

case, Case No. 9286, “. . . we suspect it will be difficult, if not impossible, for us to unpack *post hoc* any imprudence.”⁷¹¹

Finally, as Montgomery County witness Ostrander pointed out, once tracker mechanisms are in place, they are difficult to remove.⁷¹² The Maryland utilities have been asking us to approve tracker surcharges for reliability plant infrastructure for several years.⁷¹³ If we now deviate from our historic ratemaking principles and allow this GRC tracker, it will be difficult to find a principled way to deny future requests by other Maryland utilities for tracker surcharges for their similar reliability plant infrastructure projects.⁷¹⁴ I do not believe the short term benefit to the limited number of customers served by these 24 feeders is worth trading off the protections of traditional ratemaking principles for all utility ratepayers in Maryland for years to come. Today we are letting the tracker genie out of the bottle, and I fear it will continue granting the wishes of Maryland utilities for many years and we may never get it back in the bottle.

/s/ Harold D. Williams
Commissioner

⁷¹¹ Order No. 85028 , p. 146.

⁷¹² Direct Testimony of Bion C. Ostrander at 21.

⁷¹³ See; Case No. 9286; Case No.9267.

⁷¹⁴ Of course I reserve judgment on both the merits of future project proposals and their method of cost recovery.

APPENDIX I

POTOMAC ELECTRIC POWER COMPANY
CASE NO. 9311

Revenue Requirement
(S000's)

Rate Base	1,183,052
Rate of Return	<u>7.63%</u>
Required Income	\$90,267
Adjusted Income	\$73,995
Income Deficiency	\$16,272
Conversion Factor	<u>1.71361</u>
Revenue Requirement	\$27,883

Rate Base
(S000's)

Per Books Balance	\$1,162,223
Uncontested Adjs.	<u>(9,575)</u>
Uncontested Balance	\$1,152,648
Annualization of T-Y Reliability Closings	12,487
Actual Post-TY (Jan.-Mar. 2013) Reliability Closings	44,993
New Depreciation Rates	4,361
Amort. of 2012 Major Storm 6/29 Derecho	10,292
Amort. 2012 Major Storm – Hurricane Sandy	2,401
AMI Meters	(23,402)
Accenture Project	401
Adj. to Cash Working Capital	<u>(21,129)</u>
Adjusted Rate Base	1,183,052

Operating Income

(\$000's)

Per Books Balance	\$66,548
Uncontested Adj.	<u>668</u>
Uncontested Balance	\$67,216
Annualization of T-Y Reliability Closings (Jan.-Mar. 2013) Reliability Closings	(748) (580)
New Depreciation Rates	8,723
Amort. of 2012 Major Storm 6/29 Derecho	(2,287)
Amort. of 2012 Major Storm Hurricane Sandy	(534)
Uncollectible Write-Offs	(1,031)
3-Year Average AIP Costs	443
Current Rate Case Costs	(37)
Veg. Mgt. in Rate Period	\$2,825
EA&EE	(989)
AMI Meters	542
Employee Activity Costs	89
Average Overtime Expense	\$1,338
SERP	909
Outside Legal Expense	288
Accenture Cost	239
Amort. CN 9214 Expense	121
Operating Income Adjustments	9,311
Interest Synchronization	(55)
AFUDC Offset	<u>(2,477)</u>
Net Operating Income	\$73,995

POTOMAC ELECTRIC POWER COMPANY
Analysis of Proposed Rate Increase - Position by Party
Twelve Months Ended December 31, 2012

	Rate Base					Operating Income					Revenue Requirement					As of 5/20/13				
	Pepco	Staff	OPC	Mont.Civ. ⁵	AOBA ³	Pepco	Staff	OPC	Mont.Civ.	AOBA	Pepco	Staff	OPC	Mont.Civ.	AOBA	Pepco	Staff	OPC	Mont.Civ.	AOBA
Pecco Unadjusted Results, Based on Schedule (LJH-SR)-1	\$ 1,162,223	\$ 1,162,223	\$ 1,162,223	\$ 1,162,223	\$ 1,162,223	\$ 66,548	\$ 66,548	\$ 66,548	\$ 66,548	\$ 66,548	\$ 46,485	\$ 46,485	\$ 46,485	\$ 46,485	\$ 46,485	\$ 46,485	\$ 46,485	\$ 46,485	\$ 46,485	\$ 46,485
Ratemaking Adjustments																				
Uncontested Company-Proposed Ratemaking Adjustments:																				
5 Amortization of 2011 Major Storm Costs	(1,013)	(1,013)	(1,013)	(1,013)	(1,013)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	10,956	10,956	10,956	10,956	10,956	10,956	10,956	10,956	10,956	10,956
9 Amortization of 2011 Major Storm Costs	(68)	(68)	(68)	(68)	(68)	(80)	(80)	(80)	(80)	(80)	128	128	128	128	128	128	128	128	128	128
9 Amortization of OPEB Net Accrual Subsidy Amortization	-	-	-	-	-	5,475	5,475	5,475	5,475	5,475	(9,382)	(9,382)	(9,382)	(9,382)	(9,382)	(9,382)	(9,382)	(9,382)	(9,382)	(9,382)
11 Amortization of MDC Case No. 9286 Rate Increase	-	-	-	-	-	(1,544)	(1,544)	(1,544)	(1,544)	(1,544)	2,646	2,646	2,646	2,646	2,646	2,646	2,646	2,646	2,646	2,646
12 Amortization of Wage Increases	-	-	-	-	-	(207)	(207)	(207)	(207)	(207)	355	355	355	355	355	355	355	355	355	355
12 Reflection of 2013 Employee Health & Welfare Costs	-	-	-	-	-	10	10	10	10	10	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)
14 Reflection of 3-Year Average Auto & General Claim Payments	-	-	-	-	-	1,568	1,568	1,568	1,568	1,568	(2,687)	(2,687)	(2,687)	(2,687)	(2,687)	(2,687)	(2,687)	(2,687)	(2,687)	(2,687)
15 Exclusion of Institutional & Promotional Advertising Expense	-	-	-	-	-	2,690	2,690	2,690	2,690	2,690	(4,610)	(4,610)	(4,610)	(4,610)	(4,610)	(4,610)	(4,610)	(4,610)	(4,610)	(4,610)
16 Exclusion of Executive Incentive Costs	-	-	-	-	-	5	5	5	5	5	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
17 Exclusion of Case No. 9240 Costs	-	-	-	-	-	(201)	(201)	(201)	(201)	(201)	344	344	344	344	344	344	344	344	344	344
18 Inclusion of Customer Deposit Interest & Credit Facility Expenses	-	-	-	-	-	(147)	(147)	(147)	(147)	(147)	252	252	252	252	252	252	252	252	252	252
19 Amortization of MDC Case No. 9286 Rate Case Expense	-	-	-	-	-	(612)	(612)	(612)	(612)	(612)	877	877	877	877	877	877	877	877	877	877
22 Impact of Case No. 9286 Depreciation Rates on ITC Amortization	-	-	-	-	-	229	229	229	229	229	(392)	(392)	(392)	(392)	(392)	(392)	(392)	(392)	(392)	(392)
26 Remove NERC Expense Recorded in FERC Account 581	-	-	-	-	-	(201)	(201)	(201)	(201)	(201)	344	344	344	344	344	344	344	344	344	344
27 Reflection of Final Accounting Close	(6)	(6)	(6)	(6)	(6)	-	-	-	-	-	(1,172)	(1,172)	(1,172)	(1,172)	(1,172)	(1,172)	(1,172)	(1,172)	(1,172)	(1,172)
28 Inclusion of SERP Liability, Net of Tax	(8,489)	(8,489)	(8,489)	(8,489)	(8,489)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Contested Company-Proposed Adjustments:																				
1 Annualization of Test Year Reliability Closings	\$ 12,487	\$ 12,487	\$ 12,487	\$ 12,487	\$ 12,487	\$ (748)	\$ (748)	\$ (748)	\$ (748)	\$ (748)	\$ 3,006	\$ 3,006	\$ 3,006	\$ 3,006	\$ 3,006	\$ 3,006	\$ 3,006	\$ 3,006	\$ 3,006	\$ 3,006
Remove NOLC as Separate Adj. (Test Year)	(6,992)	(6,992)	(6,992)	(6,992)	(6,992)	-	-	-	-	-	(966)	(966)	(966)	(966)	(966)	(966)	(966)	(966)	(966)	(966)
2 Inclusion of Post Test Year Reliability Closings (Jan - Mar 2013)	44,993	44,993	44,993	44,993	44,993	(680)	(680)	(312)	(680)	-	7,208	7,208	3,158	7,208	-	7,208	3,158	7,208	-	-
Remove NOLC as Separate Adj. (Jan - Mar 2013)	(6,517)	(6,517)	(6,517)	(6,517)	(6,517)	-	-	-	-	-	(721)	(721)	-	(721)	-	(721)	-	-	-	-
3 Inclusion of Post Test Year Reliability Closings (Apr - Dec 2013)	123,528	123,528	-	-	-	(1,215)	-	-	-	-	19,143	-	-	-	-	19,143	-	-	-	-
Remove NOLC as Separate Adj. (Apr - Dec 2013)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Amortization of Depreciation Rates	3,538	3,538	4,094	3,538	3,538	7,077	7,077	8,723	8,168	7,077	(11,639)	(11,639)	(14,346)	(13,433)	(11,639)	(11,639)	(11,639)	(13,433)	(11,639)	(11,639)
5 Amortization of 2012 Major Storm Costs - June 29 Derecho	10,292	10,292	10,292	10,292	10,292	(2,287)	(2,287)	(1,350)	(2,287)	(2,287)	5,341	5,341	3,526	5,341	5,341	5,341	5,341	3,526	5,341	5,341
6 Amortization of 2012 Major Storm Costs - Hurricane Sandy	2,401	2,401	2,332	2,401	2,401	(534)	(534)	(316)	(534)	(534)	1,247	1,247	1,825	1,247	1,247	1,247	1,825	1,247	1,247	1,247
7 Amortization of 2012 Major Storm Costs - Hurricane Sandy	-	-	-	-	-	(1,031)	(1,031)	(1,065)	(1,031)	(1,031)	1,767	1,767	1,825	1,767	1,767	1,767	1,825	1,767	1,767	1,767
10 Reflection of Uncollectible Write-Offs	-	-	-	-	-	443	443	(132)	443	(132)	(759)	(759)	(3,298)	(759)	(759)	(759)	(3,298)	(759)	(759)	(759)
13 Reflection of 3-Year Average AIP Costs	-	-	-	-	-	(6)	(6)	(44)	(37)	(37)	226	226	10	75	63	226	10	75	63	226
20 Recovery of Current Rate Case Costs	-	-	-	-	-	2,588	2,588	7,466	2,588	2,588	(4,435)	(4,435)	(12,794)	(4,435)	(4,841)	(4,435)	(12,794)	(4,435)	(4,841)	(4,841)
21 Reflection of Vegetation Management in Rate Effective Period	-	-	-	-	-	-	-	-	-	-	(982)	(982)	(982)	(982)	(982)	(982)	(982)	(982)	(982)	(982)
23 Adjustment to Cash Working Capital Allowance	(7,109)	-	(7,109)	(7,109)	(7,109)	-	-	-	-	-	(3,276)	(3,276)	(900)	-	-	(3,276)	(900)	-	-	-
Tax Effect of Proforma Interest Expense ¹	-	-	-	-	-	1,912	525	(922)	1,912	1,912	-	-	-	-	-	-	-	-	-	-
Inclusion of Energy Advisors and Energy Engineers	-	-	-	-	-	(989)	-	-	(989)	-	1,695	-	-	-	-	1,695	-	-	-	-
Contested Staff/Intervenor-Proposed Adjustments:																				
Remove Installed AMI Meters from Electric Plant in Service	-	(23,402)	(26,369)	-	(23,402)	-	542	538	-	-	(4,161)	(4,564)	-	-	(3,232)	-	(4,161)	(4,564)	-	(3,232)
Remove Unadjusted Cash Working Capital	-	(22,186)	(15,077)	-	(22,186)	-	-	-	-	-	(3,064)	(2,082)	-	-	(3,064)	-	(3,064)	(2,082)	-	(3,064)
Additional Reduction to CWC (Results in Negative Balance)	-	(46)	-	-	-	-	-	-	-	-	(6)	-	-	-	-	-	(6)	-	-	-
Remove 50% of Employee Activity Costs	-	-	-	-	-	-	89	-	-	-	(153)	-	-	-	-	(153)	-	-	-	-
Reflection of Accumulated Depreciation (Jan 2013 - Jun 2014)	-	-	(50,359)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reflection of Average Overtime Expense	-	-	-	-	-	-	-	1,369	-	-	(6,955)	-	-	(2,393)	-	(6,955)	-	(2,393)	-	-
Remove SERP Related Expense	-	-	-	-	-	-	-	1,817	1,338	-	(2,346)	-	-	(2,346)	-	(2,346)	-	(2,346)	-	-
Remove 50% of Directors & Officers Liability Insurance	-	-	-	-	-	-	-	134	-	-	(230)	-	-	-	-	(230)	-	-	-	-
Remove 50% NOL Debt in Unadjusted Accumulated Deferred Tax	-	-	(42,579)	-	-	-	-	-	-	-	(5,881)	-	-	-	-	(5,881)	-	-	-	-
Reduce Materials & Supplies Balance in Rate Base	-	-	(3,423)	-	-	-	-	-	-	-	(473)	-	-	-	-	(473)	-	-	-	-
Reduce Outside Legal Expense	-	-	-	-	-	-	-	-	288	-	-	-	-	-	-	-	-	-	(494)	-
Remove AMI Expense Potentially Included in Cost of Service	-	-	-	-	-	-	-	-	590	-	-	-	-	-	-	-	-	-	(1,011)	-
Remove Accreture Expense for Sourcing & Procurement Project	-	-	-	-	-	-	-	-	239	-	-	-	-	-	-	-	-	-	(354)	-
Amortize Case No. 9214 Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Adjustment of Excess Long-Term Debt Costs	-	-	-	-	-	-	-	-	121	-	-	-	-	-	-	-	-	-	(207)	-
AFUDC Offset ²	-	-	-	-	-	-	-	-	-	2,500	-	-	-	-	-	-	-	-	(4,284)	-
Adjustment to Reflect Staff/Intervenor Rate of Return	-	-	-	-	-	-	-	-	(2,212)	(2,212)	3,791	3,791	4,234	3,791	3,791	3,791	4,234	3,791	3,791	3,791
Computational Issues with Income Tax Rates	-	-	-	-	-	-	-	-	-	-	(8,610)	(10,096)	-	-	(17,136)	-	(8,610)	(10,096)	-	(17,136)
Rounding	-	-	-	-	-	-	-	-	188	-	-	-	-	-	-	-	-	-	(322)	-
Total Revenue Requirement Based on Adjusted Results	\$ 1,342,778	\$ 1,168,516	\$ 1,050,995	\$ 1,161,986	\$ 1,128,669	\$ 66,508	\$ 71,319	\$ 81,960	\$ 74,828	\$ 75,029	\$ 66,351	\$ 30,568	\$ 6,372	\$ 30,272	\$ 10,183	\$ 66,351	\$ 30,568	\$ 6,372	\$ 30,272	\$ 10,183
Revenue Gross Up Factor:	58.3563%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Taxes:	59.6359%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Appendix II

As of 5/20/13

POTOMAC ELECTRIC POWER COMPANY
Analysis of Proposed Rate Increase - Position by Party
Twelve Months Ended December 31, 2012

Overall Rate of Return:	Pepco	Staff	OPC	Mont. Cty	AOBA ¹
	3.05%	3.05%	3.05%	3.29%	2.868%
	Long Term Debt	0.00%	0.00%	0.00%	0.025%
	Short Term Debt	5.01%	4.59%	4.45%	4.281%
	Common Equity	8.06%	7.50%	7.98%	7.174%
Total					

¹ Note that Montgomery County did not reflect the corresponding impact to interest synchronization for its proposed adjustments to rate base. Adjusting for such would result in a reduction to operating income and an increase to revenue requirement.
² Note that Staff and Montgomery County did not reflect the corresponding impact to AFUDC for their proposed adjustments to rate base. Adjusting for such would result in a reduction to operating income and an increase to revenue requirement.
³ AOBA supports Staff's positions on Removal of Costs for Installed AMI Meters, Unadjusted CWC, and Vegetation Management for the Rate Effective Period. AOBA supports exclusion costs for of post-test year reliability doings.
⁴ Includes consideration of Pepco's end-of-test year short-term debt balance, Pepco's March 11, 2013 bond issuance, and the \$175 million additional equity contribution from PHI on March 28, 2013.

AOBA Recommended Capital Structure and Cost Rates

Type of Capital	Amount (in Millions)	% of Total	Cost Rate	Weighted Cost Rate
LTD	1,900,767	48.12%	5.99%	2.868%
STD	231,000	5.85%	0.43%	0.025%
CE	1,818,194	46.03%	9.30%	4.281%
Total	3,949,961	100.00%		7.174%

⁵ Note that there are adjustments proposed by other intervenors in this proceeding that Montgomery County does not oppose which will be reflected in an exhibit to its Initial Brief.

Grid Resiliency Charge

For	Pepco	Staff	OPC	Mont. Cty	AOBA	AARP	MEA	GSA
Oppose	X	X	X	X	X	X	X	X

BEFORE THE PUBLIC SERVICE COMMISSION
OF
THE STATE OF MISSISSIPPI

MISSISSIPPI POWER COMPANY

DOCKET NO. 01-UN-0548

IN RE: NOTICE OF INTENT OF MISSISSIPPI POWER COMPANY TO
CHANGE RATES FOR ELECTRIC SERVICE IN ITS CERTIFICATED
AREAS IN THE TWENTY-THREE COUNTIES OF SOUTHEAST
MISSISSIPPI

FINAL ORDER

COMES NOW, the Mississippi Public Service Commission (Commission) and issues the following Final Order in this cause.

I. INTRODUCTION

MPCo is a public utility as defined in Section 77-3-3(d)(i) of the *Mississippi Code of 1972, as amended*, and is engaged in the business of generating, transmitting and distributing electric power to and for the public for compensation in twenty-three (23) counties of southeast Mississippi, having its principal place of business at Gulfport, Mississippi. The Company's mailing address is Post Office Box 4079, Gulfport, Mississippi, 39502-4079.

MPCo is the holder of a Certificate of Public Convenience and Necessity issued in Docket No. U-99, as supplemented from time to time, authorizing its operations in specified areas of the twenty-three (23) counties of southeast Mississippi and is rendering electric service in accordance with its service rules and regulations and in accordance with schedules of rates and charges, all of which are a part of its tariff that has been previously approved by order of this Commission.

MPCo is a Mississippi corporation. A copy of its corporate charter, articles of incorporation, the names and addresses of its board of directors and officers, and the name of all persons owning fifteen percent (15%) or more of its stock are on file with this Commission.

MPCo has, since 1986, operated under a Performance Evaluation Plan Rate Schedule designated variously, as revised and amended from time to time, as PEP, PEP-1, PEP-1A and PEP-2. MPCo is authorized under PEP-2 to file a rate proceeding to adjust its rates when there is major construction, purchase, or modification of plant such as occurred with the new Victor J. Daniel Generating Plant Units 3 and 4, the construction of which were authorized by this Commission in Docket No. 97-UA-496. The units were placed in service in May and April of this year, respectively.

II. PROCEDURAL HISTORY

On August 3, 2001, pursuant to PEP-2, Mississippi Power Company, Inc. (MPCo) filed its Notice of Intent ("Notice") to change its rates for electric service, presently on file with the Commission, to be effective with the first billing cycle of January 2002, for bills rendered on and after such date. In its notice, MPCo requested an increase in rates of approximately 9.5% for the average retail customer.

The Commission entered a suspension order in this docket on August 3, 2001, requesting the Public Utilities Staff (Staff) to conduct a full investigation of the lawfulness of the proposed rates and charges contained in MPCo's notice. On August 7, 2001, the Commission issued an order suspending PEP-2 (Docket 93-UA-302) until a final order was issued in the proceeding at hand or until further Order of the Commission.

Notice of the filing was given as required by law and this Commission's Public Utilities Rules of Practice and Procedure ("Rules") to all persons who were parties of record in the

Company's last proceeding in which a major change in rates was sought, to certain other interested persons, and by publication on August 8, 2001, in the *Clarion Ledger* and in the *Sun Herald*.

