baseload plant, would promote too much usage in the summer and too little in the winter.

Q. UNDER YOUR METHOD, ARE HIGH LOAD FACTOR CUSTOMERS PAYING FOR TOO MUCH EXPENSIVE ENERGY AND TOO MUCH EXPENSIVE CAPACITY?

A. No, for two reasons. First, the methodology that I use assigns all existing combustion turbine generation to demand and uses an offset of combustion turbine energy as a 5% capacity factor to my energy classification. Therefore, I am addressing the issue.

Second, the hourly data that DEC finally provided to us allows this point to be refuted. I multiplied the avoided energy cost (4.29 cents/kWh on-peak and 5.37 cents/kWh off-peak) by the loads for each class. With the exception of streetlighting, the avoided energy cost class revenue responsibility is within a few hundredths of a point of the MWh revenue responsibility in all customer classes.[40] The biggest divergence is streetlighting.

Even avoided energy plus capacity costs – essentially a marginal generation cost study - shows residential at 38.35% - compared to the 40.02% that results from my modified peak credit methodology.

Table 14: Class Allocations by kWh, Avoided Energy Costs, and Avoided Energy and Capacity Costs

			Residential	GS	Industrial	Optional	Lighting
	MWh		21,892,083	9,275,731	1,954,204	24,576,048	770,918
	%		37.44%	15.86%	3.34%	42.03%	1.32%
Avoided Energy Cost $'000			986,665	419,998	89,423	1,103,417	33,430
			37.47%	15.95%	3.40%	41.91%	1.27%
Avoided Cost Study							
Avoided Capacity and Energy			$ 1,298,944	$ 550,403	$ 116,850	$ 1,385,578	$ 35,192
	%		38.35%	16.25%	3.45%	40.91%	1.04%

Therefore, it is just plain wrong to argue that energy and capacity costs are mismatched if some generation plant is allocated to energy - particularly given my assignment of combustion turbine costs as demand-related.

[40] This analysis does not explicitly include line losses but only measures the effect of differences in load shape.

Q. WILL YOU DISCUSS THE CONCERN THAT WITHOUT SCP, CUSTOMERS WILL USE TOO MUCH POWER IN THE SUMMER MONTHS?

A. First, DEC's avoided cost calculations show DEC's avoided capacity costs (at distribution voltage) are about $86/kW-year, of which $18 (27% of it) is in the non-summer months. Moreover, the summer peak hours are 8 hours per day under Option B (1 pm to 9pm), with 7 winter peak hours (6 am to 1pm). There are 697 summer hours at 9.7 cents/kWh and 1215 winter peak hours at 1.5 cents/kWh. These costing periods bear no resemblance to a single peak hour.

Second, the avoided capacity costs in total, based on a CT are $86 per kW-year and $68 in the summer. To charge far more than that to the summer peak hour, based on embedded costs, will move too many costs out of the summer peak period and artificially encourage energy-intensive loads like electric heat and data centers.

II.C. Reject DEC's Minimum System

Q. HAVING ASSIGNED PLANT TO JURISDICTIONS BY WHERE IT IS LOCATED, HOW HAS DEC CLASSIFIED DISTRIBUTION PLANT AS CUSTOMER-RELATED AND DEMAND-RELATED?

1 A. DEC has classified substation (Account 362) and has classified

2 services (Account 369) and meters (account 370) as customer-related.

3 After directly assigning a portion of costs in Accounts 364-367, largely to

4 lighting classes, DEC has classified the remaining plant in FERC

5 Accounts 364-368 as partially customer-related and partially demand-

6 related using the following percentages:[41]

7 **Table 15: Poles and Lines**

Account 364 (poles)[42]	0% demand, 100% customer
Account 365 (overhead wires)	10.88% demand, 89.12% customer
Account 366 (underground conduit)	100% demand, 0% customer
Account 367 (underground wires)	100% demand, 0% customer
Subtotal 364-367	58.03% customer, 41.97% demand
Account 368 (line transformers)	30.63% customer, 69.37% demand

8 The reason for DEC's results is that DEC develops a minimum system as

9 if all underground lines were minimum sized overhead lines, so that the

10 real number to look at is the subtotal of 58% customer and 42% demand

11 for accounts 364-367.

