COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; 3) APPROVAL OF NEW TARIFFS; 4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00321

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recording of the evidentiary hearing conducted on March 8, 2018 in this proceeding;

- Certification of the accuracy and correctness of the digital video recording;

- All exhibits introduced at the evidentiary hearing conducted on March 8, 2018 in this proceeding;

- A written log listing, *inter alia*, the date and time of where each witness' testimony begins and ends on the digital video recording of the evidentiary hearing conducted on March 8, 2018.

A copy of this Notice, the certification of the digital video record, hearing log, and exhibits have been electronically served upon all persons listed at the end of this Notice. Parties desiring to view the digital video recording of the hearing may do so at https://psc.ky.gov/av_broadcast/2017-00321/2017-00321_08Mar18_Inter.asx.

Parties wishing an annotated digital video recording may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for a copy of this recording.

Done at Frankfort, Kentucky, this 16th day of March 2018.

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Executive Director
Public Service Commission of Kentucky

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ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; 3) APPROVAL OF NEW TARIFFS; 4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00321

CERTIFICATE

I, Pamela Hughes, hereby certify that:

1. The attached DVD contains a digital recording of the Hearing conducted in the above-styled proceeding on March 8, 2018. Hearing Log, Witness List, and Exhibit List are included with the recording on March 8, 2018.

2. I am responsible for the preparation of the digital recording.

3. The digital recording accurately and correctly depicts the Hearing of March 8, 2018.

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the Hearing of March 8, 2018, and the time at which each occurred.

Signed this 13th day of March, 2018.

Pamela Hughes

Pamela Hughes, Notary Public
State at Large
My Commission Expires: April 22, 2019

Judge: Talina Mathews; Michael Schmitt
Witness: Richard Baudino; Justin Bieber; Lane Kollen; Glenn Watkins
Clerk: Pam Hughes

Date:	Type:	Location:	Department:
3/8/2018	General Rates	Hearing Room 1	Hearing Room 1 (HR 1)

Event Time	Log Event	
8:13:28 AM	Session Started	
8:13:29 AM	Session Paused	
9:02:10 AM	Session Resumed	
9:02:13 AM	Chairman Schmitt Calls Case No. 2017-00321	
	Note: Hughes, Pam	Preliminary Remarks. Jody Cohn, atty for KIUC is not here yet but no objection to proceeding in her absence .
9:03:13 AM	Atty Boehm calls Justin Bieber to the stand	
	Note: Hughes, Pam	Sworn in by Chairman
	Note: Hughes, Pam	Senior Consultant, Energy Strategies, LLC.
9:03:41 AM	Atty Boehm direct of Witness Bieber	
	Note: Hughes, Pam	Justin Bieber. Adopts his direct testimony with no changes.
9:04:42 AM	Atty D'Ascenzo cross of Witness Bieber	
	Note: Hughes, Pam	Regarding what Witness Bieber is testifying for. He reviewed application, testimony, etc.
	Note: Hughes, Pam	Tax reduction rate of 10.6 million dollars. Duke has addressed his recommendation.
	Note: Hughes, Pam	Regarding his recommendation of filing an ADIT amortization schedule. This has been addresssed by Duke Kentucky.
	Note: Hughes, Pam	Page 3 of his testimony, lines 17-22. Excess ADIT's. Referring to the entire tax act. Proposal of the company's amoritization schedule is not inconsistent at this point.
9:10:01 AM	Atty D'Ascenzo cross of Witness Bieber	
	Note: Hughes, Pam	Page 4 of Direct testimony. First Allocation of 50% to all rate classes from the benefit from the corporate tax rate, and allocated 50% to reduce interclass subsidies.
9:13:07 AM	Atty D'Ascenzo cross of Witness Bieber	
	Note: Hughes, Pam	Page 7 of direct testimony. Companies overall revenue requirement concerns.
9:15:52 AM	Atty D'Ascenzo cross of Witness Bieber	
	Note: Hughes, Pam	Regarding Rider DCI being the targeted underground program, he is not offering an opinion on that program. Company wants to bring new programs to the Commission under this Rider. He believes the Commission has the authority to review and deny the application.
	Note: Hughes, Pam	Rider DCI and annual review from the Commission. The Commission would have authority to say the company is or not managing its cost.. Commission has authority to disallow unreasonable cost.
	Note: Hughes, Pam	Regarding his opinion that the proposed Rider DCI be rejected.
9:22:07 AM	Atty Chandler cross of Witness Bieber	
	Note: Hughes, Pam	Regarding his opinion that any savings from the corporate tax savings is single ratemaking, No, he suggests that there are some savings from reductions and can be used to further lower subsidies.
	Note: Hughes, Pam	Rider DCI and relation to safety and reliability. No evidence that Duke will be able to do this.

	Note: Hughes, Pam	Page 4, direct testimony. Single ratemaking issue.
9:26:16 AM	Witness excused	
9:26:44 AM	Richard Baudino called to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman
9:27:29 AM	Atty Chandler direct of Witness Baudino	
	Note: Hughes, Pam	Filed testimony and Data Request's . Adopts all with no changes.
	Note: Hughes, Pam	Richard Baudino, Consultant for J. kennedy and Assoc.
9:28:24 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Direct Testimony, Regarding the 3 purposes for his testimony.
	Note: Hughes, Pam	Regarding his expertise and keeping aprised of federal changes and policies. Utility rates of return and trends. Regarding that Duke Energy is a Vertically integrated utility.
9:31:09 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Page 3 of his testimony. Line 19, low interest rates and federal reserve policy. Likelihood that interest rates will be raised about 4 times this year-subject to check. Regarding Chairman Powell's testimony.
	Note: Hughes, Pam	Regarding the recommendation that the Commission adopt an ROE of 8.8%
9:35:01 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Regarding his job and if he reviews Orders from utilites, including the Ky PSC.
9:37:23 AM	Duke exhibit 1	
	Note: Hughes, Pam	Direct testimony of Mr. Baudino in Case No. 2017-00179
9:38:57 AM	Duke exhibit 2	
	Note: Hughes, Pam	Witness Baudino's direct testimony in Cases 2016-370 &371
9:39:42 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Regarding his recommendations in the Ky Power and KU/LGE cases.
9:40:57 AM	Duke exhibits 3 and 4	
	Note: Hughes, Pam	KU Order Case No. 2016-00370 & 16-371 LGE Order
	Note: Hughes, Pam	Did the Commissson in its Orders cite to that ROE.
	Note: Hughes, Pam	Rate he recommended in ROE.
9:43:39 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Same in the KU and LGE Orders 2016-370 & 371
	Note: Hughes, Pam	Page 29 and 30 of the Ky Power Order 2017-00179.
	Note: Hughes, Pam	Regarding if he monitors the review of industry trade publications. Average ROE in 2017 by RRA.
	Note: Hughes, Pam	Confidential document to be discussed but no confidential will be spoken of. Motion for Confidentiality sustained by Chairman Schmitt.
9:48:46 AM	Duke exhibit 5	
	Note: Hughes, Pam	RRA Regulatory Focus - Major Rate Case Decisions 2017.
9:49:25 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Ist page of RRA publication. Average ROE is 9.8%
9:50:07 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Bottom of page on line 23. Reads into the record. Witness states to go back to page of Wathan's testimony and reads from that page.
	Note: Hughes, Pam	Page 46 of testimony. Line 6. Automatic capital adjustment clauses. Regarding the company's pipeline replcement program. Capital investment clauses are commonly used.
	Note: Hughes, Pam	Regarding Witness Wathan's testimony. Line 8, reads first full sentence.

	Note: Hughes, Pam	Rider DCI criticism by Witness Baudino. Regarding where in Duke's application or other documents filed that the company has prohibited the Commission from looking at this.
9:59:03 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	If Commission approves Rider DCI and it will be subject to Commission review and parties able to intervene, would he feel better if that is the scenario.
10:00:31 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Page 47 of testimony. Customer proposed benefits of the Targeted underground program in testimony but did give quantifications in Data Request's.
	Note: Hughes, Pam	Page 25 in testimony. 5 recommendations if Commission approves Rider DCI. He explains his position and recommendations.
10:04:19 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Regarding if in order for the company to recover its capitol that it is investing it would have to come in every year for a rate icrease.
	Note: Hughes, Pam	Regarding offset income taxes.
10:09:04 AM	Atty D'Ascenzo cross of Witness Baudino	
	Note: Hughes, Pam	Page 20, testimony. Proxy group. Mr. Wathan's WDW2 exhibit
10:10:42 AM	Atty D'Ascenzo moves to have exhibits entered into the record.	
	Note: Hughes, Pam	Duke Kentucky exhibits 1-5 entered into the record.
10:12:52 AM	Atty Boehm cross of Witness Baudino	
	Note: Hughes, Pam	ROE of 9.8% driven by Virginia State utilities
	Note: Hughes, Pam	Page 9 of same document.
	Note: Hughes, Pam	Regarding the Orders and the RRA Regulatory Focus exhibit. Read entire 1st paragraph.
10:16:38 AM	Atty D'Ascenzo objects	
	Note: Hughes, Pam	Confidential material being addressed. Chairman states going to confidential session for these questions.
10:17:14 AM	Private Recording Activated	
10:23:23 AM	Public Recording Activated	
10:23:31 AM	Public session resumed	
10:23:42 AM	Atty Sanders cross of Witness Baudino	
	Note: Hughes, Pam	Regarding Mr. Wathan's testimony. On page 5 of his rebuttal testimony, 7 areas where he disagrees with Witness Baudino. Why is Duke less risky than other utilities of some that have been given 9.7% ROE.
	Note: Hughes, Pam	Position of investor funds if the ROE granted is lowest of all comparable utilities. He stands by his opinion that Duke should get a 8.8% ROE.
10:31:48 AM	Atty Sanders cross of Witness Baudino	
	Note: Hughes, Pam	Regarding the Approach on utiltiy stock and investor interest rates, and how they can affect the price of stocks.
	Note: Hughes, Pam	Regarding his testimony and when it was executed. Did he take the Tax Cut Act into consideration. Any opinion after the Tax Cut law went into effect- No.
10:34:00 AM	Break	
10:34:07 AM	Session Paused	
10:48:17 AM	Session Resumed	
10:48:52 AM	Chairman remarks about Public comments	
	Note: Hughes, Pam	He is going to give each one an opportunity to speak today as they have been here everyday.
10:49:47 AM	Atty Chandler re-direct of Witness Baudino	
	Note: Hughes, Pam	Average authorized ROE and concerns in it determining the ROE in this case.

10:51:24 AM	Atty Chandler gives AG exhibit 4 to Witness	
10:51:41 AM	Atty Chandler re-direct of Witness Baudino	
	Note: Hughes, Pam	Regarding the Virginia decisions about the RRA. Virginia Power and Electric Co. Multiple ROE's. Reads last sentence on page 21 regarding riders of Virginia Power.
10:52:54 AM	Atty D'Ascenzo re-cross of Witness Baudino	
	Note: Hughes, Pam	RRA Regulatory Focus report, the ROE's that were approved. Any consistent with his recommendation with the 8.8% in 2017. Chart on page 9, distribution only ROE'S.
10:56:13 AM	Chairman Schmitt cross of Witness Baudino	
	Note: Hughes, Pam	Regarding a bill proposed by the General Assembly. It want's the PSC to be limited to no greater than 6% ROE. Asks his opinion about the ROE being that low.
10:57:23 AM	Witness excused	
10:58:13 AM	Witness Watkins called to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman
10:58:29 AM	Atty Chandler direct of Witness Watkins	
	Note: Hughes, Pam	Adopts his testimony and Data Request's.
	Note: Hughes, Pam	Glenn Watkins, President and Senior Economist, Technical Associates, Inc.
10:59:14 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Regarding what he is testifying about and what documents he reviewed when preparing his testimony.
	Note: Hughes, Pam	Regarding the Cost Of Service study used in this case.
	Note: Hughes, Pam	Regarding if he has ever been involved in a Duke Energy case before this commission.
11:03:08 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Page 25 of his testimony. Line 15 question. Reasonable for the residential class.
11:04:56 AM	Duke exhibit 6	
	Note: Hughes, Pam	Regarding with the proposed customer charge issue. Rate RS is the only rate he is testifying about. Goal to reasonably mimic? Pricing structure to a consumer and how he looks at it.
	Note: Hughes, Pam	Regarding fairness of comparing rates between companies for regulated companies.
	Note: Hughes, Pam	Atty Honaker gives Witness Watkins a document Duke exhibt 6. "Edison Electric Institute" Ranking of Total Retail Average Rates.
11:10:11 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Duke is ranked 131 on this document. Page 37, Duke is ranked 166. Witness says he can't rely on this document
	Note: Hughes, Pam	First page of Duke exhibit 6. Where does Duke Kentucky fall in that ranking. Looking at other utilities on this document.
	Note: Hughes, Pam	Regarding consumers and if they look at rates when considering moving into that area.
11:17:11 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Regarding rebuttal testimony of Witness Sailers.
11:18:15 AM	Duke exhibit 7	
	Note: Hughes, Pam	Chart from Witness Sailors rebuttal
11:18:51 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Regarding his testimony on other customer charges for other utilities.
	Note: Hughes, Pam	Regarding the Commission's ability to see if reasonable charges are made.
	Note: Hughes, Pam	Owen Electric Company has highest in the state according to the Duke exhibit 7.

11:21:45 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Regarding what short run charges are in each of these utilities. Embedded costs.
	Note: Hughes, Pam	Regarding the cost structures on this exhibit 7 are different from Duke Energy and other utilties.
	Note: Hughes, Pam	How rural is LGE service territory. KU is more rural. Regarding if KU serves municipal areas.
	Note: Hughes, Pam	Regarding where is Owen Electric located in the Commonwealth.
11:26:12 AM	Duke exhibit 8	
	Note: Hughes, Pam	Survey of Regional customer charges.
11:27:06 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Residential customer charges on this exhibit. Duke Ky is $4.50 and is the lowest of all the utilities on this exhibit.
	Note: Hughes, Pam	Regarding Ky Power's recent rate case. Case No. 2017-00179. Witness Dismukes exhibit in the Ky Power case.
11:29:37 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Relationship between customer charges and volumetric rate charges. Witness does not believe there is a relationship. Incremental revenue charges
	Note: Hughes, Pam	Regarding Gradulism and what he means by that .
11:33:00 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Regarding regulated monopolies.
	Note: Hughes, Pam	Regarding fixed billl program. Explains as to why he doesn't think customers should have a lot of bill options.
	Note: Hughes, Pam	Annual energy budget for certainity. Regarding not approving the fixed bill program premium.
11:37:00 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	Regarding if he has managed a fixed bill program.
	Note: Hughes, Pam	Rate resets each year according to the customers prior use year.
	Note: Hughes, Pam	Regarding if customers would conserve energy on a fixed bill program.
	Note: Hughes, Pam	When was last time he worked for a utility?
	Note: Hughes, Pam	Regarding Historical usage.
11:39:46 AM	Atty Samford cross of Witness Watkins	
	Note: Hughes, Pam	What professional experience does witness have to testify to Duke Energy's rates and programs. Fixed bill program has been accepted in Indiana and Florida for Duke Energy. Customers in Indiana participating in the fixed bill program. 58,000 customers on fixed bill program.
	Note: Hughes, Pam	Regarding accurately estimating a fixed bill, according to his testimony. Witness doesn't see that in his testimony.
	Note: Hughes, Pam	Regarding if Witness has worked as CSR in a utility or worked as an Account Manager or Supervisor for a CSR department in a utility.
	Note: Hughes, Pam	Regarding possibility to make such an estimate of a customers bill. He states consumers won't have reason to conserve energy. What data would be needed to use to estimate fixed bill.
11:48:23 AM	Chairman cross of Witness Watkins	
	Note: Hughes, Pam	Regarding proposed Duke exhibit 6. Is witness familiar with any document from Edison Electric Institute, does he accept it as authentic as being part of a larger document.
	Note: Hughes, Pam	Regarding what is Edison Electric Institute?
11:51:11 AM	Chairman to Atty Samford about Duke exhibit 6	
	Note: Hughes, Pam	Price in cents for KWH, and what is purpose of this document to deminstrate in this proceeding.

11:52:14 AM	Atty Chandler re direct of Witness Watkins	
	Note: Hughes, Pam	Rates should be cost based. Even portions should be.
	Note: Hughes, Pam	Do utilities have defined boundries in Kentucky.
	Note: Hughes, Pam	Regarding what amount of electricity someone will use.
11:53:53 AM	Atty Chandler re direct of Witness Watkins	
	Note: Hughes, Pam	If rates are cost based, a utility will have higher and lower customer charge.
	Note: Hughes, Pam	Regarding Duke's straight fixed rate design.
	Note: Hughes, Pam	Chart in Mr. Sailors testimony, has he been generally aware and are there anything unique with those utilities
11:55:58 AM	Atty Samford re cross of Witness Watkins	
	Note: Hughes, Pam	Reasonable perameters as to giving fixed bills to customers. Is it possible to estimate customer usage.
11:57:34 AM	Atty Sanders cross of Witness Watkins	
	Note: Hughes, Pam	Regarding fixed bill and capacity to meet it's load.
11:59:25 AM	AG objects to exhibit 6 as it is not a complete document.	
	Note: Hughes, Pam	Duke attorney's state is is to show where companies rates are in the state.
12:00:35 PM	Witness excused	
12:00:55 PM	Chairman statement about Public comment	
	Note: Hughes, Pam	Will now give the two ladies a chance to speak.
12:01:35 PM	Public Comment	
	Note: Hughes, Pam	Ms. McDowell, Covington, Ky. Duke Energy Customer.
12:09:59 PM	Public Comment	
	Note: Hughes, Pam	Jeanene Smith, Cresent Springs, Ky. Duke Energy Customer.
12:11:01 PM	Camera Lock PTZ Activated	
12:18:42 PM	Chairman statement about the comments in the public meeting held in Florence, KY	
	Note: Hughes, Pam	Mrs. Smith continues her public comment.
12:20:10 PM	Break	
12:20:19 PM	Session Paused	
1:35:39 PM	Session Resumed	
1:35:43 PM	Camera Lock Deactivated	
1:35:47 PM	Atty Chandler asks opinion about Mr. Kollen's testimony	
	Note: Hughes, Pam	Tax cuts and proposals of Duke.
1:36:51 PM	Atty Samford statement	
1:37:28 PM	Witness Kollen called to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman.
1:37:42 PM	Atty Chandler direct of Witness Kollen	
	Note: Hughes, Pam	Adopts his testimony, one change to Data Request- question 26 from Duke . Reference to 2003-00253. Errata filing made on March 6th. Made corrections to summary table in his testimony.
	Note: Hughes, Pam	Lane Kollen, VP and Principal of J. Kennedy and Assoc.
1:38:06 PM	Camera Lock PTZ Activated	
1:39:52 PM	Atty Chandler direct of Witness Kollen	
	Note: Hughes, Pam	Page 5 of his testimony, the table. Makes corrections to his numbers.
	Note: Hughes, Pam	Regarding the ADIT's. Excess protected and unprotected ones, amortization. Tax Cuts and Jobs Act.
1:39:59 PM	Camera Lock Deactivated	
1:42:14 PM	Atty Chandler direct of Witness Kollen	
	Note: Hughes, Pam	Regarding any other issues when taxes were raised. Savings on the first 3 months methodologies.