A Scheduling Order was issued on August 14, 2001, establishing procedures for the timely resolution of this matter within the 120 day period prescribed by Mississippi law, including establishing intervention procedures, discovery procedures, deadlines for the filing of testimony, pre-hearing conferences, and setting his matter for hearing November 7-9, 2001.

The Intervenor in this filing were: Colonial Pipeline Company ("Colonial"); Mississippi Manufacturers Association ("MMA"); Federal Executive Agencies, by and through the Department of the Navy ("NAVY"); Williams Energy Marketing and Trading Company ("Williams"); Mississippi Casino Operators Association d/b/a Gulf Coast Gaming Association ("GCGA"); Mississippi Chapter of the National Federation of Independent Business ("NFIB"); Sierra Club, Mississippi Chapter ("Sierra"); Dynegy, Inc. ("Dynegy"); and Chevron USA, Inc. ("Chevron"). Colonial withdraw its intervention on November 6, 2001. The Staff participated as a party litigant. Each intervenor had a full opportunity for discovery in the period established in the Scheduling Order.

The Commission's Scheduling Order provided that all data requests were to be propounded no later than September 28, 2001. During the discovery phase of this proceeding, various parties propounded to MPCo approximately 420 data requests, which included sub-parts amounting to more than 1000 requests, covering all aspects of MPCo's filing and its operations. The Staff propounded 195 data requests, GCGA propounded 210 data request, MMA propounded 14 data requests and the Navy propounded 1 data request. No motion was filed with

the Commission by any party as to the sufficiency of the responses provided by MPCo or any other party.

MPCo requested a waiver of the requirements of Miss. Code Ann., Section 77-3-37(4) (2000). On August 24, 2001, GCGA filed a Motion in Opposition to MPCo's request for waiver of these requirements. On September 18, 2001, MPCo renewed its request for waiver of the requirements of Miss. Code Ann., 77-3-37(4) (2000). MPCo filed a lead-lag study on September 18, 2001.

A pre-hearing conference, scheduled by order of this Commission, was convened on October 18, 2001, in the hearing room of the Commission. The Honorable Bruce McKinley was designated by the Commission to conduct the hearing. All of the intervenors in this docket, except the Navy and NFIB, appeared and participated in the pre-hearing conference along with the Staff and MPCo. At the pre-hearing conference, discussions and information were exchanged by and among the parties in attendance. At the recommendation of Mr. McKinley and by agreement of the parties in attendance, the pre-hearing conference was recessed until November 6, 2001 at 9:00 a.m. (CST). However, the parties were encouraged by Mr. McKinley as authorized by law to enter into stipulations notwithstanding the fact that the original pre-hearing conference was recessed. On October 26, 2001, the Staff and MPCo entered into a Stipulation. The pre-hearing conference was not reconvened on November 6, 2001, after the parties acknowledged that no additional stipulations had been reached between any other parties.

Sierra pre-filed the direct testimony of Becky Gillete and Aaron Viles on October 18, 2001. the Navy pre-filed the direct testimony of Dr. John B. Legler, MMA pre-filed the direct testimony of R.G. McBride and Roland Woodard, GCGA pre-filed the direct testimony of James

R. Dittmer, and the Staff pre-filed the direct testimony of Dr. Christopher Garbacz on October 22, 2001.

On October 26, 2001, the Staff and MPCo filed a Stipulation in this docket addressing various issues presented in the Company's filing. Among other things, the Staff and Company stipulated that the Company's filing was made pursuant to the authority of PEP-2; that the Company's filing satisfied the filing requirements of Mississippi law and this Commission's Rules; that the Company's jurisdictional cost of service allocations are just and reasonable; that adjustments and/or reductions should be made to the Company's test year rate base and expenses; that the Company's test year capital structure and weighted cost of Debt, Trust Preferred Stock and Preferred Stock portions of cost of capital are appropriate, just and reasonable; that certain changes to PEP-2 are desirable; that the Company's request in this docket, as modified by the Stipulation should be approved; and that the changes to PEP-2 proposed in the Stipulation would result in the performance evaluation plan reflecting and producing rates that are just, reasonable, and in the best interest of the customers and the Company. The particular provisions of the Stipulation related to rate base and expense adjustments, cost of capital, and the refinements to PEP-2, and this Commission's findings with respect to those matters so stipulated are addressed in the Findings and Conclusions section of this Order.

On October 30, 2001, this Commission issued an order, *sua sponte*, which recognized the need for incorporating the findings and conclusions of this docket into PEP-2 and that such incorporation would allow for the orderly transition from rate case back to the normal operation of the PEP-2 rate. The order further authorized and directed the parties of record to submit such additional testimony or evidence as they deemed appropriate to address any issues raised by the

incorporation of the rate case conclusions into PEP-2 and by the re-activation of periodic evaluations under PEP-2. In response to this Commission's October 30 order, GCGA filed a motion asking this Commission to withdraw or modify that order. Oral arguments on GCGA's motion were held on November 6, 2001, at which time counsel for GCGA, MPCo, MMA and MPUS appeared and presented arguments regarding GCGA's motion and this Commission's October 30th order. That motion was overruled by the Commission.

On November 6, 2001, the Commission issued a Procedural Order establishing the procedures, including the order of presentation of witnesses and cross-examination for the upcoming hearings.

On November 6, 2001, the Staff filed supplemental testimony of Dr. Christopher Garbacz and MPCo filed supplemental testimony of Dr. Roger A. Morin, along with rebuttal testimony of H.E. Blakeslee, Frances Turnage and Charles a. Benore in accordance with the Commission's October 30, 2001 Order.

III. JURISDICTION AND SUFFICIENCY OF THE FILING

This Commission has jurisdiction of this matter by virtue of its subject and the authority conferred upon this Commission by the laws of the State of Mississippi.

This Commission finds that the pleadings, testimony, data, documentation and exhibits to this docket filed by MPCo comply with all the statutory filing requirements and the requirements of the Commission's Rules for major changes in rates in excess of \$15 million, except the requirements of Miss. Code Ann. 77-3-37(4) (b), (c) and (d) (2000), which this Commission finds inapplicable and hereby waives.

This Commission further finds that the Stipulation entered into between the Staff and the Company and filed with this Commission complies with this Commission's Rules and Mississippi law.

Hearings in his docket were held on November 7-9, 2001 in the hearing room of the Commission.

IV. FINDINGS AND CONCLUSIONS

A. STIPULATION.

As stated previously, on October 26, 2001, the Staff and Company filed a joint Stipulation addressing numerous issues related to the Company's filing, including the incorporation of those agreements into PEP-2. As part of its investigation of this request, the Staff undertook a careful and thorough examination of the Company and its business operations. The Staff propounded and the Company responded to 195 data requests, many of which had multiple subparts. The Staff also reviewed the Company's responses to other parties' data requests. Additionally, the Staff had the benefit of conducting regular audits and reviewing the Company's books and records in connection with PEP and other rate filings. This experience gives the Staff a unique insight into the Company's finances and operations. Based upon the Staff's review, it entered into the Stipulation. The Staff recommended approval of the Company's request subject to several changes. This Commission has carefully reviewed the Stipulation and finds that there is substantial evidence in the record to support the Stipulation. This Commission finds that the Stipulation and the matters contained therein are just and reasonable, will benefit retail customers and will reduce the impacts of the Company's request on such customers. Therefore, this Commission hereby adopts the Stipulation dated October 26, 2001, and incorporates the Stipulation herein by reference. Specific findings regarding certain

Stipulation recommendations will be addressed later in this order, including findings regarding recommendations by intervenors which are contrary to the terms of the Stipulation.

1. Jurisdictional Allocations.

As noted in the Stipulation, the Company's proposed change in rates is based upon a jurisdictional cost of service study. This study was offered by Ms. Donna H. Van Loon. After careful review of the study and its allocations, the Staff and MPCo stipulated, and this Commission specifically finds, that the study and its jurisdictional allocations of expenses, revenues and rate base are just and reasonable and shall be used in this proceeding and other proceedings where such allocations must be made.

2. Rate Base Items.

The Company's filing also contains information related to the Company's rate base, revenue, and expenses for the historic year, 2000, as well as projections of rate base, revenues, expenses and cost of capital for the pro forma test year, 2002. That information was presented in the pre-filed testimony and exhibits of Ms. Van Loon, Ms. Frances Turnage, and Mr. Charles Benore.

The Company filed and proposed a retail average rate base of \$753,184,879, for the pro forma test year. The Staff recommended a reduction of \$21,435,744 to the Company's pro forma retail average rate base. With that adjustment, the Staff and Company have stipulated to an adjusted rate base of \$731,749,135 for the pro forma test year, which this Commission finds to be just and reasonable and hereby adopts.

The Stipulation made specific recommendations regarding the treatment of certain rate base items:

a. Cash Working Capital: In its original filing, the Company calculated a value for cash working capital by taking one-eighth of its non-fuel operation and maintenance expense. This formula is commonly referred to as the “45-day formula.” The 45-day formula resulted in a retail cash working capital calculation of \$22,593,980. The Company later filed a lead/lag study that indicated a cash working capital calculation of \$14,030,903. PEP-2 includes a cash working capital value of negative \$5,500,000. The Staff and Company agreed and stipulated to the use of a \$0 (zero) retail cash working capital value. Mr. Dittmer, a witness for GCGA, in his testimony adjusted the Company’s lead-lag study to eliminate non-cash items. His calculation indicated that the Company’s cash working capital requirements are approximately \$638,729. Mr. Dittmer then suggested that cash working capital be set at a negative number, but those suggestions were not based on any substantial evidence. No other intervenor gave a recommendation or opinion on this issue. This Commission recognizes that determining the proper amount of cash working capital is not susceptible to exact measurement, but the preponderance of evidence offered indicates that the Company’s cash working capital is greater than zero. Therefore, this Commission finds, based upon the various amounts calculated by the parties, that the stipulated retail cash working capital value of \$0 (zero) is appropriate and is adopted for inclusion.

b. Construction Work in Progress: In its original filing, the Company proposed that 100% of the Company’s average balance of construction work in progress (“CWIP”) be included in rate base. The Company asserts that an on-going construction program is required to meet its customers’ needs for reliable service. The Staff and Company have agreed and stipulated that the Company’s average CWIP balance for all projects ending within one year of the end of the test period shall be included in rate base with any related allowance for funds used during construction (“AFUDC”) accrued by the Company included in operating income. Mr. Dittmer

was the only other witness to address this issue. He testified and proposed that this Commission change its long-standing position on construction work in progress by not allowing any construction work in progress to be included in rate base. Mr. Dittmer suggests that the Company will be compensated appropriately by virtue of its use of AFUDC. However, this Commission finds that an on-going construction program is necessary for Mississippi Power Company to meet the needs of its customers, particularly in light of our emphasis on improving reliability and customer service. Moreover, this Commission agrees with Ms. Turnage that greater use of AFUDC could ultimately lead to higher costs for customers. Therefore, this Commission finds that the Staff's and Company's stipulated position on construction work in progress is appropriate and is adopted for inclusion.

c. Regulatory Asset Over/Under Recovery of Ad Valorem Taxes: For purposes of determining operating income and rate levels in PEP-2, the Company accrues its ad valorem tax expense throughout the year for which the tax assessment is made. A portion of ad valorem tax expense is recovered during that year in base rates. The remainder is collected the following year, after the taxes are paid, through the operation of the ad valorem tax adjustment clause (ATA). Because rate base and assessed property values increase over time and because of the mechanics of ATA, this balance is a growing under-recovery. The deferred amount (ad valorem tax under-recovery) has grown over the years to a projected average balance of over \$8 million. This represents a substantial commitment of capital. The Staff and Company have stipulated and this Commission agrees and finds that it is appropriate to include the amount of this under-recovery in the determination of retail average rate base. No intervenor has objected to or proposed an alternate treatment of this regulatory asset.

d. Property Damage Reserve: This Commission has allowed the Company to accrue a storm damage reserve (a.k.a. property damage reserve) to prepare for the damages caused by natural disasters that occasionally affect the Company's facilities. Recently, this Commission issued an order in Docket No. 99-UN-497 that provides the Company with flexibility to adjust its accrual amount as the Company deems appropriate up to \$4.5 million. The Company and Staff have agreed and stipulated that, as part of the adjustments to rate base, the Company would modify downward the amount for storm damage reserve expense accrual in its rate calculation for the test period and that the Company should continue to comply with this Commission's storm damage reserve order. This Commission finds that the reduction of the storm damage reserve accrual in the test year and the continued compliance with this Commission's order is just and reasonable.

3. Revenues and Operating Expense Items.

a. Adjustments to Expenses: The Company filed and proposed projected revenues and projected expenses which would result in retail net operating income of \$76,034,767 in the 2002 test year. The Staff carefully reviewed and considered the Company's testimony and exhibits as they relate to various expense items. The Staff, as stated in the Stipulation, has carefully considered all of the information provided to the Staff and to other intervenors in response to all data requests in this proceeding, particularly with regard to the information provided on the Company's estimations of expenses for the Company's retail electric operations. The Staff has recommended, and Company has agreed, to a reduction in the Company's projected expenses in 2002 of \$865,563, including the effect of income taxes. Mr. Dittmer was the only witness who suggested specific recommendations for adjustments to the Company's expenses, including recommendations to adjust outage expenses, labor expenses, capacity

equalization calculations, and revenues for off-system sales. However, some of the adjustments proposed by Mr. Dittmer were not based upon substantial evidence and others were based on incorrect assumptions. First, Mr. Dittmer recommended that this Commission reduce outage expenses at generating units by approximately \$2.2 million in retail expenses in the test year based upon his normalizing those major outage expenses for a five-year average. However, the Company correctly pointed out that Mr. Dittmer's adjustment focuses on only the production component of the Company's total operations and maintenance cost. We are not persuaded by Mr. Dittmer's selective adjustment to the Company's operations and maintenance expenses. This Commission must consider all of the Company's operations and maintenance expenses to determine if the overall expenses are reasonable. When viewed in their totality, the Company's operations and maintenance expenses, as adjusted by the Stipulation, are reasonable.

Second, Mr. Dittmer recommended that this Commission eliminate from the Company's projected expenses the costs of establishing a Regional Transmission Organization ("RTO"). This Commission is well aware of the Federal Energy Regulatory Commission's recent attempts to form RTOs. If Southern Company and its operating companies are required to begin the process of forming an RTO in 2002, which is very likely based upon our own involvement in that process and based upon the testimony of Mr. Blakeslee, the Company's projected \$1 million probably understates the actual costs to MPCo's retail operations in 2002.

Third, Mr. Dittmer proposed an adjustment to payroll/labor costs in 2002. The Company's witness, Ms. Turnage, addressed Mr. Dittmer's proposal and demonstrated that the Company's filed labor costs are just and reasonable. Therefore, this Commission rejects Mr. Dittmer's proposal to reduce labor costs.

This Commission has long encouraged the parties to try to resolve all reasonable issues, and for this reason, this Commission requires that pre-hearing conferences be held in these cases. Several witnesses indicated that the adjustment to expenses was a "settlement" of disputed issues related to expenses. This Commission realizes that the Staff and utilities routinely disagree over the treatment of expense items, and finds that the adjustment agreed to in the Stipulation is reasonable in light of the extensive knowledge the Staff has regarding the Company's operations and the overwhelming amount of discovery produced by the Company in this proceeding.

The Staff will again have the opportunity to review the Company's 2002 expenses and to propose adjustments to those expenses in connection with the Company's PEP-2 evaluation for the twelve-month period ending December 31, 2002. This evaluation will review twelve months of historical or actual expense information, which is the same period as the projected period in this filing which was prepared using projected 2002 figures. For the foregoing reasons and based upon this Commission's treatment of the specific adjustments suggested by Mr. Dittmer, this Commission finds that the proposed expenses as adjusted by the Stipulation are just and reasonable and, when considered along with the other findings of this Commission, will result in just and reasonable rates and we hereby adopt same.

b. Adjustments to Revenues: Mr. Dittmer recommends that this Commission make an adjustment to the Company's projected off-system sales revenues for 2002. Mr. Dittmer proposes to increase the projected revenues from off-system sales by approximately \$8.1 million. Mr. Dittmer admitted however, that his adjustment was based upon the assumption that the Company should be in a better position to sell capacity off-system in 2002 than it was in 2001. Mr. Dittmer apparently did not consider the fact that the Company had been purchasing significant amounts of capacity and energy prior to the completion of Daniel Units 3 and 4, and

that these purchases were replaced by those units. Mr. Dittmer did not undertake any evaluation of market conditions and prices upon which he could base such an adjustment to the Company's projections. His proposed adjustment to off-system sales is therefore speculative and is not adopted.

Mr. Dittmer also recommends an adjustment to increase the revenues to MPCo associated with capacity equalization payments under the Intercompany Interchange Contract ("IIC"). Again, Mr. Dittmer admits that his recommendation is based upon assumptions (without any factual basis about the IIC capacity reserve sharing calculations.) In the Company's rebuttal testimony, Ms. Turnage demonstrated that Mr. Dittmer's calculations were flawed, that he overstated available capacity and that he gave no weight to the seasonal differences in the value of capacity as provided in the IIC and as shown in response to data requests on this issue. This adjustment is not adopted.

4. **Capital Structure and Cost of Capital.**

This Commission has reviewed the portions of the Stipulation agreeing to the Company's proposed capital structure and the weighted cost of the Debt, Trust Preferred Stock and Preferred Stock. This Commission adopts this portion of the Stipulation and finds that all of the elements of MPCo's proposed cost of capital, except for the Company's proposed rate of return on common stock equity, which will be considered separately, are just and reasonable and should be approved. The only other testimony was the recommendation of Dr. John Legler, the expert witness for the Navy, who testified that an average of the 2000 and 2002 year end equity/debt ratio should be utilized for the test period rather than a year-end equity/debt ratio. While we agree that there may be some merit for using an average capital structure, the average should be developed using the beginning and ending of the projected test period – December 2001 and

December 2002 – and not year end 2000 and 2002. It should also be remembered that year 2000 is prior to the time of the equity infusion for the new units. This Commission is not persuaded by Dr. Legler and finds that the stipulated year-end equity/debt ratio, which is a requirement of PEP-2 previously approved by this Commission, is appropriate for use in this case. Since this filing and its results are to be considered in light of PEP-2 and will become a part of PEP-2, it is important that, where appropriate, the findings of this order should be consistent with PEP-2.

B. RETURN ON COMMON STOCK EQUITY.

This Commission heard a great deal of testimony regarding the Company's return on common stock equity, since a part of the Company's request for rate relief is related to an increase in its cost of capital – specifically, the cost of common stock equity. The Company asserts that the existing formulas for return on equity in PEP do not reflect current conditions in the financial markets and therefore do not produce an adequate return to investors. Three persons offered testimony regarding return on common equity – Mr. Charles Benore, Dr. John Legler, and Dr. Chris Garbacz. It is important to note that each of the three cost of capital witnesses testified to and supported a recommended rate of return, a range of returns which they considered reasonable and certain formulas or models used to develop those values. In each case, the formulas or models used differ from the current formulas in the PEP plan. We have carefully considered all of the information presented, and have spent considerable time and effort evaluating that information. This information should be considered to determine a return on the common stock equity for MPCo that is just and reasonable and consistent with companies of comparable risk; that complies with the Mississippi Public Utility Act and the Rules and Regulations of this Commission; and that complies with the requirements of the United States Supreme Court rulings in *Bluefield Water Works & Development Co. v. Public Service*

Commission of West Virginia, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

1. **Benore Testimony.**

Mr. Charles Benore testified for MPCo and recommended a 13.25% return on common equity. Mr. Benore used four models in arriving at a proposed rate of return on common equity for MPCo. Those four models are the Discounted Cash Flow Model ("DCF"), the Equity Risk Premium Model ("ERP"), an average of the standard Capital Asset Pricing Model ("CAPM") and the Empirical Capital Asset Pricing Model ("ECAPM"), and the "Comparable Earnings" Method. Mr. Benore's testimony provides descriptions of the DCF, ERP and CAPM models, as does the testimony of the other witnesses. The results of the first three market models were transformed by Mr. Benore in a process described below. Mr. Benore's fourth model, a "Comparable Earnings" Method, is also discussed below. For his DCF and CAPM models and his "Comparable Earnings" method, Mr. Benore selected comparable companies using nine (9) criteria or tests intended to assure that the companies used in these formulas were comparable to MPCo as to important matters such as risk. Mr. Benore testified that MPCo should be allowed a rate of return on common equity of 13.25%, including Transformation and Comparable Earnings, both of which are discussed below.