12 DEC used what it calls a "skeleton system" but in its response to NC

13 WARN DR 1-44, which requested ALL workpapers supporting the

14 customer/demand split for Accounts 364-368, DEC failed to provide

[41] Calculated from NC WARN DR 1-44.

[42] After directly assigning about 7% of poles, mainly to streetlighting.

1 anything explaining how it calculated the cost of the "skeleton system" in
2 dollars per mile, what poles, wires, and transformers were used. All that
3 DEC told us was that it cost approximately $34,000 per mile, $17,357 for
4 poles, $13,504 for wires, and $3,244 for transformers. Everyone served at
5 distribution voltage gets the same piece of the "skeleton" – in this case
6 about 213 feet of distribution line, with associated poles and
7 transformers.[43]

8 Q. **IS A CUSTOMER CHARGE FOR ACCESS TO FACILITIES USED**
9 **IN INDUSTRIES ASIDE FROM UTILITIES?**

10 A. No. Stores do not charge "access" charges for use of facilities that do
11 not vary with what a customer buys. They charge for these costs of doing
12 business as part of their charges for goods and services.[44]

13 **Q. WHAT ARE THE ANALYTICAL PROBLEMS WITH THE**
14 **MINIMUM SYSTEM METHOD?**

15 A. First, it equates the costs of spanning the system's area with customer
16 costs. However, this is a leap of faith. The correlation between area and
17 the number of customers is relatively weak (except in fairly uniform and
18 highly rural service areas). The distribution wires per customer required

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[43] 76,721.27 miles of minimum system X 5280 feet/mile divided by 1,897,919 distribution customers excluding lighting = 213.44 feet.

[44] A few chains (Costco, Sam's Club) have adopted a membership model where customers pay a fixed fee in exchange for discounted prices when they use the store, but those entities are offering a voluntary choice to the customer.

1 to serve an apartment building are considerably less than the wires
2 required to serve a house on acreage or a school or shopping center on a
3 square block or more.
4 More importantly, if one could hypothesize such a concept as serving
5 customers without a significant demand, the area would not be served at
6 utility expense. Most utilities' line extension rules provide that service is
7 extended at utility expense based on the revenue to be generated from
8 that service (either explicitly or implicitly – as with a dollars-per-
9 customer allowance based on class average revenue). If revenue is not
10 adequate, service is only extended at the cost of the applicant. Thus,
11 fundamentally, the expansion of the distribution system as it is actually
12 built is driven by demand, not the mere existence of customers.
13 Second, assignment of an equal amount of the minimum system to
14 each individual customer makes no sense. A large store with street
15 frontage on an entire block would clearly need more feet of wire (and
16 more poIes if served from overhead) to connect it than would each of
17 fifty individual residential customers in an apartment building on the
18 same sized block. Yet under DEC's proposal each apartment dweller
19 would be assigned the same 213 feet of the minimum system as the store,
20 not one-fiftieth as much. A related failing of the minimum system can be
21 examined when we look at a primary distribution line connecting two

1 towns in a rural area of the system. That line is necessary to serve
2 demand in those communities. The same connection would be needed
3 just as much if there were one industrial customer located at the
4 connection point with a demand equal to the whole town's demand as if
5 there were 1,000 residential and small commercial customers. Yet the
6 DEC method would charge the hypothetical industrial customer 0.1% as
7 much as the hypothetical 1000 small customers.
8 Second, the minimum system method double-counts the costs of
9 serving low-use customers, both across customer classes for cost
10 allocation and within customer classes if used for rate design.
11 In a nutshell, the analytical problem arises because even a skeleton
12 minimum system method often develops a hypothetical utility system
13 made up of poles, wires, and transformers that can carry a significant
14 amount of demand. The minimum system is assigned to all customers in
15 the case of DEC based on an equal number of dollars per customer. If
16 that is done, then it is wrong to allocate the remaining demand-related
17 portion of the system by the total system demand. Analytically, if the
18 minimum system is used as a customer cost, it would be necessary to use
19 a demand allocator that would give each customer class credit for that
20 portion of the demand (an equal number of kilowatts per customer) that
21 can be carried by the minimum system.

1 Small customers are overcharged by DEC's method, which does not
2 include any credit for the demand carried by the minimum system,
3 because the minimum system carries a much larger percentage of the
4 demand of residential customers than it does of the demand of large
5 customers.

