SACE 1st Response to Staff
016270

Progress Energy

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June 6, 2008

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Sessions

FILED
JUN 06 2008
Clerk's Office
N.C. Utilities Commission

Ms. Renne Vance
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27600

RE: Docket No. E-2, Sub 931

Dear Ms. Vance:

Please find enclosed for filing in the above-referenced docket the original and 30 copies of Progress Energy Carolinas, Inc.'s Application for Approval of DSM and Energy Efficiency Cost Recovery Rider, the Direct Testimony of Robert P. Evans and supporting documentation.

Sincerely,

Len S. Anthony

Len S. Anthony
General Counsel-Progress Energy Carolinas

LSA:mhm

Enclosure

cc: Parties of Record

263731

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Kite
Hilburn
Ericson
Jones
ExDir
3/S Legal
3/S Acctg
2/S Ec/Leg
3/S Elec

Progress Energy Service Company, LLC
PO Box 1551
Raleigh, NC 27602

SACE 1st Response to Staff
016271

PEC Exhibit No. 1

STATE OF NORTH CAROLINA

OFFICIAL COPY

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 931

FILED
JUN 06 2008
Clerk's Office
N.C. Utilities Commission

In the Matter of:	)	
	)	
Application by Progress Energy Carolinas, Inc. For Authority to Adjust Its Electric Rates and Charges Pursuant to NC Gen. Statute § 62-133.9 and NCUC Rule R8-69	))))	APPLICATION FOR APPROVAL OF DSM AND ENERGY EFFICIENCY COST RECOVERY RIDER

COMES NOW, Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (hereinafter "the Company") pursuant to N.C.G.S. § 62-133.9 and Rule R8-69 of the Rules and Regulations of the North Carolina Utilities Commission and applies to the Commission as follows:

1. The Company is a public utility operating in the states of North Carolina and South Carolina where it is engaged in the generation, transmission, distribution, and sale of electricity to the public for compensation. Its general offices are located at 410 S. Wilmington Street, Raleigh, North Carolina; and its mailing address is Post Office Box 1551, Raleigh, North Carolina 27602-1551.

2. The attorneys for the Company, to whom all communications and pleadings should be addressed, are:

Len S. Anthony
Deputy General Counsel
Progress Energy Services Company
Post Office Box 1551
Raleigh, North Carolina 27602-1551
Telephone: (919) 546-6367

And

Dwight Allen
3737 Glenwood Ave.
Suite 100
Raleigh, NC 27612
Telephone: (919) 573-6103

3. N.C.G.S. § 62-133.9(d) authorizes the Commission to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management and energy efficiency programs. Recoverable costs include, but are not limited to, all capital costs, including cost of capital and depreciation expense, administrative costs, implementation costs, incentive payments to program participants, and operating costs. Such rider shall consist of the utility's forecasted cost during the rate period and an experience modification factor ("EMF") rider to collect the difference between the utility's actual reasonable and prudent costs incurred during the test period and actual revenues realized during the test period. The Commission is also authorized to approve incentives to utilities for adopting and implementing new demand-side management and energy efficiency programs, including rewards based on the sharing of savings achieved by the programs.

4. Rule R8-69(b) provides the Commission will each year conduct a proceeding for each electric public utility to establish an annual DSM/EE rider to recover DSM/EE related costs.

5. According to Rule R8-69(e) the electric public utility is to file its application for recovery of DSM/EE costs at the same time it files the information required by Rule R8-55, and the Commission is to conduct an annual DSM/EE rider hearing as soon as practicable after the hearing required by Rule R8-55.

6. Pursuant to the provisions of N.C.G.S. §62-133.9 and NCUC Rule R8-69, the Company requests the establishment of a rider to recover its reasonable and prudent forecasted

DSM/EE costs, net lost revenues and additional incentive, to be incurred during the rate period, and an EMF, and pursuant to Commission Rule R8-69(b)(2), PEC requests to recover through the EMF its costs, including net lost revenues an additional incentive incurred up to 30 days prior to the hearing in this proceeding. The additional incentive requested by PEC is an amount equal to 50% of the net benefits as determined by the Utility Cost Test as described in the direct testimony of Robert P. Evans. The rider and EMF are intended to allow PEC to recover $3,273,285 of DSM/EE expenses and incentives incurred during the test period beginning August 21, 2007 through March 31, 2008; plus $2,464,888 for expenses and incentives to be incurred during the prospective period from April 1, 2008 through July 31, 2008; and, $36,864,860 for expenses and incentives to be incurred during the rate period from December 1, 2008 through November 30, 2009. The prospective period amount will be updated with actual amounts at least 30 days prior to the hearing date in this proceeding.

7. Pursuant to the provisions of N.C.G.S. §62-133.9 and NCUC Rule R8-69, the Company requests Commission approval of the annual billing adjustments as follows (all shown on a dollars per kWh basis with and without NC gross receipts taxes):

	DSM/EE Rate		DSM/EE EMF Rate		Total Billing Impact	
Rate Class	w/o NC GRT	w/ NC GRT	w/o NC GRT	w/ NC GRT	w/o NC GRT	w/ NC GRT
Residential	$0.00165	$0.00170	$0.00025	$0.00026	$0.00190	$0.00196
Small General Service	$0.00167	$0.00173	$0.00025	$0.00026	$0.00192	$0.00199
Medium General Service	$0.00140	$0.00145	$0.00021	$0.00022	$0.00161	$0.00167
Large General Service	$0.00101	$0.00104	$0.00016	$0.00017	$0.00117	$0.00121
Lighting	$0.00037	$0.00038	$0.00007	$0.00007	$0.00044	$0.00045
NC Retail	$0.00157	$0.00162	$0.00024	$0.00025	$0.00181	$0.00187

These rates are reflected in proposed Rider BA-1, a copy of which is included as Evans Exhibit No. 11, to recover the DSM/EE expenses described above. The DSM/EE EMF rider will be in effect for the twelve month period December 1, 2008 through November 30, 2009.

8. Pursuant to Commission Rule R8-69(b)(6) PEC requests approval to defer the difference between actual reasonable and prudently incurred incremental costs and the related revenues realized under rates in effect. FERC account 182.3, "Other Regulatory Assets", will be used to deferral these costs until recovered. In addition, to the extent that PEC has incurred incremental costs of implementing new demand-side management or energy efficiency measures more than six months prior to the filing of PEC's application for approval, PEC requests approval to defer those costs as allowed by Commission Rule R8-69(b)(6).

9. The Company has attached hereto PEC Exhibit No. 1 which contains information required by NCUC Rule R8-69. In addition, the Company has attached the direct testimony and exhibits of witness Robert P. Evans in support of the requested change in rates.

WHEREFORE, the Company respectfully prays:

That, consistent with this Application, the Commission approves the changes to its rates as set forth in paragraph 7 above.

Respectfully submitted this 6th day of June 2008.

PROGRESS ENERGY CAROLINAS, INC.

By: Len S. Anthony [signature]

Len S. Anthony, General Counsel
P. O. Box 1551, PEB 17A4
410 South Wilmington Street
Raleigh, NC 27602

STATE OF NORTH CAROLINA	)	
	)	
	)	**VERIFICATION**
	)	
	)	DOCKET NO. E-2, SUB 931
COUNTY OF WAKE	)	

PERSONALLY APPEARED before me, Robert P. Evans who, after first being duly sworn, said that he is Senior Project Analyst at Progress Energy Carolinas, Inc. and as such is authorized to make this verification; that he has read the foregoing Application and knows the contents thereof; and that the same are true and correct to the best of his knowledge, information, and belief.

R P Evans

ROBERT P. EVANS

Sworn to and subscribed before me, this the 6th day of June 2008.

Marsha H. Manning

My Commission Expires:

10/03/2009

MARSHA H. MANNING
NOTARY
★ ★ ★
PUBLIC
WAKE COUNTY, N.C.

PEC Exhibit No. 1
Workpapers

Progress Energy Carolinas, Inc

Docket No. E-2, Sub 931

Demand Side Management and Energy Efficiency Programs

Workpapers

Pursuant to Commission Rule R8-69(f)(1)(viii)

June 6, 2008

Workpapers

Section A – Cost Summary

North Carolina Retail - DSM/EE Revenue Requirements Summary

Test Period

			O&M	Other O&M	Taxes	Depreciation	Cost of Capital	Carrying Cost	A&G Expense	Totals Before Incentive	Lost Revenue	Utility Incentive	Total Incentive	Totals With Incentive
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) Σ Cols (1) thru (7)	(9)	(10)	(11) Cols (9) + (10)	(12) Cols (8) + (11)
	NC DSM Program Expenses													
1	DSDR Program		439,230	-	(323)	-	(837)			438,070	-	-	-	438,070
2	EnergyWise		175,918							175,918	-	-	-	175,918
3	Total DSM	Lines 1 + 2	615,148	-	(323)	-	(837)	-		613,988	-	-	-	613,988
4	DSM Assigned A&G and CCost	Assigned Values						53,487	1,455,778	1,509,265			-	1,509,265
5	Total DSM and Assigned A&G	Lines 3 + 4	615,148	-	(323)	-	(837)	53,487	1,455,778	2,123,253	-	-	-	2,123,253
	NC EE Program Expenses													
6	Res New Construction		28,041							28,041	-	-	-	28,041
7	CIG New Construction									-	-	-		-
8	CIG Retrofit									-	-	-	-	-
9	CFL		268,897							268,897	105,420	67,762	173,182	442,079
10	Total EE	Σ Lines 6 thru 9	296,938	-	-	-	-	-		296,938	105,420	67,762	173,182	470,120
11	EE Assigned A&G and CCost	Assigned Values						25,867	654,045	679,913			-	679,913
12	Total EE and Assigned A&G	Lines 10 + 11	296,938	-	-	-	-	25,867	654,045	976,850	105,420	67,762	173,182	1,150,033
13	Test Period Total	Lines 5 + 12	912,086	-	(323)	-	(837)	79,354	2,109,823	3,100,103	105,420	67,762	173,182	3,273,285

Prospective Period

			O&M	Other O&M	Taxes	Depreciation	Cost of Capital	Carrying Cost	A&G Expense	Totals Before Incentive	Lost Revenue	Utility Incentive	Total Incentive	Totals With Incentive
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) Σ Cols (1) thru (7)	(9)	(10)	(11) Cols (9) + (10)	(12) Cols (8) + (11)
	NC DSM Program Expenses													
1	DSDR Program		483,163	223	17,727	13,702	40,483			555,299	-	-	-	555,299
2	EnergyWise		287,928							287,928	-	-	-	287,928
3	Total DSM	Lines 1 + 2	771,091	223	17,727	13,702	40,483	-		843,227	-	-	-	843,227
4	DSM Assigned A&G and CCost	Assigned Values						484,895	508,230	993,126			-	993,126
5	Total DSM and Assigned A&G	Lines 3 + 4	771,091	223	17,727	13,702	40,483	484,895	508,230	1,836,352	-	-	-	1,836,352
	NC EE Program Expenses													
6	Res New Construction		42,327							42,327			-	42,327
7	CIG New Construction		-							-			-	-
8	CIG Retrofit		92,204							92,204			-	92,204
9	CFL		8,193							8,193	106,772	68,631	175,402	183,596
10	Total EE	Σ Lines 6 thru 9	142,725	-	-	-	-	-		142,725	106,772	68,631	175,402	318,127
11	EE Assigned A&G and CCost	Assigned Values						82,073	228,335	310,409			-	310,409
12	Total EE and Assigned A&G	Lines 10 + 11	142,725	-	-	-	-	82,073	228,335	453,134	106,772	68,631	175,402	628,536
13	Prospective Period Total	Lines 5 + 12	913,815	223	17,727	13,702	40,483	566,969	736,566	2,289,486	106,772	68,631	175,402	2,464,888

Rate Period

			O&M	Other O&M	Taxes	Depreciation	Cost of Capital	Carrying Cost	A&G Expense	Totals Before Incentive	Lost Revenue	Utility Incentive	Total Incentive	Totals With Incentive
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) Σ Cols (1) thru (7)	(9)	(10)	(11) Cols (9) + (10)	(12) Cols (8) + (11)
	NC DSM Program Expenses													
1	DSDR Program		4,486,500	15,374	1,247,956	1,001,972	2,857,875			9,609,677	63,753	553,963	617,716	10,227,393
2	EnergyWise		9,048,241							9,048,241	11,759	4,717,668	4,729,427	13,777,668
3	Total DSM	Lines 1 + 2	13,534,741	15,374	1,247,956	1,001,972	2,857,875	-		18,657,917	75,512	5,271,631	5,347,143	24,005,060
4	DSM Assigned A&G and CCost	Assigned Values						1,511,130	2,623,346	4,134,476			-	4,134,476
5	Total DSM and Assigned A&G	Lines 3 + 4	13,534,741	15,374	1,247,956	1,001,972	2,857,875	1,511,130	2,623,346	22,792,393	75,512	5,271,631	5,347,143	28,139,536
	NC EE Program Expenses													
6	Res New Construction		1,292,153							1,292,153	167,331	230,693	398,024	1,690,177
7	CIG New Construction		887,433							887,433	63,511	48,817	112,328	999,761
8	CIG Retrofit		3,556,408							3,556,408	204,714	105,220	309,934	3,866,342
9	CFL		-							-	319,981	205,893	525,874	525,874
10	Total EE	Σ Lines 6 thru 9	5,735,993	-	-	-	-	-		5,735,993	755,537	590,623	1,346,160	7,082,153
11	EE Assigned A&G and CCost	Assigned Values						464,566	1,178,605	1,643,171			-	1,643,171
12	Total EE and Assigned A&G	Lines 10 + 11	5,735,993	-	-	-	-	464,566	1,178,605	7,379,164	755,537	590,623	1,346,160	8,725,324
13	Rate Period Total	Lines 5 + 12	19,270,734	15,374	1,247,956	1,001,972	2,857,875	1,975,696	3,801,951	30,171,557	831,049	5,862,254	6,693,303	36,864,860

Workpapers

Section B – DSM/EE and DSM/EE EMF Rate Determination

Schedule B

Evans Exhibit No. 10
Page 1 of 1

PROGRESS ENERGY CAROLINAS, INC.

EE/DSM Billing Rate - December 2008 through November 2009

All rates are shown in dollars per kWh

NC Rate Class	Total EE Rate (1)	Total DSM Rate (2)	Total EE EMF Rate (3)	Total DSM EMF Rate (4)	DSM/EE Billing Rate (5)
Residential	$0.00037	$0.00128	$0.00007	$0.00018	$0.00190
Small General Service	$0.00037	$0.00130	$0.00007	$0.00018	$0.00192
Medium General Service	$0.00037	$0.00103	$0.00007	$0.00014	$0.00161
Large General Service	$0.00037	$0.00064	$0.00007	$0.00009	$0.00117
Lighting	$0.00037	$0.00000	$0.00007	$0.00000	$0.00044
NC Retail	$0.00037	$0.00120	$0.00007	$0.00017	$0.00181

NOTES:

(1) Total EE Rate is derived in Evans Exhibit No. 6, column (7).
(2) Total DSM Rate is derived in Evans Exhibit No. 7, column (7).
(3) Total EE EMF Rate is derived in Evans Exhibit No. 8, column (7).
(4) Total DSM EMF Rate is derived in Evans Exhibit No. 9, column (7).
(5) DSM/EE Billing Rate does not include gross receipts taxes.

PROGRESS ENERGY CAROLINAS, INC.