Mr. Benore's testimony included a calculation of return on common equity which used the same formulas considered by Dr. Garbacz - the DCF, ERP and CAPM (both standard and empirical averaged). Using these formulas in a manner similar to that used by Dr. Garbacz (without Transformation or the "Comparable Earnings" method), Mr. Benore's formulas on average resulted in a return on common equity of 11.47%.

Mr. Benore also used a fourth model, the "Comparable Earnings" method, which calculates a return on common stock equity for MPCo based on the earnings of comparable companies. This model is likewise described in Mr. Benore's testimony. This comparable earnings test or method was criticized by Dr. Garbacz, who testified that the companies were not truly comparable in his opinion, and further because it compared the retail earnings of MPCo with the total earnings of the other companies, which included wholesale and unregulated earnings. This test determined a return on equity for MPCo of 13.3%.

Mr. Benore further testified that the results of the DCF, ERP and the average of the CAPM models should be adjusted by a process called transformation. Transformation, according to Mr. Benore's direct testimony, "is the process that determines the necessary regulatory book return so that investors have an opportunity to earn their required market return." According to Mr. Benore, the standard models for regulatory book return do not provide the return required by investors when the ratio of market value to book value of common stock is above one (1). This Commission desires that companies under its regulatory control remain healthy and earn a return that allows them to attract the capital needed to provide the quality of service that we and their customers require of them. The argument presented was that transformation has not been accepted in any other regulatory rate proceeding. Since we cannot determine any other commission that has endorsed transformation, we are not able to accept this theory at this time.

2. Legler Testimony.

The second rate of return witness heard by this Commission was Dr. John Legler, on behalf of the Navy. Dr. Legler testified that he found a range between 10.5% and 11.5%, which would produce a just and reasonable return on equity for MPCo. His recommended return was

11.0%. In his rebuttal testimony, Mr. Benore noted several errors in Dr. Legler's calculations: an improper retention growth rate estimate for FPL Group, failure to add 0.5% to the growth rate for each of his comparable companies, and the use of August 31, 2001 prices instead of September 28, 2001 prices. Dr. Legler agreed on cross-examination that he had made errors in his direct testimony and when those errors are corrected and considered, Dr. Legler's Late Filed Exhibit____(JBL-1) Schedule 2 (Revised) indicates that his calculated return on equity would become 11.25% using an average of the models used. In response to questions on cross-examination, Dr. Legler gave an opinion that a range from 10.3% to 12.17% would result in a reasonable return. Dr. Legler used three (3) models to calculate his recommended return - DCF, ERP, and CAPM.

3. Garbacz Testimony.

The third rate of return witness testifying before this Commission was Dr. Chris Garbacz, on behalf of the Staff. In his pre-filed direct testimony, Dr. Garbacz determined a recommended rate of return of 11.45% for MPCo's return on common stock equity, using three (3) models -- DCF, ERP and CAPM (both standard and empirical averaged). The models applied by Dr. Garbacz and Mr. Benore were virtually identical. In rebuttal testimony, MPCo's expert witness, Mr. Benore, pointed out three errors in Dr. Garbacz's analysis. These errors were that Dr. Garbacz (1) failed to adjust the dividend to be received by investors to the first holding year as required by the DCF model, (2) failed to adjust the ERP and CAPM for flotation costs and only adjusted the DCF model, and (3) did not use the same time period for interest rates for the Equity Risk Premium and CAPM models as used for stock prices. Dr. Garbacz accepted the first two (2) of the three (3) corrections, which results in increasing his recommended return from 11.45%

to 11.67%. Dr. Garbacz then reduced his recommended return to 11.44% to reflect his claim that MPCo is less risky.

4. Summary of Rate of Return Witnesses.

Mr. Benore's range of reasonable returns for MPCo (without transformation or comparable earnings tests) is between 11.4% and 11.5%; Dr. Legler's range, as testified on cross-examination, is between 10.30% and 12.17%; and Dr. Garbacz's range, as corrected is between 11.22% to 11.67%, adjusted under PEP. As Dr. Legler stated on cross-examination, any rate of return selected by this Commission within these ranges would be reasonable. However, it also is obvious from studying these ranges of reasonable returns that the preponderance of the testimony would require a return in the 11.4% to 11.7% range, and that a rate of return in that range would result in just and reasonable rates for MPCo and its customers.

5. Finding of Rate of Return.

After considering and carefully analyzing all of the rate of return testimony and considering our experience with rate making, including both conventional and formula-type rate of return plans previously approved by this Commission, we find that a just and reasonable rate of return on common stock equity to be used as part of determining just and reasonable rates for MPCo's customers should be set at 11.5%. This rate of return is based upon the models and the substantial weight of the credible evidence and provides reasonable rates for the customers of MPCo and a fair return for the Company. We find that this rate would be equitable, just and reasonable for use in both a conventional rate case and for use in conjunction with a performance review and analysis under PEP-2.

C. PEP-2 CONSIDERATIONS.

Rate schedule PEP-2 and its predecessors have been the rate approved for setting the revenues of the Company since 1986. At the time PEP was first adopted, this Commission recognized the need to alter the conventional method of rate making to consider and adjust for the Company's performance in meeting the most important needs of its customers. The conventional rate setting process did not take into consideration the Company's performance or set rates based upon that performance. To provide for more emphasis on the needs of utility customers in Mississippi, this Commission in 1985 ordered the Company to develop and file a performance-based rate mechanism. After extensive review and deliberation, the PEP plan was adopted. This plan has allowed the Company the flexibility to balance competing priorities, to access capital necessary to construct and maintain facilities, to provide services needed by customers and, most importantly, to do all of these at rates which have been and are low in comparison to other utilities. Since then, this Commission has ordered most of the larger utilities under its regulatory authority to adopt similar performance-based ratemaking plans.

The history and lawfulness of the Company's performance evaluation plan is well settled under Mississippi law. This Commission agrees with the Staff and Company that PEP-2 constitutes a "formula type rate of return evaluation rate" under the provisions of Miss. Code Ann. 77-3-2 (2000). That section provides this Commission the authority for the adoption of and administration of formula type rate plans and authorizes the periodic calculation, review, and adjustment of revenues, performance, and rates of return.

The Company's retail rate mechanism PEP-2 was in effect at the time of the Company's filing of its notice of intent in this docket. Rate PEP-2 provides the basis for determining the just and reasonable revenue needs of MPCo and for fixing its rates. PEP-2 also includes a section

entitled "Major Plant Addition or Modifications," which provides for changes in rates under PEP-2 when major new plant is added. MPCo's filing herein is pursuant to and authorized by this section of PEP-2.

The Staff and Company also jointly acknowledge, and this Commission concurs, that the construction of the Company's new combined cycle units at Victor J. Daniel Electric Generating Plant Units 3 and 4 constitute a major plant addition as contemplated by PEP-2, and that the Company's filing is authorized under PEP-2.

At the time that the Company filed this rate request under the "Major Plant Additions or Modifications" section of PEP-2, this Commission suspended the regular semiannual evaluations. The Staff and Company have stipulated, and this Commission concurs, that the Company should return to regular periodic PEP-2 evaluations at the end of 2002.

One object of the PEP plan is to promote rate stability. A key provision of PEP-2 limits rate changes resulting from regular semiannual evaluations to 2% of aggregate retail revenue. In order to return to normal operation of PEP and maintain rate stability, it is essential that, in deciding the rate request before us in this docket, the Commission also consider the ongoing operation of PEP-2 and make provision for appropriate integration of this decision with the ongoing operation of the PEP-2 plan.

In recognition of this, on October 30, 2001, this Commission ordered that all parties present such testimony as it deemed appropriate concerning the incorporation of the holding in this docket with and into PEP-2. This was done to recognize and allow for the orderly transition of this case to the normal and continued operations of PEP-2. In order to accomplish the integration of this proceeding with PEP-2 it is necessary for us to:

- a. Include into PEP-2 the approved changes in this docket that are necessary to

update and improve PEP-2 and to assure that PEP-2 continues to yield just and reasonable rates, and

b. Provide the means and requirements necessary to integrate the results of this case with the remaining provisions of PEP-2, which continues to be rate making mechanism for determining the Company's rates.

1. **Changes Necessary in PEP-2**

The Staff and the Company have stipulated to the following matters regarding PEP-2:

a. Future rate adjustments under PEP-2 should be determined based upon the middle of the Range of No Change, not on the top or bottom of the Range; and the "sharing" of rate increases and decreases based on price performance should be eliminated. An additional penalty/reward mechanism should be added as per the Stipulation.

b. The cash working capital value used in PEP-2 should be \$0 (zero).

c. The CWIP in PEP-2 should include all projects ending within a year of the end of the evaluation period, with any related AFUDC included in operating income.

d. The Company's rate base in PEP-2 should include the regulatory asset Over/Under Recovery of Ad Valorem Taxes.

e. The following language should be added to Rate Schedule, "PEP-2" MPSC Schedule No. 28, page 3 of 28, under the section Filing Procedures:

In considering any evaluation filed pursuant to this Rate PEP-2, nothing in this Rate shall be construed to prevent the Staff from disputing the accuracy of any investment, revenue or expense; from disputing that any investment, revenue or expense is prudent in amount or purpose or otherwise in accord with the Mississippi law, the Rules and Regulations of the Commission or this Rate PEP-2; or from disputing whether any item investment, revenue or expense is improperly recorded to an account. The Staff may request and the Company shall provide clarification and additional data underlying the entries subjacent to the categories of (1) Investment, (2) Revenues, and (3) Expenses.

f. The Company's initial evaluation under PEP-2, as revised pursuant to this Stipulation in this docket, should be made in February 2003, in accordance with the rate schedule based upon the twelve months ended December 31, 2002.

The Commission finds that the changes to PEP-2 proposed by the Stipulation will produce rates which, when combined with the other findings of this order, will be just, reasonable and in the best interest of the Company's customers and the Company, and we hereby adopt those changes for incorporation in PEP-2.

The Stipulation does not include any agreements regarding the calculation for the cost of common stock equity in PEP-2 (and specifically as to the models included for the calculation of K_{AVG} therein), which is currently provided in Appendix C of that rate schedule.

There was testimony by some of the parties as to (1) whether the rate of return on common stock equity for a conventional case should become the K_{AVG} in PEP-2 (known previously as the benchmark) and, therefore, should be adjusted – up or down – for MPCo's performance or (2) whether the conventional rate of return should be the allowed return under PEP-2 including performance. This Commission is familiar with PEP-2 and its predecessors. We have never questioned that the conventional return on equity should be the benchmark or starting point (K_{AVG}) with adjustments to be made for performance according to the PEP rate schedule. We agree with witness Dr. Roger Morin that this is what was intended in the initial PEP and all subsequent changes to PEP.

This commission finds, based on the testimony of all the rate of return witnesses, that the present models used in PEP-2 may not currently produce a return on common stock equity (or K_{AVG} as it is referred to in PEP-2) which is just and reasonable.

This Commission is of the opinion that changes to the current models used in PEP-2 should be considered in a separate docket, and that the parties in this proceeding and any new intervenors should be given further opportunity to comment and offer testimony as to changes in the formulas. In order to accomplish this review and to assure that the models provide just and reasonable returns to the Company and likewise just and reasonable rates for MPCo's customers when the semi-annual evaluation under PEP-2 are reinstituted, we are simultaneously with the issuance of this order, issuing a Show Cause Order to MPCo which will establish a new docket to determine the sufficiency of the models which will be used to calculate a just and reasonable return on equity or K_{AVG} for PEP-2.

All of the changes made to PEP-2 by this order, including those adopted from the Stipulation, are subject to change at any time that this Commission finds that they or any other provisions of PEP-2 become unreasonable or cease to result in just and reasonable rates. As we have done in the past, including in this docket, we are not hesitant to call for and make any and all changes which might be necessary.

2. Integration of the Findings in this Case with PEP-2.

As this Commission has previously stated, PEP-2 continues to be the rate mechanism under which MPCo's revenue requirements are determined and changes in rates are made. PEP-2 in the Section entitled "Major Plant Additions or Modifications" allows for a change in rates that might be greater than the 2% limitation included in PEP-2, but does not eliminate any of the features of PEP-2. Since no filing under this section of PEP-2 (or any predecessor PEP) has heretofore been made or needed, this Commission feels a need to set forth the requirements and the results of a filing under that section.

The "Major Plant" section of PEP-2 requires that a filing for extraordinary relief due to

the construction of a generating plant must comply with the major case filing requirements provided for by the Public Utility Act and the rules and regulations of this Commission. This requires voluminous financial and other data which would not be filed under an ordinary evaluation under PEP-2. It also requires that a projected test year for determining rates be used instead of the historic test year used in the PEP-2 periodic evaluations. It allows for recovery of an increase in revenues in excess of the 2% of retail revenues, if such is justified.

Neither the "Major Plant" section nor any other section of PEP-2, eliminates the need to perform a calculation of performance to determine whether a change, up or down, should be made so as to reflect MPCo's performance. This is by design. This Commission has since 1985 required that MPCo's rates be adjusted for performance in those areas which most affect the customers -- currently price, reliability and customer satisfaction. We never intended that any rate for MPCo set under PEP-2 or any of its provisions ignore performance.

When this matter was filed, we did not void PEP-2 as the rate method for MPCo, we simply suspended the semi-annual rate evaluation to be made under it. This allowed us to litigate the matters required under the "Major Modification" section and to use the remaining provisions to determine just and reasonable rates for MPCo.

The use of a projected test year, as required here, evaluates MPCo for the year 2002. It would have been counter-productive to evaluate MPCo's need for rates under PEP-2 prior to the end of the 2002 test year. This was the reason we have concluded in accord with the Stipulation, that the semi-annual rate evaluations would only resume based on the historic 12 months ended December 31, 2002. This will also give this Commission a second evaluation, based on actual, historic data of the same period for which rates are to be made here on the projected 2002 year.

The procedure for the calculation of the Company's revenue requirements in this docket, which we find to be consistent with PEP-2, is as follows:

- a. The rate base, revenues and expenses, capital structure, and weighted cost of debt, trust preferred stock and preferred stock included in the filing, as modified by the Stipulation and approved herein, shall be used.
- b. The return on common equity, as determined herein and adjusted by .25% for flotation costs shall be used as K_{AVG} in the PEP-2 calculation, as PEP-2 is modified by the Stipulation, using the Company's performance as of December 31, 2000, as was used by Dr. Garbacz.
- c. Based on this procedure, the Commission finds that the rates determined herein are just and reasonable.

The Company shall determine its revenue requirements for the test year on the basis of this order; shall allocate that revenue requirement to its rate schedules and special contracts; and shall file revised rate schedules reflecting the change.

Although not mentioned in the testimonies of the parties in this docket, the Company included in its test year expenses one-third of the total estimated amount of the costs it expected to incur in this docket. Beginning in 2002, the total costs incurred by MPCo in this docket shall be amortized over a period not to exceed 36 months.

This order shall be effective upon issuance.

Chairman Nielsen Cochran voted Agree; Vice-Chairman Michael Callahan voted Agree; Commissioner Bo Robinson voted Agree.

SO ORDERED by the Commission on this the 3rd day of December, 2001.

MISSISSIPPI PUBLIC SERVICE COMMISSION





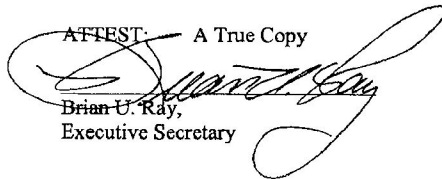
Nielsen Cochran, Chairman



Michael Callahan, Vice Chairman



Bo Robinson, Commissioner

ATTEST: A True Copy


Brian U. Ray,
Executive Secretary

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Keyspan Gas East Corporation d/b/a National Grid and
The Brooklyn Union Gas Company d/b/a National Grid NY

Cases 16-G-0058 and 16-G-0059

May 2016

Prepared Testimony of:

Jeremy Routhier-James
Utility Analyst 3
Office of Accounting, Audits and
Finance

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 Q. Please state your name, employer, and business
2 address.

3 A. My name is Jeremy Routhier-James. I am employed
4 by the New York State Department of Public
5 Service at Three Empire State Plaza in Albany,
6 New York, 12223.

7 Q. What is your position in the Department?

8 A. I am employed as a Utility Analyst 3 in the
9 Management and Operations Audit Unit of the
10 Office of Accounting, Audits and Finance.

11 Q. Please describe your educational background and
12 professional experience.

13 A. I hold a Bachelor of Arts in Sociology from the
14 State University of New York at Albany and a
15 Master of Public Administration from Marist
16 College. I have been employed by the Department
17 since April 2008, and have worked in the
18 Management and Operations Audit Unit since
19 September 2010. I am responsible for the
20 oversight of management and operations audits,
21 as well as the implementation of the resulting
22 recommendations.

23 Q. Have you supervised management and operations
24 audits of New York State utilities?

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 A. Yes. I have served as Project Manager for
2 several management and operations audits of
3 utility companies. In this role, I have been
4 responsible for leading the development of the
5 Request for Proposals which defines the scope of
6 each audit, leading the Staff team which selects
7 the independent consultants to perform the
8 audits, overseeing and participating in audit
9 field work, and reviewing and communicating
10 audit findings and recommendations to Staff and
11 the Commission. I have also managed the
12 implementation of audit recommendations as
13 Implementation Manager for several management
14 and operations audits. In this role, I have
15 been responsible for ensuring that utility
16 companies submit timely implementation updates,
17 reviewing the completion of audit recommendation
18 implementation, and reporting implementation
19 status to Staff and the Commission. Finally, I
20 serve as the Department's subject matter expert
21 in corporate governance and performance
22 management for management and operations audits.
23 In this role, I have been responsible for
24 developing audit scope components, monitoring

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 and reporting on audit findings, and overseeing
2 and reviewing utility implementation of audit
3 recommendations related to corporate governance
4 and performance management. My specific audit
5 responsibilities have included, among other
6 things, three management and operations audits
7 of National Grid USA's companies.

8 Q. In what cases have you performed these
9 functions?

10 A. I am the Implementation Manager for Case 08-E-
11 0827, a Comprehensive Management Audit of
12 Niagara Mohawk Power Corporation d/b/a National
13 Grid's Electric Business. This audit examined
14 the electric operations of Niagara Mohawk Power
15 Corporation (NMPC) and that company's shared
16 management with other National Grid USA
17 companies, including the Brooklyn Union Gas
18 Company d/b/a National Grid NY (KEDNY) and
19 KeySpan Gas East Corporation d/b/a National Grid
20 (KEDLI).

21 Q. Are you involved in any other cases?

22 A. I am the Project Manager and Implementation
23 Manager for Case 10-M-0451, a Proceeding on
24 Motion of the Commission to Investigate National

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 Grid Affiliate Cost Allocations, Policies and
2 Procedures. This audit examined certain
3 affiliate transactions between various National
4 Grid USA companies, including KEDNY and KEDLI
5 (the Companies), and the policies and procedures
6 governing such. Finally, I am the Project
7 Manager and Implementation Manager for Case 13-
8 G-0009, a Comprehensive Management and
9 Operations Audit of National Grid USA's New York
10 Gas Companies. This audit examined the gas
11 operations of NMPC, KEDNY, and KEDLI, as well as
12 the shared management with other National Grid
13 USA companies. I am also the subject matter
14 expert for corporate governance and performance
15 management in this audit, and I presented the
16 audit's findings and recommendations to the
17 Commission at its October 2, 2014 session.
18 Implementation efforts for Case 10-M-0451 were
19 completed in June 2015. Implementation for
20 Cases 08-E-0827 and 13-G-0009 is ongoing.
21 Q. Have you previously testified before the
22 Commission?
23 A. No.
24 Q. Are you sponsoring any exhibits?

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 A. Yes. I am sponsoring one exhibit,
2 Exhibit____(JRJ-1).

3 Q. Will you refer to any information provided by
4 KEDNY and KEDLI during the discovery phase of
5 this proceeding in your testimony?

6 A. Yes. I will refer to, and have relied upon,
7 responses to Information Requests (IRs) provided
8 by KEDNY and KEDLI. These responses are
9 contained in Exhibit____(JRJ-1).