6 **Q. HAVE YOU BEEN ABLE TO ANALYZE THE MINIMUM SYSTEM**
7 **IMPACTS FOR POLES AND CONDUCTORS?**

8 A. Yes. For poles and conductors, a number of technical factors come
9 into play. The carrying capacity of the minimum sized poles and
10 conductor is dependent on a number of factors including line length,
11 reactive power, and the specific voltage of primary distribution lines.
12 Nevertheless, from data provided in NCWARN DR 1-45, it appears that
13 DEC's smallest single-phase primary overhead conductor could carry
14 2085 kVA (139 amps X 15 kV), which is a significant portion of the
15 demand of a local area. Moreover, had DEC conducted a zero intercept
16 statistical study[45] of overhead conductor, the cost of a zero-amp
17 conductor would not be statistically different than zero. In other words,
18 all costs are demand-related. Similarly, the cheapest underground
19 conductor carries 2550 kVa at 15 kV. Calculations from data in

[45] A "zero intercept" study is a regression analysis relating cost of conductor or other equipment to a constant and the size of the equipment. It essentially attempts to find the cost of a component of zero size. It has somewhat less analytical problems than a minimum system and generally produces lower customer percentages.

1 NCWARN DR 1-47 would yield a zero intercept value consistent with

2 100% demand for poles.

3 **Q. ARE YOU MAKING NEW ARGUMENTS WHEN YOU RAISE**

4 **THESE ISSUES?**

5 A. My views on this topic are by no means new or path-breaking.

6 Serious critiques of the minimum system method date back almost 40

7 years. Professor Bonbright recognized the inaccuracies of treating

8 minimum system costs as customer costs in his **1961** edition of Principles

9 of Public Utility Regulation.[46] His preferred option was to recognize that

10 minimum system costs were neither demand nor customer costs but were

11 unallocable. (See Exhibit WBM -7) He adds:

12 And this is the disposition that it would probably receive in an estimate
13 of long-run marginal costs. But the fully distributed cost analyst dare not
14 avail himself of this solution, since he is the prisoner of his own
15 assumption that "the sum of the parts equals the whole." He is therefore
16 under impelling pressure to "fudge" his cost apportionment by using the
17 category of customer costs as a dumping ground for costs that he cannot
18 plausibly impute to any of his other cost categories.
19
20 A seminal *Public Utilities Fortnightly* article written 30 years ago by

21 George Sterzinger provides a further clear exposition of the problems

22 with the minimum system method. I am attaching a copy of the article

23 as Exhibit WBM-8. Dr. Sterzinger not only opposed use of the minimum

24 distribution system method because of the confusion of area and

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46 The current edition, revised by others after his death, omits this criticism.

customer costs, but he was the first to bring to the forefront the significant criticism that the minimum system method clearly overcharges small customers, because the minimum system can carry a significant portion of the residential class's demand.

Q. HAVE ANY OTHER STATE COMMISSIONS EXPLICITLY REJECTED THE MINIMUM SYSTEM METHOD WHEN IT WAS PRESENTED TO THEM BY A UTILITY?

A. Yes. A number of Commissions across the country have rejected the minimum system method or required other methods, many starting as long as 30 years ago. The Washington Utilities and Transportation Commission (WUTC) has rejected the minimum system method since 1983. In a Washington Water Power case in that year, the Commission made the following statement:

> The Commission rejects the company's use of the zero-intercept method. The minimum system method, of which the zero-intercept method is a variant, is also rejected. Both methods are likely to lead to the double allocation of costs to residential customers and over allocation of costs to low use customers.[47]

When the minimum system method cropped up in Washington in later cases, the Commission again rejected it. In a 1989 case involving Puget Sound Power and Light, the Commission order stated:

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[47] Washington Utilities and Transportation Commission, Cause U-83-26, Fifth Supp. Order, P. 33

In this case, the only directive the Commission will give regarding future cost of service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum sized system is not. The parties should not use the minimum system approach in future studies.[48]

The minimum system reappeared in the testimony of industrial intervenors in a Puget case in 1992, and the Commission not only rejected it but stated that parties should stop bringing it up altogether.