	Note: Hughes, Pam	Regarding what protected excess ADIT are under the Tax Cut and Job Act. The unprotected excess ADIT he recommends be a 5 year and not 20 years that Duke Ky wants.
1:45:57 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Several proposals to the companies captilization. In original filing the amount was within 1% base rate.
	Note: Hughes, Pam	Regarding Operating income issues and averaging data.
	Note: Hughes, Pam	Regarding a deferral in leui of rate increase.
	Note: Hughes, Pam	Regarding the companies rates be decreased is what he testified to. The company hasn't had a rate case in some years. Witness states they have had deferrals.
1:52:25 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Page 6-8 of testimony. PJM revenues. Rider PSM
	Note: Hughes, Pam	Regarding operation Off system sales for rider PSM
	Note: Hughes, Pam	Regarding the company changing the PSM. Additional expenses and credits in this Rider.
1:55:30 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Includes other components of Rider PSM.
	Note: Hughes, Pam	Recommnedations of how credits should be accounted for.
	Note: Hughes, Pam	Regarding his testimony - 3.8 million in Rider PSM in base rates
1:56:49 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding off system sales , Rider PSM should be reset at 0 going forward.
	Note: Hughes, Pam	Page 9 of his testimony. Commission has historically set off system sales and pulled into base rates. What LGE/KU rate case he is talking about.. Witness doesn't recall Case No.s.
2:00:14 PM	Duke exhibit 9	
	Note: Hughes, Pam	Direct testimony in Cases 2014-00370 & 371
2:00:47 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	KIUC was a stipulatory to that agreement.
	Note: Hughes, Pam	Direct testimony in cases 2014-00370 & 371.
	Note: Hughes, Pam	Regarding off system sales base rates in those cases.
2:03:38 PM	Duke Energy exhibit 10	
	Note: Hughes, Pam	2014-00371 KU index and Order by the Commisssion.
2:04:21 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Page 11 of that Order under Ordering paragraph 2. Witness reads this.
	Note: Hughes, Pam	Page 7 of the settlement stipulation in Order 2014-00371. Off system sales tracker.
	Note: Hughes, Pam	Page 4 of the Commission Order. Off system sales and tracker
2:07:11 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	2016-370 &371 off system sales in these cases.
	Note: Hughes, Pam	Regarding Duke Energy and off system sales not being an issue litigated. No KU off system sales or LGE in their base rates. These have all not been litigated.
2:10:11 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Rider PSM was approved in 2003-252 - Settlement in this case with modifications.
	Note: Hughes, Pam	Regarding the historical basis he cites on for this case. Settlement modified the methodology
	Note: Hughes, Pam	Regarding legal requirement for off system sales rates.
2:12:28 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding recommendation of Rider PSM and 90/10 split, witness states he has not made one.

	Note: Hughes, Pam	Page 60 of testimony, line 14. Reads question and answer.
2:15:44 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding if the AG has taken an opinion on this in other proceedings.
2:16:17 PM	Duke exhibit 11	
	Note: Hughes, Pam	PSC Order, Case No. 2003-00252
2:16:49 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	PSM rider was established in this order. Page 18 of Order (Duke exhibit 11)
2:18:12 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Page 12 of testimony. Replacement power costs. 1.7 million?
	Note: Hughes, Pam	Did he gross up 2013-2014 when he did his data...No. Polar Vortex was Jan-March 2014.
	Note: Hughes, Pam	Regarding Polar vortex outlier.
	Note: Hughes, Pam	If he had included 2013-2014 in his data it would have been much different. Yes, but the Polar Vortex was in that period and Duke wasn't sole owner of East bend.
2:26:09 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Demand side versus the supply side of the equation of vegetation management. Skilled labor force for vegetation management.
	Note: Hughes, Pam	Regarding Terms of contracts have expired at the point of his testimony. Refers to Ms. Edward's testimony. Regarding confidential rebuttal of Ms. Edwards regarding the vegetation management amounts.
	Note: Hughes, Pam	In one Data Request he said the company controls the scope of the money it spends and the work that is done.
	Note: Hughes, Pam	Regarding the vegetation management bids. Adjustments to vegetation management he used all 5 years.
2:35:07 PM	Camera Lock PTZ Activated	
2:35:15 PM	Camera Lock Deactivated	
2:37:06 PM	Camera Lock PTZ Activated	
2:37:07 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding that Commission staff requested 8 years of data in yesterday's hearing.
	Note: Hughes, Pam	Regarding planned outage deferral for O&M expense. Commission has done deferral for both LGE and KU case.
	Note: Hughes, Pam	Regarding deferral accounts. Would it be a regulatory asset in future proceedings. Intervenors would be allowed to participate.
	Note: Hughes, Pam	Regarding planned outage expense. Time periods that the company has used for different projects.
2:37:15 PM	Camera Lock Deactivated	
2:37:16 PM	Camera Lock PTZ Activated	
2:37:21 PM	Camera Lock Deactivated	
2:37:58 PM	Camera Lock PTZ Activated	
2:38:07 PM	Camera Lock Deactivated	
2:39:02 PM	Camera Lock PTZ Activated	
2:39:12 PM	Camera Lock Deactivated	
2:39:42 PM	Camera Lock PTZ Activated	
2:39:51 PM	Camera Lock Deactivated	
2:41:57 PM	Camera Lock PTZ Activated	
2:42:04 PM	Camera Lock Deactivated	
2:42:18 PM	Camera Lock PTZ Activated	
2:43:06 PM	Camera Lock Deactivated	

2:45:53 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Exibit LK_10 of direct testimony. Adjustments to income for compensation? Financial performance. Page 1 of 3 Restricted stock units. Reads footnote. Deferred compensation.
2:46:02 PM	Camera Lock PTZ Activated	
2:46:04 PM	Camera Lock Deactivated	
2:46:13 PM	Camera Lock PTZ Activated	
2:46:59 PM	Camera Lock Deactivated	
2:47:27 PM	Camera Lock PTZ Activated	
2:47:34 PM	Camera Lock Deactivated	
2:48:10 PM	Camera Lock PTZ Activated	
2:48:30 PM	Camera Lock Deactivated	
2:48:42 PM	Camera Lock PTZ Activated	
2:48:45 PM	Camera Lock Deactivated	
2:49:18 PM	Camera Lock PTZ Activated	
2:49:52 PM	Camera Lock Deactivated	
2:50:20 PM	Camera Lock PTZ Activated	
2:50:21 PM	Camera Lock Deactivated	
2:50:36 PM	Camera Lock PTZ Activated	
2:50:51 PM	Camera Lock Deactivated	
2:51:33 PM	Camera Lock PTZ Activated	
2:51:42 PM	Camera Lock Deactivated	
2:52:18 PM	Camera Lock PTZ Activated	
2:52:33 PM	Camera Lock Deactivated	
2:52:46 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding any Training in HR in a utiltiy.
	Note: Hughes, Pam	Regarding if witness has ever been a HR person for a utility.
	Note: Hughes, Pam	Comparative wage study in this case.
	Note: Hughes, Pam	Analysis to how Duke's deferred compensation. Any wage or work studies or survey.
2:52:51 PM	Camera Lock PTZ Activated	
2:52:57 PM	Camera Lock Deactivated	
2:54:47 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding if utility employees all across the commonwealth should have same compensation and beneifits
	Note: Hughes, Pam	Regarding amounts employees recieve for compensation. 100 in wages and 25 in benefits vs. 90 in wages and 30 in benefits.
2:56:24 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	East bend regulatory asset is 10 year reasonable. Did he have opportunity to look at the updated info in Ms. Lawler or Mr. Wathan's testimony
	Note: Hughes, Pam	No depreciation study independent. ALG procedure depreciation rates is his recommendation, based on calculations Witness SPanos performed in AG DR. Does not believe the ELG procedure is proper for rate increases.
2:56:49 PM	Camera Lock PTZ Activated	
2:56:58 PM	Camera Lock Deactivated	
2:57:09 PM	Camera Lock PTZ Activated	
2:57:13 PM	Camera Lock Deactivated	
2:57:39 PM	Camera Lock PTZ Activated	
2:57:45 PM	Camera Lock Deactivated	
2:57:52 PM	Camera Lock PTZ Activated	
2:58:00 PM	Camera Lock Deactivated	
2:58:12 PM	Camera Lock PTZ Activated	

2:58:24 PM	Camera Lock Deactivated	
3:00:53 PM	Break	
3:00:59 PM	Session Paused	
3:11:25 PM	Session Resumed	
3:11:30 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding opinion in the decommissioning of power plants.
	Note: Hughes, Pam	Regarding getting a CPCN.
3:13:42 PM	Objection	
	Note: Hughes, Pam	Sustained
3:14:14 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Response in Data Request, the commission has included terminal net salvage in depreciation rates.
	Note: Hughes, Pam	Any and all orders where the commission agreed with his position of net salvage.
	Note: Hughes, Pam	Support a statement in testimony about when dismantling a site and to maintain a site. He has not done any studies over the past several studies.
3:20:31 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Unfunded liability for next generation
	Note: Hughes, Pam	Decommissioning of plant and customers paying that expense.
	Note: Hughes, Pam	Regarding cost causation.
	Note: Hughes, Pam	Inequality of decommissioning a power plant placed on customers.
3:26:32 PM	Duke exhibit 12	
	Note: Hughes, Pam	Regarding a case before the North Carolina Commission. A copy of an Order to do with Virginia Electric & Power Co. before the State of North Carolina Utilties Commission.
3:29:28 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Page 42 of North Carolina Order. Page 43, 2nd full paragraph, 8th line. Reads sentence.
	Note: Hughes, Pam	Page 44. 6th line, he reads this into the record.
3:32:56 PM	Chairman Schmitt statement about the questioning.	
3:33:41 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	He agreed with the company with the excess protected ADIT and recommends a 5 year amortization. He doesn't agree with a 15 year period.
	Note: Hughes, Pam	Regarding taxes in his testimony.
3:35:59 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding Rider FTR.
3:37:34 PM	Atty Samford cross of Witness Kollen	
	Note: Hughes, Pam	Regarding if companies thinking about expanding operations make their decisions based upon rates in the area.
	Note: Hughes, Pam	Regarding that Amazon announced a significant expansion in the Duke KY territory.
3:39:07 PM	Atty Sanders cross of Witness Kollen	
	Note: Hughes, Pam	Regarding the rebuttal testimony of Ms. Lawler.
3:39:48 PM	Atty Samford moves for Duke exhibit 12 to be entered into the record	
3:40:19 PM	Atty Sanders cross of Witness Kollen	
	Note: Hughes, Pam	Page 7 -12 of Rebuttal testimony. Test year off system sales margins should be in base rates.
	Note: Hughes, Pam	Page 6 of Ms Lawlers rebuttal testimony. Has he changed his position about this?
3:42:25 PM	Atty Sanders cross of Witness Kollen	
	Note: Hughes, Pam	Net margins from Rider PSM should be used to reduce its revenue requirement

3:42:53 PM	Atty Sanders cross of Witness Kollen		
		Note: Hughes, Pam	Wathan's rebuttal testimony, page 3. Explain rational for using different time frames.
3:45:40 PM	Atty Sanders cross of Witness Kollen		
		Note: Hughes, Pam	Ms. Edwards rebuttal, page 10. Vegetation management expenses for the test year.
3:47:11 PM	Atty Sanders cross of Witness Kollen		
		Note: Hughes, Pam	Wathan's rebuttal testimony, page 9. WDW_rebuttal-2 It is reflected in the table in his testimony but not a revised sheet to the Commission.
3:49:14 PM	Chairman cross of Witness Kollen		
		Note: Hughes, Pam	Regarding refund to customers of tax spread over 15 to 20 year period.
3:50:20 PM	AG exhibit 10		
		Note: Hughes, Pam	Hands out AG exhibt 10 (Order in Case No. 2006-00172)
3:52:21 PM	Atty Chandler re direct of Witness Kollen		
		Note: Hughes, Pam	ALG and ELG differences. Mr. Spanos rebuttal testimony shows the difference in these.
		Note: Hughes, Pam	Regarding FERC prosecution being a joke. Terminal net salvage in their depreciation rates.
		Note: Hughes, Pam	Referring to that it is up to utilities to come in for rate cases.
		Note: Hughes, Pam	Mr. Spanos Rebuttal ELG depreciation rates. Case 2006-00172 the ELG rates were part of a settlement. Turn to page 6 of the Order in 2006-00172 and read part of this.
4:01:49 PM	AG exhibit 10 admitted into the record		
4:02:03 PM	Atty Sanders cross of Witness Kollen		
		Note: Hughes, Pam	Reasonable amount for vegetation management. Information that Ms. Edwards had and Witness Kollen didn't have.
4:03:42 PM	Witness excused		
4:04:42 PM	Chairman statement about Post Hearing Data Requests		
		Note: Hughes, Pam	Filed by next Tuesday. Answers to be in by March 23. Briefs are due April 2nd.
4:06:01 PM	Chairman Schmitt statement		
		Note: Hughes, Pam	Regarding letting Dukes counsel address every issue.
4:07:00 PM	Atty Chandler statement		
		Note: Hughes, Pam	Regarding if they file anything outside of the three Witnesses testimony thaey called that they will notify Duke's counsel.
4:07:21 PM	Adjourned		
4:07:30 PM	Session Paused		
10:51:50 AM	Session Ended		

Exhibit List Report

2017-00321_8MAR2018

Duke Energy Kentucky

Judge: Talina Mathews; Michael Schmitt
Witness: Richard Baudino; Justin Bieber; Lane Kollen; Glenn Watkins
Clerk: Pam Hughes

Name:	Description:
AG Exhibit 10	PSC Order in Case No. 2006-00172
Duke Exhibit 01	Direct testimony and exhibits of Richard Baudino in Case No. 2017-00179
Duke Exhibit 02	Direct testimony and exhibits of Richard Baudino in Case No.s 2016-00370 and 2016-00371
Duke Exhibit 03	PSC Order in Case No. 2016-00371
Duke Exhibit 04	PSC Order in Case No. 2016-00370
Duke Exhibit 05	[redacted]
Duke Exhibit 06	Edison Electric Institute - Ranking of Total Retail Average Rates
Duke Exhibit 07	Bruce Sailors rebuttal testimony, page 4
Duke Exhibit 08	Survey of Regional Customer Charges- Witness Dismukes exhibit DED-6 in Case No. 2017-00179
Duke Exhibit 09	Direct testimony of Lane Kollen in Case No.'s 2014-00371 & 372
Duke Exhibit 10	PSC Order in Case No. 2014-00371 KU. With Index
Duke Exhibit 11	PSC Order in Case No. 2003-00252 with Index
Duke Exhibit 12	State of North Carolina Utilities Commission Docket No. E-22, SUB 532 Order regarding Virginia Electric & Power Company.

DEK EXHIBIT 1

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)	**CASE NO. 2017-00179**

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 3, 2017

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00179

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BEFORE THE PUBLIC SERVICE COMMISSION

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ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)	**CASE NO. 2017-00179**

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit No. ___(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity for regulated electric operations for Kentucky Power Company ("KPC", or "Company"). I will also respond to the Direct Testimony of Mr. Adrien McKenzie, witness for KPC.

Q. Please summarize your conclusions and recommendations.

A. Based on current financial market conditions, I recommend that the Kentucky Public Service Commission ("KPSC" or "Commission") adopt an 8.85% return on equity for Kentucky Power Company in this proceeding. My recommendation is based on the results of a Discounted Cash Flow ("DCF") model analysis. My DCF analysis incorporates my standard approach to estimating the investor required return on equity and includes a group of 15 comparison companies and dividend and earnings growth forecasts from the Value Line Investment Survey, IBES, and Zacks.

I also included two Capital Asset Pricing Model ("CAPM") analyses for additional information. I did not incorporate the results of the CAPM in my recommendation, however the results from the CAPM support my 8.85% ROE recommendation for KPC. In fact, my CAPM results are somewhat lower than my DCF results.

In Section IV, I respond to the testimony and ROE recommendation of the Company's witness Mr. McKenzie. I will demonstrate that his recommended ROE of 10.31% significantly overstates the current investor required return for KPC. Today's financial environment of low interest rates has been deliberately and methodically supported by Federal Reserve policy actions since 2009. Although the Federal Reserve began to raise short-term interest rates in 2016, both short-term and long-term interest rates are still low. A 10.31% ROE is inconsistent with investor required returns for low-risk utilities like KPC.

A 10.31% ROE would inflate the Company's revenue requirement and contribute to a burdensome rate increase for Kentucky ratepayers. This is due to the fact that KPC must collect income taxes on the equity portion of its weighted cost of capital. My recommended 8.85% ROE equates to a 14.54% return when income taxes are applied. This is also referred to as the pre-tax return on equity. Mr. McKenzie's recommended 10.31% ROE equates to a 16.94% pre-tax return on equity. The difference between my recommendation and Mr. McKenzie's results in an increased base rate revenue requirement of $11.838 million per year, according to calculations made by KIUC witness Mr. Kollen. I strongly recommend that the KPSC reject the Company's requested 10.31% ROE in this proceeding and approve my recommended 8.85% ROE.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Long-term capital costs as measured by the general level of interest rates in the economy have declined over the last few years, though they have increased since the November 2016 election. Exhibit No. ___(RAB-2) presents a graphic depiction of the trend in interest rates from January 2008 through August 2017. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of August 2017, the average public utility bond yield was 3.92%, representing a decline of 216 basis points, or 2.16%, from January 2008. Likewise, the 20-year Treasury bond stood at 2.55% in August 2017, a decline of 1.80% (181 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in DPS-RAB-2 that affected the general level of interest rates?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011.[2]

Beginning in September 2011, the Fed initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist," was designed by the Fed to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities.

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1 (http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm).

2 (http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm)

The Fed began to pare back its purchases of securities in the last few years. On January 29, 2014 the Fed stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Fed continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October.[3]

Q. Has the Fed recently indicated any important changes to its monetary policy?

A. Yes. In March 2016, the Fed began to raise its target range for the federal funds rate, increasing it to 1/4% to 1/2% from 0% to 1/4%. The Fed further increased the target range to 1/2% to 3/4% in a press release dated December 14, 2016. On June 14, 2017, the Fed announced a further increase to 1% - 1 ¼%. On September 20, 2017 the Fed decided to maintain the federal funds rate at current levels. In its press release on that date, the Fed noted the following:

"Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. Hurricanes Harvey, Irma, and Maria have devastated many communities, inflicting severe hardship. Storm-related disruptions and rebuilding will affect economic activity in the near term, but past experience suggests that the storms are unlikely to materially alter the course of the national economy over the medium term. Consequently, the Committee continues to expect that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace, and labor market conditions will strengthen somewhat further. Higher prices for gasoline and some other items in the aftermath of the hurricanes will likely boost inflation temporarily; apart from that effect, inflation on a 12-month basis is expected to remain somewhat below 2 percent in the near term but to stabilize around the Committee's 2 percent objective over the medium term. Near-term risks to the economic outlook appear roughly balanced, but the Committee is monitoring inflation developments closely.

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[3] (http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm)

In view of realized and expected labor market conditions and inflation, the Committee decided to maintain the target range for the federal funds rate at 1 to 1-1/4 percent. The stance of monetary policy remains accommodative, thereby supporting some further strengthening in labor market conditions and a sustained return to 2 percent inflation.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. The Committee will carefully monitor actual and expected inflation developments relative to its symmetric inflation goal. *The Committee expects that economic conditions will evolve in a manner that will warrant gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.*[4] (italics added)

Q. Mr. Baudino, why is it important to understand the Fed's actions since 2008?

A. The Fed's monetary policy actions since 2008 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment. As I will demonstrate later in my testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Are current interest rates indicative of investor expectations regarding the future direction of interest rates?

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[4] https://www.federalreserve.gov/newsevents/pressreleases/monetary20170920a.html

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> "A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information."[5]

Despite recent increases in the general level of interest rates since the second half of 2016, the U.S. economy continues to operate in a low interest rate environment. It is important to realize that investor expectations of higher future interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

Moreover, the current low interest rate environment favors lower risk regulated utilities. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur.