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

12 A. Public Service Law, Section 66(19)(c), requires
13 that "upon the application of a gas or electric
14 corporation for a major change in rates...the
15 commission shall review that corporation's
16 compliance with the directions and
17 recommendations made previously by the
18 commission, as a result of the most recently
19 completed management and operations audit."
20 Accordingly, my testimony will address KEDNY and
21 KEDLI's overall compliance with the May 14, 2015
22 "Order Approving an Implementation Plan" in Case
23 13-G-0009 related to the comprehensive
24 management and operations audit of National Grid

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 USA's New York gas companies, performed by
2 NorthStar Consulting Group.

3 Q. When was the NorthStar audit completed?

4 A. NorthStar's final audit report was issued on
5 October 2, 2014. NorthStar's report contained
6 31 recommendations for improvement at KEDNY,
7 KEDLI, and NMPC. Each recommendation was
8 accompanied by a Customer Benefit Analysis which
9 detailed anticipated costs and benefits
10 associated with implementing the
11 recommendations, as well as potential risks of
12 not implementing the recommendation.
13 NorthStar's Customer Benefit Analyses were
14 developed using information provided by KEDNY,
15 KEDLI, and NMPC, and included qualitative and
16 quantitative cost and benefit estimates, as
17 appropriate. KEDNY and KEDLI witness Ms. Keri
18 Sweet Zavaglia, on pages three through five of
19 her testimony, provides additional information
20 related to the audit's background, findings, and
21 recommendations.

22 Q. What are a utilities' responsibilities regarding
23 the outcome of a management and audit report?

24 A. When the Commission issues a management and

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 operations audit report, utilities are required
2 by Public Service Law §66(19) to submit
3 implementation plans for audit recommendations
4 to the Commission. The Commission may then
5 approve, modify, or reject the submitted
6 implementation plan. Upon the Commission's
7 approval or approval with modification, the
8 implementation plan becomes enforceable. A
9 staff team of subject matter experts is
10 responsible for monitoring the utility's
11 implementation of the audit recommendations. As
12 utilities implement the recommendations, they
13 submit evidence of successful implementation to
14 Staff for review and approval. Accordingly,
15 audit recommendations generally fall into one of
16 three categories of completion status: In
17 Progress, Pending Review (reported as complete
18 by the utility but under review by Staff), and
19 Completed.

20 Q. Where in the audit process are KEDNY and KEDLI?

21 A. KEDNY, KEDLI, and NMPC filed their initial
22 implementation plan for Case 13-G-0009 with the
23 Secretary for the Department on November 3,
24 2014. Certain changes were made to the initial

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 implementation plan as a result of subsequent
2 discussions with Staff and decisions within
3 National Grid USA to modify the plan in certain
4 ways. KEDNY, KEDLI, and NMPC filed a revised
5 implementation plan with the Secretary for the
6 Department on April 21, 2015. The ensuing
7 Commission "Order Approving an Implementation
8 Plan" was issued on May 14, 2015, and directed
9 KEDNY, KEDLI, and NMPC to implement the
10 recommendations resulting from the audit
11 consistent with the revised implementation plan
12 dated April 21, 2015. Hereafter, I will refer
13 to the revised implementation plan dated April
14 21, 2015, and approved by the Commission on May
15 14, 2015, as the "Approved Implementation Plan."

16 Q. What is the status of KEDNY and KEDLI's overall
17 compliance with the Commission's aforementioned
18 "Order Approving an Implementation Plan" in Case
19 13-G-0009?

20 A. KEDNY and KEDLI, along with NMPC, have filed
21 timely written implementation updates and have
22 met with Staff between written updates in
23 accordance with the Order. The latest
24 implementation filing was submitted on January

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 20, 2016. This filing identifies 17
2 recommendations as Pending Review and 14
3 recommendations as In Progress. This means
4 KEDNY, KEDLI, and NMPC have reported that 17
5 recommendations have been implemented and the
6 remaining 14 are underway. The 17
7 recommendations listed as Pending Review are
8 currently under review by a team of Staff
9 subject matter experts, consistent with the
10 process explained above. At this time, no
11 recommendations are considered Completed.

12 Q. Have KEDNY and KEDLI included costs resulting
13 from implementation of the audit recommendations
14 in their rate filings?

15 A. Yes. Pages 1 and 2 of the Companies' response
16 to information request DPS-286, which is
17 contained in Exhibit____(JRJ-1), state that the
18 Companies have included in their revenue
19 requirements costs to implement two audit
20 recommendations which are expected to involve
21 material implementation costs. These are
22 Recommendation VI-2 to develop a Gas Estimating
23 Department and Recommendation IX-4 to modify
24 policies and procedures related to supply

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 procurement.

2 Q. Please explain Recommendation VI-2.

3 A. Recommendation VI-2 directs the Companies to
4 "develop an estimating program for gas projects
5 that is consistent with that used for NG USA's
6 electric utilities." In addition to performing
7 the audit in Case 13-G-0009, NorthStar performed
8 the management audit of NMPC's electric business
9 in Case 08-E-0827. Though Case 08-E-0827 was
10 limited to NMPC's electric operations, the audit
11 findings are relevant due to the shared
12 management structure of National Grid's
13 utilities. In its Final Report in Case 08-E-
14 0827, dated December 4, 2009, on pages VIII-13
15 through VIII-15, NorthStar found that National
16 Grid's US management had "long recognized that
17 estimating of complex construction projects
18 [was] a problem," and during the audit NMPC was
19 in the process of implementing a new department
20 called the Estimating Center of Excellence to
21 address the known deficiency. At the time,
22 NorthStar recommended NMPC continue those
23 efforts with the intent of improving performance
24 related to project estimating. Due to the scope

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 of that audit, the findings and recommendations
2 were limited to NMPC's electric operations.

3 Q. What effect did this recommendation have on
4 KEDNY and KEDLI?

5 A. When NorthStar reviewed KEDNY, KEDLI, and NMPC's
6 gas operations in Case 13-G-0009, it found
7 similar issues related to poor project
8 estimating on the gas side of the business.
9 While efforts had been made in the meantime to
10 improve electric transmission and distribution
11 project estimating, those efforts had not been
12 extended to gas projects. NorthStar recommended
13 that KEDNY, KEDLI, and NMPC develop an improved
14 estimating program based on the electric
15 estimating program at NMPC.

16 Q. What impact or savings would result from the
17 implementation of this change, as recommended?

18 A. NorthStar's Customer Benefit Analysis for
19 Recommendation VI-2 did not quantify potential
20 savings from implementing this recommendation.
21 However, the consultant noted that accurate
22 project estimates allow improved analysis,
23 facilitate an optimized capital portfolio, and
24 reduce delays, rework, redesign, scope

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 modifications, rebidding, inefficient
2 procurement, and permit extensions. This
3 results in productivity savings across all
4 aspects of the project.

5 Q. Please describe KEDNY and KEDLI's plan to
6 implement Recommendation VI-2.

7 A. The Companies, along with NMPC, proposed in the
8 Approved Implementation Plan to establish a Gas
9 Estimating Department consistent with
10 NorthStar's recommendation. The Approved
11 Implementation Plan indicated that the new
12 department would be staffed by four engineers,
13 two analysts, and one director, and would manage
14 approximately 200-225 complex projects annually
15 for the Companies and NMPC. The plan projected
16 that the new department would be established
17 within 12 to 18 months, with staffing of the
18 department occurring in the second quarter of
19 2015, training and estimating tool enhancements
20 occurring during the fourth quarter of 2015, and
21 final implementation occurring in the second
22 quarter of 2016, with the new department
23 estimating projects for Fiscal Year (FY) 2018.
24 The plan projected annual costs to staff and

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 operate the new department to be approximately
2 \$1.29M for capital expenses and \$0.31M for
3 operating expenses for KEDNY, KEDLI, and NMPC.
4 The Approved Implementation Plan did not
5 quantify potential savings, but noted that
6 improved estimate accuracy and the delivery of
7 complex projects within expectations drives
8 efficiency improvements in the execution of the
9 Capital Business Plan.

10 Q. Are the Companies implementing Recommendation
11 VI-2 consistent with the terms of the Approved
12 Implementation Plan?

13 A. Page 2 of the Companies' response to IR DPS-412,
14 contained in Exhibit____(JRJ-1), states that
15 "National Grid intends to fill the majority of
16 the positions in the Gas Estimating Department
17 in fiscal year 2017." This is well outside of
18 the time frame in the Approved Implementation
19 Plan, which indicated the new department would
20 be staffed in the second quarter of 2015.
21 Additionally, the Companies' responses to IRs
22 DPS-286 and DPS-412, contained in
23 Exhibit____(JRJ-1), indicate that the Companies'
24 revenue requirements include the costs for seven

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 FTEs in the new Gas Estimating Department who
2 are expected to manage over 125 complex projects
3 annually for KEDNY and 100 complex projects
4 annually for KEDLI. The seven FTEs include six
5 estimators and one manager. These seven FTEs
6 would only perform work for the Companies, not
7 NMPC. This represents a significant staffing
8 level increase from the Approved Implementation
9 Plan, which envisioned seven FTEs providing
10 services to the Companies and NMPC. However,
11 the volume of work (225 projects annually for
12 the Companies), appears consistent with the
13 expectations laid out in the Approved
14 Implementation Plan. Therefore, the staffing
15 increase for the Companies is inconsistent with
16 the approved plan.

17 Q. Please explain Recommendation IX-4.

18 A. Recommendation IX-4 was to "modify policies and
19 procedures covering the monthly and daily supply
20 procurement forecasting." The recommendation
21 included a list of specific improvements to
22 KEDNY, KEDLI, and NMPC's supply procurement
23 policies and procedures. The intent of this
24 recommendation was to address NorthStar's

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 finding that KEDNY, KEDLI, and NMPC did not
2 retain initial day-ahead or daily forecasts for
3 review and identification of improvement
4 opportunities.

5 Q. What impact or savings correspond to the
6 implementation of this change, as recommended?

7 A. NorthStar's Customer Benefit Analysis for
8 Recommendation IX-4 projected that KEDNY, KEDLI,
9 and NMPC would need to add one FTE to perform
10 the recommended analysis. The consultant did
11 not quantify any potential savings because
12 KEDNY, KEDLI, and NMPC did not previously
13 maintain data necessary to assess the accuracy
14 of the forecasts, hence the recommendation to do
15 so. However, the consultant noted that even a
16 0.1% reduction in the cost of gas would pay for
17 the additional FTE. The consultant also noted
18 that the analyst position could be eliminated
19 after two years if the resulting analysis
20 determined that existing forecast procedures
21 were of sufficient accuracy.

22 Q. Please describe KEDNY and KEDLI's plan to
23 implement Recommendation IX-4.

24 A. The Companies, along with NMPC, proposed in the

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 Approved Implementation Plan to enhance their
2 policies and procedures consistent with
3 NorthStar's recommendation. To facilitate this,
4 the Companies, along with NMPC, would hire one
5 additional FTE during 2015 to perform the
6 recommended analysis related to supply
7 procurement and load forecasting, at a cost of
8 approximately \$150,000 per year.

9 Q. Are the Companies implementing Recommendation
10 IX-4 consistent with the terms of the Approved
11 Implementation Plan?

12 A. Page 2 of the Companies' response to IR DPS-286,
13 which is contained in Exhibit____(JRJ-1), states
14 that an additional FTE is being hired in Energy
15 Procurement. KEDNY and KEDLI's allocable shares
16 of the annual labor costs for the new position
17 are approximately \$65,000 and \$30,000,
18 respectively. This is consistent with the
19 Approved Implementation Plan, with the exception
20 of the timing of the new hire, which is still
21 pending. The Approved Implementation Plan
22 indicated the position would be filled in 2015.

23 Q. Are there cost savings reflected in the
24 Companies' Revenue Requirement as a result of

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 this recommendation?

2 A. Any benefits resulting from this recommendation
3 would affect the cost of gas supply, which is
4 not included in the Companies' delivery revenue
5 requirement.

6 Q. Did NorthStar project material savings for any
7 other recommendations resulting from Case 13-G-
8 0009 which would be expected to materialize
9 during the Rate Year?

10 A. NorthStar's Customer Benefit Analyses did not
11 include quantified anticipated savings for many
12 recommendations. This was generally due to the
13 nature of the recommendations made. For
14 example, the consultant made a number of
15 recommendations related to the Boards of
16 Directors of National Grid USA and its New York
17 operating companies, organizational structure,
18 and risk management. These kinds of
19 recommendations often have desirable
20 implications for governance, planning, and
21 oversight, but those implications tend not to
22 materialize as dollar savings. Other
23 recommendations, such as Recommendation VI-2
24 discussed above, are expected to result in

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 productivity savings, but such savings are
2 difficult to quantify. NorthStar's Customer
3 Benefit Analyses for Recommendation VII-1
4 related to tracking and managing crew and
5 individual worker productivity, and
6 Recommendation VII-2 related to a manpower
7 planning program, include such productivity
8 savings projections. However, KEDNY, KEDLI, and
9 NMPC are still in the early stages of
10 implementing these recommendations.

11 Q. In what way will these recommendations have an
12 impact on KEDNY and KEDLI's customers?

13 A. Recommendations such as Recommendation IX-4
14 discussed above, might produce gas supply
15 savings which would be passed along to customers
16 if and when they materialize.

17 Q. Did NorthStar propose additional recommendations
18 that do not have a direct impact or immediate
19 operational effect on the Companies?

20 A. Case 13-G-0009 also included two recommendations
21 for KEDNY, KEDLI, and NMPC to conduct certain
22 studies related to specific utility costs.
23 Depending on the findings of the cost studies,
24 NorthStar's Customer Benefit Analyses projected

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 that additional savings could occur. The first
2 of these was Recommendation IV-1, concerning
3 costs related to National Grid USA's
4 implementation of SAP, a financial software
5 platform. The second was Recommendation IX-6
6 related to potentially misallocated labor costs
7 from the Energy Procurement group. The
8 Companies, along with NMPC, delivered those cost
9 studies to Staff as part of the audit
10 implementation process. Staff has reviewed
11 those reports and will discuss them as part of
12 the Staff Accounting Panel.

13 Q. As a result of your review of the Company's
14 management and operations audit compliance
15 efforts, do you recommend an adjustment to the
16 Company's rate request?

17 A. As discussed above, for Recommendation VI-2
18 related to the Gas Estimating Department, the
19 Approved Implementation Plan envisioned seven
20 FTEs performing work for the Companies and NMPC.
21 However, the Companies' rate filings propose
22 seven FTEs performing a similar volume of work
23 for just KEDNY and KEDLI. The Companies should
24 implement the Gas Estimating Department

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 consistent with the Approved Implementation
2 Plan. Accordingly, a reduction in the number of
3 FTEs is warranted. The number of Estimator
4 positions should be reduced to two for each
5 Company. The Manager position should split its
6 time with NMPC, consistent with the Approved
7 Implementation Plan, thereby reducing the
8 allocable portion of the Manager position for
9 each of the Companies from 0.5 to 0.33. This
10 information is also reflected in the Staff
11 Accounting Panel's testimony.

12 Q. What is the revenue requirement impact of these
13 reductions in FTEs?

14 A. The Staff Accounting Panel provided the
15 following information about the impact of these
16 labor adjustments on the Companies' revenue
17 requirement: For KEDNY, the removal of one FTE
18 Gas Estimator and the reduction of the time
19 allocation for the Gas Estimator Manager FTE
20 from 0.5 to 0.33 results in a downward
21 adjustment to other initiative expense of \$8089,
22 which includes \$5232 in labor and \$2857 in
23 adders. For KEDLI, the removal of one FTE Gas
24 Estimator and the reduction of the time

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 allocation for the Gas Estimator Manager FTE
2 from 0.5 to 0.33 results in a downward
3 adjustment to other initiative expense of \$8618,
4 which includes \$5232 in labor and \$3386 in
5 adders.

6 Q. Do you have any additional recommendations or
7 adjustments to the Companies' proposals for
8 implementation of these recommendations?

9 A. The Companies' implementation timeline for
10 Recommendation VI-2 effectively and
11 significantly delays the materialization of any
12 resulting productivity savings. Given the
13 increase in capital spending related to gas
14 infrastructure proposed by the Companies in
15 their current rate filings, the Companies would
16 have been better positioned to realize
17 productivity savings resulting from improved
18 estimating if they had moved faster to improve
19 their gas project estimating function. Further,
20 the enterprise-wide issue of inaccurate complex
21 construction project estimates was identified by
22 National Grid's US management and NorthStar as
23 far back as Case 08-E-0827 in 2009. Yet,
24 similar issues on the gas side of the business

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 remained unaddressed in 2014 when the field work
2 for Case 13-G-0009 occurred. Improved
3 estimating of complex construction projects
4 should produce meaningful productivity
5 improvements, and the Companies should have
6 addressed the known deficiencies in gas project
7 estimating function more swiftly. For those
8 reasons, an increase in the productivity
9 adjustment is warranted. The productivity
10 adjustment is being addressed by the Staff
11 Accounting Panel.

12 Q. Are KEDNY or KEDLI the subject of any other
13 recent management and operations audits?

14 A. Yes. Both companies, along with other major gas
15 and electric utilities in New York, are the
16 subject of two multi-utility operations audits.
17 The first is Case 13-M-0314, the Review of the
18 Accuracy and Effectiveness of Certain
19 Reliability and Customer Service Systems at all
20 Gas and Combination Gas and Electric Utilities
21 in New York State that Provide Statistics to the
22 Commission on the Services They Provide
23 Customers. The audit was conducted by Overland
24 Consulting and examined the accuracy of the

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 programs and processes used at the companies to
2 collect data on reliability, safety, and
3 customer service, and the accuracy of the
4 calculations of this data as reported to the
5 Department and the Commission. The final report
6 from this audit was released by the Commission
7 on April 20, 2016.

8 Q. What is the second case the Companies are
9 subject to?

10 A. The second is Case 13-M-0449, the Focused
11 Operations Audit of the Internal Staffing Levels
12 and the Use of Contractors for Selected Core
13 Utility Functions at Major New York Energy
14 Utilities. This audit is a focused operations
15 audit of the internal staffing levels and the
16 use of contractors for core utility functions at
17 major New York energy utilities. The audit is
18 being performed by Liberty Consulting Group and
19 examined the internal staffing of certain core
20 utility functions, as well as the criteria and
21 controls used for the use of external staffing.
22 This audit is ongoing and the final report is
23 expected to be released later in 2016.

24 Q. Does this conclude your testimony at this time?

Cases 16-G-0058 and 16-G-0059

Routhier-James

1 A. Yes.

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**STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH**

DOCKET NO. E-22, SUB 562
DOCKET NO. E-22, SUB 566

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562)	
)	
In the Matter of)	
Application of Virginia Electric and Power)	
Company, d/b/a Dominion Energy North)	
Carolina for Adjustment of Rates and Charges)	ORDER ACCEPTING PUBLIC
Applicable to Electric Service in North Carolina)	STAFF STIPULATION IN PART,
)	ACCEPTING CIGFUR
DOCKET NO. E-22, SUB 566)	STIPULATION, DECIDING
)	CONTESTED ISSUES, AND
In the Matter of)	GRANTING PARTIAL RATE
Petition of Virginia Electric and Power)	INCREASE
Company, d/b/a Dominion Energy North)	
Carolina for an Accounting Order to Defer)	
Certain Capital and Operating Costs)	
Associated with Greenville County Combined)	
Cycle Addition)	

HEARD: Tuesday, July 30, 2019, at 7:00 p.m., Halifax County Historical Courthouse,
10 N. King Street, Commissioners' Meeting Room, Halifax, North Carolina

Wednesday, July 31, 2019, at 7:00 p.m., Martin County Courthouse, 305 E.
Main Street, Williamston, North Carolina

Wednesday, August 7, 2019, at 7:00 p.m., Dare County Courthouse, 962
Marshall Collins Drive, Manteo, North Carolina

Monday, September 23, 2019, at 2:00 p.m., in Commission Hearing Room
2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioners ToNola D. Brown-Bland,
Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

Mary Lynne Grigg, Andrea R. Kells, and W. Dixon Snukals, McGuireWoods
LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 East Six Forks
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For Carolina Industrial Group for Fair Utility Rates I:

Warren K. Hicks, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North
Carolina 27602-1351

For Nucor Steel–Hertford:

Joseph W. Eason, Nelson, Mullins, Riley & Scarborough, LLP, 4140 Park
Lake Avenue, Suite 200, Raleigh, North Carolina 27612

Damon E. Xenopoulos, Stone Mattheis Xenopoulos & Brew, PC, 1025
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For the Attorney General's Office:

Jennifer Harrod, Special Deputy Attorney General, Theresa Townsend,
Special Deputy Attorney General, and Margaret A. Force, Assistant
Attorney General, North Carolina Attorney General's Office, Department of
Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

For the Using and Consuming Public:

David Drooz, Chief Counsel, Dianna Downey, Staff Attorney, Gina Holt,
Staff Attorney, Lucy Edmondson, Staff Attorney, Heather Fennell, Staff
Attorney, and Layla Cummings, Staff Attorney, North Carolina Utilities
Commission – Staff, Legal Division, 4326 Mail Service Center, Raleigh,
North Carolina 27699-4300

BY THE COMMISSION: On February 27, 2019, pursuant to Commission
Rule R1-17(a), Virginia Electric and Power Company, d/b/a Dominion Energy North
Carolina (DENC or the Company) filed a Notice of Intent to File General Rate Application
in Docket No. E-22, Sub 562.