The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals.[49]

The Arkansas PSC has not classified any costs in Accounts 364-368 as customer-related since at least 1984 for Entergy Arkansas (formerly Arkansas Power and Light) and has since applied that philosophy to the three other investor-owned electric utilities that it regulates, while allowing deviations for rural cooperatives. The Illinois Commission

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48 WUTC, Cause U-89-2688-T, Third Supp. Order, P. 71

49 WUTC, Docket No. UE-920499, Ninth Supp. Order on Rate Design, P. 11

1 rejected the minimum system method in 1989 in its order in consolidated
2 Docket 87-0695 involving Illinois Power.[50] It has subsequently continued
3 to do so.[51] The Public Utilities Commission of Texas and the Maryland
4 Public Service Commission (at least for Potomac Electric Power Corp.
5 and Baltimore Gas and Electric) have consistently treated all costs in
6 Accounts 364-368 as demand-related for over 12 years.
7 Even some utilities that include a customer component in some
8 portions of Accounts 364-368 do not come up with the relatively extreme
9 customer allocations proposed by DEC. The California PUC treats
10 transformers as customer-related (with higher costs for larger customer
11 classes reflecting larger sized transformers and reflecting that more
12 customers are connected to each transformer among residential and small
13 business customers). However, it has consistently not used a minimum
14 system method for primary distribution. The last time such a method

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[50] Illinois Commerce Commission Order in Dockets 84-0055, 87-0695 and 88-0256 (consolidated), mimeo at page 218.

[51] Illinois Commerce Commission Order in Docket 07-5666 (September 9, 2008) page 208. http://www.icc.illinois.gov/docket/files.aspx?no=07-0566&docId=128596 The order was subsequently reheard, but rehearing was denied. It was then appealed in court, but only one narrow rate design issue (regarding an electric heating rate for non-residential customers) was part of the appeal. The minimum distribution system was not appealed. The rate design portion of the appeal was denied. See Opinion filed September 30, 2010 in Second District Court of Appeals Docket 2-08-0959 and consolidated cases. http://www.icc.illinois.gov/docket/files.aspx?no=07-0566&docId=156430 .

1 was brought forward in California in a litigated case was 1988, when it
2 was rejected for San Diego Gas and Electric Company.[52]
3 The Iowa Utilities Board treats all of Accounts 364-367 as demand-
4 related and has a minimum amount only in Account 368 for transformers
5 based on a 10 kVa transformer and the number of customers per
6 transformer in each class. The Public Utilities Commission of Nevada
7 uses a marginal cost method that treats feeder lines (all but the small
8 portion of primary distribution costs associated with line extension) as
9 demand-related, and uses a measure based on actual costs charged to the
10 utility in each class (not equal dollars per customer) for line extension
11 facilities costs (services, transformers and a small amount of primary
12 distribution). Amounts charged to developers are excluded from
13 marginal cost.
14 **Q. WHAT DO YOU RECOMMEND?**
15 A. I recommend that this Commission treat 100% of Accounts 364-368
16 (overhead and underground line accounts and line transformers) as
17 demand-related. Customers served at primary voltage would not pay for
18 transformers. In the alternative, the customer cost should be assumed to
19 be 25% as great as DEC recommends. This method would assign as

[52] California Public Utilities Commission Decision No. 88-12-085. 30 CPUC 2d 299 at 318.

customer-related slightly over 50 feet of the "skeleton" (minimum cost to connect, not the entire system), which would reduce DEC's customer-related percentage by from 58.03% to 14.51%.

Q. HAVE YOU ALSO PROPOSED TO CHANGE THE ALLOCATION OF DISTRIBUTION EXPENSES?

A. Yes. Both DEC and I make the generally reasonable assumption that the expenses follow the plant, and if my recommendations are adopted my figures, with O&M following the plant, are reasonable.

However, if the Commission does not adopt my recommendation to change the allocation of plant, this case is an exception where expenses should not follow plant because of the mechanics of the DEC minimum system method. If it were to retain DEC's plant allocation, the Commission should still assign all of Accounts 583, 584, 593, and 594 by the sum of all of DEC's allocations to 364-367 (58% customer and 42% demand). The reason is that DEC substituted non-existent overhead lines for underground in its minimum system calculations. As a result DEC classifies as customer-related 100% of a very large number of tree-trimming and other overhead line expense dollars ($51 million) in Account 593. This is unreasonable, because the only reason that the entire amount is assumed to be customer related is that non-existent overhead lines are used to allocate underground distribution costs, which

1 ends up getting rid of any demand-related component of vegetation
2 management. The result is that DEC ends up overclassifying the tree
3 trimming associated with real distribution lines to the customer
4 component. The allocation of 58% customer and 42% demand for all four
5 of these accounts would reduce residential expenses by about $8 million.
6 This alternative should be adopted if the Commission does not adopt my
7 primary recommendation.