Q. How has the increase in interest rates last year affected utility stocks in terms of bond yields and stock prices?

A. Table 1 below tracks movements in the 20-year Treasury bond yield, the Mergent average utility bond yield, and the Dow Jones Utilities Average ("DJUA") from January 2016 through August 2017.

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[5] Morin, Roger A., *New Regulatory Finance*, Public Utilities Reports, Inc. (2006) at 279.

TABLE 1

Bond Yields and DJUA

	20-Year Treasury %	Avg. Utility Bond %	DJUA
2016			
January	2.49	4.62	611.35
February	2.20	4.44	620.70
March	2.28	4.40	668.57
April	2.21	4.16	654.44
May	2.22	4.06	659.44
June	2.02	3.93	716.52
July	1.82	3.70	711.42
August	1.89	3.73	666.87
September	2.02	3.80	668.13
October	2.17	3.90	675.23
November	2.54	4.21	632.67
December	2.84	4.39	645.86
2017			
January	2.75	4.24	668.87
February	2.76	4.25	703.16
March	2.83	4.30	697.28
April	2.67	4.19	704.35
May	2.70	4.19	726.62
June	2.54	4.01	706.91
July	2.65	4.06	726.48
August	2.55	3.92	743.24

Table 1 shows that the 20-year Treasury bond yield was slightly higher in August 2017 than it was in January 2016 before the Fed began raising short-term interest rates. However, the yield on the Mergent average public utility bond was substantially lower in August 2017 than in January 2016. Similarly, the DJUA was substantially higher in August 2017 than it was in January 2016.

My conclusion from this data is that even though the Federal Reserve raised short-term interest rates since March 2016, utility bond yields are lower and the DJUA is higher than they were at the beginning of 2016. Utility stocks and bonds have not been adversely affected by the Fed's raising of the federal funds rate.

Q. How does the investment community regard the electric utility industry as a whole?

A. The Value Line Investment Survey's September 15, 2017 summary report on the Electric Utility (Central) Industry noted the following regarding interest rates and utility stocks.

"This has been an excellent year for most stocks in the Electric Utility Industry. The price of almost every issue in the group has risen, and the majority have advanced by more than 10%. A few equities, including CenterPoint Energy, have climbed more than 20%. This has occurred despite the raising of interest rates by the Federal Reserve and the expectation that at least one more increase might be in the offing. Interest rates are still quite low, by historical standards, so investors continue to ''reach for yield.'' The average dividend yield of stocks in the Electric Utility Industry is 3.3%. This is still above the median of dividend-paying equities under our coverage, but the gap is narrower than usual."

Q. In 2017, the Edison Electric Institute ("EEI") published its *2016 Financial Review* of the investor-owned electric utility industry. Please summarize EEI's conclusions with respect to credit ratings for the electric utility industry.

A. EEI's report noted the following with respect to the industry's credit ratings:

"The industry's average credit rating was BBB+ in 2016, remaining for a third straight year above the BBB average that has held since 2004. Ratings activity, at 67 changes, was in line with the industry's annual average of 70 changes per year since 2008. Upgrades were 73.1% of total actions, the third-highest annual figure for upgrades in our dataset. In fact, the last four years have produced the four highest annual upgrade percentages in our historical data. EEI captures upgrades and downgrades at the subsidiary level; multiple actions within a parent holding company are included in the upgrade/downgrade totals. The industry's average credit rating and outlook are based on the unweighted averages of all Standard & Poor's (S&P) parent company ratings and outlooks.

While the industry's average rating was unchanged at BBB+, the underlying data show a modest strengthening. Six companies received upgrades at the parent level while only two were downgraded. Our universe of U.S. "parent" company electric utilities includes a few that are either a subsidiary of an independent power producer, a subsidiary of a foreign-owned company, or that have been acquired by an investment firm; three of the year's upgrades focused on a relationship with that ultimate parent company. Two other upgrades cited a reduced focus on merchant generation and an improved business risk profile. At January 1, 2017, 74.0% of ratings outlooks were "stable", 18.0% were "negative" or "watch-negative", 6.0% were "positive" or "watch-positive", and 2.0% were "developing".

EEI's analysis shows that the investor-owned electric utility industry had strong, stable, and slightly improving credit metrics in 2016.

Q. What are the current credit ratings and bond ratings for KPC?

A. Standard and Poor's ("S&P") current credit rating for the Company is A- and its senior unsecured bond rating is A-. Moody's current long-term issuer rating for the KPC is Baa2, with a rating of Baa2 for senior unsecured bonds. These credit ratings are relatively consistent with the recent average utility credit rating of BBB+ as reported by EEI. The also show that KPC is a strong, investment grade utility company.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for KPC.

A. I employed a Discounted Cash Flow ("DCF") analysis using a group of regulated electric utilities. My DCF analysis is my standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, IBES, and Zacks. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I did not rely on the CAPM for my recommended 8.85% ROE for KPC, the CAPM provide an alternative approach to estimating the ROE for KPC, albeit a less reliable one.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of a particular investment. The result of their analyses is a bond and/or credit rating that reflect these risks.

<u>Discounted Cash Flow ("DCF") Model</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: V = *asset value*
R = *yearly cash flows*
r = *discount rate*

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Under the formula, it is apparent that "k" must reflect the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for KPC?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to KPC. Since KPC is a subsidiary of American Electric Power, it does not have publicly traded stock. Thus, one cannot estimate a DCF cost of equity on the Company directly. It is necessary to use a group of companies that are similarly situated and have reasonably similar risk profiles to KPC.

Q. Please describe your approach for selecting a group of electric companies.

A. For purposes of this case, I chose to rely on the proxy group that Companies witness McKenzie used for his analysis. Although the selection criteria he used are somewhat different from those I have used in past cases, the constituent members of his proxy group comprise a reasonable basis for purposes of estimating the ROE for the Company, with three exceptions. I eliminated the following companies from Mr. McKenzie's proxy group as follows:

- Avangrid Inc.: NMF (no meaningful figure) for Value Line earnings and dividend growth forecasts and Value Line beta. Since Value Line is one of my primary sources for growth rate forecasts, there is not enough Value Line information to include this company in the proxy group.

- Emera, Inc.: Emera completed the acquisition of TECO Energy in 2016 and as a result has Value Line earnings and dividend growth estimates – 8.5% and 11.0% respectively, that reflect higher short-term growth, but are not reflective of longer term growth as Emera assimilates TECO into its corporate earnings and dividends. Value Line predicted that Emera's revenue will increase from $2.789 billion in 2015 to $6.875 billion in 2017.[6] Clearly, Emera is a different company today from what it was in 2015 and its expected short-term growth in dividends and revenues reflect this.
- Fortis, Inc.: Fortis acquired ITC Holdings in October 2016 and is a different company from what is was in 2015. Value Line forecasted that its revenues would increase from $6.727 billion in 2015 to $8.5 billion in 2017 and its total capital will increase from $21.151 billion in 2015 to $37.525 billion in 2017. This is expected to fuel a rise in earnings of 9.0% over the next five years, according to Value Line.[7]

The resulting comparison group of 15 companies that I used in my analysis is shown in the Table 2 below.

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6 Value Line Investment Survey Report, June 23, 2017.

7 Value Line Investment Survey Report, September 15, 2017.

TABLE 2
Credit Ratings
Proxy Group and Kentucky Power

	S&P	Moody's
Alliant Energy	A-	Baa1
Ameren Corp.	BBB+	Baa!
American Elec Pwr	A-	Baa1
CMS Energy Corp.	BBB+	Baa1
Dominion Energy	BBB+	Baa2
DTE Energy Co.	BBB+	Baa1
Duke Energy Corp.	A-	Baa1
Eversource Energy	A-	Baa1
NextEra Energy, Inc.	A-	Baa1
PPL Corp.	A-	Baa2
Pub Sv Enterprise Grp.	BBB+	Baa1
SCANA Corp.	BBB+	Baa3
Sempra Energy	BBB+	Baa1
Southern Company	A-	Baa2
Vectren Corp.	A-	NR
Kentucky Power	A-	Baa2

Q. What was your first step in determining the DCF return on equity for the comparison group?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from March through August 2017. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the comparison group is 3.45%. These calculations are shown in Exhibit No. ___(RAB-3).

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the electric comparison group?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and IBES. This is the method I typically use for estimating growth for my DCF calculations.

Q. Please briefly describe Value Line, Zacks, and IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, IBES also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. Please explain how you used analysts' dividend and earnings growth forecasts in your constant growth DCF analysis.

Q. Columns (1) through (5) of the top section of Exhibit No. ____(RAB-4) shows the forecasted dividend, earnings, and retention growth rates from Value Line and the earnings growth forecasts from IBES and Zacks. In my analysis, I used four of these growth rates: dividend and earnings growth from Value Line and earnings growth from Zacks and IBES. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows. Value Line is the only sources of which I am aware that forecasts dividend growth and my approach gives this forecast equal weight with each of the three earnings growth forecasts.

Q. How did you proceed to determine the DCF return of equity for the comparison group?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

Exhibit No. ___(RAB-4) presents my standard method of calculating dividend yields, growth rates, and return on equity for the comparison group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates to the current group dividend yield of 3.45% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. In evaluating investor expected growth rates, I use both the average and the median values for the comparison group under consideration.

Q. What are the results of your constant growth DCF model?

A. For Method 1 (average growth rates), the results range from 8.14% to 9.25%, with the average of these results being 8.86%. For Method 2 (median growth rates), the results range from 8.28% to 9.55%, with the average of these results being 8.85%.

<u>Capital Asset Pricing Model</u>

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[8] There is evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

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8 For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also vary widely, which underscores the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for September 20, 2017. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value

Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit No. ___(RAB-5). I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 9.00% to 9.91%. The average of these market returns is 9.45%.

Q. Why did you use median growth rate estimates rather than the average growth rate estimates for the Value Line companies?

A. Using median growth rates is likely a more accurate method of estimating the central tendency of Value Line's large data set compared to the average growth rates. Average earnings and book value growth rates may be unduly influenced by very high or very low 3 - 5-year growth rates that are unsustainable in the long run. For example, Value Line's Statistical Summary shows both the highest and lowest value for earnings and book value growth forecasts. For earnings growth, Value Line showed the highest earnings growth forecast to be 90.5% and the lowest growth rate to be -27.5%. The highest book value growth rate was 98.5% and the lowest was -32.5%. Neither of these levels of growth is compatible with long-run growth prospects for the market. The median growth rate is not influenced by such extremes because it represents the middle value of a very wide range of earnings growth rates.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Duff and Phelps compiled a study of historical returns on the stock market in its 2017 SBBI Yearbook. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period is reflective of investor expectations going forward. Exhibit No. ___(RAB-6) presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. Exhibit No. ___(RAB-6) shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2016. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.0% - 7.0%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Duff and Phelps reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[9] Duff and Phelps noted that this growth in the P/E ratio for stocks was subtracted out of the historical risk premium because "it is not believed that P/E will continue to increase in the future." The adjusted historical arithmetic market risk premium is 5.97%, which I have also included in Exhibit No. ___(RAB-6). This risk premium estimate falls near the middle of the market risk premium range.

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[9] *2017 SBBI Yearbook*, Duff and Phelps, pp. 10-28 through 10-30.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from March through August 2017. This was the latest available data from the Federal Reserve's Selected Interest Rates (Daily) H.15 web site during the preparation of my Direct Testimony. The 20-year Treasury bond is often used by rate of return analysts as the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the electric company comparison group from most recent Value Line reports. The average of the Value Line betas for the comparison group is 0.67.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 6.90% - 7.15%. Using historical risk premiums, the CAPM results are 5.99% - 7.32%.

Conclusions and Recommendations

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 3 below summarizes my return on equity results using the DCF and CAPM for my comparison group of companies.

TABLE 3
SUMMARY OF ROE ESTIMATES

Baudino DCF Methodology:	
Average Growth Rates	
- High	9.25%
- Low	8.14%
- Average	8.86%
Median Growth Rates:	
- High	9.55%
- Low	8.28%
- Average	8.85%
CAPM:	
- 5-Year Treasury Bond	6.90%
- 20-Year Treasury Bond	7.15%
- Historical Returns	5.99% - 7.32%

Q. What is your recommended return on equity for KPC?

A. I recommend that the KPSC adopt an 8.85% return on equity for KPC. My recommendation is consistent with the average DCF results from my constant growth DCF model. Based on current market evidence, an 8.85% return on equity is fair and reasonable for A-/Baa2 rated electric utility company like KPC.

Q. Mr. Baudino, are you concerned that your recommended cost of equity is too low?

A. No, not at all. The preponderance of market evidence I examined fully supports my ROE recommendation for KPC in this proceeding. As I described in Section II of my testimony, the U. S. economy is in a low interest rate environment, one that has been supported in a deliberate and considered fashion by Federal Reserve monetary policy. Both my DCF and CAPM ROE estimates show that the investor required ROE for KPC, as well as other regulated electric and gas utilities, reflects this low interest rate environment.

Q. Does KIUC recommend the inclusion of short-term debt in KPC's capital structure?

A. Yes. Mr. Kollen addresses the inclusion of short-term debt in the Company's capital structure. I will address the cost of short-term debt.

Q. What is your recommended cost of short-term debt?

A. I recommend a cost of short-term debt of 1.25%. This recommendation is based on my review of the rates on short-term commercial paper and on the London Interbank Offer Rate ("LIBOR"). LIBOR is one of the most widely used sources for determining short-term interest rates. Commercial paper is typically defined as short-term debt issued by corporations for financing such items as accounts receivable and other short-term obligations.

As of September 18, 2017, the Federal Reserve reported that the cost of 1-month commercial paper was 1.11%. The Wall Street Journal also reported on September 20, 2017 that the one-month LIBOR was 1.237%. For purposes of this case, I recommend using the approximate upper end of this range of estimates, 1.25%, as a reasonable proxy for the cost of short-term debt for KPC in this proceeding.

IV. RESPONSE TO KENTUCKY POWER TESTIMONY

Q. Have you reviewed the Direct Testimony of Mr. McKenzie?

A. Yes.

Q. Please summarize your conclusions with respect to his testimony and return on equity recommendation.

A. Mr. McKenzie's recommended 10.31% return on equity is overstated and inconsistent with the current low interest rate environment. As I shall demonstrate later in this section of my testimony, Mr. McKenzie made judgments that served to inflate his ROE results, particularly for the DCF and CAPM. As such, his testimony and analyses provide very little useful guidance for the Commission with respect to the investor required ROE for KPC.

<u>Outlook for Capital Costs</u>

Q. Beginning on page 16, line 19 of his Direct Testimony, Mr. McKenzie presented his view of current capital market conditions, noting that these conditions "continue to be affected by the Federal Reserve's unprecedented monetary policy actions, which were designed to push interest rates to historically and artificially low levels ..." Please respond to Mr. McKenzie's position with respect to current capital market conditions.

A. I agree that the economy is in a low interest rate environment that is being supported quite deliberately by Federal Reserve policy. Nonetheless, current financial market conditions do indeed provide a representative basis for estimating the cost of equity capital for Kentucky Power Company and for utilities generally. The fact that interest rates are relatively low by historical standards does not preclude the rate of return analyst from making a reasonable assessment of investor required ROEs using currently prevailing stock prices and interest rates.

Q. On page 21 of Mr. McKenzie's Direct Testimony, Figure 1 shows higher forecasted interest rates through 2021 from several different forecasting sources. Should the Commission increase its allowed return on equity based on these higher interest rate forecasts?

A. No. As I stated in Section II my Direct Testimony, current interest rates embody investor expectations based on their assessments of all available market information. This includes interest rate forecasts cited by Mr. McKenzie as well as statements from the Federal Reserve. The KPSC should not invest in the interest rate forecasts cited by Mr. McKenzie in determining a fair rate of return for KPC in this proceeding.

There is evidence that economists have systematically overestimated interest rates in recent years. Jared Bernstein wrote the following in a recent article in the New York Times[10]:

> In the early 1980s, forecasters did a good job of predicting the path of bond rates, though their job was a bit easier than usual because rates were so highly elevated that it was a pretty sure bet they'd be headed back down. ("Regression to the mean," for all you statistics fans.)
>
> But since the mid-1990s, government forecasters have consistently overestimated this critical variable.
>
> This "consistently" point is essential. Most economic forecasts are off one way or the other — too high or too low, but they tend to be pretty much balanced in either direction. But on the 10-year bond rate, the errors are systemic.
>
> Forecasters are regularly overestimating and thus regularly overstating, all else being equal, future interest payments on the debt.

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[10] "We Keep Flunking Forecasts on Interest Rates, Distorting the Budget Outlook", Jared Bernstein, *New York Times*, Feb. 23, 2015.

Another article by Akin Oyedele entitled "Interest Rate Forecasters Are Shockingly Wrong Almost All Of The Time"[11] showed that from June 2010 through June 2015 interest rate forecasts were wrong most of the time. Mr. Oyedele noted that 2014 "was particularly bad, when strategists became too optimistic that the Federal Reserve would hike rates."

These articles highlight the consistent upward bias that is likely embodied in the forecasts presented by Mr. McKenzie.

Q. Is there support for the position that today's currently low interest rates is part of a long-term trend?

A. Yes. In a weekly blog at the Brookings Institution, former Federal Reserve Chairman Ben Bernanke wrote the following:[12]

Interest rates around the world, both short-term and long-term, are exceptionally low these days. The U.S. government can borrow for ten years at a rate of about 1.9 percent, and for thirty years at about 2.5 percent. Rates in other industrial countries are even lower: For example, the yield on ten-year government bonds is now around 0.2 percent in Germany, 0.3 percent in Japan, and 1.6 percent in the United Kingdom. In Switzerland, the ten-year yield is currently slightly negative, meaning that lenders must pay the Swiss government to hold their money! The interest rates paid by businesses and households are relatively higher, primarily because of credit risk, but are still very low on an historical basis.

Low interest rates are not a short-term aberration, but part of a long-term trend. As the figure below shows, ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak above 15 percent in 1981, and have been declining ever since. That pattern is partly explained by the rise and fall of inflation, also shown in the figure. All else equal, investors demand higher yields when inflation is high to compensate them for the declining purchasing power of the

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[11] Akin Oyedele, "Interest Rate Forecasters Are Shockingly Wrong Almost All of the Time", *Business Insider*, July 18, 2015.

[12] Ben S. Bernanke, "Why Are Interest Rates So Low", Weekly Blog, Brookings, March 30, 2015. https://www.brookings.edu/blog/ben-bernanke/2015/03/30/why-are-interest-rates-so-low/

dollars with which they expect to be repaid. But yields on inflation-protected bonds are also very low today; the real or inflation-adjusted return on lending to the U.S. government for five years is currently about *minus* 0.1 percent.

Why are interest rates so low? Will they remain low? What are the implications for the economy of low interest rates?

If you asked the person in the street, "Why are interest rates so low?", he or she would likely answer that the Fed is keeping them low. That's true only in a very narrow sense. The Fed does, of course, set the benchmark nominal short-term interest rate. The Fed's policies are also the primary determinant of inflation and inflation expectations over the longer term, and inflation trends affect interest rates, as the figure above shows. But what matters most for the economy is the real, or inflation-adjusted, interest rate (the market, or nominal, interest rate minus the inflation rate). The real interest rate is most relevant for capital investment decisions, for example. The Fed's ability to affect real rates of return, especially longer-term real rates, is transitory and limited. Except in the short run, real interest rates are determined by a wide range of economic factors, including prospects for economic growth—not by the Fed.

Q. Did Mr. McKenzie present forecasted interest rates in the testimony he co-sponsored in Kentucky Utilities ("KU") and Louisville Gas and Electric ("LGE") Case Nos. 2014-00371 and 2014-00372?