On March 1, 2019, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed
a Petition to Intervene. The Petition was granted by the Commission on March 7, 2019.

On March 25, 2019, Nucor Steel–Hertford (Nucor) filed a Petition to Intervene. The Petition was granted by the Commission on March 29, 2019.

On March 29, 2019, DENC filed an Application for a general rate increase pursuant to N.C. Gen. Stat. §§ 62-133 and 62-134 and Commission Rule R1-17 (Application) along with a Rate Case Information Report – Commission Form E-1 (Form E-1) and the direct testimony and exhibits of Mark D. Mitchell – Vice President, Generation Construction; Richard M. Davis – Director of Corporate Finance and Assistant Treasurer; Robert B. Hevert – Managing Partner at ScottMadden, Inc.; Bruce E. Petrie – Manager of Generation System Planning; Jason E. Williams – Director of Environmental Services; Paul M. McLeod – Regulatory Specialist; Robert E. Miller – Regulatory Analyst; Paul B. Haynes – Director of Regulation; and Bobby E. McGuire – Director of Electric Transmission Project Development & Execution. Also on March 29, 2019, DENC filed an application for an accounting order to defer certain capital and operating costs associated with its Greenville County Power Station (Greenville CC) in Docket No. E-22, Sub 566. The Company also requested that the Commission consolidate its consideration of the deferral application with the Company's application for a general rate increase in Docket No. E-22, Sub 562.

On April 29, 2019, the Commission issued an Order Declaring General Rate Case and Suspending Rates.

On May 2, 2019, the Commission issued an Order Consolidating Dockets, which consolidated this general rate case with DENC's pending petition for deferral accounting authority to defer post-in-service costs associated with commercial operation of the Greenville County CC in Docket No. E-22, Sub 566.

On May 30, 2019, the Commission issued an Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Deadlines, and Requiring Public Notice.

On August 5, 2019, DENC filed supplemental direct testimony and exhibits of witnesses Davis, McLeod, Miller, Haynes, Petrie, and Deanna R. Kesler – Regulatory Consultant in Demand-Side Planning, as well as applicable supplemental Form E-1 information report items and supplemental Commission Rule R1-17 information.

On August 14, 2019, DENC filed additional supplemental direct testimony and exhibits of witness Haynes.

On August 15, 2019, DENC filed affidavits of publication evidencing proof of publication of notice.

On August 23, 2019, the North Carolina Utilities Commission – Public Staff (Public Staff) filed the testimony and exhibits of Sonja R. Johnson – Accountant; David M. Williamson – Utilities Engineer; Jack L. Floyd – Utilities Engineer; Michelle M. Boswell – Staff Accountant; Tommy C. Williamson – Utilities Engineer; Roxie McCullar – Consultant

at William Dunkel and Associates; Dr. J. Randall Woolridge – Consultant; Jeffrey T. Thomas – Utilities Engineer; Michael C. Maness – Director of the Accounting Division; and Jay B. Lucas – Utilities Engineer. Also on August 23, 2019, Nucor filed the testimony and exhibits of Paul J. Wielgus and Jacob M. Thomas, and CIGFUR filed the testimony and exhibits of Nicholas Phillips, Jr.

On August 27, 2019, the North Carolina Attorney General's Office (AGO) filed a Notice of Intervention.

On August 28, 2019, the Commission issued an Order Requesting Additional Information.

On September 12, 2019, DENC filed second supplemental direct testimony and exhibits of witness McLeod, supplemental Form E-1 items, and supplemental Commission Rule R1-17 information. Also on September 12, 2019, DENC filed the rebuttal testimony and exhibits of witnesses Davis, Hevert, McLeod, Miller, Haynes, and Williams.

On September 16, 2019, the Commission issued an Order Providing Notice of Commission Questions. Also on September 16, 2019, DENC filed its Witness List.

On September 17, 2019, DENC filed an Agreement and Stipulation of Partial Settlement with the Public Staff (Public Staff Stipulation). Also on September 17, 2019, the Public Staff filed Partial Settlement Joint Testimony of witnesses Johnson and James S. McLawhorn – Director, Electric Division, and DENC filed testimony of witnesses Davis, Hevert, McLeod, Miller, and Haynes in support of the Public Staff Stipulation.

On September 18, 2019, the Public Staff filed supplemental testimony of witness Maness. Also on September 18, 2019, the Public Staff filed exhibits and supporting schedules for the joint testimony of witnesses McLawhorn and Johnson previously filed on September 17, 2019.

On September 19, 2019, DENC and the Public Staff filed a joint motion to excuse several of their witnesses, and CIGFUR filed a motion to excuse its witness. The motions were granted on September 23, 2019.

On September 23, 2019, DENC filed an Agreement and Stipulation of Settlement with CIGFUR (CIGFUR Stipulation). Also on September 23, 2019, DENC filed a Revised Witness List and Late Filed Exhibits in response to the Commission's Order Providing Notice of Commission Questions.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Halifax: Tony Burnette, Dean Knight, Chuck Overton, and Silverleen Alston.

Williamston: John Liddick, Patrick Flynn, Tommy Bowen, James Wiggins, and Glenda Barnes.

Manteo: Rhett White, Manny Medeiros, John Windley, and Brad Bernard.

Raleigh: No public witnesses appeared.

The Commission received numerous consumer statements of position in this matter. All public witness testimony and consumer statements of position have been considered by the Commission and made a part of the record.

The matter came on for expert witness hearing on September 23, 2019. DENC presented the testimony of witnesses Mitchell, Davis, Hevert, McLeod, Haynes, Miller, and Williams. The testimony and exhibits of DENC witnesses McGuire, Kessler, and Petrie were stipulated into the record. The testimony and exhibits of Nucor witnesses Thomas and Wielgus were stipulated into the record. The testimony and exhibits of CIGFUR witness Phillips were stipulated into the record. The Public Staff presented the testimony of witnesses Maness, Johnson, and McLawhorn. The testimony and exhibits of Public Staff witnesses David Williamson, Floyd, Boswell, Tommy Williamson, McCullar, Woolridge, and Thomas were stipulated into the record.

The pre-filed testimony of those witnesses who testified at the expert witness hearing, as well as the pre-filed testimony of all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand, and their pre-filed exhibits were admitted into evidence.

The Public Staff and DENC filed late-filed exhibits and responses to Commission questions on September 23, September 26, September 27, October 1, October 2, October 7, October 8, and October 23, 2019.

On November 6, 2019, DENC and the Public Staff filed a Joint Proposed Order on the issues covered by the Public Staff Stipulation and separate proposed orders on the issues of cost recovery for coal combustion residuals. Post-hearing briefs were filed by DENC, the AGO, CIGFUR, and Nucor.

The above is a summary of the main filings and proceedings in this docket. Additional filings made by the parties and orders issued in this proceeding are not discussed in this Order but are included in the record.

Based on the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

Jurisdiction

1. Virginia Electric and Power Company (VEPCO) is duly organized as a public utility operating under the laws of the State of North Carolina as Dominion Energy North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. DENC is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public in North Carolina for compensation. DENC is an unincorporated division of VEPCO and has its office and principal place of business in Richmond, Virginia. VEPCO is a wholly-owned subsidiary of Dominion Energy, Inc. (DEI).

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including DENC, under the Public Utilities Act (Act), Chapter 62 of the General Statutes of North Carolina.

3. DENC is lawfully before the Commission based upon its application for a general increase in its retail rates pursuant to N.C.G.S. §§ 62-133, 62-133.2, 62-134, and 62-135, and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2018, adjusted for certain known changes in revenue, expenses, and rate base.

The Application

5. In summary, by its general rate case Application, supporting testimony, and exhibits filed on March 29, 2019, and on subsequent dates during the proceeding, DENC sought an increase in its non-fuel base rates and charges to its North Carolina retail customers of \$26,958,000, along with other relief, including cost deferrals and changes to its rate design. The Application was based upon a requested rate of return on common equity of 10.75%, an embedded long-term debt cost of 4.451%, and DENC's actual capital structure of 53.01% common equity and 46.99% long-term debt, as of December 31, 2018. DENC submitted supplemental filings and testimony after its initial Application and the effect of the Company's supplemental filings was to change its proposed annual base non-fuel revenue requirement to a \$24,195,000 increase in annual revenue.

Stipulation with Public Staff

6. On September 17, 2019, DENC and the Public Staff (Stipulating Parties) entered into and filed the Public Staff Stipulation, resolving all of the issues in this

proceeding among the Stipulating Parties, except for issues associated with coal combustion residuals (CCR) costs.

7. The Public Staff Stipulation is the product of give-and-take in settlement negotiations between the Stipulating Parties, and it is material evidence entitled to be given appropriate weight by the Commission.

Stipulation with CIGFUR

8. On September 23, 2019, DENC and CIGFUR entered into and filed the CIGFUR Stipulation, resolving rate of return and certain cost allocation, rate design, and terms and conditions issues in this proceeding.

9. The CIGFUR Stipulation is the product of give-and-take in settlement negotiations between DENC and CIGFUR, and it is material evidence entitled to be given appropriate weight by the Commission.

Capital Structure, Cost of Capital, and Overall Rate of Return

10. The capital structure set forth in Section III.A of the Public Staff Stipulation, consisting of 52.00% common equity and 48.00% long-term debt, is reasonable and appropriate for use by DENC in this case.

11. The embedded cost of debt set forth in Section III.A of the Public Staff Stipulation of 4.442% is reasonable and appropriate for use by DENC in this case.

12. The rate of return on common equity that the Company should be allowed the opportunity to earn in this docket is 9.75%, as set forth in Section III.A of the Public Staff Stipulation and is reasonable and appropriate for use in this docket.

13. The overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 7.20%, as set forth in Section III.A of the Public Staff Stipulation and is reasonable and appropriate for use in this docket.

14. The authorized levels of overall return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of N.C.G.S. § 62-133 in light of changing economic conditions and will allow the Company to maintain its facilities and services in accordance with the reasonable requirements of the Company's customers.

15. With respect to the foregoing findings on the appropriate overall rate of return on rate base and allowed rate of return on common equity for use in this proceeding, the Commission makes the following more specific findings of fact:

a. The overall rate of return on rate base and allowed rate of return on common equity underlying DENC's current base rates are 7.367% and 9.90%, respectively.¹

b. DENC's current base rates became effective for service rendered on and after January 1, 2017, and have been in effect since that date.

c. In its Application, DENC sought approval for rates which were based on an overall rate of return on rate base of 7.79% and an allowed rate of return on common equity of 10.75%.

d. As set forth in the Public Staff Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.20% and an allowed rate of return on common equity of 9.75%.

e. The reduction in overall rate of return on rate base and rate of return on common equity from both DENC's existing base rates and the Application, as reflected in the Public Staff Stipulation, is a substantial economic benefit to DENC's customers.

f. As reported by Regulatory Research Associates (RRA), the median rate of return on equity authorized for vertically integrated electric utilities during the first half of 2019 was 9.73% (compared to 9.75% in 2018). The authorized rate of return on equity for vertically integrated electric utilities is in the top third of all jurisdictions rated by RRA in terms of constructive, and less risky regulatory environments range from 9.37% to 10.55%, with a mean of 9.93% and a median of 9.95% from 2016 through early September of 2019.

g. The stipulated rate of return on common equity of 9.75% is equal to the lowest rate of return on common equity granted by the Commission for a major electric utility in the last ten years.

h. The currently authorized rate of return on common equity underlying the base rates of Public Service Company of North Carolina, Inc. (PSNC), and Piedmont Natural Gas Company, Inc. (Piedmont), is 9.70%.² The currently

¹ Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, *Application by Virginia Electric and Power Co., d/b/a Dominion North Carolina Power for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-22, Sub 532 (N.C.U.C. Dec. 22, 2016) (DENC Sub 532 Order).

² Order Approving Rate Increase and Integrity Management Tracker, *Application of Public Service Co. of North Carolina, Inc., for a General Increase in its Rates and Charges*, No. G-5, Sub 565 (N.C.U.C. Oct. 28, 2016) (PSNC Sub 565 Order); Order Approving Stipulation, Granting Partial Rate Increase,

authorized rate of return on common equity for Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), is 9.90%.³

i. The stipulated allowed rate of return on common equity of 9.75% is consistent with the rates of return on common equity identified above.

j. The stipulated overall rate of return on rate base of 7.20% and rate of return on common equity of 9.75% are supported by competent, material, and substantial evidence.

k. The evidence indicates that the overall economic climate in North Carolina (and nationally) remains strong, including data and projections from reliable sources that demonstrate: (i) generally consistent with the national rate of unemployment, the rate of unemployment in North Carolina has fallen by 8.30 percentage points since its peak in late 2009 and early 2010 to 3.70% by December 2018; (ii) unemployment in the DENC counties peaked in late 2009 – early 2010 at 13.41% and had fallen to 4.95% by December 2018; growth in the Gross Domestic Product (GDP) is relatively strongly correlated between North Carolina and the national economy, and it has been growing at a moderate pace since 2016; (iii) median household income in North Carolina has grown since 2009 at an annual rate of 2.32%; and (iv) residential electric rates in North Carolina since 2018 remain approximately 13% below the national average.

l. Irrespective of the economic conditions being experienced in North Carolina at this time, which are positive, some customers of DENC will struggle to pay their utility bills under the rate increases authorized herein.

m. Continuous safe, adequate, and reliable electric service by DENC is essential to the support of businesses, jobs, hospitals, government services, and the maintenance of a healthy environment.

n. The rate of return on common equity and capital structure approved by the Commission appropriately balances the benefits received by DENC's customers from DENC's provision of safe, adequate, and reliable electric service in support of businesses, jobs, hospitals, government services, and the

Line 434 Revenue Rider, EDIT Riders, Provisional Revenues Rider, and Requiring Customer Notice, *Application of Piedmont Natural Gas Co., Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina, Continuation of its IMR Mechanism, Adoption of an EDIT Rider, and Other Relief*, No. G-9, Sub 743 (N.C.U.C. Oct. 31, 2019) (PNG Sub 743 Order).

³ Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1146 (N.C.U.C. June 22, 2018), *appeal docketed*, No. 401A18 (N.C. Nov. 7, 2018) (DEC Sub 1146 Order); Order Accepting Stipulations, Deciding Contested Issues and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142 (N.C.U.C. Feb. 23, 2018), *appeal docketed*, No. 401A18 (N.C. Nov. 7, 2018) (DEP Sub 1142 Order).

maintenance of a healthy environment with the difficulties that some of DENC's customers will experience in paying the Company's increased rates.

16. The capital structure and rates of return on rate base and common equity set forth in the Public Staff Stipulation and the CIGFUR Stipulation result in a cost of capital which appropriately balances DENC's interest in maintaining both its credit ratings and its ability to obtain equity financing on reasonable terms, and its customers' interest in receiving electric utility service at the lowest possible rate.

Adjustments to Cost of Service

17. The Public Staff Stipulation provides for certain accounting adjustments, which are set forth in detail at Settlement Exhibit I. The Stipulating Parties agree that the settlement regarding those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The accounting adjustments outlined in Settlement Exhibit I, except line No. 18 pertaining to Chesterfield Units 3 and 4, are just and reasonable to all parties in light of all the evidence presented.

18. The Company's updates through June 30, 2019, to certain revenues, expenses, and investments, as agreed to and adjusted in the Public Staff Stipulation, are appropriate for use in this proceeding.

19. DENC's pro forma inclusion in rates of the full cost of service of the Greenville combined cycle generating plant (Greenville CC), which began commercial operation on December 8, 2018, is appropriate, with the exception of the non-fuel O&M expenses for displacement adjustment, as discussed below.

20. DENC's request to defer the costs associated with the Greenville CC from the time the unit was placed into service until placement in base rates in this rate case is appropriate. Amortization over a three-year period beginning with the effective date of new rates in this proceeding is also appropriate.

21. The Public Staff Stipulation provides that an adjustment of \$81,000 should be made to storm restoration costs to reflect the use of a ten-year historical average of these costs. This provision of the Public Staff Stipulation is just and reasonable to all parties in light of all the evidence presented.

22. The Stipulating Parties have agreed to a reduction in revenue requirement of \$142,000 for the variable non-fuel O&M expenses displacement. This agreed upon adjustment is to reflect the updated and corrected purchased energy and electric test year output numbers, and it is just and reasonable to all parties in light of the evidence presented.

23. The Public Staff's adjustment to remove the costs of the Skiffes Creek project mitigation is appropriate as provided for in the Public Staff Stipulation.

24. The Public Staff Stipulation provides that 50% of the Mount Storm impairment costs should be removed, with the remaining portion amortized over 2.75 years. This provision of the Public Staff Stipulation is just and reasonable to all parties in light of all of the evidence presented.

25. The Stipulating Parties have agreed to reduce the revenue requirement by \$720,000 to reflect the updated, actual costs of the Company's new office building (DES Office). In light of the evidence presented, this adjustment is just and reasonable to all parties.

26. As set forth in Section IV.S of the Public Staff Stipulation, the Stipulating Parties have agreed that the Company's depreciation rates will be set based on the rates set forth in the Company's Application. Subject to Findings of Fact Nos. 56-58 and the discussion thereunder, this provision of the Public Staff Stipulation is just and reasonable to all parties in light of all of the evidence presented.

Federal Excess Deferred Income Taxes

27. The Company is adjusting rates to pass along to North Carolina jurisdictional customers the benefit of federal excess deferred income taxes (EDIT) resulting from the Federal Tax Cuts and Jobs Act of 2017 (Tax Act). The system-level federal EDIT balance as of December 31, 2017, was \$2.0 billion, of which \$94.7 million was allocable to the North Carolina retail jurisdiction.

28. The Public Staff Stipulation provides that DENC will implement an increment rider, Rider EDIT, to allow for the recovery by DENC of federal EDIT of \$1,214,000 (on a pre-income tax basis). This amount includes all unprotected federal EDIT allocable to the North Carolina jurisdiction totaling approximately \$8.0 million, partially offset by the refund to ratepayers of approximately \$6.8 million associated with North Carolina jurisdictional federal EDIT amortization attributable to the 22-month period of January 1, 2018, through October 31, 2019.

29. DENC should implement Rider EDIT to recover certain federal EDIT from customers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit II, Schedule 2, the appropriate amount to be recovered from customers is a total of \$1,299,369. Rider EDIT should be calculated and reviewed using the methodology presented in the testimony of DENC witness Haynes.

30. The Company's fully-adjusted cost of service includes the income tax benefit arising from the annual amortization of federal protected EDIT during the test year, thereby incorporating a going-level of federal protected EDIT amortization in base non-fuel rates.

31. The ratemaking treatment of federal EDIT, including Rider EDIT as set forth in the Public Staff Stipulation, is just and reasonable to all parties in light of all of the evidence presented.

Base Fuel Factor

32. The Public Staff Stipulation provides for a total decrease in DENC's annual base fuel revenues of \$2.155 million from its North Carolina retail electric operations, based on a jurisdictional average base fuel factor of 2.092¢/kWh (including regulatory fee), which is just and reasonable to all parties in light of all the evidence presented.

33. The jurisdictional average base fuel factor should be voltage-differentiated between customer classes, as provided on Company Additional Supplemental Exhibit PBH-1, Schedule 1, Page 2.

34. The Company has proposed to adjust its base fuel and non-fuel expenses to reflect 71% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage), with the remaining 29% of the cost of energy purchases being recovered by DENC in base rates. This represents a reduction from the Company's current Marketer Percentage of 78%. The 71% Marketer Percentage is reasonable and appropriate for use in this proceeding and shall remain in effect until the Company's 2021 annual fuel factor filing or next general rate case, whichever comes first.