8 SECTION III -- CUSTOMER SERVICE, INFORMATION 9 AND SALES AND MARKETING EXPENSES

10 *III.A. Major Account Representatives*

11 **Q. WHAT IS A MAJOR ACCOUNT REPRESENTATIVE?**

12 A. A major account representative is a utility staffer who provides
13 services either to large customers or to national chains. Most utilities,
14 including DEC have them. DEC spends $9.5 million on them, according
15 to NC WARN DR 1-94. The table below shows the amount that DEC
16 spends by FERC0 Account.

1 **Table 16: Costs of Major Account Representatives by FERC Account[53]**

FERC Account	Labor	Non-Labor	Total
107	6,106	84,135	90,240
108		(12,276)	(12,276)
121	-	-	-
122		-	-
142		-	-
182		-	-
183		-	-
237		-	-
242	-	-	-
408	432,062		432,062
417	-	-	-
426	-	-	-
454		(6,364)	(6,364)
456		(9,074)	(9,074)
524		31	31
547		20,781	20,781
553	1,701	21,096	22,797
557	454,381	659,416	1,113,796
566		6	6
588		101	101
593	1,328	42,263	43,591
804		-	-
903	225,774	(33,582)	192,191
904		(3,181)	(3,181)
910	5,270,545	752,463	6,023,008
913		16,581	16,581
920	10,057		10,057
921	-	1,057	1,057
924		30	30
926	1,373,763		1,373,763
929	(90,604)		(90,604)
930		845	845
931		157,274	157,274
935		99,496	99,496
Total	7,685,112	1,791,098	9,476,211

2

3 About $78,000 is capitalized in Accounts 107-108, and $1,114,000

4 is included in generation Account 557, from which it is reclassified to

5 energy efficiency (NC WARN DR 2-24). The remainder is largely in

[53] NC WARN DR 1-94

customer service and information Account 910 and customer accounting Account 903 (which total over $6.2 million), and administrative overhead accounts including staff benefits and payroll taxes (920-935 plus 408).

In response to data request NC WARN 1-95, DEC states:

Major Account "Representative" assignments are generally determined by size, and incorporate a heterogeneous group of commercial, governmental, and industrial customers that have accounts in the following rate classes: General Service, Lighting, Industrial, and OPT. Furthermore, a unique customer may have multiple accounts spanning different rate classes (i.e. a large retail customer might have a main building served under OPT, a separate outparcel account served under General Service, and a separate exterior lighting account served under Lighting). Issues vary widely by customer and are not consistent over time. Thus, no attempts have been made by the Company to estimate the approximate percentage of time by rate class."

Q. WHY IS THE COST ALLOCATION OF MAJOR ACCOUNT REPRESENTATIVES AN ISSUE?

A. One of the most common errors made by utilities in electric and gas cost of service studies is the blind allocation of all costs in the CS&I and sales and marketing areas by number of customers, without reference to the activities that are actually undertaken in these accounts. The result of these allocation practices is to make small customers pay for the costs of these staffers whose job is to provide services to large customers. DEC is misallocating millions of dollars so that residential customers can pay for services provided to non-residential customers, making a mockery of cost causation in this area.

1 Non-residential customer classes are not being charged a fair share of
2 major account representatives who serve them. Even though there is
3 about $6,023,000 of major account representative costs in Accounts 910
4 (of which about three-fourths would be allocated to the North Carolina
5 jurisdiction), for example, the total amount of costs allocated to all non-
6 residential classes larger than small general service in this account is
7 $422,000 – less than 10% of the cost of servicing large customers. In
8 essence, residential and small commercial customers are paying for
9 services provided to large commercial and industrial customers.
10 Similarly, there is $192,000 in major account representative costs in
11 Account 903 (customer billing and records).
12 **Q. WHAT IS YOUR RECOMMENDATION?**
13 A. I recommend that the Commission consider removing the cost of
14 major account representatives from Accounts 903, 910 and 913 and
15 allocating them exclusively to non-residential customers.[54] I assign only
16 5% to the small general service class to recognize that ordinary small
17 business SGS customers do not receive these services. Only SGS
18 customers affiliated with larger customers (e.g., extra sites, chains and
19 franchises, government agencies) receive them. The remaining 95%

[54] For ease of implementation, I included all of these costs as a single adjustment to account 910, given that it contains 97% of the reclassified costs and accounts 903 and 916 +are also customer-related.

would be assigned to LGS, Industrial, and Optional based 50% on throughput and 50% based on customers. Even if a different allocation is used, residential should not be assigned a dime of these costs, because DEC admits in its response to DR 1-95 that residential customers are not served by Major Account Representatives.