A. Yes. On page 13 of the Direct Testimony he co-sponsored with Dr. Avera in those cases, Mr. McKenzie presented Figure 2 on page 13 of his KU testimony that showed forecasted interest rates with a graph like the one included in his Direct Testimony in this case on page 21. I reviewed the work papers submitted by Dr. Avera and Mr. McKenzie in those proceedings and found the Blue Chip financial forecast dated June 1, 2014, which formed part of the basis of Figure 2 in their testimony in those cases, which was filed on November 26, 2014.

In the Blue Chip forecasts dated June 1, 2014 presented by Mr. McKenzie in Case Nos. 2014-00371 and 2014-00372, the consensus forecast for the 30-year Treasury

Bond was 4.7% for 2016 and 5.1% for 2017.[13] The actual December 2016 30-Year Treasury Bond yield was 3.11% and for August 2017 was only 2.80%. The June 2014 Blue Chip consensus forecasts presented by Mr. McKenzie overshot the recent actual 30-Year Treasury Bond rates by 159 – 230 basis points. Stated another way, the Blue Chip consensus forecasts missed the recent actual 30-Year Treasury Bond rates by 1.59% to 2.30%.

The magnitude of the overstatement by the Blue Chip consensus forecasts is strong support for my recommendation that the Commission disregard interest rate forecasts when considering its allowed ROE for KPC in this proceeding.

DCF Model

Q. Briefly summarize Mr. McKenzie's approach to the DCF model.

A. Mr. McKenzie constructed a group of electric and gas utilities for purposes of estimating the DCF ROE for KPC. He used several sources of growth rate forecasts, which included IBES, Zacks, Value Line, Bloomberg, and S&P Capital IQ as well as an estimate of sustainable growth. I ultimately adopted Mr. McKenzie's proxy group with the three exceptions I noted earlier.

In his Exhibit AMM-5, Mr. McKenzie adjusted his DCF ROE results by excluding certain company ROE results that, in his view, were either too low or too high. On

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[13] KU response to AG 1-187, Docket No. 2014-00371, WP-25.

the low end, these results ranged from 4.2% to 6.9%. On the high end, Mr. McKenzie excluded one value of 15.2%, but saw fit to include ROE results ranging from 12.5% to 14.0%. After making these exclusions, his resulting DCF range was 8.7% to 9.8% using an average of the remaining results. The midpoints ranged from 9.8% to 10.8%.

Q. Please comment on Mr. McKenzie's approach to formulating his DCF recommendation to the Commission.

A. Mr. McKenzie conducted a biased approach in formulating his DCF recommendations. He applied a test for excluding ROE results that, in his view, were too low but failed to exclude other results that are excessively high. For example, the average Commission-allowed ROE for 2016 that was reported by Mr. McKenzie in his Exhibit AMM-9 was 9.77%. *However, Mr. McKenzie included ROEs in his Exhibit AMM-5 in that are 273 – 423 basis points higher than 9.77%.* My review of Commission allowed returns contained in Mr. McKenzie's Exhibit AMM-9 reveals that 2002 was the last year that allowed returns on equity were as high as 11% and that the last Commission allowed return near 13% was in 1989.

It is abundantly clear that Mr. McKenzie's approach to excluding ROE results from his DCF analysis had the effect of inflating his DCF ROE recommendation.

Q. Have you conducted an alternative analysis that includes all the DCF results from Mr. McKenzie's Exhibit AMM-5?

A. Yes. Table 4 below presents the average and median ROEs utilizing all the DCF results from Mr. McKenzie's Exhibit AMM-5, page 3 of 3.

Table 4
McKenzie ROE Results

Company	V Line	IBES	Zacks	Bloomberg	S&P Capital/IQ	BR+SV Growth	Average ROE
Alliant Energy	9.2%	9.6%	8.7%	9.6%	9.1%	8.8%	9.2%
Ameren Corp.	9.3%	9.3%	9.8%	9.1%	9.4%	7.1%	9.0%
American Elec Pwr	7.6%	6.0%	9.2%	7.6%	7.7%	7.9%	7.6%
Avangrid, Inc.	n/a	13.0%	12.5%	13.0%	11.8%	5.7%	11.2%
CMS Energy Corp.	9.5%	10.5%	9.0%	9.8%	10.4%	8.8%	9.7%
Dominion Energy	9.5%	8.0%	10.0%	9.0%	9.6%	4.2%	8.4%
DTE Energy Co.	8.3%	7.9%	9.2%	9.3%	9.0%	7.5%	8.5%
Duke Energy Corp.	9.7%	7.8%	10.2%	10.7%	8.8%	7.6%	9.1%
Emera Inc.	13.4%	n/a	n/a	11.4%	12.6%	12.5%	12.5%
Eversource Energy	9.7%	9.2%	9.5%	9.3%	9.0%	7.4%	9.0%
Fortis Inc.	14.0%	n/a	10.5%	10.0%	11.2%	8.1%	10.8%
NextEra Energy, Inc.	9.5%	9.7%	10.1%	10.0%	9.9%	9.3%	9.8%
PPL Corp.	n/a	6.7%	9.2%	5.4%	9.4%	11.0%	8.3%
Pub Sv Enterprise	6.4%	4.6%	6.9%	7.1%	9.0%	8.5%	7.1%
SCANA Corp.	7.8%	9.6%	9.1%	9.8%	9.2%	8.5%	9.0%
Sempra Energy	11.0%	12.9%	11.7%	15.2%	11.0%	6.7%	11.4%
Southern Company	8.2%	8.5%	9.7%	9.3%	9.1%	8.2%	8.8%
Vectren Corp.	9.9%	8.4%	8.6%	8.4%	8.6%	9.2%	8.8%
Average	9.6%	8.8%	9.6%	9.7%	9.7%	8.2%	9.3%
Median	9.5%	8.9%	9.5%	9.5%	9.3%	8.1%	9.0%

Rather than simply excluding low-end results, I recommend that the median be used as an alternative measure of central tendency. As I testified in Section III, the median is not affected by extremely high or low results, but instead represents the middle value of the data set. If there are concerns about results that are either too high or too low, the median may be used as an additional reference for the investor required ROE.

Table 4 shows that when all results are considered, the average and median results from Mr. McKenzie's Exhibit AMM-5 are closer to my DCF results. I would add that Avangrid Inc, Emera, Inc., and Fortis Inc. inflate these DCF results and should be excluded for the reasons I stated earlier.

<u>**CAPM and ECAPM**</u>

Q. Beginning on page 50 of his Direct Testimony, Mr. McKenzie described the Empirical CAPM ("ECAPM") analysis. Is this a reasonable method to use to estimate the investor required ROE for KPC?

A. No. The ECAPM is supposed to account for the possibility that the CAPM understates the return on equity for companies with betas less than 1.0. I believe it is highly unlikely that investors use the ECAPM formulation shown in Mr. McKenzie's Exhibit No. 8 to "correct" CAPM returns for regulated electric utilities. To the extent investors use the CAPM to estimate their required returns, I believe it is much more likely that they use the traditional CAPM equation that I used in Section III of my testimony. Mr. McKenzie presented no evidence that investors use the adjustment factors contained in his ECAPM analysis to adjust their expected returns for regulated utilities. Moreover, the use of an adjustment factor to "correct" the CAPM results for companies with betas less than 1.0 suggests that published betas by such sources as Value Line are incorrect and that investors should not rely on them. In fact, Mr. McKenzie testified on page 48, lines 16 through 18 of his Direct Testimony that Value Line is "the most widely referenced source for beta is regulatory proceedings."

Q. Please continue your evaluation of the results of Mr. McKenzie's CAPM and ECAPM analysis.

A. I disagree with Mr. McKenzie's general formulation of the CAPM and ECAPM and in particular with his estimate of the expected market return. He estimated the market return portion of the CAPM and ECAPM by estimating the current market return for dividend paying stocks in the S&P 500. The market return portion of the CAPM should represent the most comprehensive estimate of the total return for all investment alternatives, not just a small subset of publicly traded stocks that pay dividends. In practice, of course, finding such an estimate is difficult and is one of the thornier problems in estimating an accurate ROE when using the CAPM. If one limits the market return to stocks, then there are more comprehensive measures of the stock market available, such as the Value Line Investment Survey that I used in my CAPM analysis. Value Line's projected earnings growth used a sample of 2,001 stocks and its book value growth estimate used 1,523 stocks. Value Line's projected annual percentage return included 1,660 stocks. These are much broader samples than Mr. McKenzie's limited sample of dividend paying stocks from the S&P 500.

Q. Did Mr. McKenzie overstate the expected market return component of the CAPM and ECAPM.

A. Yes. My forward-looking market returns show an expected return on the market of 9.45%, far less than the 12.0% expected return result for the limited sample of companies Mr. McKenzie used for his ECAPM and CAPM market return.

Q. On page 49 of his Direct Testimony, Mr. McKenzie explained that he incorporated a size adjustment to his CAPM and ECAPM results. This increased his average CAPM results by about 30 basis points, or 0.30%. Is this size adjustment appropriate?

A. No. The data that Mr. McKenzie relied upon to make this adjustment came from the *2017 Valuation Handbook-U.S. Guide to Cost of Capital* by Duff and Phelps. The groups of companies from which he took this significant upward adjustment to his CAPM and ECAPM results contain many unregulated companies. Further, the decile groups from which these adjustments were taken had average betas ranging from 0.92 to 1.11[14]. These betas are greatly in excess of my utility proxy group average beta of 0.67, indicating that the unregulated companies that Mr. McKenzie used to make his size adjustment are riskier than regulated utilities. There is no evidence to suggest that the size premium used by Mr. McKenzie applies to regulated utility companies, which on average are quite different from the group of companies included in the *2017 SBBI Yearbook* research on size premiums. I recommend that the Commission reject Mr. McKenzie's size premium in the CAPM and ECAPM ROE.

Q. On page 50 of his Direct Testimony, Mr. McKenzie recommended using projected bond yields in the CAPM ROE models. Should the Commission use forecasted bond yields in its ROE analysis in this proceeding?

A. No. Current interest rates and bond yields embody all the relevant market data and expectations of investors, including expectations of changing future interest rates. Current interest rates present tangible market evidence of investor return requirements today, and these are the interest rates and bond yields that should be used in the CAPM, ECAPM, and in the bond yield plus risk premium analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

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14 Duff and Phelps, *2017 SBBI Yearbook*, pg. 7-16.

Utility Risk Premium

Q. Please summarize Mr. McKenzie's utility risk premium approach.

A. Mr. McKenzie developed an historical risk premium using Commission-allowed returns for regulated utility companies from 1974 through 2016. He also used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. On page 52 of his KU Direct Testimony, Mr. McKenzie calculated the risk premium ROE to be 11.0%.

Q. Please respond to the Company witnesses' risk premium analysis.

A. Generally, the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time and with varying risk perceptions of investors. As such, this approach is a "blunt instrument", if you will, for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on an historical risk premium analysis over a certain period of time.

Furthermore, Mr. McKenzie's 11.0% risk premium ROE was inflated by using a forecasted utility bond yield of 6.28%. This bond yield is grossly overstated and exceeds the August 2017 average Mergent utility bond yield of 3.92% by 236 basis points, or 2.36%. Looking at this another way, Mr. McKenzie's forecasted 6.28% utility bond yield is 60% higher than the current utility bond yield. I strongly recommend that the Commission reject this unreasonable forecasted bond yield used by Mr. McKenzie.

Expected Earnings Approach

Q. Beginning on page 64 of his Direct Testimony, Mr. McKenzie presented an expected earnings approach based on expected returns on equity using Value Line's rates of return on common equity for electric utilities over its 2020 - 2022 forecast horizon. Is this a reasonable method for estimating the current required return on equity in this proceeding?

A. No. The Commission should not rely on forecasted utility ROEs for 2020 - 2022 for the same reasons that it should not rely on interest rate forecasts. These forecasted ROEs have little value in today's market, especially considering that current DCF returns are significantly lower than these forecasts, which range from 11.5% to 11.8%. Moreover, recent allowed ROEs for electric utilities averaged about 9.77% in 2016. The expected ROEs presented by Mr. McKenzie are so far removed from recent allowed returns that the Commission should reject them out of hand.

Flotation Costs

Q. Beginning on page 67 of his Direct Testimony, Mr. McKenzie discussed flotation costs. Are flotation costs a legitimate consideration for the Commission's determination of ROE in this proceeding?

A. No. Mr. McKenzie recommended that the Commission consider adding an adjustment of 25 basis points to recognize flotation costs. A flotation cost adjustment attempts to recognize and collect the costs of issuing common stock. Such costs typically include legal, accounting, and printing costs as well as well as broker fees and discounts.

In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. This is an appropriate assumption regarding investor expectations. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Non-Utility Benchmark

Q. Beginning of page 73 of his Direct Testimony, Mr. McKenzie presented the results of a low-risk non-utility DCF model. Is it appropriate to use a group of unregulated companies to estimate a fair return on equity for LGE and KU?

A. No. Mr. McKenzie's use of unregulated non-utility companies to estimate a fair rate of return for LGE and KU is completely inappropriate and should be rejected by the Commission.

Utilities have protected markets, e.g. service territories, and may increase the prices they charge in the face of falling demand or loss of customers. This is contrary to competitive, unregulated companies who often lower their prices when demand for their products decline. Obviously, the non-utility companies face risks that a lower risk electric company like KPC does not face. As a consequence, non-utility companies will have higher required returns from their shareholders. The average DCF results for Mr. McKenzie's non-utility group range from 10.4% - 11.5%. This is substantially greater than the utility proxy group DCF results for both myself and Mr. McKenzie and shows that investors expect higher return for unregulated companies.

Although Mr. McKenzie stated that he did not directly consider the non-utility group DCF results in arriving at this recommendation, he stated that it was a "relevant consideration in evaluating a fair ROE for the Company," (McKenzie Direct Testimony, page 73. Lines 8 - 11). I disagree. The relevant consideration should be the DCF results for the utility proxy group that I employed in my analysis.

Q. Does this complete your Direct Testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Richard A. Baudino

Sworn to and subscribed before me on this
2nd day of October 2017.

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

Jessica K. In

Notary Public

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00179

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 3, 2017

EXHIBIT ___ (RAB-1)

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Director of Consulting, Consultant** - Responsible for consulting assignments in revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
Atmos Cities Steering Committee
Canadian Federation of Independent Businesses
CF&I Steel, L.P.
Cities of Midland, McAllen, and Colorado City
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service

Expert Testimony Appearances
of
Richard A. Baudino
As of October 2017

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co	Revenue requirements, rate design, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of October 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of October 2017

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co	Union Light, Heat & Power Co	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of October 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of October 2017

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Cost of debt.

**Expert Testimony Appearances
of
Richard A. Baudino
As of October 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

**Expert Testimony Appearances
of
Richard A. Baudino
As of October 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co. Pennsylvania Power Co.	Smart Meter Plan cost allocation

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03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
08/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
08/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation
09/16	2016-00162	KY	Kentucky Office of the Attorney General	Columbia Gas of Ky.	Return on equity, cost of short-term debt
09/16	16-0550-W-P	WV	West Va. Energy Users Gp.	West Va. American Water Co.	Infrastructure Replacement Program Surcharge
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring fencing and other conditions for acquisition, service quality and reliability
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP and Sharyland Dist. and Transmission Services, LLC	Return on equity
02/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
03/17	10580	TX	Atmos Cities Steering Committee	Atmos Pipeline Texas	Return on equity, capital structure, weighted cost of capital
03/17	R-3867-2013	Quebec, Canada	Canadian Federation of Independent Businesses	Gaz Metro	Marginal Cost of Service Study

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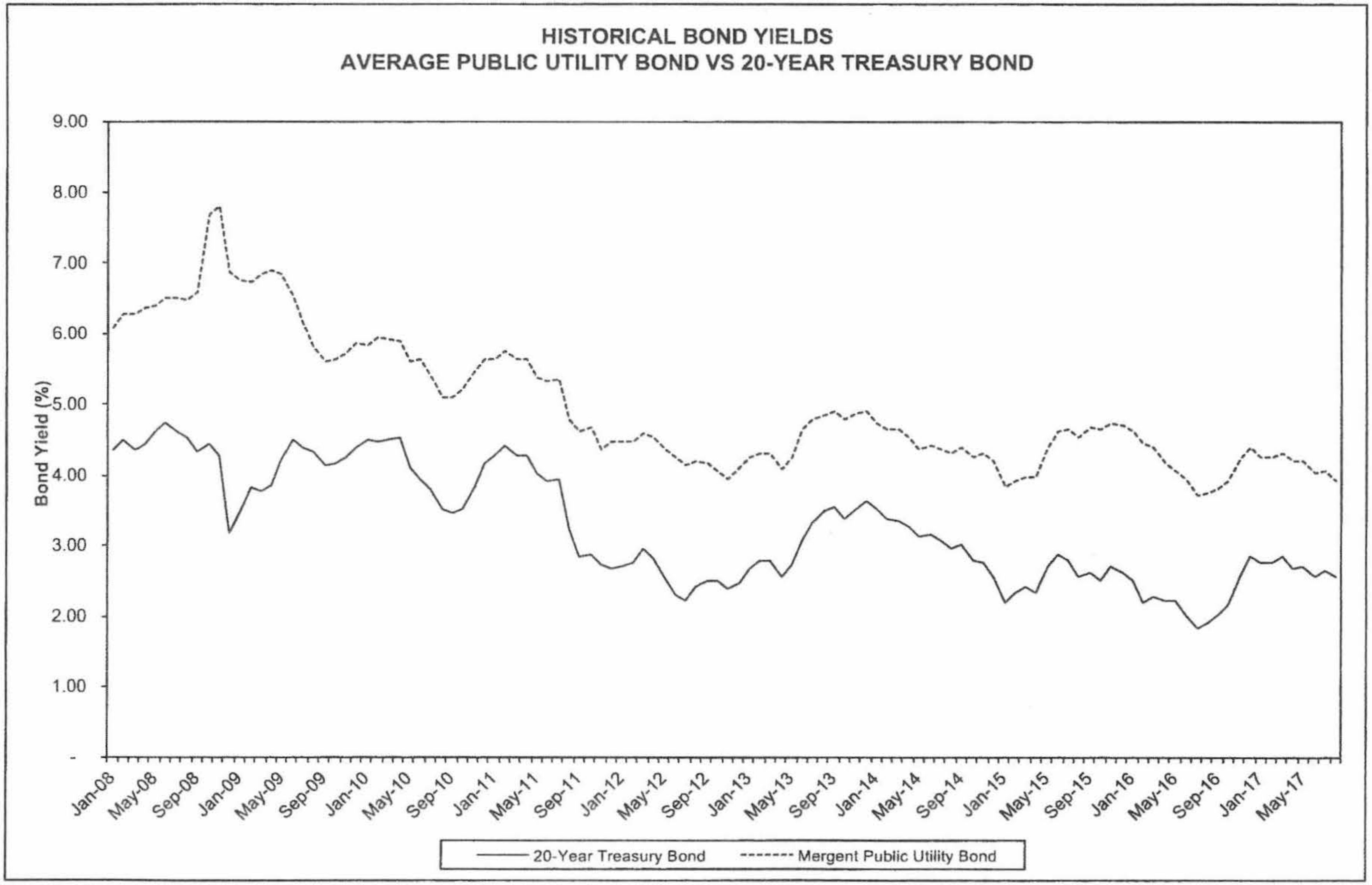
05/17	R-2017-2586783	PA	Philadelphia Industrial and Commercial Gas Users Gp.	Philadelphia Gas Works	Cost and revenue allocation, rate design, Interruptible tariffs
08/17	R-2017-2595853	PA	AK Steel	Pennsylvania American Water Co.	Cost and revenue allocation, rate design
8/17	17-3112-INV	VT	Vt. Dept. of Pubic Service	Green Mountain Power	Return on equity, cost of debt, weighted cost of capital
9/17	4220-UR-123	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co	Return on equity, cost of short-term debt