Cost of Service Allocation Methodology

35. The Public Staff and CIGFUR Stipulations provide for the use of the Summer-Winter Peak and Average (SWPA) methodology calculated using the system load factor to weight the average component and (1 – system load factor) to weight the peak demand component to allocate the Company's cost of service to the North Carolina jurisdiction and among the customer classes in this case. The Stipulating Parties and CIGFUR agree that use of the SWPA methodology for allocation between jurisdictions and among customer classes shall not be a precedent for, and may be contested in, future general rate case proceedings. The Stipulating Parties further agree that the Company's proposed adjustments (1) to DENC's recorded summer and winter peaks to recognize the peak demand contributions of non-utility generators (NUGs) interconnected to the Company's distribution system, and (2) to remove the demand and energy requirements of three customers, one wholesale customer North Carolina Electric Membership Corporation (NCEMC), and two large industrial customers in the Company's Virginia jurisdiction for whom the obligation to provide generation service has ended or will end during 2019 are appropriate and reasonable. The SWPA cost of service methodology, adjusted as described, is appropriate for determining the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility for purposes of this case.

36. DENC's adjustment to the peak component of SWPA appropriately recognizes the impact that NUGs have on DENC's utility system and is appropriate for use in this proceeding.

37. DENC's adjustment to remove the demand and energy requirements of customers whose service has ended or will end during 2019 is appropriate for use in this proceeding.

38. The SWPA cost of service methodology, as adjusted by DENC, has been used in this Order to determine the appropriate levels of rate base, revenues, and expenses for North Carolina retail service.

39. DENC's continued use of the SWPA methodology in this proceeding properly assigns production plant costs to all customer classes, including the Schedule NS Class, in recognition of its significant use of the Company's generation throughout the year.

Rate Design

40. For purposes of apportioning and assigning the approved increase in base non-fuel and base fuel revenues between the North Carolina customer classes in this proceeding, the apportionment should be consistent with the principles described in the testimony of Public Staff witness Floyd and the rate design presented by Company witness Haynes in his direct testimony, as adjusted by and as referenced in Section VI of the Public Staff Stipulation, which are reasonable, appropriate, and nondiscriminatory. The Public Staff Stipulation further provides that in developing rates based upon the foregoing class apportionment, the Company should consider the rate of return indices for the LGS and 6VP classes and an appropriate rate of return index for the Schedule NS class. Finally, the Public Staff Stipulation provides that all classes should share in the total base revenue increase. The rate design principles proposed by the Company, as filed revised by the Public Staff Stipulation, are just and reasonable.

Service Regulations, Vegetation Management, and Quality of Service

41. The amendments to the service regulations proposed by the Company are reasonable.

42. The vegetation management plan of the Company is reasonable.

43. The overall quality of service provided by DENC is good.

Conversion Costs of Chesterfield Power Station Units 3 and 4

44. The resolution of the recovery of the CCR wet to dry CCR handling conversion costs incurred by DENC at the Chesterfield Power Station (Chesterfield) Units 3 and 4, as set forth in Section VII.A of the Public Staff Stipulation, is not approved.

45. DENC's decision to incur wet to dry CCR handling conversion costs for Chesterfield Units 3 and 4 was not reasonable and prudent.

46. DENC should not be allowed to recover from North Carolina retail ratepayers the jurisdictional costs arising from the wet to dry CCR conversion project for Units 3 and 4 at Chesterfield.

Acceptance of Stipulations

47. Based upon all of the evidence in the record, including consideration of the public witness testimony and the evidence from parties who have not agreed with the Public Staff and CIGFUR Stipulations, with the exception of Section VII.A of the Public Staff Stipulation and subject to in Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance, the provisions of the Stipulations are just and reasonable to the customers of DENC and to all parties to this proceeding, and serve the public interest. Therefore, the Stipulations should be approved in their entirety, with the exception of Section VII.A of the Public Staff Stipulation and subject to the Findings of Fact Nos. 56-58 and the discussion thereunder relating to the costs of removal portion of depreciation allowance. In addition, the Stipulations are entitled to substantial weight and consideration in the Commission's decision in this docket.

48. The base non-fuel and base fuel revenues provided in and resulting from the Public Staff and CIGFUR Stipulations, with the exception of Section VII.A of the Public Staff Stipulation, are just and reasonable to the customers of DENC, to DENC, and to all parties to this proceeding, and serve the public interest.

Recovery of CCR Costs

49. Since its last rate case, on a North Carolina retail jurisdictional basis, from the period beginning July 1, 2016 and running through June 30, 2019 (the Deferral Period), DENC has incurred \$21.8 million in costs associated with the management of CCRs (the CCR Costs). The \$21.8 million includes: (1) \$19.2 million in expenditures made during the Deferral Period to comply with federal and state environmental regulations associated with managing CCRs and converting or closing waste ash management facilities at seven of DENC's generation stations; and (2) \$2.7 million in financing costs incurred during the Deferral Period.

50. The record includes substantial evidence that, particularly where CCRs were being managed in lined landfills, the CCR Costs incurred during the Deferral Period were prudently incurred.

51. Although the Public Staff offered evidence challenging the manner in which DENC had managed CCRs and its various CCR waste management facilities over several decades, insofar as the specific CCR Costs incurred during the Deferral Period are concerned, while the record contains evidence that identifies instances of imprudence, the record contains insufficient evidence to permit the Commission to quantify the effects of imprudent actions on ratepayers.

52. DENC is entitled to recover the CCR Costs established in this general rate case, in the manner and subject to the conditions as set forth herein.

Ratemaking Treatment of Recoverable CCR Costs

53. Just and reasonable rates will be achieved by excluding from rate base the CCR Costs and amortizing recovery of the CCR Costs over a period of ten years.

54. It is reasonable, based on the evidence in the record in this proceeding, for DENC to recover its financing costs on the CCR Costs incurred during the Deferral Period, up to the effective date of rates approved pursuant to this Order, calculated at the Company's previously authorized weighted average cost of capital.

55. It is reasonable, based on the evidence in the record in this proceeding for annual compounding to be used in calculating the financing costs of deferred costs, including the CCR Costs, during the Deferral Period.

Accounting for CCR Remediation and Closure Costs

56. DENC did not account for CCR remediation costs as costs of removal in computing and requesting recovery of its allowance for depreciation expense.

57. DENC's failure to incorporate costs of remediation and closure of CCR waste management facilities as part of its allowance for depreciation expense is contrary to accepted depreciation expense accounting principles.

58. It is appropriate to require DENC to properly account for costs of remediation and closure of CCR waste management facilities as part of costs of removal included in its allowable depreciation expense.

CCR Insurance Claims

59. DENC should be required to take reasonable and prudent actions to pursue claims for insurance coverage of CCR remediation costs, where justified by DENC's insurance policy coverage.

60. All insurance proceeds received or recovered by DENC from the existing and potential CCR insurance claims should be placed in a regulatory liability account until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. The regulatory liability account should accrue a carrying charge at the net-of-tax overall rate of return authorized for DENC in this Order.

61. Within ten days of the resolution of any of DENC's CCR insurance claims, whether by settlement, judgment or otherwise, DENC should file a report with the Commission explaining the result and stating the amount of insurance proceeds to be

received or recovered by DENC. This reporting requirement should apply even if there is litigation that is appealed to a higher court.

62. If meritorious concerns are raised by any party or by the Commission regarding the reasonableness of DENC's efforts to obtain an appropriate amount of recovery from the CCR insurance claims, DENC should bear the burden of proving that it exercised reasonable care and made prudent efforts to obtain the maximum recovery from the insurance claims.

Accounting for Deferred Costs

63. The Company is authorized to receive a specific amount of revenue for each of the deferred costs approved by this Order. If DENC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Revenue Requirement

64. After giving effect to the Commission's partial approval of the Public Staff Stipulation and full approval of the CIGFUR Stipulation, and the Commission's decisions on contested issues, the annual revenue requirement for DENC will allow the Company a reasonable opportunity to earn the rate of return on its rate base.

65. As soon as practicable following the issuance of this Order, DENC should calculate and file the annual revenue requirement with the Commission, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DENC should file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding. DENC should provide the Commission with electronic copies of the filing, complete with formulas intact.

Just and Reasonable Rates

66. The base non-fuel and base fuel revenues and rates approved herein are just and reasonable to the customers of DENC, to DENC, and to all parties to this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Form E-1 of DENC, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any

party. In addition, the Commission finds and concludes that the Company's use of a test period of the 12 months ended December 31, 2018, with appropriate adjustments for certain known changes in revenue, expenses, and rate base, comports with the requirements of N.C.G.S. § 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact and conclusions is contained in the verified Application and Form E-1 of DENC, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of the Evidence

On February 27, 2019, pursuant to Commission Rule R1-17(a), DENC filed notice of its intent to file a general rate case application.

On March 29, 2019, DENC filed its Application and initial direct testimony and exhibits, seeking a net increase of \$26,958,000 in its annual base non-fuel rate revenue from its North Carolina retail electric operations. The Application is based on a requested rate of return on common equity of 10.75%, an overall rate of return of 7.79%, an embedded long-term debt cost of 4.451%, and DENC's actual capital structure of 53.01% common equity and 46.99% long-term debt, as of December 31, 2018. Further, the Application states that DENC's 2018 return on equity was 7.52% and its overall rate of return was 6.08%.

The Company's last general rate case was in 2016 in Docket No. E-22, Sub 532 (2016 Rate Case or Sub 532). By Order issued on December 22, 2016, the Commission approved an increase in DENC's base non-fuel revenues of \$34,732,000, and a decrease of \$8,942,000 in its base fuel revenues. DENC's current authorized rate of return on common equity is 9.9%, its authorized overall rate of return is 7.367%, and its authorized capital structure for ratemaking purposes is 51.75% common equity and 48.25% long-term debt. On March 4, 2019, the Commission approved a base non-fuel revenue reduction of \$14,349,000 in Docket No. E-22, Sub 560, due to the net reduction in the Company's revenue requirement (i.e., the income tax expense component in then-current base rates) associated with the reduction in the federal corporate income tax rate pursuant to the Federal Tax Cuts and Jobs Act of 2017.

In its present Application, the Company proposed to implement the non-fuel base rate increase on a temporary basis subject to refund effective on November 1, 2019, along with an accelerated implementation of its new lower base fuel rate – to be filed in August 2019 – as part of any temporary rates (subject to refund) proposed to become effective November 1, 2019. The Company also proposed a methodology for returning certain federal EDIT to customers through a decrement rider, Rider EDIT, over a one–

year period. Further, DENC proposed to amortize the post-in-service costs of the Greenville CC it had requested to defer in Docket No. E-22, Sub 566.⁴

In its supplemental testimony filed on August 5, 2019, DENC updated the increase sought in its non-fuel base rates and charges to its North Carolina retail customers to \$24.9 million.

In its second supplemental testimony filed on September 12, 2019, DENC updated the increase sought to \$24.2 million.

Discussion and Conclusion

The Commission finds and concludes that DENC's Application satisfies the requirements of N.C.G.S. § 62-133, et seq., and Commission Rule R1-17. Further, DENC is a public utility within the meaning of N.C.G.S. § 62-3(23). Therefore, pursuant to N.C.G.S. § 62-30, et seq., the Commission has jurisdiction to consider and decide DENC's Application for a rate increase and other relief.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings of fact and conclusions is contained in the testimony of DENC witnesses Davis, McLeod, Hevert, Miller, and Haynes; Public Staff witnesses McLawhorn and Johnson; and the entire record in this proceeding.

Summary of the Evidence

On September 17, 2019, the Stipulating Parties filed the Public Staff Stipulation resolving all issues except the recovery of the Company's CCR costs. The Public Staff Stipulation is based on the same test period as the Company's Application. In summary, the Public Staff Stipulation provides:

- the revenue requirement increase of \$24,879,000 proposed by the Company in its August 5, 2019, supplemental filing should be reduced by at least \$13,517,000, based on the Company's position of an increase in the revenue requirement of \$6.428 million, consisting of an increase of \$8.583 million in non-fuel revenues and a decrease of \$2.155 million in base fuel revenues, and the Public Staff's position of an increase in the revenue requirement of \$2.037 million, consisting of an increase in \$4.192 million in non-fuel revenues and a decrease of \$2.155 million in base fuel revenues, with the difference between the Company's and the Public Staff's positions resulting from the unresolved issues identified in Section II.A.i of the Public Staff Stipulation (cost

⁴ Consolidated into Docket No. E-22, Sub 562 by Commission Order Consolidating Dockets (May 2, 2019).

recovery of the Company's CCR costs, the recovery amortization period, and return during the amortization period);

- a rate of return on common equity of 9.75% and an overall rate of return on rate base of 7.20%;
- a capital structure for ratemaking purposes consisting of 52% equity and 48% long-term debt;
- an embedded cost of debt of 4.442%;
- agreement on numerous adjustments to the Company's cost of service;
- a \$2.155 million decrease in DENC's annual base fuel revenues and a base fuel factor of 2.092¢/kWh, including regulatory fee;
- a decrement Rider A1, equal to (0.375¢/kWh) on a jurisdictional basis, calculated as the difference between the currently approved Rider B Experience Modification Factor (EMF) of 0.388¢/kWh and the proposed Rider B EMF in the Company's 2019 Fuel Case (Docket No. E-22, Sub 579) of 0.013¢/kWh;
- a Rider EDIT allowing for the recovery of \$1,214,000 of federal EDIT, which includes the amortization of all unprotected federal EDIT totaling approximately \$8.0 million partially offset by the refund of approximately \$6.8 million associated with federal EDIT amortization attributable to the 22-month period of January 1, 2018, through October 31, 2019;
- allocation of the Company's cost of service based on the SWPA method, including adjustments to recognize the peak demand contributions of NUGs interconnected to the Company's distribution system and to remove the demand and energy requirements of three customers in DENC's Virginia jurisdiction for whom the obligation to provide generation service has ended or will end during 2019;
- inclusion of certain wet-to-dry conversion costs at the Chesterfield Power Station (Chesterfield) in the revenue requirement, subject to a similar dispute pending in the Company's Virginia jurisdiction; and
- agreement that the overall quality of electric service provided by DENC is good.

In support of the Public Staff Stipulation, Company witness McLeod testified that DENC, the Public Staff, and intervenors engaged in substantial discovery regarding the matters addressed in the Public Staff Stipulation. Witness McLeod further testified that the Public Staff Stipulation is the result of give-and-take negotiations in which each party made substantial compromises on individual issues in order to obtain a compromise from

the other parties on other issues. He stated that the Stipulating Parties believe the results reached are fair to the Company and its customers. Witness McLeod also noted that the Public Staff Stipulation resolves all but one contested issue in the case between the Stipulating Parties without the necessity of contentious litigation. With respect to the contested issue not resolved by the Public Staff Stipulation, witness McLeod explained that \$4.3 million of the CCR costs would be resolved outside of the Public Staff Stipulation as the Company would not support the “equitable sharing” methodology for these remaining CCR costs. Tr. vol. 4, 334-41.

Company witness Hevert also filed testimony in support of the Public Staff Stipulation. He testified that the 9.75% rate of return on common equity agreed to in the Public Staff Stipulation reflects negotiations among the Stipulating Parties and, taken as a whole with the rest of the Public Staff Stipulation, would be viewed by the financial community as constructive and equitable. Witness Hevert acknowledged that the 9.75% Stipulation rate of return on common equity falls below his recommended range of 10.00% to 11.00% but noted that the stipulated rate of return on common equity is a reasonable resolution of a complex and frequently contentious issue. Tr. vol. 4, 115-19.

Company witness Davis’ testified in support of the Public Staff Stipulation’s capital structure of 52.00% equity and 48.00% long-term debt. He stated that while differing from the recommendation in his direct testimony, the stipulated capital structure represents a reasonable compromise when considered within the context of the Public Staff Stipulation taken as a whole. Tr. vol. 4, 231-33.

Company witness Miller’s testimony in support of the Public Staff Stipulation supported the cost of service issues agreed upon in the Public Staff Stipulation and provided updated schedules with a fully adjusted cost of service study showing the effects of all adjustments and rate changes to the North Carolina classes based on the Public Staff Stipulation. Tr. vol. 4, 538-42.

Finally, DENC witness Haynes’ testimony in support of the Public Staff Stipulation explained the cost allocation, revenue apportionment, rate design, and cost of service studies agreed upon in the Public Staff Stipulation. Witness Haynes testified that the Public Staff Stipulation presents a just and reasonable approach to establishing the cost of service for the Company’s North Carolina jurisdiction using the SWPA allocation methodology. He also explained that the SWPA methodology used the system load factor to weight the average component and the peak demand component, which was the same approach proposed in the Company’s direct and rebuttal testimony, as well as the approach supported by Public Staff witness Floyd. Witness Haynes also explained that the Company still proposed to include decrement Rider A1 to mitigate the effect of the November 1, 2019, base non-fuel increase. Tr. vol. 4, 485-90.

Public Staff witnesses McLawhorn and Johnson filed joint testimony in support of the Public Staff Stipulation. They testified to the Public Staff’s perception of several benefits provided by the Public Staff Stipulation, including a reduction in the base non-fuel revenue increase initially requested by DENC and the avoidance of protracted

litigation between the Stipulating Parties. Similar to DENC witness McLeod, witnesses McLawhorn and Johnson stated that the CCR costs issue was not resolved in the Public Staff Stipulation and, therefore, the accounting and ratemaking adjustments cannot be finalized until the Commission makes a determination on that issue. Tr. vol. 6, 52.

Discussion and Conclusions

As the Public Staff Stipulation has not been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject the Public Staff Stipulation is governed by the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*). In *CUCA I*, the Supreme Court held:

[A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding.

The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a non-unanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a non-unanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] . . . satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." *Id.* at 231-32, 524 S.E.2d at 16.

The Commission gives substantial weight to the testimony of DENC witness McLeod regarding the Stipulating Parties' efforts in negotiating the Public Staff Stipulation. Further, the Commission gives significant weight to the settlement testimony of Public Staff witnesses McLawhorn and Johnson, which in their discussion of the benefits that the Public Staff Stipulation will provide to customers and their testimony

describing the compromise reflected in the Public Staff Stipulation's terms, indicate the Public Staff's commitment to fully represent the using and consuming public.

As a result, the Commission finds and concludes that the Public Staff Stipulation is the product of the give-and-take between the Stipulating Parties during their settlement negotiations in an effort to appropriately balance DENC's need for increased revenues and its customers' needs to receive safe, adequate, and reliable electric service at the lowest possible rates. In addition, the Commission finds and concludes that the Public Staff Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the Public Staff Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The evidence supporting these findings of fact and conclusions is contained in the testimony of DENC witnesses Davis, Hevert, Miller, and Haynes; CIGFUR witnesses Wielgus and Thomas; and the entire record in this proceeding.

Summary of the Evidence

On September 23, 2019, DENC and CIGFUR (CIGFUR Stipulating Parties) filed the CIGFUR Stipulation resolving certain issues related to rate of return, cost allocation, rate design, and terms and conditions. In summary, the CIGFUR Stipulation provides:

- the Company's SWPA methodology calculated using the system load factor to weight the average component and (1 - system load factor) to weight the peak demand component is appropriate for use in allocating the Company's per books cost of service to the North Carolina jurisdiction and between customer classes in this case;
- DENC and CIGFUR agree to the two adjustments the Company made in the course of calculating the SWPA;
- in the next general rate case, the Company should file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method in addition to the SWPA used in this proceeding and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes; and
- considering that no customers have taken service under the pilot Real Time Pricing (RTP) rates filed by the Company and approved by the Commission in Sub 532, the Company will work with CIGFUR to consider whether certain provisions within those rates should be modified. If there is mutual agreement between CIGFUR and DENC to such modifications, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates,

DENC agrees to re-file such rates with the Commission for approval with the modifications agreed upon within 60 days of such agreement.

At the hearing, Company witnesses Haynes and Miller stated their support for the CIGFUR Stipulation in the summaries of their testimonies. Witness Haynes stated that the CIGFUR Stipulation presents a just and reasonable approach to establishing the Company's North Carolina jurisdictional cost of service and class cost of service for the allocation of production and transmission plant costs and related expenses based on the SWPA allocation methodology. He indicated that the Company believes the CIGFUR Stipulation represents a reasonable compromise of the allocation and rate design issues in this case, is fair to all parties, and should be approved by the Commission. Witness Miller stated that the CIGFUR Stipulation represents a reasonable compromise of the cost of service issues in this case, is fair to all parties, and should be approved by the Commission. Tr. vol. 4, 497, 545.