Q. WHAT WOULD BE THE IMPACT OF THIS CHANGE?

A. It would reduce O&M expenses assigned to the North Carolina residential class by $6.2 million (including A&G overheads) with increases to the non-residential classes. It also reduces the residential rate base by about $4.5 million for a further reduction in return and taxes of about $0.5 million.

III.B. Sales, Marketing, and Economic Development Costs

Q. WHAT IS THE ISSUE RELATED TO COST ALLOCATION FOR SALES, MARKETING, AND ECONOMIC DEVELOPMENT?

A. DEC includes economic development in Account 908140 of $1,031,000 (NC WARN DR 1-84). Marketing and sales expenses are included in Accounts 911-913 and are $1,686,000, mostly for advertising expenses. All of these costs are allocated by number of customers, assigning residential customers about 86% of the costs.

Q. WHY IS THIS ALLOCATION UNREASONABLE?

1 A. Both economic development and sales and marketing costs are policy
2 driven costs that are undertaken to provide benefits. The increased sales
3 due to economic development (new customers or new sales to existing
4 customers) and due to marketing benefit electric ratepayers in theory by
5 generating profits for the utility that reduce, postpone and/or reduce the
6 size of future rate cases. Residential customers do not receive a
7 proportionate benefit from these activities, if successful.

8 **Q. ARE YOU AWARE OF ANY UTILITIES THAT HAVE CHOSEN**
9 **NOT TO USE A CUSTOMER-BASED ALLOCATOR FOR**
10 **ECONOMIC DEVELOPMENT AND SALES AND MARKETING**
11 **EXPENSES?**

12 A. Yes. Entergy Arkansas uses a gross plant allocator.

13 **Q. WHAT IS YOUR RECOMMENDATION FOR THESE COSTS?**

14 A. I recommend that they be allocated to customer classes by base rate
15 revenue, which tracks the benefits that customers should receive if
16 programs are successful.[55]

17 **III.C. Other Customer Service and Information Costs**

18 **Q. HAVE YOU CHANGED THE TREATMENT OF ANY OTHER**
19 **CUSTOMER SERVICE AND INFORMATION COSTS?**

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[55] I use current base rate revenue as the allocator to prevent problems from spreadsheet circularity.

1 A. Yes. As noted in the revenue requirement section above, after making
2 an adjustment to the revenue requirement, I reclassified the remaining
3 costs of survey research from Account 910 to A&G accounts. These costs
4 provide information to management and do not directly provide services
5 or information to customers. They are thus overhead expenses which
6 DEC used to assign to the right FERC account (923, Outside Services)
7 through 2009. However, DEC changed its mind in 2010 and has since
8 assigned them to an inappropriate account, where 86% of the costs go to
9 residential customers.

10 **Q. HAVE YOU CHANGED THE ALLOCATION OF A&G**
11 **EXPENSES?**

12 A. I made only one change in methodology, to remove uncollectible
13 accounts expenses when calculating O&M expenses that are used to
14 allocate A&G. Some of the A&G is salary-related and other is related to
15 O&M. DEC's calculations included uncollectible accounts expenses in
16 customer accounts expenses when making its calculations of O&M
17 expenses to allocate A&G. These costs are clearly not salary-related, and
18 a book entry for bad debt requires little or no administration. Therefore,
19 just as fuel and purchased power are removed when calculating A&G
20 allocations, so too should uncollectible accounts expenses be removed.

Other than this change, my A&G expense allocation is different from DEC's expenses only because underlying costs are different, not from any other methodological differences in how to make the various calculations.

SECTION IV – SUMMARY OF RECOMMENDED COST ALLOCATION

Q. BASED ON YOUR TESTIMONY ABOVE, HAVE YOU SUMMARIZED THE RESULTS OF YOUR RECOMMENDED COST ALLOCATION?

A. Yes, in the table below. The cost allocation is calculated based on DEC's revenue requirement and an equalized rate of return for all customer classes (before considerations of deviation from the cost of service as modeled) to show the impacts on a comparable basis. I do not recommend DEC's revenue requirement but use it only for comparability.