Demand Side Management Experience Modification Factor Rate Derivation

NC Rate Class	Adjusted NC Rate Class kWHr Sales [1]	Rate Class Demand Allocation Factor [2]	DSM EMF Revenue Requirement: DSM EMF Program Costs [3]	DSM EMF Revenue Requirement: DSM EMF Utility Incentive and Net Lost Revenue Costs [4]	DSM EMF Rate ($/kWh): DSM EMF Program Rate	DSM EMF Rate ($/kWh): DSM EMF Utility Incentive and Net Lost Revenue Rate	DSM EMF Rate ($/kWh): Total DSM EMF Rate
	(1)	(2)	(3) = Col. 3 total * (2)	(4) = Col. 4 total * (2)	(5) = (3) / (1)	(6) = (4) / (1)	(7) = (5) + (6)
Residential	15,496,949,876	70.58%	$2,794,614	$0	$0.00018	$0.00000	$0.00018
Small General Service	1,960,336,986	9.07%	$359,023	$0	$0.00018	$0.00000	$0.00018
Medium General Service	5,576,230,957	20.35%	$805,969	$0	$0.00014	$0.00000	$0.00014
Large General Service [5]	0	0.00%	$0	$0	$0.00009	$0.00000	$0.00009
Lighting	438,605,662	0.00%	$0	$0	$0.00000	$0.00000	$0.00000
NC Retail	23,472,123,482	100%	$3,959,605	$0	$0.00017	$0.00000	$0.00017

NOTES:

(1) Rate Class Sales, excluding "Opt-Out" sales, are derived in Evans Exhibit No. 4, column (3).
(2) Rate Class Demand Allocation Factor is derived in Evans Exhibit No. 5.
(3) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (8) for the historic test yeat August 21, 2007 to March 31, 2008 and the forecast period April 2008 through July 2008. The forecast period will be updated to reflect actual costs prior to the September hearing.
(4) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (11) for the historic test yeat August 21, 2007 to March 31, 2008 and the forecast period April 2008 through July 2008. The forecast period will be updated to reflect actual costs prior to the September hearing.
(5) A rate is shown for the LGS Class, even though all customers are assumed to opt-out, based upon the class load requirement.

PROGRESS ENERGY CAROLINAS, INC.

Energy Efficiency Experience Modification Factor Rate Derivation

			EE EMF Revenue Requirement		EE EMF Rate ($/kWh)		
NC Rate Class	Adjusted NC Rate Class kWHr Sales [1]	Rate Class Energy Allocation Factor [2]	EE EMF Program Costs [3]	EE EMF Utility Incentive and Net Lost Revenue Costs [4]	EE EMF Program Rate	EE EMF Utility Incentive and Net Lost Revenue Rate	Total EE EMF Rate
	(1)	(2)	(3) = Col. 3 total * (2)	(4) = Col. 4 total * (2)	(5) = (3) / (1)	(6) = (4) / (1)	(7) = (5) + (6)
Residential	15,496,949,876	66.02%	$944,115	$230,145	$0.00006	$0.00001	$0.00007
Small General Service	1,960,336,986	8.35%	$119,429	$29,113	$0.00006	$0.00001	$0.00007
Medium General Service	5,576,230,957	23.76%	$339,719	$82,813	$0.00006	$0.00001	$0.00007
Large General Service [5]	0	0.00%	$0.00	$0.00	$0.00006	$0.00001	$0.00007
Lighting	438,605,662	1.87%	$26,721	$6,514	$0.00006	$0.00001	$0.00007
NC Retail	23,472,123,482	100.00%	$1,429,984	$348,585	$0.00006	$0.00001	$0.00007

NOTES:

(1) Rate Class Sales, excluding "Opt-Out" sales, are derived in Evans Exhibit No. 4, column (3).

(2) Rate Class Energy Allocation Factor is derived in Evans Exhibit No. 4

(3) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (8) for the historic test yeat August 21, 2007 to March 31, 2008 and the forecast period April 2008 through July 2008. The forecast period will be updated to reflect actual costs prior to the September hearing.

(4) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (11) for the historic test yeat August 21, 2007 to March 31, 2008 and the forecast period April 2008 through July 2008. The forecast period will be updated to reflect actual costs prior to the September hearing.

(5) A rate is shown for the LGS Class, even though all customers are assumed to opt-out, based upon the class load requirement.

PROGRESS ENERGY CAROLINAS, INC.

Demand Side Management Rate Derivation

NC Rate Class	Adjusted NC Rate Class kWHr Sales [(1)]	Rate Class Demand Allocation Factor [(2)]	DSM Revenue Requirement: DSM Program Costs [(3)]	DSM Revenue Requirement: DSM Utility Incentive and Net Lost Revenue Costs [(4)]	DSM Rate ($/kWh): DSM Program Rate	DSM Rate ($/kWh): DSM Utility Incentive and Net Lost Revenue Rate	DSM Rate ($/kWh): Total DSM Rate
	(1)	(2)	(3) = Col. 3 total * (2)	(4) = Col. 4 total * (2)	(5) = (3) / (1)	(6) = (4) / (1)	(7) = (5) + (6)
Residential	15,496,949,876	70.58%	$16,086,436	$3,773,911	$0.00104	$0.00024	$0.00128
Small General Service	1,960,336,986	9.07%	$2,066,618	$484,833	$0.00105	$0.00025	$0.00130
Medium General Service	5,576,230,957	20.35%	$4,639,340	$1,088,399	$0.00083	$0.00020	$0.00103
Large General Service [(5)]	0	0.00%	$0	$0	$0.00052	$0.00012	$0.00064
Lighting	438,605,662	0.00%	$0	$0	$0.00000	$0.00000	$0.00000
NC Retail	23,472,123,482	100.00%	$22,792,393	$5,347,143	$0.00097	$0.00023	$0.00120

NOTES:

(1) Rate Class Sales, excluding "Opt-Out" sales, are derived in Evans Exhibit No. 4, column (3).
(2) Rate Class Demand Allocation Factor is derived in Evans Exhibit No. 5.
(3) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (8).
(4) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (11).
(5) A rate is shown for the LGS Class, even though all customers are assumed to opt-out, based upon the class load requirement.

Evans Exhibit No. 6
Page 1 of 1

PROGRESS ENERGY CAROLINAS, INC.

Energy Efficiency Rate Derivation

			EE Revenue Requirement		EE Rate ($/kWh)		
NC Rate Class	Adjusted NC Rate Class kWHr Sales [(1)]	Rate Class Energy Allocation Factor [(2)]	EE Program Costs [(3)]	EE Utility Incentive and Net Lost Revenue Costs [(4)]	EE Program Rate	EE Utility Incentive and Net Lost Revenue Rate	Total EE Rate
	(1)	(2)	(3) = Col. 3 total * (2)	(4) = Col. 4 total * (2)	(5) = (3) / (1)	(6) = (4) / (1)	(7) = (5) + (6)
Residential	15,496,949,876	66.02%	$4,871,930	$888,772	$0.00031	$0.00006	$0.00037
Small General Service	1,960,336,986	8.35%	$616,291	$112,428	$0.00031	$0.00006	$0.00037
Medium General Service	5,576,230,957	23.76%	$1,753,055	$319,805	$0.00031	$0.00006	$0.00037
Large General Service [(5)]	0	0.00%	$0	$0	$0.00031	$0.00006	$0.00037
Lighting	438,605,662	1.87%	$137,889	$25,155	$0.00031	$0.00006	$0.00037
NC Retail	23,472,123,482	100%	$7,379,164	$1,346,160	$0.00031	$0.00006	$0.00037

NOTES:

(1) Rate Class Sales, excluding "Opt-Out" sales, are derived in Evans Exhibit No. 4, column (3).
(2) Rate Class Energy Allocation Factor is derived in Evans Exhibit No. 4
(3) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (8).
(4) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (11).
(5) A rate is shown for the LGS Class, even though all customers are assumed to opt-out, based upon the class load requirement.

PROGRESS ENERGY CAROLINAS, INC.

Demand Allocation Factors - Applicable to DSM Programs

North Carolina Rate Class Demand Allocation Factors

Rate Class	Total NC Rate Class Sales [1]	Sales Subject to Opt-Out [2]	Rate Class Demand [3]	Revised Rate Class Demand	Rate Class Allocation Factor
	(1)	(2)	(3)	(4) = ((1 - 2) / 1) * 3	(5) = (4)/Total of Column 4
Residential	15,496,950	0	4,019,614	4,019,614	70.57809%
Small General Service	1,985,374	25,037	522,994	516,398	9.06714%
Medium General Service	11,734,023	6,157,792	2,439,422	1,159,260	20.35477%
Large General Service	9,076,284	9,076,284 [4]	1,168,621	0	0.00000%
Lighting	453,441	14,836	0	0	0.00000%
NC Retail	38,746,072	15,273,949	8,150,651	5,695,273	100.00000%

NOTES:

(1) Total NC Rate Class Sales (MWHrs) are for the forecasted year ended November 2009.
(2) Opt-Out sales for the year ended March 31, 2008 are provided in Evans Exhibit No. 3
(3) The CP demands are from the annual NC Cost of Service Study for August 9, 2007 during the hour ended at 4 p.m.
(4) LGS Opt-Out sales were set to match the forecast sales since all customers in the LGS class are eligible to opt-out.

PROGRESS ENERGY CAROLINAS, INC.

Energy Allocation Factors - Applicable to EE Program Costs

North Carolina Rate Class Energy Allocation Factors

Rate Class	Total NC Rate Class Sales (MWhrs) [1] (1)	Opt-Out Sales[2] (2)	Adjusted NC Rate Class MWHr Sales (3) = (1) - (2)	Rate Class Energy Allocation Factor (4) = (3) / NC Total in Column 3
Residential	15,496,950	0	15,496,950	66.02%
Small General Service	1,985,374	25,037	1,960,337	8.35%
Medium General Service	11,734,023	6,157,792	5,576,231	23.76%
Large General Service	9,076,284	9,076,284 [3]	0	0.00%
Lighting	453,441	14,836	438,606	1.87%
NC Retail	38,746,072	15,273,949	23,472,123	100.00%

NOTES:

(1) Total NC Rate Class Sales (MWHrs) are for the forecasted year ended November 2009.
(2) Opt-Out sales for the year ended March 31, 2008 are provided in Evans Exhibit No. 3
(3) LGS Opt-Out sales were set to match the forecast sales since all customers in the LGS class are eligible to opt-out.

PROGRESS ENERGY CAROLINAS, INC.
Annual Sales for NC Customers Eligible for DSM/EE Opt-Out
Annual Sales for the Year Ended March 31, 2008

Rate Class	Commercial	Industrial*	Total
RES	0	0	0
SGS	8,027,300	17,009,689	25,036,989
MGS	3,823,495,393	2,334,296,625	6,157,792,018
LGS	1,133,541,491	8,007,538,528	9,141,080,019
Lighting	0	14,835,590	14,835,590
Total Opt-Out Sales	4,965,064,184	10,373,680,432	15,338,744,616

* Industrial category also includes Revenue Class 45, Public Authority

Workpapers

Section C – Determination of DSDR Related Revenue Requirement

PROGRESS ENERGY CAROLINAS, INC.

DSDR DSM Measure

Revenue Requirement Analysis

						TEST PERIOD					PROSPECTIVE PERIOD			RATE PERIOD	
			Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Dec-08	Jan-09
			Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 16	Month 17
	RATE BASE														
1	Gross Plant in Service	Workpaper C-3	-	-	-	-	-	-	-	-	-	-	6,170,930	14,810,232	18,563,155
2	Accum. Depreciation	-1 * Σ Line 13				-	-	-	-	-	-	-	(15,799)	(161,152)	(209,680)
3	Net Plant in Service	Lines 1 + 2	-	-	-	-	-	-	-	-	-	-	6,155,131	14,649,080	18,353,475
4	Accum. Deferred Income Taxes	-1 x Line 32	-	-	-	-	(18,831)	(37,703)	(56,617)	(75,581)	(154,894)	(234,491)	(328,401)	(945,801)	(1,343,621)
5	Rate Base	Lines 3 + 4	-	-	-	-	(18,831)	(37,703)	(56,617)	(75,581)	(154,894)	(234,491)	5,826,729	13,703,279	17,009,854
	COST OF SERVICE (REVENUE REQUIREMENT)														
	Return:	Workpaper C-1													
6	Debt at 8.62% Wgt'd at 48.57%	Line 5 X 8.62% X 48.57% / 12		-	-	-	(66)	(132)	(198)	(264)	(540)	(818)	20,329	47,810	59,346
7	Preferred at 8.75% Wgt'd at 7.43%	Line 5 X 8.75% X 7.43% / 12		-	-	-	(10)	(20)	(31)	(41)	(84)	(127)	3,157	7,424	9,215
8	Equity at 12.75% Wgt'd at 44.0%	Line 5 X 12.75% X 44.0% / 12		-	-	-	(88)	(176)	(265)	(353)	(724)	(1,096)	27,240	64,063	79,521
9	Gross up for Income Taxes; t = 39.1851%	(Lines 7 + 8)/(1-t)-(Lines 7 + 8)		-	-	-	(63)	(127)	(190)	(254)	(521)	(788)	19,586	46,061	57,176
10	Total Return	Lines 6 + 7 + 8 + 9	-	-	-	-	(227)	(455)	(683)	(912)	(1,869)	(2,830)	70,311	165,358	205,259
11	Property Tax [0.47%] & Insurance [0.05%])	Line 1 X 0.52% /12	-	-	-	-	-	-	-	-	-	-	2,674	6,418	8,044
12	O&M Expense	Forecast	-	-	4,396	125,715	83,089	29,273	274,425	(213,220)	297,476	208,233	260,291	351,393	438,329
13	Book Depreciation	Line 18 + 21 + 24	-	-	-	-	-	-	-	-	-	-	15,799	37,918	48,528
14	Income Tax on Permanent Difference	Note 1													
15	Total Revenue Requirement	Lines 10 + 11 + 12 + 13 + 14	-	-	4,396	125,715	82,862	28,818	273,742	(214,132)	295,607	205,403	349,076	561,087	700,160
	Book Depreciation														
	Distribution Plant														
16	Gross Plant in Service	Workpaper C-3	-	-	-	-	-	-	-	-	-	-	5,423,189	13,015,654	15,861,927
17	Book Decreciation Rate	Workpaper B-5	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%
18	Book Depreciation Expense	Line 16 * Line 17	-	-	-	-	-	-	-	-	-	-	12,428	29,828	36,350
	Communications Equipment														
19	Gross Plant in Service	Workpaper C-3	-	-	-	-	-	-	-	-	-	-	747,741	1,794,578	2,701,228
20	Book Decreciation Rate	Workpaper C-5	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%
21	Book Depreciation Expense	Line 19 * Line 20	-	-	-	-	-	-	-	-	-	-	3,371	8,091	12,178
	Software														
22	Gross Plant in Service	Workpaper C-3	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Book Decreciation Rate	Workpaper C-6	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%
24	Book Depreciation Expense	Line 22 * Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-
	DEFERRED INCOME TAXES:														
31	Software Expense	Workpaper C-3	-	-	-	-	48,056	48,056	48,056	48,056	201,810	201,810	201,810	201,810	915,166
32	Tax Depreciation	Workpaper C-2	-	-	-	-	-	-	-	-	-	-	51,704	250,039	142,322
33	(CPI Income)	Workpaper C-3	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Book Depreciation on Cash Basis (excludes AFUDC)	Line 13, Note 2	-	-	-	-	-	-	-	-	-	-	15,799	37,918	48,528
35	(AFUDC Debt Income)	Workpaper C-3	-	-	-	-	-	(106)	(212)	(340)	(596)	(1,321)	(1,945)	(5,463)	(6,273)
36	AFUDC Debt Depreciation	Note 1													
37	Tax Expense/(Income) minus Book Expense/(Income)	Line 31 + 32 + 33 - 34 - 35 - 36	-	-	-	-	48,056	48,162	48,268	48,396	202,406	203,130	239,659	419,393	1,015,233
38	Combined Fed & State Tax Rate	Input	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%
39	Deferred Income Taxes	Line 37 * Line 38	-	-	-	-	18,831	18,872	18,914	18,964	79,313	79,597	93,910	164,340	397,820
40	Accumulated Deferred Income Taxes	Σ Line 39	-	-	-	-	18,831	37,703	56,617	75,581	154,894	234,491	328,401	945,801	1,343,621

Notes

1 - Since no assets that accrue AFUDC will go in service before the end of the rate period, a calculation of AFUDC Debt depreciation or Income Tax on the Perm Diff are not needed for this filing.

2 - Since no assets that accrue AFUDC will go in service before the end of the rate period, for the purposes of this filing, plant book basis equals cash basis.

SACE 1st Response to Staff
016289

PROGRESS ENERGY CAROLINAS, INC.