Discussion and Conclusions

As with the Public Staff Stipulation, because the CIGFUR Stipulation has not been adopted by all of the parties to this docket the Commission's determination of whether to accept or reject the CIGFUR Stipulation is governed by the standards set out by the North Carolina Supreme Court in *CUCA I* and *CUCA II*.

The Commission gives significant weight to the testimony of DENC witnesses Haynes and Miller regarding the Company's support for the CIGFUR Stipulation.

As a result, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the CIGFUR Stipulating Parties during their settlement negotiations in an effort to appropriately balance DENC's need for increased revenues and CIGFUR's interest in advocating for its member customers. In addition, the Commission finds and concludes that the CIGFUR Stipulation was entered into by the CIGFUR Stipulating Parties after discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the CIGFUR Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

Capital Structure

The evidence supporting these findings of fact and conclusions is contained in the testimony and exhibits of Company witness Davis, Public Staff witness Woolridge, CIGFUR witness Phillips, and the Public Staff and CIGFUR Stipulations, as well as testimony and exhibits presented at the hearing of this matter.

In his prefiled direct testimony, DENC witness Davis proposed a capital structure consisting of 53.01% common equity and 46.99% long-term debt, DENC's capital

structure as of December 31, 2018. He discussed the Company's significant capital needs going forward, and explained how the Company plans to finance those capital needs, based on a balance of debt and common equity that DENC believes will support the Company's credit ratings going forward, and continue to enable the Company to access a number of markets, under a wide range of economic environments, on reasonable terms and conditions. Witness Davis stated that this market access is critical to fund the ongoing infrastructure capital expenditure programs that will be necessary to meet the Company's public service obligations in North Carolina and throughout its system. Tr. vol. 4, 204-09, 214-17.

In his supplemental testimony, witness Davis updated the Company's proposed capital structure to its actual structure as of June 30, 2019, which reflected a long-term debt component of 46.351% and an equity component of 53.649%. Based on the Company's proposed updated cost rates for long-term debt and common equity, witness Davis' proposed updated capital structure produced an updated overall weighted-average cost of capital of 7.826%. Tr. vol 4, 219-20.

Public Staff witness Woolridge testified that the Company's proposed capital structure included more common equity than the average of the proxy group he used in conducting his analysis. He stated that it is appropriate to use the common equity ratios of the parent holding companies and that the high debt ratio and low equity ratio of DEI is a credit negative for DENC as evaluated by Moody's. He noted, however, that because DENC is a regulated business, it is exposed to less risk and can carry relatively more debt in its capital structure than most unregulated companies, like DEI. Witness Woolridge further testified that DENC should take advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements and, as a result, recommended a capital structure of 50.00% common equity and 50.00% debt based on a 9.00% rate of return on common equity. Witness Woolridge also made an alternative capital structure recommendation of the Company's actual capital structure as of June 30, 2019, of 46.35% long-term debt and 53.65% common equity based on an 8.75% return on equity. Tr. vol. 6, 552-62.

CIGFUR witness Phillips testified that DENC's proposed capital structure includes more equity and less debt than other electric utilities and recommended a capital structure not to exceed 52.00% common equity. In support of his recommendation, witness Phillips analyzed the proxy groups that he claimed met the various jurisdictional regulatory capital structures of a comparable group of electric utility companies. He referenced groups that consisted of all electric utilities nationwide with equity ratios determined in the first half of 2019 and North Carolina gas and electric utilities that have had authorized rates of return on equity approved in recent years. Witness Phillips concluded that the Company's proposed capital structure was inconsistent with those authorized by the Commission in recent rate cases. Tr. vol 6, 412, 416, 429-31.

In his rebuttal testimony, witness Davis testified that witness Phillips' recommendation ignores the Company's actual capital structure as of June 30, 2019, as well as DENC's capital structure at year-end of each of the previous three years in favor

of arbitrarily developed structures. Witness Davis stated that it is important that the Company's actual capital structure be considered in determining the appropriate capital structure for purposes of this rate case because imputing the structure of other peer utilities in different jurisdictions can lead to erroneous conclusions. He also explained that the Company's financing plan is structured to maintain the Company's current credit ratings, which provide the greatest benefit to customers in the long-term. Witness Davis stated that an arbitrarily derived capital structure could be viewed negatively by the Company's credit agencies. Finally, witness Davis explained that using the Company's actual capital structure helps to support the significant capital spending program the Company has and continues to undertake to enhance and improve DENC's generation and transmission infrastructure. Tr. vol. 6, 221-29.

Under Section III.A of the Public Staff Stipulation, the Stipulating Parties proposed a capital structure of 52% common equity and 48% long-term debt. In their stipulation testimony, Company witness Davis and Public Staff witnesses Johnson and McLawhorn testified that the capital structure reflected in the Public Staff Stipulation represents a compromise by both parties in an effort to reach agreement and is in the public interest. Witness Davis testified that the capital structure represented in the Stipulation provides an equity ratio that is 165 basis points lower than the Company's request of 53.649%, 200 basis points higher than the Public Staff's initial recommendation presented in witness Woolridge's testimony, and 25 basis points higher than the equity ratio authorized in the 2016 Rate Case. Witness Davis stated that he, like the Public Staff witnesses, believes the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that such a ratio will allow the Company to continue providing safe and reliable service to its customers. Tr. vol. 6, 51-52, vol. 4, 231-33.

In the CIGFUR Stipulation, CIGFUR and DENC stipulated that it was appropriate to use a capital structure consisting of 52% equity and 48% long-term debt.

In evaluating the evidence on capital structure in this proceeding, the Commission first notes that the equity/debt ratios reflected in the Stipulation of 52.00% equity and 48.00% long-term debt are consistent with and well within the prior experience of the Commission.⁵ These are not determinative factors from the Commission's perspective, but they do provide some context supporting the reasonableness of the stipulated capital structure.

Based upon its own review and independent analysis of the evidence, the Commission concludes that a capital structure of 52.00% equity and 48.00% long-term debt, as is reflected in the Public Staff Stipulation, is just and reasonable and appropriate for use in this proceeding on several grounds.

⁵ See DENC Sub 532 Order (51.75% common equity and 48.25% debt); PSNC Sub 565 Order (52.0% common equity, 44.62% long-term debt, 3.38% short-term debt); PNG Sub 743 Order (52.00% equity, 47.15% long-term debt, 0.85% short-term debt); DEC Sub 1146 Order (52% common equity and 48% long-term debt); DEP Sub 1142 Order (52% common equity and 48% long-term debt).

First, this capital structure is very close, i.e., 25 basis points, to the capital structure authorized for DENC in its last rate case. Second, this capital structure was accepted by CIGFUR in the CIGFUR Stipulation. Third, while the Commission recognizes that Public Staff witness Woolridge recommended a 50% common equity and 50% debt capital structure based on a 9.00% rate of return on equity as his primary recommendation, he also proposed use of the actual capital structure as of December 31, 2018, of 46.351% long-term debt and 53.649% common equity based on an 8.75% return on equity. Fourth, Section X of the Public Staff Stipulation provides:

[T]his Stipulation is in the public interest because it reasonably balances customer interests in mitigating rate impacts with investor interests in providing for reasonable recovery of investments, thereby providing the necessary level of revenue requirement to allow the Company to maintain its financial strength and credit quality and continue to provide high quality electric utility service to its customers.

Fifth, Section IV of the CIGFUR Stipulation contains this same language. Sixth, the Commission gives substantial weight to Company witness Davis' testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. As witness Davis noted, witness Phillips relies primarily on the averages of his respective proxy groups without providing any further rationale in support of his recommended capitalization ratios. Seventh, the Commission places substantial weight as well on witness McLawhorn's and witness Johnson's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by at least \$13 million. Eighth, the Commission also gives weight to the Public Staff Stipulation and the benefits that it provides to DENC's customers, which the Commission is obliged to consider as an independent piece of evidence under *CUCA I* and *CUCA II*. Each party to the Public Staff Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on the Application and pre-filed testimony, it is apparent that the Public Staff Stipulation ties the 52/48 capital structure to substantial concessions the Company made to reduce its revenue requirement.

Accordingly, based on the matters set forth above, and in the exercise of its independent judgment, the Commission finds that the weight of the evidence in this proceeding favors using the stipulated capital structure and that such capital structure is just, reasonable, and appropriate for use in setting rates in this docket.

Cost of Debt

The evidence supporting this finding of fact and conclusions is contained in the testimony and exhibits of Company witness Davis and Public Staff witness Woolridge, the Public Staff and CIGFUR Stipulations, and the entire record of this proceeding.

In its Application and supporting testimony, the Company proposed a long-term debt cost of 4.45% at the end of the test year. In his supplemental testimony, Company witness Davis updated the debt cost to 4.442% as of June 30, 2019. The Public Staff and CIGFUR Stipulations accept the 4.442% cost of debt proposed by the Company in witness Davis' supplemental testimony. No party contested the cost of debt proposed by the Company or agreed upon in the Public Staff and CIGFUR Stipulations.

The Commission, therefore, finds and concludes that the use of a debt cost of 4.442% is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-16

The evidence for these findings of fact and conclusions is contained in the Application; the direct testimony and exhibits of witnesses Hevert, Woolridge, and Phillips; the Public Staff and CIGFUR Stipulations; the testimony of public witnesses; the rebuttal testimony of witness Hevert; the settlement testimony of witnesses Hevert, McLawhorn, and Johnson; and the hearing testimony of witness Hevert.

The Public Staff and CIGFUR Stipulations both state that an allowed rate of return on common equity of 9.75% is reasonable for use in this proceeding, a decrease from the 9.9% level authorized by the Commission in the Company's last rate case. No other party presented evidence on the appropriate rate of return on common equity. The Commission's consideration of the evidence and decision on this issue is set out below and is organized into three sections. The first is a summary of the record evidence on rate of return on common equity. The second is a summary of the law applicable to the Commission's decision on rate of return on common equity. The third is an application of the law to the evidence and a discussion and explanation of the Commission's ultimate decision on rate of return on common equity.

Summary of Record Evidence on Return on Equity

In its Application, the Company requested approval for its rates to be set using an overall rate of return of 7.79% and a rate of return on equity of 10.75%. This request was based upon and supported by the direct testimony of DENC witness Hevert. These rates of return compare to an overall return of 7.367% and rate of return on common equity of 9.90% underlying DENC's current rates. DENC witness Mitchell also filed testimony supporting the approval of the rate of return on common equity recommended by witness Hevert. Witnesses for the Public Staff and CIGFUR also filed direct testimony on the appropriate rate of return on equity. This evidence was followed by the Public Staff and CIGFUR Stipulations, rebuttal testimony filed by witness Hevert, settlement testimony filed by DENC witness Hevert and Public Staff witnesses McLawhorn and Johnson, and finally testimony of witness Hevert at the hearing of this matter. In addition to this expert testimony, the Commission received the testimony of a number of public witnesses on DENC's proposed rate increase as well as numerous statements of consumer position. All of this evidence is summarized below.

Direct Testimony of Mark Mitchell (DENC)

DENC witness Mitchell testified that the Company was facing significant capital investment needs. He stated that in order to attract the capital to meet these substantial future needs, the Company must achieve an adequate authorized rate of return on common equity in this proceeding, and that the 10.75% rate of return on common equity proposed by DENC would allow the Company to attract capital on reasonable terms in the capital markets. He explained that the ability to attract capital on favorable terms is important to DENC's ability to maintain its current credit ratings and, ultimately, minimize the cost of capital for customers, and that an adequate return also ensures DENC's ability to commit capital to future construction projects to provide safe, reliable, and cost-effective electric service to North Carolina customers without eroding the Company's shareholders' interests. Tr. vol. 4, 168, 177-82.

Direct Testimony of Robert B. Hevert (DENC)

Witness Hevert, DENC's primary cost of equity witness, filed direct testimony and exhibits in support of DENC's request for a 10.75% rate of return on common equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation. In his direct testimony and exhibits, witness Hevert discussed the specific analyses he conducted in support of DENC's rate filing and provided a detailed description of the results of these analyses and resulting cost of equity recommendations. He applied the Constant Growth Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), the Empirical Capital Asset Pricing Model (ECAPM), the Bond Yield Plus Risk Premium approach, and the Expected Earnings Analysis to develop his rate of return on equity recommendation. He stated that the Commission's decision should result in providing DENC with the opportunity to earn a rate of return on common equity that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case. Witness Hevert also noted that the regulatory conditions approved by the Commission in the merger of DENC's parent company, DEI, and SCANA Corporation were designed to ensure that the Company has "sufficient access to equity and debt capital at a reasonable cost to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their customers." Tr. vol. 4, 32-33.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a rate of return on equity range of 8.34% to 10.38%. The results of witness Hevert's CAPM analysis showed a range of 8.25% to 11.34% in market risk premiums. The results of his ECAPM analysis showed a range of 9.61% to 12.76% in rate of returns on equity. The results of his Bond Yield Plus Risk Premium analysis indicated a rate of return on common equity range from 9.93% to 10.17%. The results of his Expected

Earnings Analysis showed an average rate of return on common equity of 10.38% and a median rate of return on equity of 10.52%. Based on his analyses, witness Hevert concluded that a rate of return on common equity in the range of 10.00% to 11.00% represents the rate of return on common equity required by equity investors for investment in integrated electric utilities in today's capital markets. Within that range, he recommended a rate of return on common equity for DENC of 10.75% in both his direct and rebuttal testimony. Tr. vol. 4, 45-56.

Witness Hevert explained that his rate of return on common equity recommendation also took into consideration several additional factors, including (1) DENC's need to fund its substantial planned capital investment program, (2) the regulatory environment in which the Company operates, and (3) flotation costs. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized rates of return on common equity tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his rate of return on common equity estimates for the effect of these factors. Tr. vol. 4, 56-67.

Witness Hevert also addressed the capital market environment and testified that it is important to assess the reasonableness of any financial model's results in the context of observable market data. In particular, he discussed the fact that investors see a probability of increasing interest rates based on near-term forecasts of the 30-year Treasury yield. Tr. vol. 4, 77-81.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his rate of return on common equity recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and in the U.S. generally since late 2009 and early 2010, with December 2018 rates of 3.70% in the State. He noted that since the Company's last general rate filing in March 2016, unemployment in the counties served by DENC has fallen by 1.40%. Witness Hevert also noted that since the second quarter of 2013, the State has generally matched the national rate for real GDP, but that since 2009, median household income in North Carolina has grown at a somewhat slower annual rate than the national median income annual rate than the national median income. Total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Finally, he noted that since 2018, residential electricity costs in North Carolina remain approximately 13.00% below the national average. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within DENC's service area have experienced steady economic improvement since the Company's last rate case and that improvement is projected to continue. In his opinion, DENC's proposed rate of return on common equity is fair and reasonable to DENC, its shareholders and its customers, in light of the impact of changing economic conditions on DENC's customers. Tr. vol. 4, 67-77.

Direct Testimony of J. Randall Woolridge (Public Staff)

Public Staff witness Woolridge performed DCF and CAPM analyses for both his and witness Hevert's proxy groups of electric utilities. Witness Woolridge developed his DCF growth rate after reviewing 13 growth rate measures including historic and projected growth rate measures and evaluating growth in dividends, book value, earnings per share (EPS), and growth rate forecasts from Yahoo, Reuters, and Zack's. Witness Woolridge testified that it is well known that long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Public Staff witness Woolridge determined a DCF equity cost rate of 8.55% for his proxy group, and 8.95% for the witness Hevert proxy group. Tr. vol. 6, 534-37.

In witness Woolridge's CAPM analysis, he used for the risk free interest rate the top end of the range of yields on 30-year U.S. Treasury bonds over the 2013-2019 time period, 4.00%. He used the Value Line Investment Survey betas of 0.60 for his proxy group and 0.58 for witness Hevert's proxy group. Witness Woolridge's market risk premium was 5.50%, based in part on the June 2019 CFO survey conducted by CFO Magazine and Duke University, which included approximately 200 responses, in which the expected market risk premium was 4.05%. He testified that thus, his 5.50% value is a conservatively high estimate of the market risk premium. Witness Woolridge also testified that Duff & Phelps, a well-known valuation and corporate finance advisor that publishes extensively on cost of capital, recommended on December 31, 2018, using a 5.5% market risk premium, for the U.S. Witness Woolridge's CAPM equity cost rate was 7.30% for his proxy group and 7.20% for witness Hevert's proxy group. Tr. vol. 6, 591-604.

Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness Hevert's proxy groups is in the 7.20% to 8.95% range. He gave primary weight to his DCF results based on his belief that risk premium studies, including the CAPM, are a less reliable indicator of equity cost rates for public utilities. Witness Woolridge also indicated that he found the DCF model to provide the best measure of equity cost rates considering the investment valuation process and the relative stability of the utility business. Tr. vol. 6, 531, 604-05.

While noting that his equity cost rate studies indicated a rate of return on common equity between 7.20% and 8.95%, witness Woolridge took into account the fact that his range was below the authorized rates of return on common equity for electric utilities nationally and made a primary recommendation of a 9.00% rate of return on equity, assuming a 50.00% common equity ratio. Witness Woolridge also provided an alternative recommendation of an 8.75% rate of return on common equity based on the Company's originally recommended equity ratio of 53.649%. Tr. vol. 6, 532-33.

Witness Woolridge did not perform an ECAPM analysis and testified that the ECAPM is an ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals. He also took issue with witness Hevert's Bond Yield Plus Risk Premium analysis and argued that it is inflated, gauges commission behavior rather

than investor behavior, and overstates the actual rate of return on common equity. Tr. vol. 6, 612-13, 640-44.

Witness Woolridge also expressed concerns with witness Hevert's Expected Earnings analysis and argued that the approach is inappropriate for several reasons: (1) it is accounting based and does not measure market based investor return requirements; (2) book equity does not change with investor return requirements as do market prices; (3) there is a negative relationship between the Return on Common Equity and Common Equity ratios; (4) the approach is circular; and (5) the data partially reflect earnings of non-regulated operations. Tr. vol. 6, 613, 644-48.

Witness Woolridge also testified as to current capital market conditions as of the date of his testimony in August 2019. He stated that although the Federal Reserve increased the Federal Funds rate between 2015 and 2018, interest rates and capital costs remained at low levels. Witness Woolridge also pointed out that the 30-year Treasury yields are at historically low levels and are accompanied by slow economic growth and low inflation. Tr. vol. 6, 548, 591, 610.

Witness Woolridge responded to witness Hevert's assessment of the economic conditions in North Carolina. He generally agreed with witness Hevert's review of several measures of economic conditions, including the rate of unemployment, real GDP growth, median household income, residential electricity rates, and broad measures of income and consumption, as well as witness Hevert's general conclusion that economic conditions in North Carolina have improved since the Company's last rate case. Witness Woolridge argued, however, that although economic conditions generally have improved, other conditions such as the higher unemployment rate in the DENC service territory as opposed to the whole state, and the median household income in North Carolina that is lower than the national norm, as well as the over 100 basis point difference in DENC's requested rate of return on common equity and the average authorized rates of return on equity for electric utilities in 2018-2019, do not support the Company's proposed rate of return. Tr. vol. 6, 652-55.

Direct Testimony of Nicholas Phillips, Jr. (CIGFUR)

CIGFUR witness Phillips did not perform cost of capital analyses. In his testimony witness Phillips found the Company's proposed rate of return on equity to be excessive based on his review of authorized rates of return on common equity for the first half of 2019, which averaged 9.57%, as reported by RRA. Witness Phillips recommended that the Commission authorize a rate of return on common equity that does not exceed the national average of 9.57%. Tr. vol. 6, 427-31.

Rebuttal Testimony of Robert B. Hevert (DENC)

In his rebuttal testimony, Company witness Hevert responded to the arguments raised by CIGFUR witness Phillips. Witness Hevert explained that he analyzed the authorized rate of return on common equity for vertically integrated electric utilities based

on the jurisdiction's ranking by RRA, which provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives. Witness Hevert stated that according to RRA, less constructive environments are associated with higher levels of risk, but North Carolina currently is ranked "Average/1," which falls approximately in the top-third of the 53 jurisdictions ranked by RRA. Witness Hevert testified that authorized rates of return on common equity for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions, like North Carolina, range from 9.37% to 10.55%, with an average of 9.93%, and a median of 9.95%. Finally, witness Hevert pointed to Company Rebuttal Exhibit RBH-16, which shows that the mean and median authorized rates of return on common equity for 2019, updated through August 16, 2019, are 9.61% and 9.73%, respectively. Tr. vol. 4, 107-12.