NC WARN allocates $149 million less for residential customers (a 6.3% reduction from DEC's cost of service estimate) with increases for lighting and optional customers.

Exhibit WBM-9 shows somewhat more detail, and the actual cost study is contained in my workpapers.

Table 17: Comparison of NC WARN and DEC Cost of Service Studies at Equalized Rate of Return

	System	North Carolina	Residential	GS	Lighting	Industrial	Optional
NC WARN COST OF SERVICE STUDY							
TOTAL O&M EXPENSE	3,586,910	2,498,126	1,071,928	395,508	43,577	81,881	904,286
TOTAL DEPRECIATION EXPENSE	1,055,547	795,047	354,460	129,803	23,996	29,135	257,393
TOTAL OTHER TAX & MISC EXPENSE	384,963	309,938	142,038	52,414	9,464	10,390	95,518
RETURN ON RATE BASE	1,343,707	975,129	435,287	156,940	36,264	35,200	311,112
NET INCOME TAX	620,000	457,549	203,922	73,808	16,611	16,573	146,484
INTEREST ON CUSTOMER DEPOSITS	6,164	5,456	4,748	510	61	7	130
TOTAL AMORTIZED ITC	(6,550)	(4,359)	(1,812)	(740)	(58)	(171)	(1,578)
COST OF SERVICE	6,990,741	5,036,886	2,210,570	808,243	129,915	173,015	1,713,344
DUKE COST OF SERVICE STUDY							
TOTAL O&M EXPENSE	3,586,910	2,497,614	1,128,064	403,959	37,134	83,848	843,459
TOTAL DEPRECIATION EXPENSE	1,055,547	794,786	385,048	136,228	19,951	30,793	222,375
TOTAL OTHER TAX & MISC EXPENSE	384,963	309,603	148,220	53,446	8,709	10,581	88,503
RETURN ON RATE BASE	1,343,707	975,129	475,400	164,167	31,425	36,675	266,937
NET INCOME TAX	620,000	457,549	222,729	77,358	14,286	17,360	125,575
INTEREST ON CUSTOMER DEPOSITS	6,164	5,456	4,748	510	61	7	130
TOTAL AMORTIZED ITC	(6,550)	(4,359)	(1,953)	(793)	(32)	(192)	(1,388)
COST OF SERVICE	6,990,741	5,035,778	2,362,256	834,875	111,534	179,072	1,545,591
DIFFERENCE							
TOTAL O&M EXPENSE	0	512	(56,136)	(8,451)	6,443	(1,967)	60,827
TOTAL DEPRECIATION EXPENSE	0	261	(30,588)	(6,425)	4,045	(1,658)	35,018
TOTAL OTHER TAX & MISC EXPENSE	0	335	(6,182)	(1,032)	755	(191)	7,015
RETURN ON RATE BASE	0	0	(40,113)	(7,227)	4,839	(1,475)	44,175
NET INCOME TAX	0	0	(18,807)	(3,550)	2,325	(787)	20,909
INTEREST ON CUSTOMER DEPOSITS	0	0	0	0	0	0	0
TOTAL AMORTIZED ITC	0	0	141	53	(26)	21	(190)
COST OF SERVICE	0	1,108	(151,685)	(26,632)	18,381	(6,057)	167,753
		0.02%	-6.42%	-3.19%	16.48%	-3.38%	10.85%

Q. WHAT IS YOUR RECOMMENDATION FOR CHANGES IN CLASS REVENUE REQUIREMENTS?

A. I recommend that cost of service be used as a guide here. However, it is a very different guide than DEC's cost study which shows residential receiving a larger increase than average. Based on my model, the rate increase for the residential class is well below the system average. Moreover, I would recommend that no class receive a change that differs from the system average rate change by more than 3% or 0.25 cents per kilowatt hour, whichever is greater. There should be lower than average increases for residential, small commercial, and small industrial, and higher than average increases for lighting and optional customers.

Directionally, residential and small commercial should receive about equal percentages below the system average (to reflect generalized information on the difference between PCAF and SCP), but both should be below the system average increase.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes. Although I reserve the right to supplement it if DEC answers certain data requests.