DSDR DSM Measure
Revenue Requirement Analysis

			RATE PERIOD										SUMMARY TOTALS		
			Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Test Period	Prospective	Rate Period
			Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24	Month 25	Month 26	Month 27	Totals	Period Totals	Totals
	RATE BASE														
1	Gross Plant in Service	Workpaper C-3	22,316,079	26,069,002	29,821,925	33,574,849	37,327,772	41,080,696	44,833,619	48,586,543	52,339,466	56,092,389	-	6,170,930	56,092,389
2	Accum. Depreciation	-1 * Σ_{1-n} Line 13	(268,819)	(338,567)	(418,926)	(509,895)	(611,474)	(723,664)	(846,464)	(979,873)	(1,123,893)	(1,278,524)	-	(15,799)	54,813,866
3	Net Plant in Service	Lines 1 + 2	22,047,260	25,730,435	29,402,999	33,064,954	36,716,298	40,357,032	43,987,156	47,606,669	51,215,573	54,813,866	-	6,155,131	54,813,866
4	Accum. Deferred Income Taxes	-1 x Line 32	(1,746,944)	(2,154,970)	(2,570,365)	(2,994,508)	(3,429,568)	(3,876,574)	(4,339,354)	(4,821,407)	(5,329,844)	(5,884,481)	(56,617)	(328,401)	(5,884,481)
5	Rate Base	Lines 3 + 4	20,300,316	23,575,464	26,832,635	30,070,446	33,286,730	36,480,458	39,647,801	42,785,262	45,885,729	48,929,385	(56,617)	5,826,729	48,929,385
	COST OF SERVICE (REVENUE REQUIREMENT)														
	Return:	Workpaper C-1													
6	Debt at 8.62% Wgt'd at 48.57%	Line 5 X 8.62% X 48.57% / 12	70,827	82,253	93,618	104,914	116,136	127,278	138,329	149,275	160,093	170,712	(395)	18,707	1,320,591
7	Preferred at 8.75% Wgt'd at 7.43%	Line 5 X 8.75% X 7.43% / 12	10,998	12,772	14,537	16,291	18,034	19,764	21,480	23,180	24,860	26,509	(61)	2,905	205,064
8	Equity at 12.75% Wgt'd at 44.0%	Line 5 X 12.75% X 44.0% / 12	94,904	110,215	125,443	140,579	155,615	170,546	185,353	200,021	214,516	228,745	(529)	25,066	1,769,522
9	Gross up for Income Taxes; t = 39.1851%	(Lines 7 + 8)/(1-t)-(Lines 7 + 8)	68,236	79,245	90,194	101,077	111,888	122,623	133,270	143,816	154,238	164,468	(380)	18,023	1,272,293
10	Total Return	Lines 6 + 7 + 8 + 9	244,965	284,486	323,791	362,862	401,673	440,212	478,432	516,292	553,706	590,434	(1,365)	64,701	4,567,470
11	Property Tax [0.47%] & Insurance [0.05%])	Line 1 X 0.52% /12	9,670	11,297	12,923	14,549	16,175	17,802	19,428	21,054	22,680	24,307	-	2,674	184,347
12	O&M Expense	Forecast	438,329	438,329	438,329	438,329	438,329	438,329	438,329	438,329	438,329	438,329	516,899	552,780	5,173,008
13	Book Depreciation	Line 18 + 21 + 24	59,138	69,749	80,359	90,969	101,579	112,189	122,800	133,410	144,020	154,630	-	15,799	1,155,290
14	Income Tax on Permanent Difference	Note 1													
15	Total Revenue Requirement	Lines 10 + 11 + 12 + 13 + 14	752,103	803,860	855,401	906,709	957,756	1,008,532	1,058,988	1,109,085	1,158,735	1,207,699	515,534	635,954	11,080,115
	Book Depreciation														
	Distribution Plant														
16	Gross Plant in Service	Workpaper C-3	18,708,200	21,554,473	24,400,745	27,247,018	30,093,291	32,939,564	35,785,837	38,632,109	41,478,382	44,324,655	-	6,941,682	44,324,655
17	Book Decreciation Rate	Workpaper C-5	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%	0.2292%			
18	Book Depreciation Expense	Line 16 * Line 17	42,873	49,396	55,918	62,441	68,964	75,487	82,009	88,532	95,055	101,577	-	-	788,429
	Communications Equipment														
19	Gross Plant in Service	Workpaper C-3	3,607,879	4,514,529	5,421,180	6,327,831	7,234,481	8,141,132	9,047,783	9,954,433	10,861,084	11,767,734	-	747,741	11,767,734
20	Book Decreciation Rate	Workpaper C-5	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%	0.4508%			
21	Book Depreciation Expense	Line 19 * Line 20	16,266	20,353	24,440	28,528	32,615	36,703	40,790	44,878	48,965	53,053	-	3,371	366,861
	Software														
22	Gross Plant in Service	Workpaper C-3	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Book Decreciation Rate	Workpaper C-5	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%	1.6667%			
24	Book Depreciation Expense	Line 22 * Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-
	DEFERRED INCOME TAXES:														
31	Software Expense	Workpaper C-3	915,166	915,166	915,166	915,166	915,166	915,166	915,166	915,166	915,166	915,166	144,169	653,485	10,268,638
32	Tax Depreciation	Workpaper C-2	163,804	187,433	213,688	243,225	276,982	316,364	363,623	422,697	501,463	619,610	-	51,704	3,701,251
33	(CPI Income)	Workpaper C-3	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Book Depreciation on Cash Basis (excludes AFUDC)	Line 13, Note 2	59,138	69,749	80,359	90,969	101,579	112,189	122,800	133,410	144,020	154,630	-	15,799	1,155,290
35	(AFUDC Debt Income)	Workpaper C-3	(9,444)	(8,429)	(11,587)	(14,987)	(19,700)	(21,415)	(25,021)	(25,740)	(24,918)	(35,281)	-	(4,201)	(208,257)
36	AFUDC Debt Depreciation	Note 1													
37	Tax Expense/(Income) minus Book Expense/(Income)	Line 31 + 32 + 33 - 34 - 35 - 36	1,029,276	1,041,279	1,060,083	1,082,409	1,110,269	1,140,756	1,181,011	1,230,193	1,297,527	1,415,428	144,486	693,591	13,022,856
38	Combined Fed & State Tax Rate	Input	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%	39.19%			
39	Deferred Income Taxes	Line 37 * Line 28	403,323	408,026	415,395	424,143	435,060	447,006	462,780	482,052	508,437	554,637	56,617	271,784	5,103,019
40	Accumulated Deferred Income Taxes	Σ_{1-n} Line 39	1,746,944	2,154,970	2,570,365	2,994,508	3,429,568	3,876,574	4,339,354	4,821,407	5,329,844	5,884,481	56,617	328,401	5,884,481

Progress Energy Carolinas, Inc.

Calculation Tax and Return Related Input Factors

	Component	Percent	Rate	Wgt'd Rate	After Tax Wgt'd Cost	Pre Tax Wgt'd Cost
1	Debt	48.6%	8.62%	4.1867%	2.5462% (a)	4.1867%
2	Preferred	7.4%	8.75%	0.6501%	0.6501%	1.0690% (b)
3	Common	44.0%	12.75%	5.6100%	5.6100%	9.2247% (c)
4	Total	100.0%		10.4469%	8.8063%	14.4805%
5						
6	**After Tax Cost of Debt**					
7	Wgt'd Debt Component				4.1867%	
8	PEC Composite Income Tax Rate				39.1851% (d)	
9	Federal Income Tax Amount				1.6406%	
10						
11	After Tax Debt Cost Component				**2.5462%** (a)	
12						
13	**Incremental Tax Rate**					
14	Pretax Debt Component				4.1867%	
15	After-Tax Debt Component				2.5462%	
16	After Tax Percent of Pretax Amt				60.8149%	
17	Effective Incremental Tax Rate					
18	*(1 - After Tax Percent of Pretax)*				**39.1851%** (d)	
19						
20	**Pre Tax Cost of Equity**					
21	Wgt'd Common Equity Component					5.6100%
22	Wgt'd Preferred Component				0.6501%	
23	Total Equity					5.6100%
24	After Tax Percent of Pretax Amt				60.8149%	60.8149%
25	Pre Tax Cost of Equity					
26	*(Pre Tax Cost of Equity / After Tax Percent of Pretax Amt)*				**1.0690%** (b)	**9.2247%** (c)
27						
28						
29	**Composite Income Tax Rate**					
30						

	Jurisdiction	Rate
31	Jurisdiction	Rate
32	Federal	32.7465%
33	North Carolina	5.7824%
34	South Carolina	0.6562%
35	PEC Composite Income Tax Rate	**39.1851%** (d)

PEC Exhibit No. 1
Filing Requirements

Progress Energy Carolinas, Inc.

Docket No. E-2, Sub 931

Demand Side Management and Energy Efficiency Programs

Filing Requirements

Pursuant to Rule R8-69

June 6, 2008

Recovery request for actual DSM/EE costs incurred from August 21, 2007 through March 31, 2008 and for forecasted costs covering both the period April 1, 2008 through July 31, 2008 and the period December 1, 2008 through November 30, 2009. This request will result in the establishment of DSM/EE and DSM/EE EMF riders pursuant to NCUC Rule R8-69 and G.S. 62-133.9

Contents Listed By Applicable NCUC Rule

Rule R8-69(d)(2) - List of customers opting out of participation

Rule R8-69. Cost recovery for demand-side management and energy efficiency measures of electric public utilities.

(d) **Special Provisions for Industrial or Large Commercial Customers.**

(2) At the time the electric public utility petitions for the annual rider, it shall provide the Commission with a list of those industrial or large commercial customers that have opted out of participation in the new demand-side management or energy efficiency measures.

As of June 2, 2008 the following PEC industrial and large commercial customers have opted out of participation in new demand-side management or energy efficiency measures, pursuant to G.S. 62-133.9(f) and Commission Rule R8-69(d)(1):

1. AJINOMOTO USA INC
2. FRONTIER SPINNING MILLS
3. MOEN INC
4. PILKINGTON
5. POLYMER GROUP INC
6. SAINT GOBAIN CONTAINERS
7. INVISTA SARL
8. PRAXAIR, INC

Rule R8-69(f)(1)(i) - Projected NC retail sales for the rate period

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(i) Projected North Carolina retail monthly kWh sales for the rate period.

The Company's projected North Carolina retail monthly kWh sales for the rate period, December 1, 2008 through November 30, 2009, are provided in the following table:

Projected North Carolina Retail Monthly kWh Sales

Month	Estimated kWh
Dec-08	3,165,225,000
Jan-09	3,394,236,000
Feb-09	3,224,456,000
Mar-09	3,040,441,000
Apr-09	2,925,919,000
May-09	2,880,848,000
Jun-09	3,283,240,000
Jul-09	3,698,326,000
Aug-09	3,849,462,000
Sep-09	3,519,867,000
Oct-09	2,999,051,000
Nov-09	2,765,001,000
Total	38,746,072,000

Rule R8-69(f)(1)(ii)a - Total expenses expected to be incurred during the rate period

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(ii) For each measure for which cost recovery is requested through the DSM/EE rider:

a. total expenses expected to be incurred during the rate period in the aggregate and broken down by type of expenditure, per appropriate capacity, energy and measure unit metric and the proposed jurisdictional allocation factors

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For purposes of cost recovery through the DSM/EE rider, the Company's expected expenses for the rate period, December 1, 2008 through November 30, 2009, have been broken down by type of expenditure and provided in the following table:

	Recoverable Expenditures					
Program / Measure	O&M	Depreciation	Cost of Capital	[illegible] General Taxes	Utility Incentives	Total Costs and Incentives
Demand-Side Management Programs						
DSDR Implementation	$ 5,190,734	$ 1,155,290	$ 3,295,177	$ 1,438,914	$ 712,033	$ 11,792,148
EnergyWise	10,432,771	-	-	-	5,453,160	15,885,930
Energy Efficiency Programs						
Res New Construction	1,523,652	-	-	-	470,203	1,993,856
CIG New Construction	1,046,424	-	-	-	134,109	1,180,532
CIG Retrofit	4,193,567	-	-	-	370,801	4,564,368
CFL Program	-	-	-	-	621,753	621,753
Other DSM/EE Activities						
A&G	4,414,048	-	-	-	-	4,414,048
Program Subtotals	$ 26,801,195	$ 1,155,290	$ 3,295,177	$ 1,438,914	$ 7,762,059	$ 40,452,635
Return on Balances[1]						2,287,301
Expenditure Totals						$ 42,739,936

The total expenditures, excluding utility incentives and A&G, for PEC's various DSM/EE measures have been unitized on the basis of appropriate capacity or energy metric and are provided on the following table:

Program / Measure	Total Costs	DSM Costs per MW	EE Cost per MWH
Demand-Side Management Programs			
DSDR Implementation	$ 11,080,115	$ 380,760	NA
EnergyWise	10,432,771	197,590	NA
Energy Efficiency Programs			
Res New Construction	$ 1,523,652	NA	$ 420
CIG New Construction	1,046,424	NA	607
CIG Retrofit	4,193,567	NA	755
CFL Program	-	NA	NA

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[1] The Return on Balances amount, on a system basis, reflects the sum of the North Carolina specific return calculated on the North Carolina deferral balance and the South Carolina specific return on the South Carolina deferral balance.

For purposes of cost recovery through the North Carolina DSM/EE rider, the Company's expected expenses for the rate period, December 1, 2008 through November 30, 2009, have been broken down for North Carolina jurisdictional retail customers by type of expenditure and provided in the following table:

	Recoverable Expenditures (North Carolina Only)					
Program / Measure	O&M	Depreciation	Cost of Capital	Income and General Taxes	Utility Incentives	Total Costs and Incentives
Demand-Side Management Programs						
DSDR Implementation	$ 4,501,874	$1,001,972	$2,857,875	$1,247,956	$ 617,716	$10,227,393
EnergyWise	9,048,241	-	-	-	4,729,427	13,777,668
Energy Efficiency Programs						
Res New Construction	1,292,153	-	-	-	398,024	1,690,177
CIG New Construction	887,433	-	-	-	112,328	999,761
CIG Retrofit	3,556,408	-	-	-	309,934	3,866,342
CFL Program	-	-	-	-	525,874	525,874
Other DSM/EE Activities						
A&G	3,801,951	-	-	-	-	3,801,951
Program Subtotals	$ 23,088,059	$1,001,972	$2,857,875	$1,247,956	$6,693,303	$34,889,165
Return on Balances						1,975,696
Expenditure Totals						$36,864,860

The Company's proposed jurisdictional allocation factors for the rate period, December 1, 2008 through November 30, 2009, are provided in the following table. It is important to note that these jurisdictional allocation factors apply to costs that have not been directly assigned.

Measure/Program Category	North Carolina
Demand Side Management (DSM)	
DSDR Implementation	86.7%
EnergyWise	86.7%
Energy Efficiency Programs	
CIG New Construction	84.8%
CIG Retrofit	84.8%
Residential New Construction	84.8%
Other DSM/EE Activities	
DSM / EE A&G	86.1%

Rule R8-69(f)(1)(ii)b - Expected cost savings directly attributable to measures

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(ii) For each measure for which cost recovery is requested through the DSM/EE rider:

b. total costs that the utility does not expect to incur during the rate period as a direct result of the measure in the aggregate and broken down by type of cost, per appropriate capacity, energy and measure unit metric, and the proposed jurisdictional allocation factors as well as any changes in the estimated future amounts since last filed with the Commission;

For measures in which cost recovery has been requested through the DSM/EE rider, the Company has provided its total expected cost savings for the rate period, December 1, 2008 through November 30, 2009 that are directly applicable to the measures. These can be classified as short run variable costs. In addition to the cost savings, associated unit metrics have been provided on the following table.

Program / Measure	Fuel ($000s)	MWH	Savings Per MWH
DSDR Implementation	$ 989	22,211	$ 44.52
EnergyWise – Res Load Control	78	236	330.50
CIG New Construction	70	1,724	40.60
CIG Retrofit	229	5,558	41.20
Res New Construction	154	3,626	42.47
CFL Program	270	6,934	36.63
Totals	$ 1,790	40,289	$ 44.43

While notional with respect to expenditure periods, the Company's avoided costs were provided to the Commission as a part of its program requests in Commission Docket Nos. E-2, Sub 926, Sub 927, and Sub 928.