EXHIBIT ___ (RAB-2)


HISTORICAL BOND YIELDS
AVERAGE PUBLIC UTILITY BOND VS 20-YEAR TREASURY BOND
Bond Yield (%)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Jan-08
May-08
Sep-08
Jan-09
May-09
Sep-09
Jan-10
May-10
Sep-10
Jan-11
May-11
Sep-11
Jan-12
May-12
Sep-12
Jan-13
May-13
Sep-13
Jan-14
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Jan-15
May-15
Sep-15
Jan-16
May-16
Sep-16
Jan-17
May-17
20-Year Treasury Bond
Mergent Public Utility Bond

EXHIBIT ___ (RAB-3)

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17
Alliant Energy	High Price ($)	40.320	40.220	41.710	42.190	41.660	43.230
	Low Price ($)	38.240	39.210	38.950	40.160	39.360	40.500
	Avg. Price ($)	39.280	39.715	40.330	41.175	40.510	41.865
	Dividend ($)	0.315	0.315	0.315	0.315	0.315	0.315
	Mo. Avg. Div.	3.21%	3.17%	3.12%	3.06%	3.11%	3.01%
	6 mos. Avg.	3.11%					
Ameren Corp.	High Price ($)	56.570	55.680	57.090	57.210	56.670	60.790
	Low Price ($)	53.480	54.030	53.720	54.380	53.540	56.160
	Avg. Price ($)	55.025	54.855	55.405	55.795	55.105	58.475
	Dividend ($)	0.440	0.440	0.440	0.440	0.440	0.440
	Mo. Avg. Div.	3.20%	3.21%	3.18%	3.15%	3.19%	3.01%
	6 mos. Avg.	3.16%					
American Electric Power	High Price ($)	68.250	68.460	71.910	72.970	70.810	74.290
	Low Price ($)	64.810	66.500	66.930	69.190	68.110	70.080
	Avg. Price ($)	66.530	67.480	69.420	71.080	69.460	72.185
	Dividend ($)	0.590	0.590	0.590	0.590	0.590	0.590
	Mo. Avg. Div.	3.55%	3.50%	3.40%	3.32%	3.40%	3.27%
	6 mos. Avg.	3.41%					
CMS Energy Corp.	High Price ($)	45.550	45.850	47.700	48.370	47.020	48.910
	Low Price ($)	43.610	44.360	44.750	46.020	45.340	45.980
	Avg. Price ($)	44.580	45.105	46.225	47.195	46.180	47.445
	Dividend ($)	0.333	0.333	0.333	0.333	0.333	0.333
	Mo. Avg. Div.	2.99%	2.95%	2.88%	2.82%	2.88%	2.81%
	6 mos. Avg.	2.89%					
Dominion Energy	High Price ($)	79.360	78.460	81.300	81.650	77.570	80.670
	Low Price ($)	74.590	76.250	76.390	76.170	75.400	76.560
	Avg. Price ($)	76.975	77.355	78.845	78.910	76.485	78.615
	Dividend ($)	0.755	0.755	0.755	0.755	0.755	0.755
	Mo. Avg. Div.	3.92%	3.90%	3.83%	3.83%	3.95%	3.84%
	6 mos. Avg.	3.88%					
DTE Energy Co.	High Price ($)	102.960	105.810	109.890	111.350	108.000	112.580
	Low Price ($)	99.450	100.970	103.280	105.130	104.190	106.160
	Avg. Price ($)	101.205	103.390	106.585	108.240	106.095	109.370
	Dividend ($)	0.825	0.825	0.825	0.825	0.825	0.825
	Mo. Avg. Div.	3.26%	3.19%	3.10%	3.05%	3.11%	3.02%
	6 mos. Avg.	3.12%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17
Duke Energy Corp.	High Price ($)	83.590	83.350	86.010	87.490	85.330	87.950
	Low Price ($)	80.020	81.270	81.850	83.590	82.720	84.650
	Avg. Price ($)	81.805	82.310	83.930	85.540	84.025	86.300
	Dividend ($)	0.855	0.855	0.855	0.855	0.855	0.890
	Mo. Avg. Div.	4.18%	4.16%	4.07%	4.00%	4.07%	4.13%
	6 mos. Avg.	4.10%					
Eversource Energy	High Price ($)	60.360	60.500	62.190	63.340	61.560	63.670
	Low Price ($)	57.280	58.270	58.110	60.520	59.550	60.370
	Avg. Price ($)	58.820	59.385	60.150	61.930	60.555	62.020
	Dividend ($)	0.475	0.475	0.475	0.475	0.475	0.475
	Mo. Avg. Div.	3.23%	3.20%	3.16%	3.07%	3.14%	3.06%
	6 mos. Avg.	3.14%					
NextEra Energy, Inc.	High Price ($)	133.280	134.330	141.830	144.870	146.880	151.280
	Low Price ($)	127.780	127.090	132.780	138.150	138.000	145.380
	Avg. Price ($)	130.530	130.710	137.305	141.510	142.440	148.330
	Dividend ($)	0.983	0.983	0.983	0.983	0.983	0.983
	Mo. Avg. Div.	3.01%	3.01%	2.86%	2.78%	2.76%	2.65%
	6 mos. Avg.	2.85%					
PPL Corp.	High Price ($)	37.950	38.320	40.100	40.200	38.840	39.810
	Low Price ($)	35.820	36.910	37.400	38.440	37.190	38.350
	Avg. Price ($)	36.885	37.615	38.750	39.320	38.015	39.080
	Dividend ($)	0.395	0.395	0.395	0.395	0.395	0.395
	Mo. Avg. Div.	4.28%	4.20%	4.08%	4.02%	4.16%	4.04%
	6 mos. Avg.	4.13%					
Public Svc. Enterprise Gp.	High Price ($)	46.080	45.940	45.270	45.800	45.360	47.470
	Low Price ($)	43.770	43.920	42.470	42.790	41.670	44.730
	Avg. Price ($)	44.925	44.930	43.870	44.295	43.515	46.100
	Dividend ($)	0.430	0.430	0.430	0.430	0.430	0.430
	Mo. Avg. Div.	3.83%	3.83%	3.92%	3.88%	3.95%	3.73%
	6 mos. Avg.	3.86%					
SCANA Corp.	High Price ($)	70.940	67.870	68.440	71.280	67.990	68.350
	Low Price ($)	64.200	64.790	64.480	66.810	60.000	59.340
	Avg. Price ($)	67.570	66.330	66.460	69.045	63.995	63.845
	Dividend ($)	0.613	0.613	0.613	0.613	0.613	0.613
	Mo. Avg. Div.	3.63%	3.70%	3.69%	3.55%	3.83%	3.84%
	6 mos. Avg.	3.71%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17
Sempra Energy	High Price ($)	113.150	113.960	116.960	117.970	114.950	119.660
	Low Price ($)	107.890	107.860	110.030	112.110	110.350	112.850
	Avg. Price ($)	110.520	110.910	113.495	115.040	112.650	116.255
	Dividend ($)	0.823	0.823	0.823	0.823	0.823	0.823
	Mo. Avg. Div.	2.98%	2.97%	2.90%	2.86%	2.92%	2.83%
	6 mos. Avg.	2.91%					
Southern Company	High Price ($)	51.470	50.480	50.930	51.970	48.050	50.080
	Low Price ($)	49.300	49.010	49.150	47.870	46.710	47.690
	Avg. Price ($)	50.385	49.745	50.040	49.920	47.380	48.885
	Dividend ($)	0.560	0.560	0.580	0.580	0.580	0.580
	Mo. Avg. Div.	4.45%	4.50%	4.64%	4.65%	4.90%	4.75%
	6 mos. Avg.	4.65%					
Vectren Corp.	High Price ($)	59.030	60.470	61.870	62.790	60.240	67.170
	Low Price ($)	55.060	58.150	58.030	58.240	57.480	59.450
	Avg. Price ($)	57.045	59.310	59.950	60.515	58.860	63.310
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.420
	Mo. Avg. Div.	2.95%	2.83%	2.80%	2.78%	2.85%	2.65%
	6 mos. Avg.	2.81%					
Monthly Avg. Dividend Yield		3.51%	3.49%	3.44%	3.39%	3.48%	3.38%
6-month Avg. Dividend Yield		3.45%					

Source: Yahoo! Finance

EXHIBIT ___ (RAB-4)

PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) First Call/ IBES
Alliant Energy	4.50%	6.00%	5.00%	5.50%	6.90%
Ameren Corp.	4.50%	6.00%	4.00%	6.50%	6.10%
American Elec Pwr	5.00%	4.00%	4.50%	5.40%	2.87%
CMS Energy Corp.	6.50%	6.50%	5.50%	7.00%	7.52%
Dominion Energy	8.50%	5.50%	1.50%	6.00%	3.46%
DTE Energy Co.	7.00%	6.00%	4.00%	5.90%	4.59%
Duke Energy Corp.	4.50%	4.50%	2.00%	4.00%	2.65%
Eversource Energy	5.50%	6.50%	4.50%	6.00%	5.81%
NextEra Energy, Inc.	9.50%	7.00%	5.00%	7.40%	7.34%
PPL Corp.	3.50%	NMF	4.00%	5.00%	0.04%
Pub Sv Enterprise Grp.	5.00%	1.00%	4.50%	2.40%	0.57%
SCANA Corp.	5.00%	4.00%	4.50%	4.70%	4.75%
Sempra Energy	8.50%	8.00%	5.00%	8.50%	7.80%
Southern Company	3.50%	3.50%	3.00%	4.30%	3.22%
Vectren Corp.	4.50%	6.50%	5.00%	5.50%	5.50%
Averages	5.70%	5.36%	4.13%	5.61%	4.61%
Median Values	5.00%	6.00%	4.50%	5.50%	4.75%

Sources: Value Line Investment Survey, July 28, Aug. 18, and Sept. 15, 2017
Yahoo! Finance for IBES growth rates retrieved September 12, 2017
Zacks growth rates retrieved September 12, 2017

PROXY GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.45%	3.45%	3.45%	3.45%	3.45%
Average Growth Rate	5.70%	5.36%	5.61%	4.61%	5.32%
Expected Div. Yield	3.55%	3.54%	3.54%	3.53%	3.54%
DCF Return on Equity	***9.25%***	***8.90%***	***9.15%***	***8.14%***	***8.86%***
Method 2:					
Dividend Yield	3.45%	3.45%	3.45%	3.45%	3.45%
Median Growth Rate	5.00%	6.00%	5.50%	4.75%	5.31%
Expected Div. Yield	3.53%	3.55%	3.54%	3.53%	3.54%
DCF Return on Equity	***8.53%***	***9.55%***	***9.04%***	***8.28%***	***8.85%***

EXHIBIT ___ (RAB-5)

PROXY GROUP
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.45%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.55%
4	Risk Premium	
5	(Line 1 minus Line 3)	6.90%
6	Comparison Group Beta	0.67
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	4.60%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.15%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.45%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.78%
4	Risk Premium	
5	(Line 1 minus Line 3)	7.67%
6	Comparison Group Beta	0.67
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.12%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	6.90%

PROXY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
March-17	2.83%
April-17	2.67%
May-17	2.70%
June-17	2.54%
July-17	2.65%
August-17	2.55%
6 month average	2.66%

Source: www.federalreserve.gov

5 Year Treasury Bond Data

	Avg. Yield
March-17	2.01%
April-17	1.82%
May-17	1.84%
June-17	1.77%
July-17	1.87%
August-17	1.78%
6 month average	1.85%

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	10.50%
Book Value	7.50%
Average	9.00%
Average Dividend Yield	0.87%
Estimated Market Return	9.91%
Value Line Projected 3-5 Yr. Median Annual Total Return	9.00%
Average of Projected Mkt. Returns	9.45%

Source: Value Line Investment Survey for Windows retreived Sept. 21, 2017

Comparison Group Betas:	Value Line
Alliant Energy	0.70
Ameren Corp.	0.65
American Elec Pwr	0.65
CMS Energy Corp.	0.65
Dominion Energy	0.65
DTE Energy Co.	0.65
Duke Energy Corp.	0.60
Eversource Energy	0.65
NextEra Energy, Inc.	0.65
PPL Corp.	0.70
Pub Sv Enterprise Grp.	0.70
SCANA Corp.	0.65
Sempra Energy	0.80
Southern Company	0.55
Vectren Corp.	0.75
Average	0.67

Source: Value Line Investment Survey

EXHIBIT ___ (RAB-6)

PROXY GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.00%	12.00%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.00%	5.00%	
Historical Market Risk Premium	5.00%	7.00%	5.97%
Comparison Group Beta, Value Line	0.67	0.67	0.67
Beta * Market Premium	3.33%	4.67%	3.98%
Current 20-Year Treasury Bond Yield	2.66%	2.66%	2.66%
CAPM Cost of Equity, Value Line Beta	**5.99%**	**7.32%**	**6.64%**

Source: *2017 SBBI Yearbook, Stocks, Bonds, Bills, and Inflation*, Duff and Phelps; pp. 2-6, 6-17, 10-30

DEK EXHIBIT 2

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**) CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**) CASE NO. 2016-00371**

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 3, 2017

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**) CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	**) CASE NO. 2016-00371**

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BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT OF	)	
ITS ELECTRIC RATES AND FOR	)	**CASE NO. 2016-00370**
CERTIFICATES OF PUBLIC	)	
CONVENIENCE AND NECESSITY	)	

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR AN	)	
ADJUSTMENT OF ITS ELECTRIC AND	)	**CASE NO. 2016-00371**
GAS RATES AND FOR CERTIFICATES OF	)	
PUBLIC CONVENIENCE AND NECESSITY	)	

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit No. ___(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity for regulated electric operations for Louisville Gas and Electric Company and Kentucky Utilities ("LGE", "KU", or "Companies"). I will also respond to the Direct Testimony of Mr. Adrien McKenzie, witness for the Companies.

Q. Please summarize your conclusions and recommendations.

A. Based on current financial market conditions, I recommend that the Kentucky Public Service Commission ("KPSC" or "Commission") adopt a 9.0% return on equity for LGE and KU in this proceeding. My recommendation is based on the results of a Discounted Cash Flow ("DCF") model analysis. My DCF analysis incorporates my standard approach to estimating the investor required return on equity and employs a group of 19 proxy companies and dividend and earnings growth forecasts from the Value Line Investment Survey, First Call/IBES, and Zacks.

I also included two Capital Asset Pricing Model ("CAPM") analyses for additional information. I did not incorporate the results of the CAPM in my recommendation, however the results from the CAPM support my 9.0% ROE recommendation for LGE and KU. In fact, my CAPM results are lower than my DCF results.

In Section IV, I respond to the testimony and ROE recommendation of the Companies' witness Mr. McKenzie. I will demonstrate that his recommended ROE of 10.23% significantly overstates the current investor required return for the Companies. The current financial environment of low interest rates has been deliberately and methodically supported by Federal Reserve policy actions since

2009 and is ongoing, even considering recent increases in the federal funds rate and in interest rates generally. A 10.23% ROE for regulated electric utilities such as LGE and KU simply cannot be supported in the current financial market environment and would contribute to a burdensome rate increase for Kentucky ratepayers. I strongly recommend that the KPSC reject the Companies' requested ROE in this proceeding.

The ROE numbers I mentioned are stated on an after tax basis; however, they must be grossed-up for income taxes in order to calculate the revenue requirement impacts. In fact, a ROE of 10.23% on an after-tax basis, as requested by the Companies, is equivalent to a return of 16.80% for KU and 16.79% for LGE when grossed up for federal and state income taxes, bad debt expense, and Commission assessment. Similarly, my recommended ROE of 9.0% on an after-tax basis is equivalent to a return of 14.78% for KU and 14.77% for LG&E when grossed-up for federal and state income taxes, bad debt expense, and Commission assessment. Each 1.0% return on equity is equivalent to $31.207 million in revenue requirements for KU and $20.788 million in revenue requirements for LGE, per calculations made by my colleague, Mr. Lane Kollen. ***In total, my recommended ROE of 9.0% results in revenue reductions of $38.508 million for KU and $25.570 million for LGE.*** Please refer to Mr. Kollen's Direct Testimony for the detailed calculations.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Generally speaking, interest rates have declined over the last few years, though they have increased since the November 2016 election. Exhibit No. ___(RAB-2) presents a graphic depiction of the trend in interest rates from January 2008 through January 2017. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of January 2017, the average public utility bond yield was 4.24%, representing a decline of 184 basis points, or 1.84 percentage points, from January 2008. Likewise, the 20-year Treasury bond stood at 2.75% in January 2017, a decline of 1.60 percentage points (160 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit No. ___(RAB-2)?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011.[2]

Beginning in September 2011, the Fed initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist," was designed by the Fed to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities.

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1 (http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm).

2 (http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm)

More recently, the Fed began to pare back its purchases of securities. For example, on January 29, 2014 the Fed stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Fed continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October.[3]

Q. Has the Fed recently indicated any important changes to its monetary policy?

A. Yes. In March 2016, the Fed raised its target range for the federal funds rate to 1/4% to 1/2% from 0% to 1/4%. The Fed further increased the target range to 1/2% to 3/4% in a press release dated December 14, 2016. In its press release dated February 1, 2017, the Fed held the federal funds rate steady and stated:

> "Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace, labor market conditions will strengthen somewhat further, and inflation will rise to 2 percent over the medium term. Near-term risks to the economic outlook appear roughly balanced. The Committee continues to closely monitor inflation indicators and global economic and financial developments.
>
> In view of realized and expected labor market conditions and inflation, the Committee decided to maintain the target range for the federal funds rate at 1/2 to 3/4 percent. The stance of monetary policy remains accommodative, thereby supporting some further strengthening in labor market conditions and a return to 2 percent inflation."

Q. Mr. Baudino, why is it important to understand the Fed's actions since 2007?

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[3] (http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm)

A. The Fed's monetary policy actions since 2007 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been quite successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment. As I will demonstrate later in my testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Are current interest rates indicative of investor expectations regarding the future direction of interest rates?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> "A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information."[4]

Despite recent increases in interest rates, including long-term Treasury Bonds and average utility bonds, the U.S. economy continues to operate in a low interest rate environment. It is likely at some point this year that the Federal Reserve will once again raise short-term interest rates. However, the timing and the level of any such move are not known now. It is important to realize that investor expectations of higher interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

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[4] Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.

The current low interest rate environment favors lower risk regulated utilities. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur.

Q. How does the investment community regard the electric utility industry currently?

A. The Value Line Investment Survey issued its report on the Electric Utility (West) Industry dated January 27, 2017. I have taken the following excerpts from that report, which I believe will be helpful in providing a broader perspective on how the current economic environment is affecting the regulated utility industry.

> "The year that just ended was an excellent one for most electric utility equities. In the first half, most stocks performed tremendously as interest rates declined from an already-low level and many investors sought a (relatively) safe haven in an increasingly volatile market. These issues gave back some of their first-half gains in the final six months of 2016, but the industry posted a total return of 17.4%. This topped the total return of the Standard and Poor's 500, which was 12.0%.
>
> * * *
>
> In early 2017, most electric utility stocks have not moved significantly. Thus, they retain their high valuation. In 2016, most traded at a price-earnings ratio in the high teens—about the same as the overall market—and the dividend yields of most issues were below 4%. These measures indicate a high valuation, by historical standards. The industry's current average dividend yield is 3.5%. Investors should note, too, that the recent quotations of some electric utility issues are near the upper end or even above their 2019-2021 Target Price Range."