Public Staff and CIGFUR Stipulations

In both the Public Staff and the CIGFUR Stipulations, DENC and the Public Staff, and DENC and CIGFUR agreed that the appropriate overall rate of return and rate of return on common equity for use in this proceeding were 7.20% and 9.75%, respectively. These agreements represent substantial movement by the parties from the positions on overall return and return on common equity articulated in testimony. This stipulated overall return of 7.20% and return on common equity of 9.75% was supported by settlement testimony filed by Company witness Hevert. The overall reasonableness of the stipulated rates of return was also addressed by Public Staff witnesses McLawhorn and Johnson in their settlement testimony.

Settlement Testimony of Robert B. Hevert (DENC)

In his testimony supporting the Stipulations, witness Hevert noted that although the 9.75% stipulated rate of return on common equity is somewhat below the lower bound of his recommended range, he recognized that the Stipulations reflect negotiation on many issues between the parties. Witness Hevert stated that the terms of the Stipulations, when taken as a whole, would be regarded favorably by the financial community. He noted that the median rate of return on common equity authorized in 2019 at the time of his testimony was 9.73%, only two basis points from the stipulated rate of return on common equity. Witness Hevert testified that the stipulated rate of return on common equity fell below his Risk Premium model results, it fell in the 69th percentile of the mean and median of his DCF results, the 32nd percentile of his CAPM and ECAPM results, and the 40th percentile of his Expected Earnings analysis. Thus, witness Hevert concluded that the stipulated rate of return on equity was supported by returns in other jurisdictions and fell within the range of his model results, though at the lower end. Tr. vol. 4, 116-19.

Hearing Testimony of Robert B. Hevert (DENC)

Under cross-examination by the AGO, witness Hevert defended the use of projected treasury yields in his CAPM analysis by pointing out that there was only about a 21-basis point difference between the current and projected treasury yields, which was not a material difference. He noted that the CAPM results based on the current yield also

support his recommendation. Witness Hevert also pointed out that using projected yields gave an important perspective, especially in light of the fact that in the recent market, the 30-year Treasury yield fell 71 basis points in 34 trading days. He further pointed out that in the Sub 1142 Order in DEP's 2017 rate case and a recent Virginia case the commissions found his DCF analysis to produce unreasonably low rate of return on equity results, even using only earnings estimates. Witness Hevert did not dispute that of the 32 data points he considered in determining his range and recommended rate of return on equity, 24 were lower than his recommended rate of return on common equity. Nonetheless, witness Hevert noted that a mean of these results would not necessarily provide an appropriate estimate of DENC's cost of equity, as various qualitative factors should also be considered, such as capital expenditure plans and the regulatory environment. Tr. vol. 4, 143-47.

Public Witness Testimony/Statements of Consumer Position

In addition to the direct prefiled testimony of the expert witnesses for the parties, a number of public witnesses also gave testimony suggesting that DENC customers would experience difficulty paying the increased rates requested in the Application and opposing the rate increases proposed by DENC. The Commission also received numerous statements of consumer position with regard to this docket, many of which expressed concern about DENC's proposed rate increase.

Law Governing the Commission's Decision on Return on Equity

Rate of return on common equity is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which stipulations between DENC and the Public Staff and DENC and CIGFUR have been reached. In the absence of a settlement agreed to by all the parties, the law of North Carolina requires the Commission to exercise its independent judgment and arrive at its own independent conclusion as to the proper rate of return on common equity. See, e.g., *CUCA I*, 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the rate of return on common equity, the Commission must evaluate the available evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (*Cooper I*). In this case, the expert witness evidence relating to the Company's cost of equity capital was presented by Company witness Hevert, Public Staff witness Woolridge, and CIGFUR witness Phillips. No return on equity evidence was presented by any other party.

The baseline for establishment of an appropriate rate of return on common equity is the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*

of *W. Va.*, 262 U.S. 679 (1923) (*Bluefield*), and *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944) (*Hope*) which establish that:

To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [a rate of return on common equity], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

DEC Sub 1146 Order at 50; see also *State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Se.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute “the test of a fair rate of return declared” in *Bluefield* and *Hope*. *Id.*

It is also important for the Commission to keep in mind that the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Service Commission*, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a “capital charge”) and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds . . . and it is true also of the economic obligation to pay dividends on stock, preferred or common.

Id. at 306. (Brandeis, J., dissenting) (emphasis added). Similarly, the United States Supreme Court observed in *Hope*, “[f]rom the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business . . . [which] include service on the debt and dividends on the stock.” 320 U.S. at 591, 603.

Leading academic commentators also define rate of return on equity as the cost of equity capital. Professor Charles Phillips, for example, states that “the term ‘cost of capital’ may be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs.” Phillips, Charles F, Jr., *The*

Regulation of Public Utilities 388 (Public Utilities Reports, Inc. 1993). Professor Roger Morin approaches the matter from the economist's viewpoint:

While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.

[T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). Professor Morin adds:

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Id. at 20.

In addition, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. *State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (*Public Staff*). Further, and echoing the discussion above concerning the fact that rate of return on equity represents the cost of equity capital, the Commission must execute the Supreme Court's command "irrespective of economic conditions in which ratepayers find themselves." Order Granting General Rate Increase, *Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023, at 37 (N.C.U.C. May 30, 2013), *aff'd*, *State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444,

761 S.E.2d 640 (2014) (2013 DEP Rate Case Order). The Commission noted in that order:

The Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on equity when the general body of ratepayers is in a better position to pay than other times, which would seem to be a logical but misguided corollary to the position the Attorney General advocates on this issue.

Id. Indeed, in *Cooper I* the Supreme Court emphasized "changing economic conditions" and their impact upon customers. *Cooper I*, 366 N.C. at 484, 739 S.E.2d at 548.

The Commission further noted in the 2013 DEP Rate Case Order that while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission noted this in the 2013 DEP Rate Case Order:

This impact is essentially inherent in the ranges presented by the return on equity expert witnesses whose testimony plainly recognizes economic conditions — through the use of economic models — as a factor to be considered in setting rates of return.

2013 DEP Rate Case Order at 38.

Finally, under long-standing decisions of the North Carolina Supreme Court, the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *Public Staff*, 323 N.C. at 490, 374 S.E.2d at 369. As the Commission has previously noted:

Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process the appropriate [rate of return on common equity] is the one requiring the greatest degree of subjective judgment by the Commission. Setting [a rate of return on common equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,

Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for

determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.

The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.

In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:

There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.

As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

2013 DEP Rate Case Order at 35-36 (additions and omissions after the first quoted paragraph in original).

Moreover, the North Carolina Supreme Court has interpreted N.C.G.S. § 62-133 as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on equity for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing rate of return on equity-related factors—the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service. 2013 DEP Rate Case Order at 35-36.

In addition to adhering to the broad controlling legal principles on the allowed rate of return discussed above, the Commission must adhere to the multi-element formula set forth in N.C.G.S. § 62-133 when it sets rates. The rate of return on cost of property element of the formula in N.C.G.S. § 62-133(b)(4) is a significant, but not an independent element. Each element of the formula must be analyzed to determine the utility's cost of service and revenue requirement. The Commission must make many subjective decisions with respect to each element in the formula in establishing the rates it approves in a general rate case. The Commission must approve accounting and pro forma adjustments to comply with N.C.G.S. § 62-133(b)(3) and must approve depreciation rates pursuant to N.C.G.S. § 62-133(b)(1). The subjective decisions the Commission makes as to each of these elements have multiple and varied impacts on the decisions it makes on other rate-affecting elements, such as the decision it must make on the rate of return on common equity.

Pursuant to N.C.G.S. § 62-133(c), rates in North Carolina are set based on a modified historic test period. A component of cost of service equally important as the return on investment component is test year revenues. N.C.G.S. § 62-133(b)(3). The higher the level of test year revenues, the lower the need for a rate increase, all else remaining equal. Historically, and in this case, test year revenues are established through resort to regression analysis, using historic rates of revenue growth or decline to determine end of test year revenues. Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Order will affect not only the ability of DENC's customers to pay electric rates, but also the ability of DENC to earn the authorized rate of return during the period rates will be in effect. Thus, in accordance with the above-discussed applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to attract investors to raise the capital needed to provide reliable electric service and recover its cost of providing service.

In fixing rates, the Commission is also cognizant that when a utility's costs and expenses grow at a faster pace than revenues during the period when rates will be in effect, it will experience a decline in its realized rate of return on investment to a level below its authorized rate of return. Differences exist between the authorized return and the earned, or realized, return. Components of the cost of service must be paid from the

rates the utility charges before the equity investors are paid their return on equity. Operating and administrative expenses must be paid, depreciation must be funded, taxes must be paid, and the utility must pay interest on the debt it incurs. To the extent revenues are insufficient to cover the entire cost of service, the shortfall reduces the return to the equity investor, last in line to be paid. When this occurs, the utility's realized, earned return is less than the authorized return, an occurrence commonly referred to as regulatory lag. In setting the rate of return, just as the Commission is constrained to address the impact of difficult economic times on customers' ability to pay for service by establishing a lower rate of return on equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise is constrained to address the effect of regulatory lag on the Company by establishing a higher rate of return on equity. Instead, the Commission sets the rate of return considering both of these negative impacts in its ultimate decision fixing a utility's rates.

It is against this backdrop of overarching principles and law that the Commission turns to the evidence present in this case.

Discussion and Application of Law to the Facts

The Commission has examined the Company's Application and supporting testimony and exhibits and Form E-1 filings seeking to justify its requested increase. DENC's updated request prior to entering into the stipulations was a retail revenue increase of \$24.2 million in annual revenues. The Public Staff, who in this docket represents all users and consumers of the Company's electric service, and DENC entered into a stipulation that resulted in reducing the retail revenue increase sought by the Company. CIGFUR and DENC entered into a separate stipulation that provided for the same reduction in the revenue increase, as well as a 9.75% rate of return on common equity. As with all settlement agreements, each party to the stipulations gained some benefits that it deemed important and gave some concessions for those benefits. Based on DENC's Application, it is apparent that the stipulations tie the 9.75% rate of return on common equity to substantial agreed upon concessions made by DENC. As noted above, since the AGO and Nucor, parties in this docket, did not agree to the settlements, the Commission is required to examine the stipulations and exercise its independent judgment to arrive at its own independent conclusion as to the proper rate of return on common equity.

The starting point for an examination of what constitutes a reasonable rate of return on common equity begins with the various economic and financial analyses provided by the parties' expert witnesses. In this proceeding, those analyses were provided in the testimonies of three different witnesses: witness Hevert for DENC; witness Woolridge for the Public Staff; and witness Phillips for CIGFUR. These testimonies, as summarized above, provide a relatively broad range of methods, inputs, and recommendations regarding the proper rate of return on common equity determination for DENC. For example, witness Hevert relied in his direct testimony on four different analyses to arrive at his rate of return on common equity recommendation. These analyses were a Constant Growth DCF Analysis, a Capital Asset Pricing Model analysis, an Empirical Capital Asset

Pricing Model, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. By way of comparison, Public Staff witness Woolridge relied upon a DCF analysis and a Capital Asset Pricing Model analysis in reaching his conclusions; however, the inputs utilized by witness Woolridge in his analyses are different from those utilized by witness Hevert. Witness Phillips looked at the average allowed rates of return on common equity for both vertically integrated and distribution-only electric utilities for the first and second quarters of 2019 of 9.57% and recommended that average as a cap to the allowed rate of return on common equity.

These varying analyses, as is typical, produced varying results. Witness Hevert's analyses prompted him to propose a rate of return on common equity range of 10.00% to 11.00% with a specific rate of return on common equity recommendation of 10.75%. Witness Woolridge's analyses resulted in a recommended rate of return on common equity range of 7.20% to 8.95% with a primary recommendation of a 9.00% rate of return on common equity with a 50.00% common equity capital structure and a secondary recommendation of an 8.75% rate of return on common equity if DENC's actual capital structure of 46.351% long-term debt and 53.649% common equity, as proposed in the supplemental testimony of Company witness Davis, was approved. Finally, as noted above, witness Phillips recommended a cap on rate of return on common equity of 9.57%.

The Commission finds the cost of equity analyses helpful in reaching its conclusion on an appropriate rate of return on common equity for DENC, but notes that the ranges of the various analyses span a range from 7.20% to 12.76% and the specific rate of return on common equity recommendations of the witnesses span a range from 8.75% on the low end to 10.75% on the high end.

The Commission finds that the DCF, CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses of DENC witness Hevert, and the stipulations are credible, probative, and entitled to substantial weight.

DENC witness Hevert in his direct testimony provided his constant growth DCF analyses, as shown on Exhibit RBH-1, pages 1, 2, and 3: 30-day dividend yield mean 9.24%, median 9.18%; 90-day dividend yield mean 9.31%, median 9.25%; and 180-day dividend yield mean 9.39%, median 9.38%. Although the Commission, as stated in previous Commission general rate case orders, does not approve of witness Hevert's sole use of analysts' predicted earnings per share to determine the DCF growth rate, the Commission finds witness Hevert's constant growth DCF analyses mean and median rate of return on common equity results credible, probative, and entitled to substantial weight.

Witness Hevert's CAPM analysis for his Proxy Group Average Value Line Beta Coefficient, as shown on Exhibit RBH-4, page 1, includes current 30-year treasury rates to calculate the risk free rate of 3.04%, producing what witness Hevert described as a Value Line Market DCF Derived rate of return on equity of 9.78%. Witness Hevert's ECAPM analysis for his Proxy Group Average Bloomberg Beta Coefficient, as shown on Exhibit RBH-4, page 1, produces what witness Hevert described as a Bloomberg Market DCF Derived rate of return on common equity of 9.61%. The Commission approves of

the use of current risk-free rates rather than predicted near-term or long-term rates. The Commission finds the above-described CAPM and ECAPM analyses credible, probative, and entitled to substantial weight.

DENC witness Hevert's Bond Yield Plus Risk Premium, as shown on Exhibit RBH-5, using the current 30-year Treasury yield of 3.04% and applying it to the approved rates of return on common equity in 1,581 electric utility rate proceedings between January 1980 and February 28, 2019, results in a rate of return on common equity of 9.93%. As previously stated, the Commission approves the use of current interest rates, rather than projected near-term or long-term interest rates. The Commission finds witness Hevert's updated Bond Yield Plus Risk Premium analysis using the current 30-year Treasury yield to be credible, probative, and entitled to substantial weight.

The Commission has carefully evaluated the DCF analysis recommendation of witness Woolridge. As shown on witness Hevert's settlement testimony Exhibit RBH-S-1, from 2016 – 2019, there were 81 vertically integrated electric utility decisions by public service commissions resulting in a mean approved 9.74% rate of return on common equity. The mean year-to-date 2019 rate of return on common equity is 9.61%, and the median rate of return on equity is 9.73%.

As shown on Exhibit RBH-S-1, during this period there was only one public service commission (the South Dakota Public Service Commission) decision approving a rate of return on common equity below 9.00% for a vertically integrated electric utility (8.75% in May 2019). Public Staff witness Woolridge's DCF analysis produced a rate of return on common equity ranging from 8.55 – 8.95%, adjusted upward for a specific rate of return on common equity recommendation of 9.00% with a 50.00% common equity capital structure component. As shown on Exhibit JRW-8, page 1, the result of the CAPM analysis for the Electric Proxy Group and the Hevert Proxy Group were 7.3% and 7.2%, respectively. These DCF and CAPM results are substantially below the mean allowed rate of return on common equity of 9.74% from 2016 through mid-September 2019.

In summary, the Commission concludes there is substantial evidence supporting the reasonableness of a rate of return on common equity of 9.75%. First, that rate of return is well within the range of recommended returns by the economic experts in this docket of 7.20% to 11.00%. Second, it falls just 36 basis points above the 9.39% mean results of DENC witness Hevert's DCF analysis and below the mean high results of his DCF analysis. Third, it falls within the range of DENC witness Hevert's CAPM results. Fourth, it falls within the results of DENC witness Hevert's ECAPM results. Fifth, it falls only 18 basis points below the lower end of the range of DENC witness Hevert's Bond Yield Plus Risk Premium analysis results. Sixth, it is slightly below the recommended range of DENC witness Hevert (10.00% to 11.00%). Seventh, it falls squarely within the range and very close to the average of recent vertically-integrated electric utility allowed rates of return on common equity nationally.⁶ Eighth, it is equal to the lowest rate of return

⁶ The Commission determines the appropriate rate of return on common equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on common equity trends and decisions by other regulatory authorities, as well as other recent decisions of this

on equity awarded by this Commission in general rate cases for major electric utilities in at least the last 10 years.⁷ Ninth, it is 15 basis points lower than DENC's current allowed rate of return on common equity. Tenth, it is supported as the appropriate rate of return on common equity for DENC by all of parties filing rate of return testimony in this proceeding in lieu of the recommendations made by their respective witnesses on this subject, and the stipulated rate of return on common equity of 9.75% is supported by credible filed settlement testimony by the cost of capital witness for DENC. Finally, and without expressly adopting his methodology, it is consistent with witness Phillips' notion that DENC's return should be capped at the average rate of return on common equity approved by other state commissions for the first two quarters of 2019.⁸

These factors lead the Commission to conclude that a 9.75% rate of return on common equity is supported by the substantial weight of the evidence in this proceeding. However, to meet its obligation in accord with the holding in *Cooper I*, the Commission will next address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses Hevert and Woolridge, which the Commission finds entitled to substantial weight, addresses changing economic conditions at some length. Witness Hevert provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are "highly correlated" with conditions in the broader nationwide economy. As such, witness Hevert testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his rate of return on common equity estimates.

Public Staff witness Woolridge agreed with DENC witness Hevert that economic conditions have improved in North Carolina. He pointed out that while the State's unemployment rate has fallen by one-third since its peak in the 2009-2010 period and is slightly below the national average of 3.90%, the unemployment rate in DENC's service territory is 4.95%, over 100 basis points higher than the national and North Carolina averages. Witness Woolridge also noted that North Carolina's residential electric rates

Commission, deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return on common equity significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return on common equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary.

⁷ See Docket Nos. E-2, Subs 1023 and 1142; E-7, Subs 909, 989, and 1146; and E-22, Subs 459, 479, and 532.

⁸ Witness Phillips' proposal was a cap at 9.57% based on the first and second quarter average rates of return reported by RRA. However, witness Phillips included distribution-only electric utilities, which are not appropriate. DENC witness Hevert's rebuttal testimony explained that the results reported by Mr. Phillips were skewed by the Otter Tail decision, and a better measure was the median rate of return on common equity authorized for vertically-integrated utilities in 2019 through August 2019 of 9.73%, as opposed to the mean of 9.61%. The Commission finds the use of vertically-integrated electric utilities to be a more comparable measure, as well as the more current data.

are below the national average; however, its median household income is more than 10% below the U.S. norm.

Based upon the general state of the economy and the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the stipulated rate of return on common equity of 9.75% will not cause undue hardship to customers even though some will struggle to pay the increased rates resulting from the Stipulations. When the Commission's decisions are viewed as a whole, including the decision to establish the rate of return on common equity at 9.75%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.⁹

The many Commission-approved adjustments reduced the revenues to be recovered from customers and the return to be paid to equity investors. Some adjustments reduced the authorized rate of return on investment financed by equity investors. These adjustments have the effect of reducing rates and providing rate stability to consumers (and return to equity investors) in recognition of the difficulty some consumers will have paying increased rates in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on common equity of 9.75% instead of 10.75%, this is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of the adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.

For example, to the extent the Commission made downward adjustments to rate base, disallowed test year expenses, increased test year revenues, or reduced the equity capital structure component, the Commission reduced the rates consumers will pay during the future period when rates will be in effect. Because the compensation owed to investors for investing in the Company's provision of service to consumers takes the form of return on investment, downward adjustments to rate base, disallowances of test year expenses, increases to test year revenues, or reduction in the equity capital structure component will reduce investors' return on investment irrespective of the determination of rate of return on common equity.

Considering the changing economic conditions and their effects on DENC's customers, the Commission recognizes the financial difficulty that an increase in DENC's

⁹ The Commission notes that consumers pay "rates," a charge in cents per kilowatt-hour (kWh) for the electricity they consume. They do not pay a "rate of return on common equity," though it is a component of the Company's cost of providing service which is built into the charge per kWh. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the rate of return on common equity in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.75%.