The Company's proposed jurisdictional allocation factors for the rate period, December 1, 2008 through November 30, 2009, are provided in the following table:

Measure/Program Category	North Carolina
Demand Side Management (DSM)	
DSDR Implementation	86.7%
EnergyWise	86.7%
Energy Efficiency Programs	
CIG New Construction	84.8%
CIG Retrofit	84.8%
Residential New Construction	84.8%

Rule R8-69(f)(1)(ii)c - Measurement and verification activities for rate period

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(ii) For each measure for which cost recovery is requested through the DSM/EE rider:

c. a description of the measurement and verification activities to be conducted during the rate period, including their estimated costs;

Anticipated measurement and verification (M&V) activities for the Company's programs were provided as a part of its program requests in Commission Docket Nos. E-2, Sub 926, Sub 927, and Sub 928. In addition, the Company is in the process of obtaining a third-party consultant to provide for ongoing M&V support.

Rule R8-69(f)(1)(ii)d - Expected summer and winter peak demand reductions

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(ii) For each measure for which cost recovery is requested through the DSM/EE rider:

d. total expected summer and winter peak demand reduction per appropriate capacity, energy, and measure unit metric and in the aggregate;

The following tables provide estimated summer and winter peak demand reductions, at the generator, for the measures in which the Company is seeking cost recovery. The reductions are provided by measure and in aggregate.

Expected Summer Peak Demand Reduction (MW)

	CFL Program	DSDR Implementation	EnergyWise	C/G New Construction	C/G Retrofit	Res New Construction	Total
2008	0.7	6.7	12.8	0.1	0.1	0.2	20.6
2009	0.7	29.1	52.8	0.4	1.3	1.1	85.4
2010	0.7	101.5	92.7	0.9	2.9	2.4	201.1
2011	0.7	174.2	132.7	1.7	5.3	5.1	319.7
2012	0.7	247.0	172.7	2.7	8.2	9.1	440.4

Expected Winter Peak Demand Reduction (MW)[2]

	CFL Program	DSDR Implementation	EnergyWise	C/G New Construction	C/G Retrofit	Res New Construction	Total
2008	0.7	-	2.8	-	-	-	3.3
2009	0.7	-	9.5	-	-	-	10.0
2010	0.7	-	16.2	-	-	-	16.7
2011	0.7	-	22.9	-	-	-	23.4
2012	0.7	-	29.6	-	-	-	30.1

[2] With the exception of PEC's EnergyWise program, PEC's DSM/EE measures are focused on its summer peak. The winter peak reductions associated with PEC's measures, including those from the EnergyWise program, will be determined through the measurement and verification (M&V) process. The Company's CFL program provides year-round benefits.

Rule R8-69(f)(1)(ii)e - Expected energy reductions

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(ii) For each measure for which cost recovery is requested through the DSM/EE rider:

e. total expected energy reduction in the aggregate and per appropriate capacity, energy and measure unit metric

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The following table provides estimated energy reductions, at the generator, for the measures in which the Company is seeking cost recovery. The reductions are provided both by measure and in aggregate.

Expected Energy Reductions (MWH)

	CFL Program	DSDR Implementation	EnergyWise[3]	CIG New Construction	CIG Retrofit	Res New Construction	Total
2008	6,934	9,195	59	345	505	774	17,812
2009	6,934	22,211	236	1,724	5,558	3,626	40,289
2010	6,934	38,956	413	3,966	12,885	8,189	71,343
2011	6,934	57,389	590	7,415	23,244	17,316	112,888
2012	6,934	76,443	766	11,726	35,877	31,006	162,752

[3] Energy reductions associated with EnergyWise are proportional to the number of load control events. For the purposes of this response, it has been assumed that were five summer load control events and four winter load control events. The Company's tariff provides for up to sixty-hours of winter and sixty-hours of summer load control on connected devices.

Rule R8-69(f)(1)(iii)a - Actual test period costs

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

a. total expenses for the test period in the aggregate and broken down by type of expenditure per appropriate capacity, energy and measure unit metric and the proposed jurisdictional allocation factors

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For purposes of cost recovery through the DSM/EE rider, the Company's actual expenditures for the test period, August 21, 2007 through March 31, 2008, have been broken down by type of expenditure and are provided in the following table:

	Recoverable Expenditures					
Program/Measure	O&M	Depreciation	Cost of Capital	Income and General Taxes	Utility Incentives	Total Costs and Incentives
Demand-Side Management Programs						
DSDR Implementation	$ 516,899	-	$ (985)	$ (380)	-	$ 515,534
EnergyWise	195,831	-	-	-	-	195,831
Energy Efficiency Programs						
Res New Construction	33,489	-	-	-	-	33,489
CIG New Construction		-	-	-	-	-
CIG Retrofit	-	-	-	-	-	-
CFL	284,399	-	-	-	207,421	491,820
Other DSM/EE Activities						
A&G	2,396,536	-	-	-	-	2,396,536
Program Subtotals	$3,427,154	-	$ (985)	$ (380)	$ 207,421	$ 3,633,209
Return on Balances[4]						86,340
Expenditure Totals						$ 3,719,550

For purposes of cost recovery through the North Carolina DSM/EE rider, the Company's expected expenses for the test period, August 21, 2007 through March 31, 2008, have been broken down for North Carolina jurisdictional retail customers by type of expenditure and are provided in the following table:

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[4] The Return on Balances amount, on a system basis, reflects the sum of the North Carolina specific return calculated on the North Carolina deferral balance and the South Carolina specific return on the South Carolina deferral balance.

	Recoverable Expenditures (North Carolina Only)					
Program / Measure	O&M	Depreciation	Cost of Capital	Income and General Taxes	Utility Incentives	Total Costs and Incentives
Demand-Side Management Programs						
DSDR Implementation	$ 439,230	-	$ (837)	$ (323)	-	$ 438,070
EnergyWise	175,918	-	-	-	-	175,918
Energy Efficiency Programs						
Res New Construction	28,041	-	-	-	-	28,041
CIG New Construction	-	-	-	-	-	-
CIG Retrofit	-	-	-	-	-	-
CFL	268,897	-	-	-	173,182	442,079
Other DSM/EE Activities						
A&G	2,109,823	-	-	-	-	2,109,823
Program Subtotals	$3,021,909	-	$ (837)	$ (323)	$173,182	$3,193,931
Return on Balances						79,354
Expenditure Totals						$3,273,285

For programs under development, comparative metrics are not applicable for the test period. As illustrated in the values below, the CFL test period cost for each annualized MWH saved is approximately $38.79. This translates into approximately $3.88 per MWH over the ten-year study period.

Program / Measure	Total Costs	DSM Costs per MW	EE Cost per MWH
Demand-Side Management Programs			
DSDR Implementation	$ 438,070	NA	NA
EnergyWise	175,918	NA	NA
Energy Efficiency Programs			
Res New Construction	$ 28,041	NA	NA
CIG New Construction	-	NA	NA
CIG Retrofit	-	NA	NA
CFL Program	268,897	NA	$ 38.79

Whenever possible, costs are directly assigned. However, when this is not practical, jurisdictional allocation factors are employed. The Company's proposed jurisdictional allocation factors for the test period, August 21, 2007 through March 31, 2008, are provided in the following table:

Measure/Program Category	North Carolina
Demand Side Management (DSM)	
DSDR Implementation	85.0%
EnergyWise	85.0%
Energy Efficiency Programs	
CIG New Construction	83.7%
CIG Retrofit	83.7%
Residential New Construction	83.7%
CFL Program	83.7%
Other DSM/EE Activities	
DSM / EE A&G	84.6%

Rule R8-69(b)(2)– Experienced over or under-recovery of cost prior to hearing

Rule R8-69 (b) Recovery of Costs Upon the request of the electric public utility, the Commission shall also incorporate the experienced over-recovery or under-recovery of costs up to thirty (30) days prior to the date of the hearing in its determination of the DSM/EE EMF rider, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual DSM/EE rider hearing.

The Company anticipates that it will have actual results available from the end of its test period through July 31, 2008 within the timeline provided for by Commission Rule R-69(b)(2). The Company has incorporated its estimated costs for the period April 1, 2008 through July 31, 2008 in the following table. Actual results will be provided to the Commission at least 30 days prior to the date of its hearing in this matter. At that time, the actual amounts will be used in place of the following estimates.

	Recoverable Expenditures					
Program / Measure	**O&M**	**Depreciation**	**Cost of Capital**	**Income and General Taxes**	**Utility Incentives**	**Total Costs and Incentives**
Demand-Side Management Programs						
DSDR Implementation	$ 553,037	$15,799	$46,678	$20,440	-	$ 635,954
EnergyWise	333,977	-	-	-	-	333,977
Energy Efficiency Programs						
Res New Construction	50,167	-	-	-	-	50,167
CIG New Construction	-	-	-	-	-	-
CIG Retrofit	110,117	-	-	-	-	110,117
CFL	9,785	-	-	-	207,421	217,206
Other DSM/EE Activities						
A&G	856,404	-	-	-	-	856,404
Program Subtotals	**$1,913,487**	**$15,799**	**$46,678**	**$20,440**	**$207,421**	**$2,203,825**
Return on Balances[5]						612,648
Expenditure Totals						**$2,816,472**

	Recoverable Expenditures (North Carolina)					
Program / Measure	**O&M**	**Depreciation**	**Cost of Capital**	**Income and General Taxes**	**Utility Incentives**	**Total Costs and Incentives**
Demand-Side Management Programs						
DSDR Implementation	$ 483,386	$13,702	$40,483	$17,727	-	$ 555,299
EnergyWise	287,928	-	-	-	-	287,928
Energy Efficiency Programs						
Res New Construction	42,327	-	-	-	-	42,327
CIG New Construction	-	-	-	-	-	-
CIG Retrofit	92,204	-	-	-	-	92,204
CFL	8,193	-	-	-	175,402	183,596
Other DSM/EE Activities						
A&G	736,566	-	-	-	-	736,566
Program Subtotals	**$1,650,604**	**$13,702**	**$40,483**	**$17,727**	**$175,402**	**$1,897,919**
Return on Balances						566,969
Expenditure Totals						**$2,464,888**

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[5] The Return on Balances amount, on a system basis, reflects the sum of the North Carolina specific return calculated on the North Carolina deferral balance and the South Carolina specific return on the South Carolina deferral balance.

Rule R8-69(f)(1)(iii)b - Cost savings directly attributable to measures

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

b. total costs that the utility did not incur for the test period as a direct result of the measure in the aggregate and broken down by type of cost per appropriate capacity, energy and measure unit metric, and the proposed jurisdictional allocation factors, as well as any changes in the estimated future amounts since last filed with the Commission;

Other than the Company's CFL Program, there were no measures for which the Company is requesting cost recovery through the DSM/EE EMF rider in service during the test period extending from August 21, 2007 through March 31, 2008. The estimated fuel savings for the CFL program during the test period is $84,666 which translates into the metric $36.63 per MWh.

Whenever possible, costs are directly assigned. However, when this is not practical, jurisdictional allocation factors are employed. The Company's proposed jurisdictional allocation factors for the test period, August 21, 2007 through March 31, 2008, are provided in the following table:

Measure/Program Category	North Carolina
Demand Side Management (DSM)	
DSDR Implementation	85.0%
EnergyWise	85.0%
Energy Efficiency Programs	
CIG New Construction	83.7%
CIG Retrofit	83.7%
Residential New Construction	83.7%
CFL Program	83.7%
Other DSM/EE Activities	
DSM / EE A&G	84.6%

Rule R8-69(f)(1)(iii)c - Measurement and verification activities for test period

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

c. a description of, the results of, and the costs of all measurement and verification activities conducted in the test period;

With the exception of the Company's CFL Program, there were no measures for which the Company is requesting cost recovery through the DSM/EE EMF rider in service during the test period extending from August 21, 2007 through March 31, 2008. As such, measurement and verification activities were not in place for these programs during the test period.

The Company employed Summit Blue Consulting, LLC, to evaluate its "CFL Buy Down Program". Summit Blue's resulting impact evaluation, while received outside of the test period, did confirm the reasonableness of the Company's estimates.

Rule R8-69(f)(1)(iii)d - Test period summer and winter peak demand reductions

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

d. total summer and winter peak demand reduction per appropriate capacity, energy, and measure unit metric and in the aggregate, as well as any changes in estimated future amounts;

With the exception of the Company's CFL Program, there were no measures for which the Company is requesting cost recovery through the DSM/EE EMF rider in service during the test period extending from August 21, 2007 through March 31, 2008. As such, the requested information will be made available for programs when in service experience is available in subsequent cost recovery requests. In addition, there are no changes in estimated future values relative to information supplied previously to the Commission.

Estimates of summer and winter peak demand reductions for the Company's CFL Program have been provided in the accompanying response to Commission Rule R8-69(f)(1)(ii)d.

Rule R8-69(f)(1)(iii)e - Test period energy reductions

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

e. total energy reduction in the aggregate and per appropriate capacity, energy and measure unit metric, as well as any changes in the estimated future amounts since last filed with the Commission;

With the exception of the Company's CFL Program, there were no measures for which the Company is requesting cost recovery through the DSM/EE EMF rider in service during the test period extending from August 21, 2007 through March 31, 2008. As such, the requested information will be made available for programs when in service experience is available in subsequent cost recovery requests. In addition, there are no changes in estimated future values relative to information supplied previously to the Commission.

The estimated energy impacts for the Company's CFL Program have been provided in the accompanying response to Commission Rule R8-69(f)(1)(ii)e.

Rule R8-69(f)(1)(iii)f - Test period findings and results of measures

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

f. a discussion of the findings and the results of the program or measure;

Other than for the Company's CFL Program, there were no measures for which the Company is requesting cost recovery through the DSM/EE EMF rider in service during the test period extending from August 21, 2007 through March 31, 2008. Discussions of findings and results of programs and/or measures will be provided in subsequent recovery requests.

The Company employed Summit Blue Consulting, LLC, to evaluate its "CFL Buy Down Program". Summit Blue's resulting impact evaluation indicated that this program achieved annualized energy savings of 6,706 MWh, a 630 kW summer peak demand savings. The impact evaluation also indicated that these savings are expected to persist for ten years.

Rule R8-69(f)(1)(iii)g - Evaluation of event based measure during test period

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

g. evaluations of event-based programs including the date, weather conditions, event trigger, number of customers notified and number of customers enrolled; and

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There were no event based measures, for which the Company is requesting cost recovery through the DSM/EE EMF rider in service during the test period extending from August 21, 2007 through March 31, 2008. As such, no event based programs were activated during the test period. The Company's current estimates of event based measure impacts are provided in responses to Commission Rules R8-69(f)(1)(ii)d and R8-69(f)(1)(ii)e.

Rule R8-69(f)(1)(iii)h – Comparison of impact estimates

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

h. a comparison of impact estimates presented in the measure application from the previous year, those used in reporting for previous measure years, and an explanation of significant differences in the impacts reported and those previously found or used.

With the exception of the Company's CFL Program, there were no measures, for which the Company is requesting cost recovery through the DSM/EE EMF rider, in place during the test period extending from August 21, 2007 through March 31, 2008. In addition, there were no impact estimates in measure applications or reports submitted by the Company in the prior year. This absence of previously reported impact estimates includes the Company's CFL Program.

Rule R8-69(f)(1)(iv) – Determination of utility incentives

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(iv) For each measure for which recovery of utility incentives is requested, a detailed explanation of the method proposed for calculating those utility incentives, the actual calculation of the proposed utility incentives, and the proposed method of providing for their recovery and true-up through the annual rider. If recovery of net lost revenues is requested, the total net lost kWh sales and net lost revenues per appropriate capacity, energy, and program unit metric and in the aggregate for the test period, and the proposed jurisdictional allocation factors, as well as any changes in estimated future amounts since last filed with the Commission.

The Company's proposed utility incentives can be broken down into three categories. These are (1) net lost revenues, (2) specific incentives for demand side management (DSM) programs, and (3) specific incentives for energy efficiency (EE) programs. The proposed mechanisms associated with these incentives are described below and the specific calculations are included as a part of the Company's supporting workpapers.