Value Line's remarks with respect to the electric utility industry indicate that despite the recent increase in interest rates, utility stocks continue to be highly valued investments for their stability in today's volatile marketplace for stocks. The safety and relatively high dividend yields for regulated utilities are attractive to investors, although Value Line recommended caution due to the group's currently high price valuation.

Q. What are the current credit ratings and bond ratings for LGE and KU?

A. Standard and Poor's ("S&P") current credit rating for the Companies is A- and their first mortgage bond rating is A. Moody's current long-term issuer rating for the Companies is A3, with a rating of A1 for their first mortgage bonds.

Q. Has LGE's and KU's parent company, PPL Corporation, made recent statements regarding the operations and risks of its Kentucky electric utility companies?

A. Yes. In a recent presentation[5], PPL Corp. noted the following about its operations (page 13):

- Growing, pure-play regulated business operating in premium jurisdictions
- 5-6% projected earnings growth from 2017 – 2020, with above-average dividend yield
- Strong dividend growth potential
- Targeting 8 – 10% annual returns
- Investing in the future and improving efficiency
- Confident in our ability to deliver on commitments to shareowners and customers

In the same presentation, PPL stated the following about its Kentucky operations (pg. 28):

- Constructive jurisdiction provides a timely return on planned Cap Ex
- Environmental Cost Recovery (ECR) with "virtually no regulatory lag"

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[5] *PPL Corporation Poised for Growth. Investing in our future.* Evercore ISI Utility CEO Retreat, Palm Beach, FL, January 12 – 13, 2017.

- Return mechanisms include CWIP for ECR and Gas Line Tracker
- Pass through clauses include Purchased Power, Fuel and Gas Supply Adjustment and Energy Efficiency/Demand Side Management recovery
- Cap Ex plans exclude spending that may be required under the Clean Power Plan

Please refer to Exhibit No. ___(RAB-3) for selected pages from this presentation.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for the electric operations of LGE and KU.

A. I employed a Discounted Cash Flow ("DCF") analysis using a group of 19 regulated electric and gas utilities. My DCF analysis is my standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, First Call/IBES, and Zacks. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I did not rely on the CAPM for my recommended ROE for LGE and KU, the results from the CAPM tend to support the reasonableness of my recommendation.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. The estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of an investment. The result of their analyses is a bond and/or credit rating that reflect these risks.

<u>Discounted Cash Flow ("DCF") Model</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: V = *asset value*
R = *yearly cash flows*
r = *discount rate*

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Under the formula, it is apparent that "k" must reflect the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for LGE and KU?

A. My first step was to construct a proxy group of companies with a risk profile that is reasonably similar to the Companies. Since LGE and KU are subsidiaries of PPL Corp., they do not have publicly traded stock. Thus, one cannot estimate a DCF cost of equity on the Companies directly. It is necessary to use a group of companies that are similarly situated and have reasonably similar risk profiles to LGE and KU.

Q. Please describe your approach for selecting a group of electric companies.

A. For purposes of this case, I chose to rely on the proxy group that Companies witness McKenzie used for his analysis. Although the selection criteria he used are somewhat different from those I have used in past cases, the constituent members of his proxy group comprise a reasonable basis for purposes of estimating the ROE for the Companies, with three exceptions. I eliminated the following companies from Mr. McKenzie's proxy group as follows:

- Avangrid Inc.: NMF (no meaningful figure) for Value Line earnings and dividend growth forecasts. No Value Line beta, Safety Rank, and Financial Strength ratings. Since Value Line is one of my primary sources for growth rate forecasts, there is not enough Value Line information to include this company in the proxy group.

- Entergy Corp.: Negative earnings growth rates from First Call/IBES and Zacks and 0.5% earnings growth rate from Value Line. These earnings growth forecasts are not indicative of long-term growth and negative growth rates cannot reasonably be used in the DCF model to properly estimate the investor required rate of return.
- PPL Corp.: NMF for Value Line earnings growth forecast.

The resulting comparison group of 19 electric and gas companies that I used in my analysis is shown in the Table 1 below.

TABLE 1
Credit Ratings
Proxy Group and LGE/KU

	S&P	Moody's
Alliant Energy Corporation	A-	Baa1
Ameren Corp.	BBB+	Baa1
Avista Corporation	BBB	Baa1
Black Hills Corp.	BBB	Baa2
CenterPoint Energy, Inc.	A-	Baa1
CMS Energy Corp.	BBB+	Baa2
Consolidated Edison	A-	A3
DTE Energy Co.	BBB+	Baa1
Eversource Energy	A	Baa1
Exelon Corp.	BBB	Baa2
NorthWestern Corp.	BBB	A3
PG&E Corp.	BBB+	Baa1
Public Service Enterprise Group	BBB+	Baa2
SCANA Corp.	BBB+	Baa3
Sempra Energy	BBB+	Baa1
Southern Company	A-	Baa2
Vectren Corp.	A-	A2
WEC Energy	A-	A3
Xcel Energy Inc.	A-	A3
LG&E/KU	A-	A3

Q. How do LGE/KU's credit ratings compare to those of the proxy group?

A. LGE and KU have slightly better credit ratings than the proxy group. With respect to Moody's ratings, 4 of the 19 companies have A ratings similar to those of LGE and KU. The remaining 15 companies have Moody's ratings that are lower than the Companies. With respect to the S&P ratings, 11 of the 19 companies in the proxy group have ratings lower than LGE and KU. This suggests that LGE and KU are likely to have a slightly lower required return on equity compared to the proxy group.

Q. What was your first step in determining the DCF return on equity for the proxy group?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from August 2106 through January 2017. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the comparison group is 3.43%. These calculations are shown in Exhibit No. ___(RAB-4).

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the electric comparison group?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and First Call/IBES. This is the method I typically use for estimating growth for my DCF calculations.

Q. Please briefly describe Value Line, Zacks, and First Call/IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, First Call/IBES also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. Please explain how you used analysts' dividend and earnings growth forecasts in your constant growth DCF analysis.

Q. Page 1, Columns (1) through (5) of Exhibit No. ____(RAB-5) shows the forecasted dividend, earnings, and retention growth rates from Value Line and the earnings growth forecasts from First Call/IBES and Zacks. In my analysis I used four of these growth rates: dividend and earnings growth from Value Line and earnings growth from Zacks and First Call/IBES. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows. Value Line is the only sources of which I am aware that forecasts dividend growth and my approach gives this forecast equal weight with the three earnings growth forecasts.

Q. How did you proceed to determine the DCF return of equity for the comparison group?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

Page 2 of Exhibit No. ___(RAB-5) presents my standard method of calculating dividend yields, growth rates, and return on equity for the comparison group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 3.43% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. In evaluating investor expected growth rates, I use both the average and the median values for the group under consideration. The calculations of the resulting DCF returns on equity for both methods are presented on page 2 of Exhibit No. ____(RAB-5).

Q. What are the results of your constant growth DCF model?

A. The DCF results for the constant growth DCF approach are shown on page 2 of Exhibit No. ____(RAB-5). For the average growth rates in Method 1, the results range from 8.59% to 9.27%, with the average of these results being 8.83%. Using the median growth rates in Method 2, the results range from 8.51% to 9.53%, with the average of these results being 9.06%.

<u>**Capital Asset Pricing Model**</u>

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[6] There is evidence that beta is not the primary factor in determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

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[6] For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for February 14, 2017. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value

Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit No.____(RAB-6). I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 9.50% to 9.85%. The average of these market returns is 9.67%.

Q. Why did you use median growth rate estimates rather than the average growth rate estimates for the Value Line companies?

A. Using median growth rates is likely a more accurate method of estimating the central tendency of Value Line's large data set compared to the average growth rates. Average earnings and book value growth rates may be unduly influenced by very high or very low 3 - 5-year growth rates that are unsustainable in the long run. For example, Value Line's Statistical Summary shows both the highest and lowest value for earnings and book value growth forecasts. For earnings growth, Value Line showed the highest earnings growth forecast to be 140.4% and the lowest growth rate to be -30.5%. The highest book value growth rate was 72.5% and the lowest was -33%. None of these levels of growth is compatible with long-run growth prospects for the market as a whole. The median growth rate is not influenced by such extremes because it represents the middle value of a very wide range of earnings growth rates.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Duff and Phelps publishes a study of historical returns on the stock market in its 2016 SBBI Yearbook. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit No. ___(RAB-7) presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. Exhibit No. ___(RAB-7) shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2015. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.0% - 7.0%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Duff and Phelps reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[7] Duff and Phelps noted that this growth in the P/E ratio for stocks was subtracted out of the historical risk premium because "it is not believed that P/E will continue to increase in the future." The adjusted historical arithmetic market risk premium is 6.03%,

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[7] *2016 SBBI Yearbook*, Duff and Phelps, pp. 10-28 through 10-30.

which I have also included in Exhibit No. ___(RAB-7). This risk premium estimate falls near the middle of the market risk premium range.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from August 2016 through January 2017. This was the latest available data from the Federal Reserve's Selected Interest Rates (Daily) H.15 web site during the preparation of my Direct Testimony. The 20-year Treasury bond is often used by rate of return analysts as the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the electric company comparison group from most recent Value Line reports. The average of the Value Line betas for the comparison group is 0.69.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 7.25% - 7.51%. Using historical risk premiums, the CAPM results are 5.80% - 7.18%.

Conclusions and Recommendations

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 2 below summarizes my return on equity results using the DCF and CAPM for my comparison group of companies.

TABLE 2
SUMMARY OF ROE ESTIMATES

Baudino DCF Methodology:	
Average Growth Rates	
- High	9.27%
- Low	8.59%
- Average	8.83%
Median Growth Rates:	
- High	9.53%
- Low	8.51%
- Average	9.06%
CAPM:	
- 5-Year Treasury Bond	7.25%
- 20-Year Treasury Bond	7.51%
- Historical Returns	5.80% - 7.18%

Q. What is your recommended return on equity for LGE and KU?

A. I recommend that the KPSC adopt a 9.0% return on equity for the Companies. My recommendation is consistent with the average DCF results from my constant growth DCF model. Based on current market evidence, a 9.0% return on equity is fair and reasonable for A-rated, lower risk electric utility companies like LGE and KU. In fact, as I demonstrated in Table 1, LGE and KU have credit ratings that slightly exceed those of the proxy group as a whole. Thus, a reasonable case could be made that the Companies' ROE should be set slightly lower than the overall results for the proxy group. However, 9.0% is certainly a reasonable allowed ROE for the Companies in today's low interest rate environment.

Q. What is your recommended weighted cost of capital?

A. Mr. Kollen presents KIUC's recommended weighted cost of capital in his testimony. I have accepted the Companies' proposed capital structures in this proceeding.

IV. RESPONSE TO LGE AND KU TESTIMONY

Q. Have you reviewed the Direct Testimony of Mr. McKenzie?

A. Yes.

Q. Please summarize your conclusions with respect to his testimony and return on equity recommendation.

A. Mr. McKenzie's recommended 10.23% return on equity is overstated and inconsistent with the current low interest rate environment. As I shall demonstrate later in this section of my testimony, Mr. McKenzie made judgments that served to inflate his ROE results, particularly for the DCF and CAPM. As such, his testimony and analyses provide very little useful guidance for the Commission with respect to the investor required ROE for LGE and KU.

The rest of Section IV contains my detailed responses to Mr. McKenzie's analyses and recommendations. I will use references from Mr. McKenzie's KU Direct Testimony for purposes of clarity and brevity. Mr. McKenzie used the same approaches to estimating the ROE for both LGE and KU, so my responses apply to Mr. McKenzie's LGE testimony as well.

Outlook for Capital Costs

Q. On page 13, Mr. McKenzie presented his view of current capital market conditions, noting that these conditions "continue to be deeply affected by the Federal Reserve's unprecedented monetary policy actions, which were designed to push interest rates to historically and artificially low levels ..." Please respond to Mr. McKenzie's position with respect to current capital market conditions.

A. I agree that the economy is in a low interest rate environment that is being supported quite deliberately by Federal Reserve policy. Nonetheless, current financial market conditions do indeed provide a representative basis for estimating the cost of equity capital for LGE and KU, and for utilities generally. The fact that interest rates are relatively low by historical standards does not preclude the rate of return analyst from making a reasonable assessment of investor required ROEs using current stock prices and interest rates.

Q. On page 15 of Mr. McKenzie's KU Direct Testimony, Figure 3 shows higher forecasted interest rates through 2021 from several different forecasting sources. Should the Commission increase its allowed return on equity based on these higher interest rate forecasts?

A. No. As I stated in Section II my Direct Testimony, current interest rates embody investor expectations based on their assessments of all available market information. This includes interest rate forecasts cited by Mr. McKenzie as well as statements from the Federal Reserve. The KPSC should not invest in the interest rate forecasts cited by Mr. McKenzie in determining a fair rate of return for LGE and KU.

There is evidence that economists have systematically overestimated interest rates in recent years. Jared Bernstein wrote the following in a recent article in the New York Times[8]:

> In the early 1980s, forecasters did a good job of predicting the path of bond rates, though their job was a bit easier than usual because rates were so highly elevated that it was a pretty sure bet they'd be headed back down. ("Regression to the mean," for all you statistics fans.)

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[8] "We Keep Flunking Forecasts on Interest Rates, Distorting the Budget Outlook", Jared Bernstein, *New York Times*, Feb. 23, 2015.

But since the mid-1990s, government forecasters have consistently overestimated this critical variable.

This "consistently" point is essential. Most economic forecasts are off one way or the other — too high or too low, but they tend to be pretty much balanced in either direction. But on the 10-year bond rate, the errors are systemic.

Forecasters are regularly overestimating and thus regularly overstating, all else being equal, future interest payments on the debt.

Another article by Akin Oyedele entitled "Interest Rate Forecasters Are Shockingly Wrong Almost All Of The Time"[9] showed that from June 2010 through June 2015 interest rate forecasts were wrong most of the time. Mr. Oyedele noted that 2014 "was particularly bad, when strategists became too optimistic that the Federal Reserve would hike rates."

These articles highlight the consistent upward bias that is likely embodied in the forecasts presented by Mr. McKenzie.

Q. Is there support for the position that today's currently low interest rates is part of a long-term trend?

A. Yes. In a weekly blog at the Brookings Institution, former Federal Reserve Chairman Ben Bernanke wrote the following:[10]

Interest rates around the world, both short-term and long-term, are exceptionally low these days. The U.S. government can borrow for ten years at a rate of about 1.9 percent, and for thirty years at about 2.5 percent. Rates in other industrial countries are even lower: For example, the yield on ten-year government bonds is now around 0.2 percent in Germany, 0.3 percent in Japan, and 1.6 percent in the United

9 Akin Oyedele, "Interest Rate Forecasters Are Shockingly Wrong Almost All of the Time", *Business Insider*, July 18, 2015.

10 Ben S. Bernanke, "Why Are Interest Rates So Low", Weekly Blog, Brookings, March 30, 2015. https://www.brookings.edu/blog/ben-bernanke/2015/03/30/why-are-interest-rates-so-low/

Kingdom. In Switzerland, the ten-year yield is currently slightly negative, meaning that lenders must pay the Swiss government to hold their money! The interest rates paid by businesses and households are relatively higher, primarily because of credit risk, but are still very low on an historical basis.

Low interest rates are not a short-term aberration, but part of a long-term trend. As the figure below shows, ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak above 15 percent in 1981, and have been declining ever since. That pattern is partly explained by the rise and fall of inflation, also shown in the figure. All else equal, investors demand higher yields when inflation is high to compensate them for the declining purchasing power of the dollars with which they expect to be repaid. But yields on inflation-protected bonds are also very low today; the real or inflation-adjusted return on lending to the U.S. government for five years is currently about *minus* 0.1 percent.

Why are interest rates so low? Will they remain low? What are the implications for the economy of low interest rates?

If you asked the person in the street, "Why are interest rates so low?", he or she would likely answer that the Fed is keeping them low. That's true only in a very narrow sense. The Fed does, of course, set the benchmark nominal short-term interest rate. The Fed's policies are also the primary determinant of inflation and inflation expectations over the longer term, and inflation trends affect interest rates, as the figure above shows. But what matters most for the economy is the real, or inflation-adjusted, interest rate (the market, or nominal, interest rate minus the inflation rate). The real interest rate is most relevant for capital investment decisions, for example. The Fed's ability to affect real rates of return, especially longer-term real rates, is transitory and limited. Except in the short run, real interest rates are determined by a wide range of economic factors, including prospects for economic growth—not by the Fed.

Q. Did Mr. McKenzie present forecasted interest rates in the testimony he co-sponsored in KU and LGE Case Nos. 2014-00371 and 2014-00372?

A. Yes. On page 13 of the Direct Testimony he co-sponsored with Dr. Avera in those cases, Mr. McKenzie presented Figure 2 on page 13 of his KU testimony that showed forecasted interest rates with a graph like the one included in his KU Direct Testimony in this case on page 15. I reviewed the work papers submitted by Dr. Avera and Mr. McKenzie in those proceedings and found the Blue Chip financial forecast dated June 1, 2014, which formed part of the basis of Figure 2 in their testimony in those cases, which was filed on November 26, 2014.

In the Blue Chip forecasts dated June 1, 2014 presented by Mr. McKenzie in the last KU and LGE rate cases, the consensus forecast for the 30-year Treasury Bond was 4.7% for 2016 and 5.1% for 2017.[11] The actual December 2016 30-Year Treasury Bond yield was 3.11% and for January 2017 was 3.02%. The June 2014 Blu Chip consensus forecasts presented by Mr. McKenzie overshot the recent actual 30-Year Treasury Bond rates by 159 – 208 basis points. Stated another way, the Blue Chip consensus forecasts missed the recent actual 30-Year Treasury Bond rates by 1.59% to 2.08%.

The magnitude of the overstatement by the Blue Chip consensus forecasts are strong support for my recommendation that the Commission disregard interest rate forecasts when considering its allowed ROE for LGE and KU in this proceeding.

<u>DCF Model</u>

Q. Briefly summarize Mr. McKenzie's approach to the DCF model.

A. Mr. McKenzie constructed a group of electric and gas utilities for purposes of estimating the DCF ROE for LEG and KU. He used several sources of growth rate forecasts, which included IBES, Zacks, and Value Line as well as an estimate of sustainable growth. I ultimately adopted Mr. McKenzie's proxy group with the three exceptions I noted earlier.

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11 KU response to AG 1-187, Docket No. 2014-00371, WP-25.

In his Exhibit No. 5, Mr. McKenzie adjusted his DCF ROE results by excluding certain company ROE results that, in his view, were either too low or too high. On the low end, these results ranged from 0.1% to 6.9%. On the high end, Mr. McKenzie excluded one value of 15.3%, but saw fit to include ROE results of 12.4% and 13.2%. After making these exclusions, his resulting DCF range was 8.4% to 9.5% using an average of the remaining results. The midpoints ranged from 8.9% to 10.4%.

Q. Please comment on Mr. McKenzie's approach to formulating his DCF recommendation to the Commission.

A. Mr. McKenzie conducted a biased approach in formulating his DCF recommendations. He applied a test for excluding ROE results that, in his view, were too low but failed to exclude other results that were too high. For example, the average Commission-allowed ROE for 2015 that was reported by Mr. McKenzie in his Exhibit No. 9 was 9.85%. Furthermore, the *EEI Q4 Financial Update* showed that the average Commission-allowed ROE in the fourth quarter of 2016 was 9.57%. With recent Commission allowed ROEs of around 9.6%, Mr. McKenzie included ROEs in his Exhibit No. 5 ranging from 12.4% to 13.2%. My review of Commission allowed returns contained in Mr. McKenzie's Exhibit No. 9 reveals that 2002 was the last year that allowed returns on equity were as high as 11% and that the last Commission allowed return near 13% was in 1989.