A. Net Lost Revenues

Net lost revenues are determined by multiplying lost sales by a net lost revenue rate.

Net Lost Revenues = Lost Sales X Net Lost Revenue Rate

Lost Sales are those sales that do not occur by virtue of employing the DSM / EE measures. These values are initially based on estimates and subsequently confirmed through the measurement and verification (M&V) process.

Net Lost Revenue Rate is difference between the average retail rate applicable to the customer class impacted by the measure and (1) the related customer charge component of that rate, (2) the fuel component of the rate, and (3) the incremental variable O&M rate. When multiple customer classes are impacted by the DSM / EE measures, a weighted or system wide net lost revenue rate is employed.

B. DSM Utility Incentive

For DSM programs, the Company has proposed an incentive equal to 50 % of the net present value of the DSM program savings based upon the Utility Cost Test ("UCT"). The UCT is an industry standard test, which compares the costs incurred by a utility in offering a DSM/EE program to the benefits as measured by the costs avoided by the utility. Since the UCT looks at the cost to the utility and utilizes the traditional concept of least cost provisioning, use of the test will provide appropriate incentives to PEC but, at the same time, encourage the Company to pursue least cost alternatives.

PEC proposes that the incentive amount be recovered over a 10-year period. For DSM programs, PEC will determine an incentive per kW saved using the forecast upon which the cost/benefit tests are based. This incentive per kW will be applied to actual peak demand reductions achieved in each year, such that if PEC achieves the targeted demand reduction of the program, the company will receive 100% of the target incentive. If PEC achieves less kW of demand reduction than projected, the incentive will be proportionally less. If PEC achieves more kW of demand reduction than projected, the incentive will be proportionally more. The incentive will be collected through a charge per kWh.

C. EE Utility Incentive

As with its DSM programs, the Company has proposed an incentive equal to 50 % of the net present value of the EE program savings based upon the Utility Cost Test ("UCT").

For EE programs, PEC will use a similar methodology, but will solve for a rate per MWh of energy reduction achieved, such that if the company achieves the targeted energy reduction of the program, the company will receive 100% of the target incentive. Again, if PEC achieves fewer MWh of reduction than expected, the incentive will be proportionally less. If PEC achieves more MWh of reduction than expected, the incentive will be proportionally more.

Estimates of lost sales quantities for the Company's system are provided in the following table. They have been segmented into the recovery periods.

Program / Measure	Sales Loss For Purposes of Lost Revenue Calculation (kWh) - System		
	Test Period (8/21/07 through 3/31/08)	Prospective Period (4/1/08 through 7/31/08)	Rate Period (12/1/08 through 11/30/09)
Demand-Side Management Programs			
DSDR Implementation	-	-	1,581,200
EnergyWise	-	-	235,600
Energy Efficiency Programs			
Res New Construction	-	-	3,482,500
CIG New Construction	-	-	1,639,800
CIG Retrofit	-	-	5,285,500
CFL	2,185,400	2,185,400	6,556,200
Total Reduction in Energy (kWh)	2,185,400	2,185,400	18,780,800

The following table provides calculated North Carolina jurisdictional utility incentives for the Company's test period (8/21/07 through 3/31/08).

Program / Measure	Utility Incentives (North Carolina Only) – Test Period (8/21/07 through 3/31/08)			
	Net Lost Revenue	Capacity Incentive	Energy Incentive	Total
Demand-Side Management Programs				
DSDR Implementation	-	-	-	-
EnergyWise	-	-	-	-
Energy Efficiency Programs				
Res New Construction	-	-	-	-
CIG New Construction	-	-	-	-
CIG Retrofit	-	-	-	-
CFL	105,420	-	67,762	173,182
Total Utility Incentives Including Net Lost Revenue	$105,420		$67,762	$173,182

The following table provides calculated North Carolina jurisdictional utility incentives for the Company's "prospective" period (4/1/08 through 7/31/08).

Program / Measure	Utility Incentives (North Carolina Only) – Prospective Period (4/1/08 through 7/31/08)			
	Net Lost Revenue	Capacity Incentive	Energy Incentive	Total
Demand-Side Management Programs				
DSDR Implementation	-	-	-	-
EnergyWise	-	-	-	-
Energy Efficiency Programs				
Res New Construction	-	-	-	-
CIG New Construction	-	-	-	-
CIG Retrofit	-	-	-	-
CFL	106,772	-	68,631	175,402
Total Utility Incentives Including Net Lost Revenue	$106,772	-	$68,631	$175,402

The following table provides calculated North Carolina jurisdictional utility incentives for the Company's rate period (12/1/08 through 11/30/09).

Program / Measure	Utility Incentives (North Carolina Only) – Rate Period (12/1/08 through 11/30/09)			
	Net Lost Revenue	Capacity Incentive	Energy Incentive	Total
Demand-Side Management Programs				
DSDR Implementation	$63,753	$553,963	-	$ 617,716
EnergyWise	11,759	4,717,668	-	4,729,427
Energy Efficiency Programs				
Res New Construction	167,331	-	230,693	398,024
CIG New Construction	63,511	-	48,817	112,328
CIG Retrofit	204,714	-	105,220	309,934
CFL	319,981	-	205,893	525,874
Total Utility Incentives Including Net Lost Revenue	$831,049	$5,271,631	$590,623	$6,699,303

The Company's proposed jurisdictional allocation factors for the test period, August 21, 2007 through March 31, 2008, are provided in the following table:

Measure/Program Category	North Carolina
Demand Side Management (DSM)	
DSDR Implementation	85.0%
EnergyWise	85.0%
Energy Efficiency Programs	
CIG New Construction	83.7%
CIG Retrofit	83.7%
Residential New Construction	83.7%
CFL Program	83.7%

Rule R8-69(f)(1)(v) – Actual revenue from DSM/EE and DSM/EE EMF riders

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(v) Actual revenues produced by the DSM/EE rider and the DSM/EE EMF rider established by the Commission during the test period and for all available months immediately preceding the rate period.

The Company did not have a DSM/EE rider or DSM/EE EMF in effect during the test period extending from August 21, 2007 through March 31, 2008.

Rule R8-69(f)(1)(vi) - Proposed DSM/EE and DSM/EE EMF riders

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(vi) The requested DSM/EE rider and DSM/EE EMF rider and the basis for their determination.

Attached to this document is NC Rider BA-1 (Annual Billing Adjustments). Detailed information regarding the determination of the DSM/EE and DSM/EE EMF factors has been provided as a part of the attached testimony of Robert P. Evans. The following table provides a summary of the Company's requested DSM/EE rates.

Rate Class	DSM /EE Rate	DSM /EE EMF	DSM /EE Annual Rider
Residential	0.165¢/kWh	0.025¢/kWh	0.190¢/kWh
Small General Service	0.167¢/kWh	0.025¢/kWh	0.192¢/kWh
Medium General Service	0.140¢/kWh	0.021¢/kWh	0.161¢/kWh
Large General Service	0.101¢/kWh	0.016¢/kWh	0.117¢/kWh
Lighting	0.037¢/kWh	0.007¢/kWh	0.044¢/kWh

Carolina Power & Light Company
d/b/a Progress Energy Carolinas, Inc.
(North Carolina Only)

ANNUAL BILLING ADJUSTMENTS
RIDER BA-1

APPLICABILITY – RATES INCLUDED IN TARIFF CHARGES

The rates shown below are included in the MONTHLY RATE provision in each schedule identified in the table below:

Billing Adjustment Factors (¢/kWh)*					
Rate Class	Fuel Adjustment		DSM/EE Adjustment		Net Adjustment
	Rate(1)	EMF(2)	Rate(3)	EMF(4)	
Residential			0.170	0.026	
Applicable to Schedules: RES, R-TOUD & R-TOUE					
Small General Service			0.173	0.026	
Applicable to Schedules: SGS & TSS					
Medium General Service			0.145	0.022	
Applicable to Schedules: MGS, SGS-TOU, SI, CH-TOUE, GS-TES, APH-TES, CSG, CSE & Riders 66 & SS (less than 1 MW)					
Large General Service			0.104	0.017	
Applicable to Schedules: LGS, LGS-TOU, LGS-RTP and Riders 66 & SS (1 MW and greater)					
Lighting			0.038	0.007	
Applicable to Schedules: ALS, SLS, SLR & SFLS					

* Billing Adjustment Factors, shown above, include North Carolina gross receipts taxes.

Billing Adjustment Factors Description:

(1) The Fuel Adjustment Rate is adjusted annually to reflect incremental changes in the costs of fuel and fuel-related costs from the rates approved in the last general rate case.

(2) The Fuel Adjustment Experience Modification Factor (EMF) is adjusted annually to reflect the difference between reasonable and prudently incurred fuel and fuel-related costs and the fuel and fuel-related revenues realized during a test period under review and shall remain in effect for a fixed 12 month period.

(3) The Demand Side Management/Energy Efficiency (DSM/EE) Rate is adjusted annually to reflect the costs and incentives associated with demand side management and energy efficiency measures and programs approved by the North Carolina Utilities Commission.

(4) The Demand Side Management/Energy Efficiency Experience Modification Factor (DSM/EE EMF) is adjusted annually to reflect the difference between reasonable and prudently incurred DSM/EE costs and incentives and DSM/EE revenues realized during the period under review and shall remain in effect for a fixed 12 month period.

Demand Side Management/Energy Efficiency "Opt-Out" Option

North Carolina Utilities Commission Rule R8-69(e) allows commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers to elect to not participate in any utility-offered DSM/EE program and, after written notification to the utility, not be subject to the DSM/EE Rate and EMF, shown above. For purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. Since these rates are included in the rate tariff charges, Customers electing this option shall receive the following DSM/EE Credit on their monthly bill statement:

DSM/EE Credit = DSM/EE Rate Credit plus DSM/EE EMF Credit

Where:

DSM/EE Rate Credit = Billed kWh times DSM/EE Rate*
DSM/EE EMF Credit = Billed kWh times DSM/EE EMF Rate*

* The DSM/EE Rate and EMF shall be as shown in the above table for the schedule applicable to Customer's monthly bill.

Following the December bill each year, usage for commercial accounts electing to "opt-out" of the DSM/EE rates shall be reviewed and the customer shall be notified and removed from the "opt-out" option if annual consumption is less than 1,000,000 kWh in the prior twelve months.

APPLICABILITY – RATES NOT INCLUDED IN TARIFF CHARGES

The rates shown below are not included in the MONTHLY RATE provision of the applicable schedule used in billing and shall therefore be added to Customer's monthly bill statement:

Billing Adjustment Factors Per Customer ($/month)*			
Revenue Class	REPS Rate(5)	REPS EMF(6)	Net Billing Rate
Residential	$per month	$per month	$per month
Commercial/Public Streets and Highways	$per month	$per month	$per month
Industrial/Public Authority	$per month	$per month	$per month

* Billing Adjustment Factors, shown above, include North Carolina gross receipts taxes.

For purposes of the applicability of the REPS-related Billing Adjustment Factors, a "Customer" is defined as all accounts (metered and unmetered) serving the same customer of the same revenue classification located on the same or contiguous properties. Upon written notification from Customer, accounts meeting these criteria shall be combined under a single account number to allow Customer to receive only one monthly bill statement for all meters under the account and only one monthly REPS charge.

Billing Adjustment Factors Description:

(5) The Renewable Energy Portfolio Standard (REPS) Rate is adjusted annually to reflect research and development costs and incremental costs incurred to comply with the state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS).

(6) The Renewable Energy Portfolio Standard Experience Modification Factor (REPS EMF) Rate is adjusted annually to recover the difference between reasonable and prudently incurred REPS costs and REPS revenues realized during the period under review and shall remain in effect for a fixed 12 month period.

SALES TAX

To the above charges will be added any applicable North Carolina Sales Tax.

Effective for service rendered on and after December 1, 2008;
The DSM/EE EMF, Fuel Adjustment EMF and REPS EMF are effective for service rendered through November 30, 2009
NCUC Docket No. E-2, Subs 929, 930 & 931

Rule R8-69(f)(1)(vii) – Projected NC retail sales for customers opting out of measures

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(vii) Projected North Carolina retail monthly kWh sales for the rate period for all industrial and large commercial accounts, in the aggregate, that are not assessed the rider charges as provided in this rule.

For the purpose of its initial filing, the Company has assumed that all industrial and all large commercial accounts capable of opting out, will opt out. The following table provides the Company's estimate of North Carolina retail monthly kWh sales in the aggregate, that will not be assessed DSM/EE or DSM/EE EMF rider charges as provided for in Commission Rule R8-69.

Aggregate Industrial & Large Commercial Sales Not Assessed Rider Charges

Month	Estimated KWh
Dec-08	1,185,094,390
Jan-09	1,182,619,075
Feb-09	1,251,853,261
Mar-09	1,158,314,252
Apr-09	1,241,559,795
May-09	1,226,114,971
Jun-09	1,294,544,632
Jul-09	1,396,379,402
Aug-09	1,389,049,864
Sep-09	1,365,646,034
Oct-09	1,375,764,434
Nov-09	1,271,804,507
Total	15,338,744,616

Rule R8-69(f)(1)(viii) – Supporting workpapers

Rule R8-69 (f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(viii) All workpapers supporting the calculations and adjustments described above

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Workpapers supporting calculations and adjustments have been attached to this document.

Rule R8-69(f)(2) – Workpapers and testimony

Rule R8-69 (f) Filing Requirements and Procedure.

(2) Each electric public utility shall file the information required under this rule, accompanied by workpapers and direct testimony and exhibits of expert witnesses supporting the information filed in this proceeding, and any change in rates proposed by the electric utility, by the date specified in subdivision (e)(2) of this rule. An electric public utility may request a rider lower than that to which its filed information suggests that it is entitled.

The testimony and exhibits of Robert P. Evans are elements of this request. Information detailing the development of the Company's proposed DSM/EE and DSM/EE EMF rates are provided as a part of Mr. Evans' testimony.

263696

NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 931

DIRECT TESTIMONY OF ROBERT P. EVANS

ON BEHALF OF CAROLINA POWER & LIGHT COMPANY

D/B/A/ PROGRESS ENERGY CAROLINAS, INC.

Q. PLEASE STATE YOUR NAME, YOUR BUSINESS ADDRESS AND THE BUSINESS RELATIONSHIP WITH PROGRESS ENERGY CAROLINAS, INC..

A. My name is Robert P. Evans and my business address is 411 Fayetteville Street, Post Office Box 1551, Raleigh, North Carolina 27602. I am employed by Progress Energy Carolinas, Inc. ("PEC") as a Senior Energy Delivery Project Specialist in the Energy Delivery Department.

Q. PLEASE BRIEFLY STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Iowa State University ("ISU") in 1978 with a Bachelor of Science Degree in Industrial Administration and a minor in Industrial Engineering. As a part of my undergraduate work, I participated in both the graduate level Regulatory Studies Programs sponsored by American Telephone and Telegraph Corporation and graduate level study programs in Engineering Economics. Subsequent to my graduation from ISU, I received additional Engineering Economics training at the Colorado School of Mines, completed the NARUC Regulatory Studies program at Michigan State, and completed the Advanced AGA Ratemaking program at the University of Maryland. I am currently working on a

Renewable Energy Technology certification from North Carolina State University. Upon graduation from ISU, I joined the Iowa State Commerce Commission, now known as the Iowa Utility Board ("IUB"), in the Rates and Tariffs Section of the Utilities Division. During my tenure with the IUB, I held several positions, including Senior Rate Analyst in charge of Utility Rates and Tariffs and Assistant Director of the Utility Division. In those positions I provided testimony in gas, electric, water and telecommunications proceedings as an expert witness in the areas of rate design, service rules, and tariff applications. In 1982, I accepted employment with City Utilities of Springfield, Missouri, as an Operations Analyst. In that capacity, I provided support for rate-related matters associated with the municipal utility's gas, electric, water and sewer operations. In addition, I worked closely with its load management and energy conservation programs. In 1983, I joined the Rate Services staff of the Iowa Power and Light Company, now known as MidAmerican Energy, as a Rate Engineer. In this position, I was responsible for the preparation of rate related filings and presented testimony on rate design, service rules, and accounting issues before the IUB. In 1986, I accepted employment with Tennessee-Virginia Energy Corporation, which is now known as the United Cities Division of ATMOS Energy, as Director of Rates and Regulatory Affairs. While in this position, I was responsible for regulatory filings, regulatory relations, and customer billing. In 1987, I went to work for the Virginia State Corporation Commission in the Division of Energy Regulation as a Utilities Specialist. In this capacity I worked with electric and natural gas issues and provided testimony on cost of service and rate design matters brought before that regulatory body. In 1988, I joined North Carolina Natural Gas Corporation ("NCNG") as its Manager of Rates and Budgets. Subsequently, I was promoted to Director-Statistical

Services in its Planning and Regulatory Compliance Department. In that position, I performed a variety of work associated with financial, regulatory, statistical analysis, and presented testimony on a variety of issues before the North Carolina Utilities Commission. I held that position until the closing of NCNG's merger with Carolina Power and Light Company, the predecessor of Progress Energy Corporation, on July 15, 1999.

From July 1999 through January 2008 I was employed in Principal and Senior Analyst roles by the Progress Energy Service Company, LLC. In these roles I provided NCNG, Progress Energy Carolinas, Inc., Progress Energy Florida, Inc. with rate and regulatory support in their state and federal venues and financial forecasting.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. I am responsible for financial analysis and support of PEC's Energy Efficiency (EE) and Demand Side Management (DSM) programs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain and support PEC's Application for a DSM/EE cost recovery rider and Experience Modification Factor ("EMF") and provide the information required by Commission Rule R8-69.

Q. ARE YOU SPONSORING PEC'S DSM/EE COST RECOVERY RIDER APPLICATION?

A. Yes. In addition to this testimony and accompanying exhibits, I am sponsoring PEC'S DSM/EE Cost Recovery Rider Application identified as PEC Exhibit No. 1.

JURISDICTIONAL COST ALLOCATION

Q. HOW ARE DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY (DSM/EE) COSTS ALLOCATED TO THE NORTH CAROLINA RETAIL JURISDICTION?

A. DSM/EE costs are reviewed monthly and allocated to the appropriate retail jurisdiction. Costs are directly assigned to the jurisdiction whenever the program benefits only one jurisdiction. Costs that offer a system benefit are allocated based upon the primary emphasis of the program. The allocation of these costs recognizes that EE programs emphasize an overall reduction on energy consumption while DSM programs emphasize an overall reduction on the system peak demand. This approach applies to all costs regardless of whether they relate to the DSM/EE rider or the EMF.

Q. PLEASE ELABORATE ON THE METHODOLOGY USED TO ALLOCATE DSM/EE COSTS THAT OFFER A SYSTEM BENEFIT.

A. PEC first reviews all costs to be recovered and separates them into three categories: (1) EE-related costs, (2) DSM-related costs and (3) general administrative (A&G) costs that support both EE and DSM programs. Since A&G costs relate to both EE and DSM, they are divided into these two categories. The division of these costs into either the EE or DSM category is based upon the percentage of each type of expenditure anticipated during the next forecast calendar year. For example, if 30% of these costs in the forecast period are EE-related, then 30% of the A&G costs will be considered as EE-related costs for allocation purposes. The use of a forecast period recognizes the types of new programs PEC will offer in the immediate future that will be supported by these administrative costs. The assignment of A&G costs as either EE or DSM related is reviewed annually each June based upon forecast costs for the next calendar year. Historic general administrative costs in this proceeding have been assigned to the appropriate category based upon forecasted EE and DSM costs for 2009.

Q. HOW ARE COSTS IDENTIFIED AS EE-RELATED ALLOCATED TO THE JURISDICTION?

A. Any program costs that are identified as being EE-related, including A&G costs, are allocated to NC retail operations based upon the ratio of NC retail sales to PEC system retail sales using results from the annual per books cost of service study. The allocation percentage is updated each May to reflect the study results filed with the Commission in April. In this proceeding, the energy allocation reflects the 2006 per books cost of service study for the period August 21, 2007 through April 30, 2008 and the 2007 per books cost of service study for the period thereafter.

Q. HOW ARE COSTS IDENTIFIED AS DSM-RELATED ALLOCATED TO THE JURISDICTION?

A. Any program costs that are identified as being DSM-related, again including assigned A&G costs, are allocated to NC retail based upon the ratio of the NC retail peak demand to the PEC system retail peak demand using data supporting the annual per books cost of service study. The allocation percentage is updated each May to reflect the annual cost of service study results filed with the Commission in April. In this proceeding, the demand allocation reflects the summer coincident peak used in the 2006 per books cost of service study for the period August 21, 2007 through April 30, 2008 and the 2007 per books cost of service study thereafter.

Q. ARE YOU PROPOSING THAT DSM/EE COSTS BE RECOVERED SOLELY FROM RETAIL CUSTOMERS AND, IF SO, WHY DO YOU BELIEVE THAT TO BE APPROPRIATE?

A. Yes, I am. Senate Bill 3 recognizes that large customers perform their own analyses regarding DSM/EE initiatives and implement, at their own expense, those initiatives that are determined to be economic. Therefore, large customers do not need to participate in a utilities' DSM/EE programs. As a result, Senate Bill 3 allows these customers to "opt-out" of paying for the utility's DSM/EE program costs. PEC's wholesale customers are similar to PEC's industrial customers. They perform their own DSM/EE analyses and implement those programs that are economic and beneficial at their own expense. Therefore they should not be assigned costs related to PEC's retail programs. For example, many wholesale customers already offer appliance control and other programs designed to reduce the system peak. Although the wholesale customers may individually choose to implement DSM/EE programs similar to those offered by PEC, such programs would be funded solely by the wholesale customer, not PEC. Thus, PEC's wholesale customers should not be expected to pay for programs that solely target participation to PEC's retail customers while the cost for the wholesale customer's programs must be borne solely by the wholesale customer's consumers. In addition, N.C. Gen. Stat. § 62-133.9(e) provides that utilities shall assign the costs of DSM/EE the programs only to the class or classes of customers that directly benefit from the programs. PEC's wholesale customers do not directly benefit from PEC's DSM/EE programs.

In fact, to the extent retail EE/DSM programs reduce retail usage and demand, system costs will automatically be shifted to the wholesale jurisdiction due to changes in allocation factors. Since wholesale customer will not participate in any of PEC's DSM/EE programs, they will not have the opportunity to benefit from the reduced usage and demand created by the programs.

Q. HOW DO INVESTOR OWNED UTILITIES IN OTHER JURISDICTIONS ALLOCATE DSM/EE COSTS?

A. The jurisdictions that we reviewed allocate costs consistent with PEC's proposed method. In fact, PEC surveyed EEI members with this question of allocation of DSM/EE costs. All of the respondents, total of nine, indicated that they did not allocate any costs to the wholesale jurisdiction.

<u>SUMMARY OF DSM/EE COSTS</u>

Q. CAN YOU PROVIDE A SUMMARY OF THE COSTS THE COMPANY IS REQUESTING TO RECOVER IN THIS PROCEEDING?

A. Yes. The Company's requested jurisdictionally allocated North Carolina DSM/EE costs associated with this proceeding have been broken into three discrete periods. For the test period, extending from August 21, 2007 through March 31, 2008, the Company is requesting recovery of $3,273,285. For the rate period, extending from December 1, 2008 through November 30, 2009, the Company is requesting recovery of $36,864,860. An estimated amount of $2,464,888 is being requested for the prospective period extending from the end of the test period through July 31, 2008. These prospective period estimates will be replaced by actual amounts at least 30-days prior to the hearing date in this proceeding.

A summary of the costs associated with the Company's recovery request is provided in the following table, which has been broken down by the aforementioned time periods and by DSM/EE measures.

Program / Measure	Test Period	Prospective Period	Rate Period
Demand-Side Management Programs			
DSDR Implementation	$ 438,070	$ 555,299	$10,227,393
EnergyWise	175,918	287,928	13,777,668
Energy Efficiency Programs			
Res New Construction	$ 28,041	$42,327	$ 1,690,177
CIG New Construction	-	-	999,761
CIG Retrofit	-	92,204	3,866,342
CFL Program	442,079	183,596	525,874
A&G and Carrying Costs			
A&G	2,109,823	736,566	3,801,951
Carrying Cost on Balances	79,354	566,969	1,975,696
Total Cost	$ 3,273,285	$2,464,888	$36,864,860

In addition to the summary table above, a further breakdown by cost element including utility incentives, is provided on attached Evans Exhibit No. 1.

UTILITY INCENTIVES

Q. HOW WERE THE UTILITY INCENTIVES CALCULATED?

A. The Company's proposed utility incentives can be broken down into two categories. These are (1) incentive to create future benefits based on achieved kW for DSM programs or kWh for EE programs and (2) net lost revenues.

For DSM programs, the Company has proposed an incentive equal to 50 % of the net present value of the DSM program savings based upon the Utility Cost Test ("UCT"). The UCT is an industry standard test, which compares the costs incurred by a utility in offering a DSM/EE program to the benefits as measured by the costs avoided by the utility. Since the UCT looks at the cost to the utility and utilizes the traditional concept of least cost provisioning, use of the test combined with the Company's proposed utility incentives, will encourage the Company to pursue least cost alternatives.

PEC proposes that the incentive amount be recovered over a 10-year period. For DSM programs, PEC will determine an incentive per kW saved using the forecast upon which the cost/benefit tests are based. This incentive per kW will be applied to actual peak demand reductions achieved in each year. Thus, if PEC achieves the targeted demand reduction of the program, the Company will receive 100% of the target incentive. If PEC achieves less kW of demand reduction than projected, the incentive will be proportionally less. If PEC achieves more kW of demand reduction than projected, the incentive will be proportionally more. The incentive will be collected through a charge per kWh. An example of this incentive calculation is provided on Part A of Evans Exhibit No. 2. As in the Company's proposal, the target utility incentive in this example is based upon 50% of the UCT result of $200,000. The incentive rate on line 5 of this section is calculated so that the recovery of $100,000 target incentive, in current dollars, is achieved during the initial ten-year period using the cumulative MW savings from the program request. Using this example, if the 2009 target of 10 MW is achieved, an incentive of $3,115 would be provided to the Company.

Consistent with its proposal for DSM programs, the Company has proposed an EE Utility Incentive equal to 50 % of the net present value of the EE program savings based upon the Utility Cost Test ("UCT").

For EE programs, PEC will use a similar methodology, but will solve for a rate per MWh of energy reduction achieved. Accordingly, if the Company achieves the targeted energy reduction of the program, the Company will receive 100% of the target incentive. Again, if

PEC achieves fewer MWh of reduction than expected, the incentive will be proportionally less. If PEC achieves more MWh of reduction than expected, the incentive will be proportionally more. An example of this incentive calculation is provided on Part B of Evans Exhibit No. 2. As in the previous example, the target utility incentive is based upon 50 % of the UCT result of $200,000. The incentive rate on line 5 of this section is calculated so that the recovery of $100,000 target incentive, in current dollars, is achieved during the initial ten-year period using the cumulative MWH savings from the program request. Using this example, if the 2009 target of 10 MWh is achieved, an incentive of $3,115 would be provided to the Company.

Net lost revenues, which are applicable to both DSM and EE programs, are determined by multiplying lost sales by a net lost revenue rate.

NET LOST REVENUES = LOST SALES X NET LOST REVENUE RATE

Lost Sales are those sales that do not occur by virtue of employing the DSM / EE measures. These values are initially based on engineering estimates and/or past impact evaluations, with future periods based on updated impact evaluations conducted through the measurement and verification (M&V) activities and applied prospectively.

Net Lost Revenue Rate is the difference between the average retail rate applicable to the customer class impacted by the measure and (1) embedded gross receipts taxes, (2) the related average customer charge component of that rate, (3) the average fuel component of the rate, and (4) the incremental variable O&M rate as approved in the Company's last CSP tariff. When multiple customer classes are impacted by the DSM / EE measures, a weighted or system wide net lost revenue rate is employed. An example of this incentive calculation is provided on Part C of Evans Exhibit No. 2. To determine the Net Lost

Revenue Rate, gross receipts taxes, average customer charges, a variable O&M component, and average fuel costs are removed from the Company's rates. Reductions in sales, associated with DSM and EE programs are multiplied by this rate to make the Company whole with respect to its margins. In the example, the 10 MWh loss would equate to Net Lost Revenues of $573.10.

RATE DEVELOPMENT

Q. ONCE ALL RELEVANT COSTS ARE ALLOCATED TO NORTH CAROLINA AND IDENTIFIED AS BEING EITHER DSM/EE RELATED, HOW ARE RATES ESTABLISHED?

A. PEC schedules are designed to establish three natural rate groups: Residential, General Service and Lighting. While all customers within both the Residential and Lighting groups have similar usage characteristics, this is not true for the General Service Class, which ranges from a small customer using a few hundred kWh per year to a huge industrial complex using millions of kWh per month. To address this diversity in usage, PEC proposes that the General Service Class be separated into three rate groups: Small General Service (small consumers below 30 kW being billed solely on kWh usage), Medium General Service (consumers being billed for both energy and demand with loads from 30 kW to 999 kW) and Large General Service (customers using 1 MW or greater). PEC's tariffs easily fall within one of these five rate classes; therefore, this grouping supports a common rate design theory of grouping customers with similar usage characteristics.

Q. CAN YOU IDENTIFY THE RATE TARIFFS THAT FALL WITHIN EACH RATE CLASS?

A. The following table lists the schedules and riders proposed within each rate class:

Residential	Small General Service	Medium General Service	Large General Service	Lighting
RES R-TOUD R-TOUE	SGS TSS	MGS SGS-TOU SI GS-TES APH-TES CH-TOUE CSE CSG Riders 66 & SS (less than 1 MW)	LGS LGS-TOU LGS-RTP Riders 66 & SS (1 MW & Greater)	ALS SLS SLR SFLS

Q. HOW ARE EE AND DSM RELATED COSTS ALLOCATED TO EACH RATE CLASS?

A. PEC proposes to continue the philosophy used to allocate cost to the retail jurisdiction – EE-related costs will be allocated using an energy allocation while DSM-related costs will be allocated using a demand allocation, after each has been adjusted to reflect the impact of customers opting-out of the DSM annual rider.

Q. HOW ARE SALES AND DEMAND ADJUSTED FOR THE IMPACT OF "OPT-OUT" CUSTOMERS?

A. Commercial customers consuming 1,000,000 kWh per year and all industrial customers, regardless of usage, are eligible under Commission Rules to "opt-out" of the annual DSM/EE rider. PEC reviewed its customer records and identified 1,829 commercial customers consuming 4,965,064,184 kWh during the year ended March 31, 2008. For purposes of determining eligibility to "opt-out", a customer is defined as a metered account billed under a single application of a rate tariff. Customers with multiple meters being billed separately will not be eligible to aggregate all of these meters to achieve "opt-out" eligibility unless the customer is billed under the totalized metering option of the additional facilities plan. Also, if one metered account is eligible to "opt-out", other meters at the same premise are not eligible to "opt-out" unless they also individually consume 1,000,000 kWh per year. "Opt-out" eligibility will be reviewed each year after the December bill and only customers consuming 1,000,000 kWh or more in the calendar year will be eligible to "opt-out" of the next year's DSM/EE Rider charges. New commercial customers will need to demonstrate during the prior calendar year that their consumption has exceeded 1,000,000 kWh before they will be eligible to "opt-out". This approach will eliminate the need to review consumption monthly, potentially forcing customers to "opt-in" or "opt-out" as annual usage vacillates around 1,000,000 kWh. A similar review identified industrial sales of 10,373,680,432 kWh eligible to "opt-out". Rate Class allocation factors were developed assuming that all eligible customers opt-out of the DSM rider. If these customers do not choose the "opt-out", any revenue gain will be returned to customers in next year's EMF rider.

Commercial and industrial sales for the year ended March 31, 2008 for all customers eligible to "Opt-Out" of the DSM/EE rate are provided in Evans Exhibit No. 3.