It is abundantly clear that Mr. McKenzie's one-sided approach to excluding ROE results from his DCF analysis had the effect of inflating his DCF ROE recommendation.

Q. Have you conducted an alternative analysis that includes all the DCF results from Mr. McKenzie's Exhibit No. 5?

A. Yes. Table 3 below presents the average and median ROEs utilizing all the DCF results from Mr. McKenzie's Exhibit No. 5, page 3 of 3.

Table 3
McKenzie ROE Results

Company	V Line	IBES	Zacks	br+sv Growth
Alliant Energy	9.1%	9.7%	9.2%	8.1%
Ameren Corp.	9.6%	8.8%	9.7%	7.2%
Avangrid, Inc.	NA	13.2%	13.2%	NA
Avista Corp.	8.4%	8.4%	8.7%	7.1%
Black Hills Corp.	10.5%	9.7%	8.9%	10.7%
CenterPoint Energy	6.6%	9.9%	10.1%	7.4%
CMS Energy Corp.	9.1%	10.4%	9.7%	8.7%
Consolidated Edison	6.2%	5.8%	6.5%	6.9%
DTE Energy Co.	9.3%	8.9%	9.1%	7.8%
Entergy Corp.	6.6%	2.0%	0.1%	8.2%
Eversource Energy	9.5%	8.9%	9.5%	7.5%
Exelon Corp.	10.9%	6.5%	7.5%	9.7%
NorthWestern Corp.	10.1%	8.6%	8.6%	8.2%
PG&E Corp.	15.3%	9.0%	7.6%	8.4%
PPL Corp.	NA	7.1%	8.2%	9.2%
Pub Sv Enterprise Grp.	7.0%	5.5%	8.5%	8.8%
SCANA Corp.	7.9%	9.4%	8.8%	8.0%
Sempra Energy	11.0%	10.7%	10.0%	8.8%
Southern Company	8.5%	7.6%	8.4%	8.6%
Vectren Corp.	12.4%	8.4%	8.7%	9.7%
WEC Energy Group	9.5%	10.2%	9.7%	6.9%
Xcel Energy Inc.	9.0%	8.8%	8.9%	7.7%
Average	9.3%	8.5%	8.6%	8.3%
Median	9.2%	8.8%	8.8%	8.2%

Rather than simply excluding low-end results, I recommend that the median be used as an alternative measure of central tendency. As I testified in Section III, the median is not affected by extremely high or low results, but instead represents the middle value of the data set. If there are concerns about results that are either too high or too low, the median may be used as an additional reference for the investor required ROE.

Table 3 shows that when all results are considered, the average and median results from Mr. McKenzie's Exhibit No. 5 are quite close. In my opinion, this suggests that low-end results are offset by high-end results. If all DCF results are considered, Mr. McKenzie's average and median ROEs are close to my recommended ROE of 9.0%.

<u>**CAPM and ECAPM**</u>

Q. Beginning on page 46 of his KU Direct Testimony, Mr. McKenzie described the Empirical CAPM ("ECAPM") analysis. Is this a reasonable method to use to estimate the investor required ROE for LGE and KU?

A. No. The ECAPM is supposed to account for the possibility that the CAPM understates the return on equity for companies with betas less than 1.0. I believe it is highly unlikely that investors use the ECAPM formulation shown in Mr. McKenzie's Exhibit No. 8 to "correct" CAPM returns for electric utilities. To the extent investors use the CAPM to estimate their required returns, I believe it is much more likely that they use the traditional CAPM equation that I used in Section III of my testimony. Mr. McKenzie presented no evidence that investors use the adjustment factors contained in his CAPM and ECAPM analyses. Moreover, the use of an adjustment factor to "correct" the CAPM results for companies with betas less than 1.0 suggests that published betas by such sources as Value Line are incorrect and that investors should not rely on them. In fact, Mr. McKenzie testified on page 44, lines 14 through 16 of his KU Direct Testimony that Value Line is "the most widely referenced source for beta is regulatory proceedings."

Q. Please continue your evaluation of the results of Mr. McKenzie's CAPM and ECAPM analysis.

A. I disagree with Mr. McKenzie's general formulation of the CAPM and ECAPM and in particular with his estimate of the expected market return. He estimated the market return portion of the CAPM and ECAPM by estimating the current market return for dividend paying stocks in the S&P 500. The market return portion of the CAPM should represent the most comprehensive estimate of the total return for all investment alternatives, not just a small subset of publicly traded stocks that pay dividends. In practice, of course, finding such an estimate is difficult and is one of the thornier problems in estimating an accurate ROE when using the CAPM. If one limits the market return to stocks, then there are more comprehensive measures of the stock market available, such as the Value Line Investment Survey that I used in my CAPM analysis. Value Line's projected earnings growth used a sample of 2,067 stocks and its book value growth estimate used 1,518 stocks. Value Line's projected annual percentage return included 1,673 stocks. These are much broader samples than Mr. McKenzie's limited sample of dividend paying stocks from the S&P 500.

Q. Did Mr. McKenzie overstate the expected market return component of the CAPM and ECAPM.

A. Yes, most definitely. My forward-looking market returns show an expected return on the market of 9.85%, far less than the 11.3% expected return result for the limited sample of companies Mr. McKenzie used for his ECAPM and CAPM market return.

Q. On pages 44 through 45 of his KU Direct Testimony, Mr. McKenzie explained that he incorporated a size adjustment to his CAPM and ECAPM results. This increased his average CAPM results by about 60 basis points, or 0.60%. Is this size adjustment appropriate?

A. No. The data that Mr. McKenzie relied upon to make this adjustment came from the *2016 Valuation Handbook – Guide to Cost of Capital*. The groups of companies from which he took this significant upward adjustment to his CAPM and ECAPM results contain many unregulated companies. Further, the decile groups from which these adjustments were taken had average betas ranging from 0.92 to 1.17[12]. These betas are greatly in excess of my utility proxy group average beta of 0.69, suggesting that the unregulated companies that Mr. McKenzie used to make his size adjustment are riskier than regulated utilities. There is no evidence to suggest that the size premium used by Mr. McKenzie applies to regulated utility companies, which on average are quite different from the group of companies included in the *2016 Valuation Handbook* research on size premiums. I recommend that the Commission reject Mr. McKenzie's size premium in the CAPM ROE.

Q. On page 46 of his Direct Testimony, Mr. McKenzie recommended using projected bond yields in the CAPM ROE models. Should the Commission consider using forecasted bond yields in its ROE analysis in this proceeding?

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[12] WP-33 submitted by LGE in response to AG DR1, Q-282.

A. Definitely not. Current interest rates and bond yields embody all the relevant market data and expectations of investors, including expectations of changing future interest rates. Current interest rates present tangible market evidence of investor return requirements today, and these are the interest rates and bond yields that should be used in the CAPM, ECAPM, and in the bond yield plus risk premium analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

<u>Utility Risk Premium</u>

Q. Please summarize Mr. McKenzie's utility risk premium approach.

A. Mr. McKenzie developed an historical risk premium using Commission-allowed returns for regulated utility companies from 1974 through 2015. He also used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. On page 52 of his KU Direct Testimony, Mr. McKenzie calculated the risk premium ROE to be 9.99%.

Q. Please respond to the Company witnesses' risk premium analysis.

A. Generally, the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time and with varying risk perceptions of investors. As such, this approach is a "blunt instrument", if you will, for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on an historical risk premium analysis over a certain period of time.

Finally, for the reasons I discussed earlier, the use of forecasted bond yields is inappropriate and should be rejected.

Expected Earnings Approach

Q. Beginning on page 52 of his KU Direct Testimony, Mr. McKenzie presented an expected earnings approach based on expected returns on equity using Value Line's rates of return on common equity for electric utilities over its 2019 - 2021 forecast horizon. Is this a reasonable method for estimating the current required return on equity in this proceeding?

A. No. The Commission should not rely on forecasted utility ROEs for 2019 - 2021 for the same reasons that it should not rely on interest rate forecasts. These forecasted ROEs have little value in today's market, especially considering that current DCF returns are significantly lower than these forecasts, which range from 11.3% to 12.2%. Moreover, recent allowed ROEs for electric utilities averaged about 9.6% in the fourth quarter of 2016. The expected ROEs presented by Mr. McKenzie are so far removed from recent allowed returns that the Commission should reject them out of hand.

Flotation Costs

Q. Beginning on page 55 of his Direct Testimony, Mr. McKenzie discussed flotation costs. Are flotation costs a legitimate consideration for the Commission's determination of ROE in this proceeding?

A. No. Mr. McKenzie recommended that the Commission consider adding an adjustment of 13 basis points to recognize flotation costs. A flotation cost adjustment attempts to recognize and collect the costs of issuing common stock. Such costs typically include legal, accounting, and printing costs as well as well as broker fees and discounts.

In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Non-Utility Benchmark

Q. Beginning of page 57 of his KU Direct Testimony, Mr. McKenzie presented the results of a low-risk non-utility DCF model. Is it appropriate to use a group of unregulated companies to estimate a fair return on equity for LGE and KU?

A. No. Mr. McKenzie's use of unregulated non-utility companies to estimate a fair rate of return for LGE and KU is completely inappropriate and should be rejected by the Commission.

Utilities have protected markets, e.g. service territories, and may increase the prices they charge in the face of falling demand or loss of customers. This is contrary to competitive, unregulated companies who often lower their prices when demand for their products decline. Obviously, the non-utility companies have higher overall risk structures than a lower risk electric company like LGE or KU and will have higher required returns from their shareholders. The average DCF results for Mr.

McKenzie's non-utility group range from 10.0% - 11.2%. This is substantially greater than the utility proxy group DCF results for both myself and Mr. McKenzie.

Although Mr. McKenzie stated that he did not directly consider the non-utility group DCF results in arriving at this recommendation, he stated that it was a "relevant consideration in evaluating a fair ROE for the Company," (KU Direct Testimony, page 59). I disagree. The relevant consideration should be the DCF results for the utility proxy group that I employed in my analysis.

Q. Does this complete your Direct Testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Richard A. Baudino

Sworn to and subscribed before me on this 3rd day of March 2017.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 6, 2015

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Cities of Midland, McAllen, and Colorado City
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service

**Expert Testimony Appearances
of
Richard A. Baudino
As of February 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of February 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2017

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of February 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2017

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
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Richard A. Baudino
As of February 2017

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

Expert Testimony Appearances
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Richard A. Baudino
As of February 2017

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2017

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2017

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

**Expert Testimony Appearances
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Richard A. Baudino
As of February 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

**Expert Testimony Appearances
of
Richard A. Baudino
As of February 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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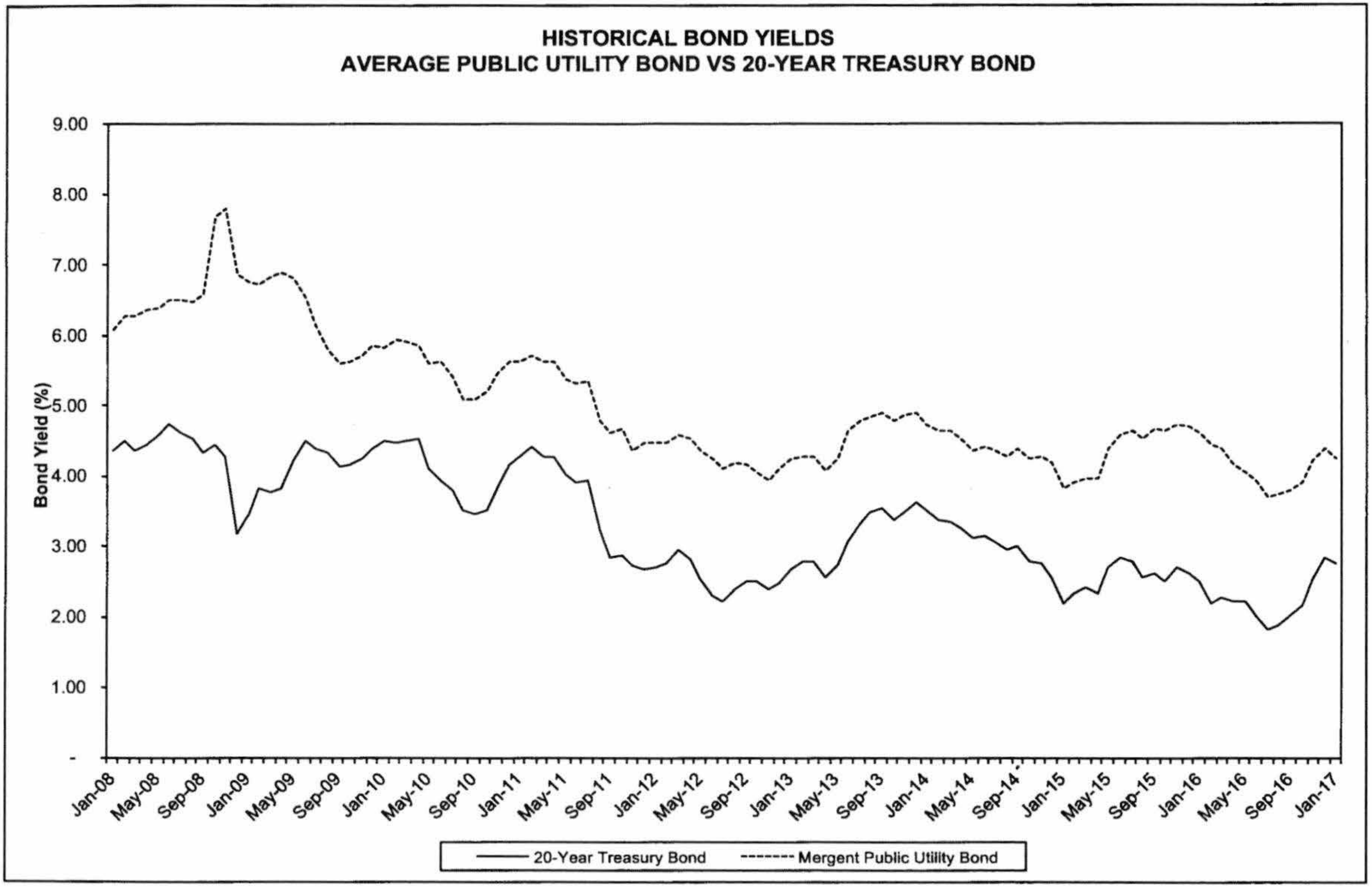
Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
08/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
08/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation
09/16	2016-00162	KY	Kentucky Office of the Attorney General	Columbia Gas of Ky.	Return on equity, cost of short-term debt
09/16	16-0550-W-P	WV	West Va. Energy Users Gp.	West Va. American Water Co.	Infrastructure Replacement Program Surcharge
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring fencing and other conditions for acquisition, service quality and reliability
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP and Sharyland Dist. and Transmission Services, LLC	Return on equity
02/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital


HISTORICAL BOND YIELDS
AVERAGE PUBLIC UTILITY BOND VS 20-YEAR TREASURY BOND
Bond Yield (%)
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Jan-08
May-08
Sep-08
Jan-09
May-09
Sep-09
Jan-10
May-10
Sep-10
Jan-11
May-11
Sep-11
Jan-12
May-12
Sep-12
Jan-13
May-13
Sep-13
Jan-14
May-14
Sep-14
Jan-15
May-15
Sep-15
Jan-16
May-16
Sep-16
Jan-17
20-Year Treasury Bond
Mergent Public Utility Bond

PPL CORPORATION

Poised for growth.
Investing in our future.

Evercore ISI Utility CEO Retreat, Palm Beach, FL • January 12 - 13, 2017

Exhibit No.__(RAB-3)
Page 1 of 3

Summary

- Growing, pure-play regulated business operating in premium jurisdictions
- 5-6% projected earnings growth from 2017 - 2020, with above-average dividend yield
- Strong dividend growth potential
- Targeting 8 - 10% total annual returns[1]
- Investing in the future and improving efficiency
- Confident in our ability to deliver on commitments to shareowners and customers

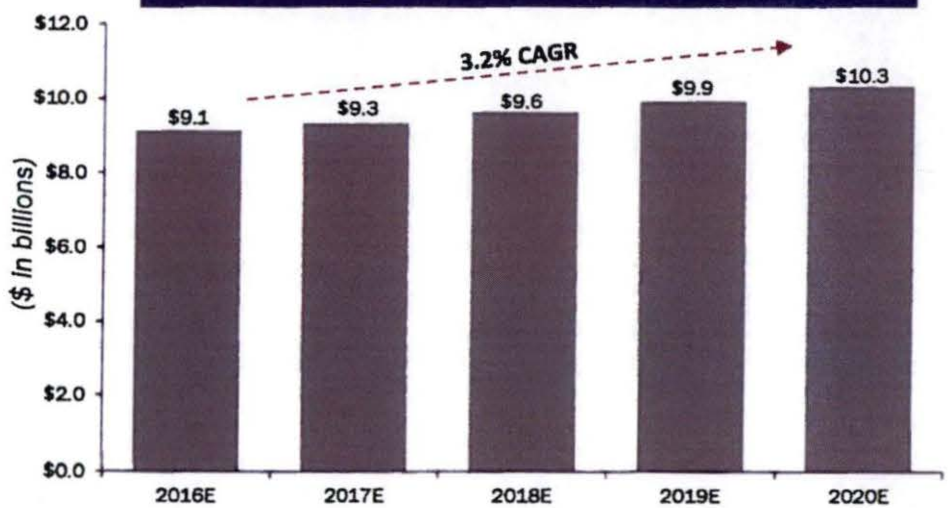
(1) Total annual return is the combination of annual EPS growth and dividend yield.

ppl

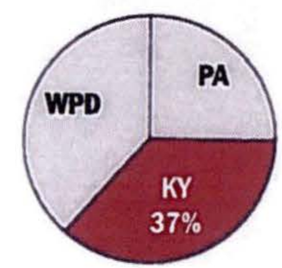
Kentucky Regulated

- Constructive jurisdiction provides a timely return on planned Cap Ex
  - Environmental Cost Recovery (ECR): $1.5 billion estimated spend on projects approved, or subject to KPSC approval; $0.8 billion with 10.0% ROE and $0.7 billion with 9.8% ROE - virtually no regulatory lag
  - Other supportive recovery mechanisms
    - Return mechanisms include CWIP for ECR and Gas Line Tracker
    - Pass through clauses include Purchased Power, Fuel and Gas Supply Adjustment and Energy Efficiency/Demand Side Management recovery
- Cap Ex plans exclude spending that may be required under the Clean Power Plan