Q. THE SALES FOR "OPT-OUT" CUSTOMERS ARE EASILY IDENTIFIED, BUT HOW IS THE COINCIDENT PEAK OF THESE CUSTOMERS ESTIMATED?

A. Metering currently installed for these customers does not provide usage data at the system peak hour; therefore, this impact is estimated based upon the ratio of "opt-out" sales to total sales for the rate class times the rate class peak demand. Since each rate group has similar usage characteristics this approach should accurately approximate the demand of "opt-out" accounts.

Q. AFTER ADJUSTING ENERGY AND DEMAND FOR "OPT-OUT" CUSTOMERS, ARE THE RESULTING ALLOCATION FACTORS THEN USED TO DETERMINE REVENUE REQUIREMENTS FOR EACH RATE CLASS?

A. Yes. The resulting Rate Class energy allocation factors are multiplied times the EE related costs and the resulting Rate Class demand allocation factors are multiplied times the DSM costs. The two rates are added to establish the DSM/EE rate for service rendered on and after December 1, 2008.

The energy allocation rate class factors were developed based upon the forecasted rate class usage for the rate recovery. The factors were developed after subtracting actual sales for "opt-out" customers for the year ended March 31, 2008 since usage for "opt-out" customers is not forecasted. The energy allocation factors applicable to each rate class based upon the forecast rate class sales for the recovery period of December 2008 through November 2009 are provided in Evans Exhibit No. 4.

The demand allocation rate class percentages were developed based upon the summer coincident peak for 2007 from the annual cost of service study, after subtracting the estimated demand for "opt-out" customers as discussed above. The forecast does not provide rate class coincident peak demands therefore the most recent historic data was deemed to be representative of future demand impacts. The demand allocation factors applicable to each rate class are provided in Evans Exhibit No. 5.

Q. HOW ARE RATE CLASS DSM/EE RATES ESTABLISHED?

A. PEC recommends that the rate class revenue requirement be recovered in the schedule energy rates. The sum of the resulting rate class EE and DSM revenue requirement is divided by rate class sales, after adjustment for "opt-out" customers, to establish the rate class DSM/EE rate. Evans Exhibit No. 6 provides the Energy Efficiency Rate derivation. Evans Exhibit No. 7 provides the Demand Side Management Rate derivation.

Q. PEC IS PROPOSING A DSM/EE RATE THAT RECOVERS PROGRAM COSTS, ANY NET LOST REVENUES, AND UTILITY INCENTIVES ALLOWED BY THE COMMISSION. IS THERE A NEED TO SEPARATELY IDENTIFY THE REVENUE RECEIVED FROM EACH COST COMPONENT SEPARATELY?

A. No. PEC will compare the rate revenue against the actual booked program costs, and corresponding incentives and net lost revenue, to assess any revenues that would need to be trued-up in a future DSM/EE Experience Modification Factor. The cost impact of the incentives and net lost revenue will be based upon the initial assumptions approved with the program until such time that measurements and validation (M&V) is completed. After completion of M&V, any future incentives and net lost revenues will be based upon the findings of the M&V analysis and therefore any necessary true-up will the direct result of program participation.

Q. HOW IS THE RATE FOR THE DSM/EE EXPERIENCE MODIFICATION FACTOR IN THIS PROCEEDING ESTABLISHED?

A. As discussed above, any costs to be recovered in the EMF are first allocated to NC Retail. These costs are then compared to DSM revenues during the period with the difference being used to create an EMF revenue requirement. In the future, the revenue to be recovered or refunded in the EMF should be relatively small, therefore, PEC recommends that these costs not be separated into DSM or EE related categories, but be combined and allocated to rate classes using an energy allocation. PEC proposes to depart from this approach in this proceeding because DSM/EE costs are not currently being recovered in rates. PEC recommends the same approach be used as used for DSM/EE cost of allocation EE related costs using an energy allocation and DSM related costs using a demand allocation. The allocation percentages are identical to that proposed for DSM/EE costs. Evans Exhibit No. 8 provides the Energy Efficiency Experience Modification Factor Rate derivation. Evans Exhibit No. 9 provides the DSM/EE Experience Modification Factor Rate derivation.

Q. WHAT RATES ARE PROPOSED FOR EACH RATE CLASS?

A. Evans Exhibit No. 10 calculates the DSM/EE annual rate and EMF proposed in this proceeding. The DSM/EE rates recover costs forecasted to be incurred during December 2008 through November 2009. The DSM/EE EMF recovers costs incurred from August 21, 2007 through March 31, 2008 plus costs incurred during the period April 1, 2008 through July 31, 2008. Projected costs during this period will be trued-up prior to the September hearing. PEC proposes the following rates, exclusive of gross receipts taxes, for each rate class (shown in cents per kWh):

Rate Class	DSM/EE Rate	DSM/EE EMF	DSM/EE Annual Rider
Residential	0.165	0.025	0.190
Small General Service	0.167	0.025	0.192
Medium General Service	0.140	0.021	0.161
Large General Service	0.101	0.016	0.117
Lighting	0.037	0.007	0.044

Q. HOW WILL PEC'S TARIFFS BE REVISED TO RECOVER THESE RATES?

A. Evans Exhibit No. 11 provides Annual Billing Adjustment Rider BA-1 that describes the rates proposed to be recovered in this proceeding. PEC proposes that these rates be included in the energy rates of each schedule to make it easier for customers to use a single tariff to calculate and verify their monthly bill. Since all customers would then be billed these rates, customers electing to "opt-out" of the annual DSM/EE Rider will receive a Monthly Credit on their bill. PEC believes that this will easily identify the bill impact if they elect to "opt-in to DSM/EE in the future. It also clearly identifies those customers that elect to "opt-out" so they can ensure they are being accurately billed to reflect their election. Customers will be required to notify PEC of their election to "opt-out" in writing. A communications plan is currently being developed for implementation late this summer to notify customers of their ability to "opt-out". This should allow ample time to implement the customer's decision prior to the rate going into effect on December 1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

263695

Evans Exhibit No. 1
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North Carolina Retail - DSM/EE Revenue Requirements Summary

	Test Period		O&M	Other O&M	Taxes	Depreciation	Cost of Capital	Carrying Cost	A&G Expense	Totals Before Incentive	Lost Revenue	Utility Incentive	Total Incentive	Totals With Incentive
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) Σ Cols (1) thru (7)	(9)	(10)	(11) Cols (9) + (10)	(12) Cols (8) + (11)
	NC DSM Program Expenses													
1	DSDR Program		439,230	-	(323)	-	(837)			438,070	-	-	-	438,070
2	EnergyWise		175,918							175,918	-	-	-	175,918
3	Total DSM	Lines 1 + 2	615,148	-	(323)	-	(837)	-		613,988	-	-	-	613,988
4	DSM Assigned A&G and CCost	Assigned Values						53,487	1,455,778	1,509,265			-	1,509,265
5	Total DSM and Assigned A&G	Lines 3 + 4	615,148	-	(323)	-	(837)	53,487	1,455,778	2,123,253	-	-	-	2,123,253
	NC EE Program Expenses													
6	Res New Construction		28,041							28,041	-	-	-	28,041
7	CIG New Construction									-	-	-	-	-
8	CIG Retrofit									-	-	-	-	-
9	CFL		268,897							268,897	105,420	67,762	173,182	442,079
10	Total EE	Σ Lines 6 thru 9	296,938	-	-	-	-	-		296,938	105,420	67,762	173,182	470,120
11	EE Assigned A&G and CCost	Assigned Values						25,867	654,045	679,913			-	679,913
12	Total EE and Assigned A&G	Lines 10 + 11	296,938	-	-	-	-	25,867	654,045	976,850	105,420	67,762	173,182	1,150,033
13	Test Period Total	Lines 5 + 12	912,086	-	(323)	-	(837)	79,354	2,109,823	3,100,103	105,420	67,762	173,182	3,273,285

	Prospective Period		O&M	Other O&M	Taxes	Depreciation	Cost of Capital	Carrying Cost	A&G Expense	Totals Before Incentive	Lost Revenue	Utility Incentive	Total Incentive	Totals With Incentive
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) Σ Cols (1) thru (7)	(9)	(10)	(11) Cols (9) + (10)	(12) Cols (8) + (11)
	NC DSM Program Expenses													
1	DSDR Program		483,163	223	17,727	13,702	40,483			555,299	-	-	-	555,299
2	EnergyWise		287,928							287,928	-	-	-	287,928
3	Total DSM	Lines 1 + 2	771,091	223	17,727	13,702	40,483	-		843,227	-	-	-	843,227
4	DSM Assigned A&G and CCost	Assigned Values						484,895	508,230	993,126			-	993,126
5	Total DSM and Assigned A&G	Lines 3 + 4	771,091	223	17,727	13,702	40,483	484,895	508,230	1,836,352	-	-	-	1,836,352
	NC EE Program Expenses													
6	Res New Construction		42,327							42,327			-	42,327
7	CIG New Construction		-							-			-	-
8	CIG Retrofit		92,204							92,204			-	92,204
9	CFL		8,193							8,193	106,772	68,631	175,402	183,596
10	Total EE	Σ Lines 6 thru 9	142,725	-	-	-	-	-		142,725	106,772	68,631	175,402	318,127
11	EE Assigned A&G and CCost	Assigned Values						82,073	228,335	310,409			-	310,409
12	Total EE and Assigned A&G	Lines 10 + 11	142,725	-	-	-	-	82,073	228,335	453,134	106,772	68,631	175,402	628,536
13	Prospective Period Total	Lines 5 + 12	913,815	223	17,727	13,702	40,483	566,969	736,566	2,289,486	106,772	68,631	175,402	2,464,888

	Rate Period		O&M	Other O&M	Taxes	Depreciation	Cost of Capital	Carrying Cost	A&G Expense	Totals Before Incentive	Lost Revenue	Utility Incentive	Total Incentive	Totals With Incentive
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) Σ Cols (1) thru (7)	(9)	(10)	(11) Cols (9) + (10)	(12) Cols (8) + (11)
	NC DSM Program Expenses													
1	DSDR Program		4,486,500	15,374	1,247,956	1,001,972	2,857,875			9,609,677	63,753	553,963	617,716	10,227,393
2	EnergyWise		9,048,241							9,048,241	11,759	4,717,668	4,729,427	13,777,668
3	Total DSM	Lines 1 + 2	13,534,741	15,374	1,247,956	1,001,972	2,857,875	-		18,657,917	75,512	5,271,631	5,347,143	24,005,060
4	DSM Assigned A&G and CCost	Assigned Values						1,511,130	2,623,346	4,134,476			-	4,134,476
5	Total DSM and Assigned A&G	Lines 3 + 4	13,534,741	15,374	1,247,956	1,001,972	2,857,875	1,511,130	2,623,346	22,792,393	75,512	5,271,631	5,347,143	28,139,536
	NC EE Program Expenses													
6	Res New Construction		1,292,153							1,292,153	167,331	230,693	398,024	1,690,177
7	CIG New Construction		887,433							887,433	63,511	48,817	112,328	999,761
8	CIG Retrofit		3,556,408							3,556,408	204,714	105,220	309,934	3,866,342
9	CFL		-							-	319,981	205,893	525,874	525,874
10	Total EE	Σ Lines 6 thru 9	5,735,993	-	-	-	-	-		5,735,993	755,537	590,623	1,346,160	7,082,153
11	EE Assigned A&G and CCost	Assigned Values						464,566	1,178,605	1,643,171			-	1,643,171
12	Total EE and Assigned A&G	Lines 10 + 11	5,735,993	-	-	-	-	464,566	1,178,605	7,379,164	755,537	590,623	1,346,160	8,725,324
13	Rate Period Total	Lines 5 + 12	19,270,734	15,374	1,247,956	1,001,972	2,857,875	1,975,696	3,801,951	30,171,557	831,049	5,862,254	6,693,303	36,864,860

ILLUSTRATIVE EXAMPLES OF UTILITY INCENTIVE CALCULATIONS

A. ABC DSM Program

Utility Incentives - DSM Programs

		Source		
1	PEC Discount Rate	Input		8.3%
2	Utility Cost Test	Sample	$	200,000
3	Percent of Savings Incentive	Input		50%
4	Target Utility Incentive (NPV)	Lines 2*3	$	100,000
5	Incentive Rates ($/kW-yr)	Solved	$	3.12

Calculated DSM Program Incentive Rate Per KW Saved

		Source	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
6	Year		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
7	Cumulative MW Savings Achieved by Program	Sample	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0
8	Incentive Rates ($/kW-yr)	Line 5	$ 3.12	$ 3.12	$ 3.12	$ 3.12	$ 3.12	$ 3.12	$ 3.12	$ 3.12	$ 3.12	$ 3.12
9	Annual Incentive for Program	Lines 7 x 8 x 1000	$ 3,115	$ 6,230	$ 9,345	$ 12,460	$ 15,575	$ 18,690	$ 21,805	$ 24,920	$ 28,035	$ 31,150

		Source	
10	NPV of Annual Incentive	NPV Line 9	$100,000
		CHK	$0

Present Values of these amounts = Target Incentive

B. DEF EE Program

Utility Incentives - EE Programs

		Source		
1	PEC Discount Rate	Input		8.3%
2	Utility Cost Test	Sample	$	200,000
3	Percent of Savings Incentive	Input		50%
4	Target Utility Incentive (NPV)	Lines 2*3	$	100,000
5	Incentive Rates ($/MW-yr)	Solved	$	311.50

Calculated EE Program Incentive Rate Per MWH Saved

		Source	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
6	Year		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
7	Cumulative MWh Savings Achieved by Program	Sample	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	90.0	100.0
8	Incentive Rates ($/MWh)	Line 5	$ 311.50	$ 311.50	$ 311.50	$ 311.50	$ 311.50	$ 311.50	$ 311.50	$ 311.50	$ 311.50	$ 311.50
9	Annual Incentive for Program	Lines 7*8	$ 3,115	$ 6,230	$ 9,345	$ 12,460	$ 15,575	$ 18,690	$ 21,805	$ 24,920	$ 28,035	$ 31,150

		Source	
10	NPV of Annual Incentive	NPV Line 9	$100,000
		CHK	$0

Present Values of these amounts = Target Incentive

C. DEF EE Program

Utility Incentives - Lost Revenue

			Residential		
		Source	2009	2008	2009
1	Gross Margin (Net of GRT)		$ 59.68	$ 59.68	$ 59.68
2	Less: Incremental Variable O&M	From CSP 23B	2.07	2.13	2.13
3	Net Rate for Lost Revenue Determination / MWh	Lines 1 - 2	$ 57.61	$ 57.55	$ 57.55
4	Program Based Lost Sales (MWh)	Sample	10.0	20.0	30.0
5	Net Lost Revenue	Lines 3 x 4	576.1	1,151.0	1,726.5

Calculated Net Lost Revenues

PROGRESS ENERGY CAROLINAS, INC.
Annual Sales for NC Customers Eligible for DSM/EE Opt-Out
Annual Sales for the Year Ended March 31, 2008

Rate Class	Commercial	Industrial*	Total
RES	0	0	0
SGS	8,027,300	17,009,689	25,036,989
MGS	3,823,495,393	2,334,296,625	6,157,792,018
LGS	1,133,541,491	8,007,538,528	9,141,080,019
Lighting	0	14,835,590	14,835,590
Total Opt-Out Sales	4,965,064,184	10,373,680,432	15,338,744,616

* Industrial category also includes Revenue Class 45, Public Authority

PROGRESS ENERGY CAROLINAS, INC.

Energy Allocation Factors - Applicable to EE Program Costs

North Carolina Rate Class Energy Allocation Factors

	Total NC Rate Class Sales (MWhrs) [1]	Opt-Out Sales[2]	Adjusted NC Rate Class MWHr Sales	Rate Class Energy Allocation Factor
	(1)	(2)	(3) = (1) - (2)	(4) = (3) / NC Total in Column 3
Rate Class				
Residential	15,496,950	0	15,496,950	66.02%
Small General Service	1,985,374	25,037	1,960,337	8.35%
Medium General Service	11,734,023	6,157,792	5,576,231	23.76%
Large General Service	9,076,284	9,076,284 [3]	0	0.00%
Lighting	453,441	14,836	438,606	1.87%
NC Retail	38,746,072	15,273,949	23,472,123	100.00%

NOTES:

(1) Total NC Rate Class Sales (MWHrs) are for the forecasted year ended November 2009.
(2) Opt-Out sales for the year ended *March 31, 2008 are provided in Evans Exhibit No. 3*
(3) LGS Opt-Out sales were set to match the forecast sales since all customers in the LGS class are eligible to opt-out.

PROGRESS ENERGY CAROLINAS, INC.

Demand Allocation Factors - Applicable to DSM Programs

North Carolina Rate Class Demand Allocation Factors

Rate Class	Total NC Rate Class Sales [(1)]	Sales Subject to Opt-Out [(2)]	Rate Class Demand [(3)]	Revised Rate Class Demand	Rate Class Allocation Factor
	(1)	(2)	(3)	(4) = ((1 - 2) / 1) * 3	(5) = (4)/Total of Column 4
Residential	15,496,950	0	4,019,614	4,019,614	70.57809%
Small General Service	1,985,374	25,037	522,994	516,398	9.06714%
Medium General Service	11,734,023	6,157,792	2,439,422	1,159,260	20.35477%
Large General Service	9,076,284	9,076,284 [(4)]	1,168,621	0	0.00000%
Lighting	453,441	14,836	0	0	0.00000%
NC Retail	38,746,072	15,273,949	8,150,651	5,695,273	100.00000%

NOTES:
(1) Total NC Rate Class Sales (MWHrs) are for the forecasted year ended November 2009.
(2) Opt-Out sales for the year ended March 31, 2008 are provided in Evans Exhibit No. 3
(3) The CP demands are from the annual NC Cost of Service Study for August 9, 2007 during the hour ended at 4 p.m.
(4) LGS Opt-Out sales were set to match the forecast sales since all customers in the LGS class are eligible to opt-out.

Evans Exhibit No. 6
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PROGRESS ENERGY CAROLINAS, INC.

Energy Efficiency Rate Derivation

NC Rate Class	Adjusted NC Rate Class kWHr Sales [1] (1)	Rate Class Energy Allocation Factor [2] (2)	EE Revenue Requirement: EE Program Costs [3] (3) = Col. 3 total * (2)	EE Revenue Requirement: EE Utility Incentive and Net Lost Revenue Costs [4] (4) = Col. 4 total * (2)	EE Rate ($/kWh): EE Program Rate (5) = (3) / (1)	EE Rate ($/kWh): EE Utility Incentive and Net Lost Revenue Rate (6) = (4) / (1)	EE Rate ($/kWh): Total EE Rate (7) = (5) + (6)
Residential	15,496,949,876	66.02%	$4,871,930	$888,772	$0.00031	$0.00006	$0.00037
Small General Service	1,960,336,986	8.35%	$616,291	$112,428	$0.00031	$0.00006	$0.00037
Medium General Service	5,576,230,957	23.76%	$1,753,055	$319,805	$0.00031	$0.00006	$0.00037
Large General Service [5]	0	0.00%	$0	$0	$0.00031	$0.00006	$0.00037
Lighting	438,605,662	1.87%	$137,889	$25,155	$0.00031	$0.00006	$0.00037
NC Retail	23,472,123,482	100%	$7,379,164	$1,346,160	$0.00031	$0.00006	$0.00037

NOTES:

(1) Rate Class Sales, excluding "Opt-Out" sales, are derived in Evans Exhibit No. 4, column (3).
(2) Rate Class Energy Allocation Factor is derived in Evans Exhibit No. 4
(3) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (8).
(4) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (11).
(5) A rate is shown for the LGS Class, *even though all* customers are assumed to opt-out, based upon the class load requirement.

PROGRESS ENERGY CAROLINAS, INC.

Demand Side Management Rate Derivation

NC Rate Class	Adjusted NC Rate Class kWHr Sales [1]	Rate Class Demand Allocation Factor [2]	DSM Revenue Requirement: DSM Program Costs [3]	DSM Revenue Requirement: DSM Utility Incentive and Net Lost Revenue Costs [4]	DSM Rate ($/kWh): DSM Program Rate	DSM Rate ($/kWh): DSM Utility Incentive and Net Lost Revenue Rate	DSM Rate ($/kWh): Total DSM Rate
	(1)	(2)	(3) = Col. 3 total * (2)	(4) = Col. 4 total * (2)	(5) = (3) / (1)	(6) = (4) / (1)	(7) = (5) + (6)
Residential	15,496,949,876	70.58%	$16,086,436	$3,773,911	$0.00104	$0.00024	$0.00128
Small General Service	1,960,336,986	9.07%	$2,066,618	$484,833	$0.00105	$0.00025	$0.00130
Medium General Service	5,576,230,957	20.35%	$4,639,340	$1,088,399	$0.00083	$0.00020	$0.00103
Large General Service [5]	0	0.00%	$0	$0	$0.00052	$0.00012	$0.00064
Lighting	438,605,662	0.00%	$0	$0	$0.00000	$0.00000	$0.00000
NC Retail	23,472,123,482	100.00%	$22,792,393	$5,347,143	$0.00097	$0.00023	$0.00120

NOTES:

(1) Rate Class Sales, *excluding* "Opt-Out" sales, are derived in Evans Exhibit No. 4, column (3).
(2) Rate Class Demand Allocation Factor is derived in Evans Exhibit No. 5.
(3) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (8).
(4) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (11).
(5) A rate is shown for the LGS Class, even though all customers are assumed to opt-out, based upon the class load requirement.

Evans Exhibit No. 8
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PROGRESS ENERGY CAROLINAS, INC.

Energy Efficiency Experience Modification Factor Rate Derivation

			EE EMF Revenue Requirement		EE EMF Rate ($/kWh)		
NC Rate Class	Adjusted NC Rate Class kWHr Sales [1]	Rate Class Energy Allocation Factor [2]	EE EMF Program Costs [3]	EE EMF Utility Incentive and Net Lost Revenue Costs [4]	EE EMF Program Rate	EE EMF Utility Incentive and Net Lost Revenue Rate	Total EE EMF Rate
	(1)	(2)	(3) = Col. 3 total * (2)	(4) = Col. 4 total * (2)	(5) = (3) / (1)	(6) = (4) / (1)	(7) = (5) + (6)
Residential	15,496,949,876	66.02%	$944,115	$230,145	$0.00006	$0.00001	$0.00007
Small General Service	1,960,336,986	8.35%	$119,429	$29,113	$0.00006	$0.00001	$0.00007
Medium General Service	5,576,230,957	23.76%	$339,719	$82,813	$0.00006	$0.00001	$0.00007
Large General Service [5]	0	0.00%	$0.00	$0.00	$0.00006	$0.00001	$0.00007
Lighting	438,605,662	1.87%	$26,721	$6,514	$0.00006	$0.00001	$0.00007
NC Retail	23,472,123,482	100.00%	$1,429,984	$348,585	$0.00006	$0.00001	$0.00007

NOTES:

(1) Rate Class Sales, excluding "Opt-Out" sales, are derived in Evans Exhibit No. 4, column (3).
(2) Rate Class Energy Allocation Factor is derived in Evans Exhibit No. 4
(3) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (8) for the historic test yeat August 21, 2007 to March 31, 2008 and the forecast period April 2008 through July 2008. The forecast period will be updated to reflect actual costs prior to the September hearing.
(4) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (11) for the historic test yeat August 21, 2007 to March 31, 2008 and the forecast period April 2008 through July 2008. The forecast period will be updated to reflect actual costs prior to the September hearing.
(5) A rate is shown for the LGS Class, even though all customers are assumed to opt-out, based upon the class load requirement.

PROGRESS ENERGY CAROLINAS, INC.

Demand Side Management Experience Modification Factor Rate Derivation

NC Rate Class	Adjusted NC Rate Class kWHr Sales [1]	Rate Class Demand Allocation Factor [2]	DSM EMF Revenue Requirement: DSM EMF Program Costs [3]	DSM EMF Revenue Requirement: DSM EMF Utility Incentive and Net Lost Revenue Costs [4]	DSM EMF Rate ($/kWh): DSM EMF Program Rate	DSM EMF Rate ($/kWh): DSM EMF Utility Incentive and Net Lost Revenue Rate	DSM EMF Rate ($/kWh): Total DSM EMF Rate
	(1)	(2)	(3) = Col. 3 total * (2)	(4) = Col. 4 total * (2)	(5) = (3) / (1)	(6) = (4) / (1)	(7) = (5) + (6)
Residential	15,496,949,876	70.58%	$2,794,614	$0	$0.00018	$0.00000	$0.00018
Small General Service	1,960,336,986	9.07%	$359,023	$0	$0.00018	$0.00000	$0.00018
Medium General Service	5,576,230,957	20.35%	$805,969	$0	$0.00014	$0.00000	$0.00014
Large General Service [5]	0	0.00%	$0	$0	$0.00009	$0.00000	$0.00009
Lighting	438,605,662	0.00%	$0	$0	$0.00000	$0.00000	$0.00000
NC Retail	23,472,123,482	100%	$3,959,605	$0	$0.00017	$0.00000	$0.00017

NOTES:

(1) Rate Class Sales, excluding "Opt-Out" sales, are derived in Evans Exhibit No. 4, column (3).
(2) Rate Class Demand Allocation Factor is derived in Evans Exhibit No. 5.
(3) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (8) for the historic test yeat August 21, 2007 to March 31, 2008 and the forecast period April 2008 through July 2008. The forecast period will be updated to reflect actual costs prior to the September hearing.
(4) The Total EE and Assigned A&G Revenue Requirement is derived in Evans Exhibit No. 1, column (11) for the historic test yeat August 21, 2007 to March 31, 2008 and the forecast period April 2008 through July 2008. The forecast period will be updated to reflect actual costs prior to the September hearing.
(5) A rate is shown for the LGS Class, even though all customers are assumed to opt-out, based upon the class load requirement.

PROGRESS ENERGY CAROLINAS, INC.

EE/DSM Billing Rate - December 2008 through November 2009

All rates are shown in dollars per kWh

NC Rate Class	Total EE Rate (1)	Total DSM Rate (2)	Total EE EMF Rate (3)	Total DSM EMF Rate (4)	DSM/EE Billing Rate (5)
Residential	$0.00037	$0.00128	$0.00007	$0.00018	$0.00190
Small General Service	$0.00037	$0.00130	$0.00007	$0.00018	$0.00192
Medium General Service	$0.00037	$0.00103	$0.00007	$0.00014	$0.00161
Large General Service	$0.00037	$0.00064	$0.00007	$0.00009	$0.00117
Lighting	$0.00037	$0.00000	$0.00007	$0.00000	$0.00044
NC Retail	$0.00037	$0.00120	$0.00007	$0.00017	$0.00181

NOTES:

(1) Total EE Rate is derived in Evans Exhibit No. 6, column (7).
(2) Total DSM Rate is derived in Evans Exhibit No. 7, column (7).
(3) Total EE EMF Rate is derived in Evans Exhibit No. 8, column (7).
(4) Total DSM EMF Rate is derived in Evans Exhibit No. 9, column (7).
(5) DSM/EE Billing Rate does not include gross receipts taxes.

Carolina Power & Light Company
d/b/a Progress Energy Carolinas, Inc.
(North Carolina Only)

ANNUAL BILLING ADJUSTMENTS
RIDER BA-1

APPLICABILITY – RATES INCLUDED IN TARIFF CHARGES

The rates shown below are included in the MONTHLY RATE provision in each schedule identified in the table below:

Billing Adjustment Factors (¢/kWh)*					
Rate Class	Fuel Adjustment		DSM/EE Adjustment		Net Adjustment
	Rate(1)	EMF(2)	Rate(3)	EMF(4)	
Residential			0.170	0.026	
Applicable to Schedules: RES, R-TOUD & R-TOUE					
Small General Service			0.173	0.026	
Applicable to Schedules: SGS & TSS					
Medium General Service			0.145	0.022	
Applicable to Schedules: MGS, SGS-TOU, SI, CH-TOUE, GS-TES, APH-TES, CSG, CSE & Riders 66 & SS (less than 1 MW)					
Large General Service			0.104	0.017	
Applicable to Schedules: LGS, LGS-TOU, LGS-RTP and Riders 66 & SS (1 MW and greater)					
Lighting			0.038	0.007	
Applicable to Schedules: ALS, SLS, SLR & SFLS					

* Billing Adjustment Factors, shown above, include North Carolina gross receipts taxes.

Billing Adjustment Factors Description:

(1) The Fuel Adjustment Rate is adjusted annually to reflect incremental changes in the costs of fuel and fuel-related costs from the rates approved in the last general rate case.

(2) The Fuel Adjustment Experience Modification Factor (EMF) is adjusted annually to reflect the difference between reasonable and prudently incurred fuel and fuel-related costs and the fuel and fuel-related revenues realized during a test period under review and shall remain in effect for a fixed 12 month period.

(3) The Demand Side Management/Energy Efficiency (DSM/EE) Rate is adjusted annually to reflect the costs and incentives associated with demand side management and energy efficiency measures and programs approved by the North Carolina Utilities Commission.

(4) The Demand Side Management/Energy Efficiency Experience Modification Factor (DSM/EE EMF) is adjusted annually to reflect the difference between reasonable and prudently incurred DSM/EE costs and incentives and DSM/EE revenues realized during the period under review and shall remain in effect for a fixed 12 month period.

Demand Side Management/Energy Efficiency "Opt-Out" Option

North Carolina Utilities Commission Rule R8-69(e) allows commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers to elect to not participate in any utility-offered DSM/EE program and, after written notification to the utility, not be subject to the DSM/EE Rate and EMF, shown above. For purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. Since these rates are included in the rate tariff charges, Customers electing this option shall receive the following DSM/EE Credit on their monthly bill statement:

DSM/EE Credit = DSM/EE Rate Credit plus DSM/EE EMF Credit

Where:

DSM/EE Rate Credit = Billed kWh times DSM/EE Rate*
DSM/EE EMF Credit = Billed kWh times DSM/EE EMF Rate*

* The DSM/EE Rate and EMF shall be as shown in the above table for the schedule applicable to Customer's monthly bill.

Following the December bill each year, usage for commercial accounts electing to "opt-out" of the DSM/EE rates shall be reviewed and the customer shall be notified and removed from the "opt-out" option if annual consumption is less than 1,000,000 kWh in the prior twelve months.

APPLICABILITY – RATES NOT INCLUDED IN TARIFF CHARGES

The rates shown below are not included in the MONTHLY RATE provision of the applicable schedule used in billing and shall therefore be added to Customer's monthly bill statement:

Billing Adjustment Factors Per Customer ($/month)*			
Revenue Class	REPS Rate(5)	REPS EMF(6)	Net Billing Rate
Residential	$per month	$per month	$per month
Commercial/Public Streets and Highways	$per month	$per month	$per month
Industrial/Public Authority	$per month	$per month	$per month

** Billing Adjustment Factors, shown above, include North Carolina gross receipts taxes.*

For purposes of the applicability of the REPS-related Billing Adjustment Factors, a "Customer" is defined as all accounts (metered and unmetered) serving the same customer of the same revenue classification located on the same or contiguous properties. Upon written notification from Customer, accounts meeting these criteria shall be combined under a single account number to allow Customer to receive only one monthly bill statement for all meters under the account and only one monthly REPS charge.

Billing Adjustment Factors Description:

(5) The Renewable Energy Portfolio Standard (REPS) Rate is adjusted annually to reflect research and development costs and incremental costs incurred to comply with the state's Renewable Energy and Energy Efficiency Portfolio Standard (REPS).

(6) The Renewable Energy Portfolio Standard Experience Modification Factor (REPS EMF) Rate is adjusted annually to recover the difference between reasonable and prudently incurred REPS costs and REPS revenues realized during the period under review and shall remain in effect for a fixed 12 month period.

SALES TAX

To the above charges will be added any applicable North Carolina Sales Tax.

Effective for service rendered on and after December 1, 2008;
The DSM/EE EMF, Fuel Adjustment EMF and REPS EMF are effective for service rendered through November 30, 2009
NCUC Docket No. E-2, Subs 929, 930 & 931