Projected Rate Base Growth



2017E KY Regulated Rate Base



Total: $25.0 billion

ppl

Exhibit No.__(RAB-3)
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PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-17	Dec-16	Nov-16	Oct-16	Sep-16	Aug-16
Alliant Energy	High Price ($)	38.290	38.340	38.670	38.330	40.600	40.580
	Low Price ($)	36.560	35.260	34.880	36.310	37.090	37.690
	Avg. Price ($)	37.425	36.800	36.775	37.320	38.845	39.135
	Dividend ($)	0.315	0.294	0.294	0.294	0.294	0.294
	Mo. Avg. Div.	3.37%	3.20%	3.20%	3.15%	3.03%	3.00%
	6 mos. Avg.	3.16%					
Ameren Corp.	High Price ($)	53.400	52.880	51.460	50.250	51.910	52.590
	Low Price ($)	51.350	48.320	46.970	46.840	47.790	49.150
	Avg. Price ($)	52.375	50.600	49.215	48.545	49.850	50.870
	Dividend ($)	0.440	0.440	0.425	0.425	0.425	0.425
	Mo. Avg. Div.	3.36%	3.48%	3.45%	3.50%	3.41%	3.34%
	6 mos. Avg.	3.42%					
Avista Corp.	High Price ($)	40.170	43.000	42.260	41.740	43.740	43.710
	Low Price ($)	37.880	38.690	39.210	38.990	40.380	40.300
	Avg. Price ($)	39.025	40.845	40.735	40.365	42.060	42.005
	Dividend ($)	0.343	0.343	0.343	0.343	0.343	0.343
	Mo. Avg. Div.	3.52%	3.36%	3.37%	3.40%	3.26%	3.27%
	6 mos. Avg.	3.36%					
Black Hills Corp.	High Price ($)	62.700	62.830	61.900	62.070	63.790	63.870
	Low Price ($)	60.020	57.580	54.760	56.530	57.510	56.860
	Avg. Price ($)	61.360	60.205	58.330	59.300	60.650	60.365
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.420
	Mo. Avg. Div.	2.74%	2.79%	2.88%	2.83%	2.77%	2.78%
	6 mos. Avg.	2.80%					
CenterPoint Energy	High Price ($)	26.230	24.980	24.420	23.180	24.430	24.010
	Low Price ($)	24.450	23.570	21.910	21.830	22.270	21.970
	Avg. Price ($)	25.340	24.275	23.165	22.505	23.350	22.990
	Dividend ($)	0.258	0.258	0.258	0.258	0.258	0.258
	Mo. Avg. Div.	4.07%	4.25%	4.45%	4.59%	4.42%	4.49%
	6 mos. Avg.	4.38%					
CMS Energy Corp.	High Price ($)	42.610	42.000	42.270	42.550	44.440	45.370
	Low Price ($)	41.120	39.420	38.780	40.010	41.140	41.490
	Avg. Price ($)	41.865	40.710	40.525	41.280	42.790	43.430
	Dividend ($)	0.310	0.310	0.310	0.310	0.310	0.310
	Mo. Avg. Div.	2.96%	3.05%	3.06%	3.00%	2.90%	2.86%
	6 mos. Avg.	2.97%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-17	Dec-16	Nov-16	Oct-16	Sep-16	Aug-16
Consolidated Edison	High Price ($)	74.830	74.300	75.620	76.030	79.540	80.610
	Low Price ($)	72.130	68.850	68.760	71.350	72.930	74.090
	Avg. Price ($)	73.480	71.575	72.190	73.690	76.235	77.350
	Dividend ($)	0.670	0.670	0.670	0.670	0.670	0.670
	Mo. Avg. Div.	3.65%	3.74%	3.71%	3.64%	3.52%	3.46%
	6 mos. Avg.	3.62%					
DTE Energy Co.	High Price ($)	99.490	99.920	96.780	96.540	97.600	98.440
	Low Price ($)	96.580	92.190	89.660	90.750	90.610	92.240
	Avg. Price ($)	98.035	96.055	93.220	93.645	94.105	95.340
	Dividend ($)	0.825	0.825	0.770	0.770	0.770	0.730
	Mo. Avg. Div.	3.37%	3.44%	3.30%	3.29%	3.27%	3.06%
	6 mos. Avg.	3.29%					
Eversource Energy	High Price ($)	55.900	55.740	55.330	55.470	56.840	59.280
	Low Price ($)	54.080	50.560	50.990	51.880	53.040	53.580
	Avg. Price ($)	54.990	53.150	53.160	53.675	54.940	56.430
	Dividend ($)	0.445	0.445	0.445	0.445	0.445	0.445
	Mo. Avg. Div.	3.24%	3.35%	3.35%	3.32%	3.24%	3.15%
	6 mos. Avg.	3.27%					
Exelon Corp.	High Price ($)	36.210	36.360	34.060	34.130	35.270	37.700
	Low Price ($)	34.800	31.770	29.820	31.680	32.860	33.610
	Avg. Price ($)	35.505	34.065	31.940	32.905	34.065	35.655
	Dividend ($)	0.318	0.318	0.318	0.318	0.318	0.318
	Mo. Avg. Div.	3.58%	3.73%	3.98%	3.87%	3.73%	3.57%
	6 mos. Avg.	3.74%					
Northwestern Corp.	High Price ($)	57.880	58.080	59.130	57.760	60.710	61.320
	Low Price ($)	55.990	54.070	54.780	53.850	56.180	57.090
	Avg. Price ($)	56.935	56.075	56.955	55.805	58.445	59.205
	Dividend ($)	0.500	0.500	0.500	0.500	0.500	0.500
	Mo. Avg. Div.	3.51%	3.57%	3.51%	3.58%	3.42%	3.38%
	6 mos. Avg.	3.50%					
PG&E Corp.	High Price ($)	61.910	61.540	62.230	62.690	64.400	65.390
	Low Price ($)	59.890	57.600	57.630	58.200	60.440	61.480
	Avg. Price ($)	60.900	59.570	59.930	60.445	62.420	63.435
	Dividend ($)	0.490	0.490	0.490	0.490	0.490	0.490
	Mo. Avg. Div.	3.22%	3.29%	3.27%	3.24%	3.14%	3.09%
	6 mos. Avg.	3.21%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-17	Dec-16	Nov-16	Oct-16	Sep-16	Aug-16
Public Svc. Enterprise Gp.	High Price ($)	44.700	44.290	43.110	42.250	44.010	46.100
	Low Price ($)	42.860	40.720	39.280	40.380	41.070	42.250
	Avg. Price ($)	43.780	42.505	41.195	41.315	42.540	44.175
	Dividend ($)	0.410	0.410	0.410	0.410	0.410	0.410
	Mo. Avg. Div.	3.75%	3.86%	3.98%	3.97%	3.86%	3.71%
	6 mos. Avg.	3.85%					
SCANA Corp.	High Price ($)	74.060	74.990	73.520	73.830	75.920	75.800
	Low Price ($)	67.710	69.710	67.310	67.910	69.040	69.830
	Avg. Price ($)	70.885	72.350	70.415	70.870	72.480	72.815
	Dividend ($)	0.575	0.575	0.575	0.575	0.575	0.575
	Mo. Avg. Div.	3.24%	3.18%	3.27%	3.25%	3.17%	3.16%
	6 mos. Avg.	3.21%					
Sempra Energy	High Price ($)	104.250	104.700	107.100	109.420	111.400	111.960
	Low Price ($)	99.710	98.120	92.950	101.700	102.150	103.620
	Avg. Price ($)	101.980	101.410	100.025	105.560	106.775	107.790
	Dividend ($)	0.755	0.755	0.755	0.755	0.755	0.755
	Mo. Avg. Div.	2.96%	2.98%	3.02%	2.86%	2.83%	2.80%
	6 mos. Avg.	2.91%					
Southern Company	High Price ($)	49.850	49.640	51.680	52.230	53.730	53.800
	Low Price ($)	48.190	46.200	46.790	49.140	50.770	50.000
	Avg. Price ($)	49.020	47.920	49.235	50.685	52.250	51.900
	Dividend ($)	0.560	0.560	0.560	0.560	0.560	0.560
	Mo. Avg. Div.	4.57%	4.67%	4.55%	4.42%	4.29%	4.32%
	6 mos. Avg.	4.47%					
Vectren Corp.	High Price ($)	55.200	53.050	51.880	50.340	52.040	52.470
	Low Price ($)	51.500	48.410	46.520	47.000	47.870	48.560
	Avg. Price ($)	53.350	50.730	49.200	48.670	49.955	50.515
	Dividend ($)	0.420	0.420	0.420	0.400	0.400	0.400
	Mo. Avg. Div.	3.15%	3.31%	3.41%	3.29%	3.20%	3.17%
	6 mos. Avg.	3.26%					
WEC Energy	High Price ($)	59.630	59.120	59.740	60.130	63.350	65.240
	Low Price ($)	57.630	54.960	53.660	56.460	59.030	59.320
	Avg. Price ($)	58.630	57.040	56.700	58.295	61.190	62.280
	Dividend ($)	0.495	0.495	0.495	0.495	0.495	0.495
	Mo. Avg. Div.	3.38%	3.47%	3.49%	3.40%	3.24%	3.18%
	6 mos. Avg.	3.36%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-17	Dec-16	Nov-16	Oct-16	Sep-16	Aug-16
Xcel Energy	High Price ($)	41.430	41.200	41.750	41.800	43.490	44.130
	Low Price ($)	40.040	38.220	38.000	39.080	40.340	41.070
	Avg. Price ($)	40.735	39.710	39.875	40.440	41.915	42.600
	Dividend ($)	0.340	0.340	0.340	0.340	0.340	0.340
	Mo. Avg. Div.	3.34%	3.42%	3.41%	3.36%	3.24%	3.19%
	6 mos. Avg.	3.33%					
Monthly Avg. Dividend Yield		3.42%	3.48%	3.51%	3.47%	3.37%	3.32%
6-month Avg. Dividend Yield		3.43%					

Source: Yahoo! Finance

PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) First Call/ IBES
Alliant Energy Corporation	4.50%	6.00%	5.50%	5.50%	6.00%
Ameren Corp.	4.00%	6.00%	3.50%	6.50%	5.85%
Avista Corporation	3.00%	3.00%	2.50%	N/A	5.65%
Black Hills Corp.	6.00%	7.50%	5.00%	6.20%	7.56%
CenterPoint Energy, Inc.	4.50%	2.00%	2.50%	5.00%	6.63%
CMS Energy Corp.	6.50%	6.00%	5.50%	6.00%	7.60%
Consolidated Edison	3.00%	3.00%	3.00%	3.10%	2.02%
DTE Energy Co.	6.50%	6.00%	3.50%	6.00%	5.05%
Eversource Energy	5.50%	7.00%	4.50%	6.30%	5.77%
Exelon Corp.	4.00%	5.00%	4.50%	4.40%	1.47%
NorthWestern Corp.	5.50%	6.50%	4.00%	5.00%	4.34%
PG&E Corp.	7.00%	11.00%	4.00%	4.40%	5.40%
Public Service Enterprise Group	5.00%	2.50%	4.50%	2.40%	1.17%
SCANA Corp.	4.50%	4.50%	4.50%	5.70%	5.70%
Sempra Energy	7.00%	8.00%	6.00%	7.40%	6.17%
Southern Company	3.50%	4.50%	3.50%	4.10%	3.14%
Vectren Corp.	5.00%	9.00%	5.50%	5.30%	4.57%
WEC Energy	7.00%	6.00%	3.50%	6.00%	6.73%
Xcel Energy Inc.	6.00%	5.50%	4.00%	5.40%	5.69%
Averages	5.16%	5.74%	4.18%	5.26%	5.08%
Median Values	5.00%	6.00%	4.00%	5.45%	5.69%

Sources: Value Line Investment Survey, Dec. 16, 2016; Jan. 27 and Feb. 17, 2017
Yahoo! Finance for IBES growth rates retrieved February 14, 2017
Zacks growth rates retrieved February 14, 2017

PROXY GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.43%	3.43%	3.43%	3.43%	3.43%
Average Growth Rate	5.16%	5.74%	5.26%	5.08%	5.31%
Expected Div. Yield	3.52%	3.53%	3.52%	3.51%	3.52%
DCF Return on Equity	***8.68%***	***9.27%***	***8.78%***	***8.59%***	***8.83%***
Method 2:					
Dividend Yield	3.43%	3.43%	3.43%	3.43%	3.43%
Median Growth Rate	5.00%	6.00%	5.45%	5.69%	5.54%
Expected Div. Yield	3.51%	3.53%	3.52%	3.52%	3.52%
DCF Return on Equity	***8.51%***	***9.53%***	***8.97%***	***9.21%***	***9.06%***

PROXY GROUP
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.67%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.75%
4	Risk Premium	
5	(Line 1 minus Line 3)	6.92%
6	Comparison Group Beta	0.69
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	4.76%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.51%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.67%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.92%
4	Risk Premium	
5	(Line 1 minus Line 3)	7.75%
6	Comparison Group Beta	0.69
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.33%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.25%

PROXY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
August-16	1.89%
September-16	2.02%
October-16	2.17%
November-16	2.54%
December-16	2.84%
January-17	2.75%
6 month average	2.37%

5 Year Treasury Bond Data

	Avg. Yield
August-16	1.13%
September-16	1.18%
October-16	1.27%
November-16	1.60%
December-16	1.96%
January-17	1.92%
6 month average	1.51%

Source: www.federalreserve.gov/datadownload/Choose.aspx?rel=H15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.81%
Estimated Market Return	9.85%
Value Line Projected 3-5 Yr. Median Annual Total Return	9.50%
Average of Projected Mkt. Returns	9.67%

Source: Value Line Investment Survey for Windows retreived Feb. 14, 2017

Comparison Group Betas:	Value Line
Alliant Energy Corporation	0.70
Ameren Corp.	0.65
Avista Corporation	0.70
Black Hills Corp.	0.90
CenterPoint Energy, Inc.	0.85
CMS Energy Corp.	0.65
Consolidated Edison	0.55
DTE Energy Co.	0.65
Eversource Energy	0.70
Exelon Corp.	0.70
NorthWestern Corp.	0.70
PG&E Corp.	0.65
Public Service Enterprise Group	0.70
SCANA Corp.	0.65
Sempra Energy	0.80
Southern Company	0.55
Vectren Corp.	0.75
WEC Energy	0.60
Xcel Energy Inc.	0.60
Average	0.69

Source: Value Line Investment Survey

PROXY GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.00%	12.00%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.00%	5.00%	
Historical Market Risk Premium	5.00%	7.00%	6.03%
Comparison Group Beta, Value Line	0.69	0.69	0.69
Beta * Market Premium	3.43%	4.81%	4.14%
Current 20-Year Treasury Bond Yield	2.37%	2.37%	2.37%
CAPM Cost of Equity, Value Line Beta	**5.80%**	**7.18%**	**6.51%**

Source: *2016 SBBI Yearbook, Stocks, Bonds, Bills, and Inflation*, Duff and Phelps; pp. 2-6, 6-17, 10-30

DEK EXHIBIT 4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	CASE NO. 2016-00371

ORDER

Louisville Gas and Electric Company ("LG&E") is a combination electric and gas utility that generates, transmits, distributes, and sells electricity to consumers in Jefferson County, Kentucky, and in portions of eight other Kentucky counties.[1] LG&E also purchases, stores, and transports natural gas and distributes and sells natural gas at retail in Jefferson County and portions of 16 other Kentucky counties.[2] Its most recent general rate increase was granted in Case No. 2014-00372.[3]

BACKGROUND

On October 21, 2016, LG&E filed a notice of its intent to file an application for approval of an increase in its electric and gas rates based on a forecasted test year ending June 30, 2018. On November 23, 2016, LG&E filed its application, which included new rates to be effective January 1, 2017, based on a request to increase electric revenues

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[1] Application, ¶ 2.

[2] *Id.*

[3] Case No. 2014-00372, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates* (Ky. PSC June 30, 2015).

by $93.6 million, or 8.5 percent per year for the forecasted test period ending June 30, 2018, compared to the operating revenues for the forecasted test period under existing electric rates.[4] LG&E also sought an increase in its gas rates that would result in an increase in revenues of approximately $13.8 million, which would represent a 4.2 percent increase over current rates.[5] The proposed increase in electric rates would raise the monthly bill of an average residential electric customer by $9.65, or 9.5 percent.[6] The average LG&E residential electric customer consumes approximately 957 kilowatt ("kWh") of electricity per month.[7] The proposed increase in gas rates would raise the monthly bill of an average residential gas customer by $2.99, or 5 percent.[8] The average LG&E residential gas customer consumes approximately 55 Ccf of gas per month.[9]

LG&E's application also included requests Certificates of Public Convenience and Necessity ("CPCNs") to implement an Advanced Meter System ("AMS") and a Distribution Automation system ("DA"). LG&E stated that the AMS project would involve replacing approximately 418,000 electric meters and adding 322,000 AMS gas indices, which would have two-way communications capabilities.[10] The AMS electric meters would also be equipped with remote service switching capabilities.[11] The estimated capital cost of the

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[4] Application, ¶ 6.

[5] Application, ¶ 8.

[6] Application, ¶ 7.

[7] *Id.*

[8] Application, ¶ 9.

[9] *Id.*

[10] Application, ¶ 16.

[11] *Id*

proposed AMS project is $119 million for LG&E electric and $55 million for LG&E gas.[12] According to LG&E, the AMS project would result in incremental operation and maintenance ("O&M") cost during the deployment phase of $13 million for LG&E electric and $2.5 million for LG&E gas.[13] The deployment period was expected to begin in late 2017 and be completed by the end of 2019.[14] LG&E also requested authority to establish a regulatory asset for the remaining net book value of the electric meters retired as a result of the proposed AMS project.[15] LG&E estimated that the amount of this regulatory asset would be approximately $12.1 million.[16] In connection with the proposed AMS project, LG&E also sought deviations from certain regulations dealing with meter inspections and testing.

According to LG&E, the proposed DA project involves the extension of intelligent control over electric power grid functions to the distribution system level.[17] The project would enable LG&E's distribution system to provide real-time information and allow for remote monitoring, remote control, and automation of distribution line equipment.[18] For both LG&E and Kentucky Utilities Company ("KU"), LG&E's sister company,[19] the total

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[12] *Id.*

[13] *Id.*

[14] *Id.*

[15] Application, ¶ 35.

[16] *Id.*

[17] Application, ¶ 25.

[18] *Id.*

[19] KU has also filed a base rate application seeking, among other things, an increase in its electric rates. That application is docketed as Case No. 2016-00370, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and for Certificates of Public Convenience and Necessity* (Application filed Nov. 23, 2016).

capital cost of the proposed DA project is approximately $112 million.[20] The project would be completed in approximately seven years.[21] Of the total capital expenditure, LG&E estimated $23 million to be incurred before the end of the forecasted test year on June 30, 2018.[22] LG&E and KU (jointly "Companies") estimated the O&M expense related to the proposed DA project to be $6 million over the seven-year implementation period, $1.16 million of which would be incurred before the end of the forecasted test year.[23] The DA project would affect approximately 20 percent of the Companies' circuits, 40 percent of the Companies' distribution line miles, and 50 percent of the Companies' customers.[24]

LG&E also requested that its Gas Line Tracker Mechanism ("GLT") rates be updated for services rendered on and after July 1, 2017.[25] With the conclusion of the GLT service riser and main replacement projects, LG&E proposed to implement a $101 million, 15-year program to replace steel customer service lines, known as the Gas Service Line Replacement Program,[26] and a $60 million, three-year program to replace 15.5 miles of 45–60 year old transmission pipeline, known as the Transmission Pipeline Modernization Program.[27] LG&E proposed changes to its GLT tariff to accommodate its proposed addition of the Transmission Pipeline Modernization Program. The Firm

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[20] Application, ¶ 32.

[21] *Id.*

[22] *Id.*

[23] *Id.*, ¶ 33.

[24] *Id.*, ¶ 25.

[25] *Id.*, ¶ 42.

[26] *Id.*, ¶43.

[27] *Id.*, ¶ 44.

Transportation FT Rate Schedule and the new SGSS and LGDS schedules are proposed to be added to GLT recovery for the transmission project.[28] All GLT projects prior to July 1, 2017, have been removed from GLT rate base.[29] GLT service charges going forward are proposed to reflect recovery of the proposed Gas Service Line Replacement Program and Transmission Pipeline Modernization Program.[30]

LG&E estimated that it would receive approximately $522,000 of jurisdictional reservation and termination fees in connection with agreements related to the refined coal production facilities at the Companies' Ghent, Mill Creek, and Trimble County Generating Stations.[31] Pursuant to Case No. 2015-00264,[32] LG&E had been recording these proceeds as a regulatory liability and it now proposes to amortize this regulatory liability over three years.[33]

Lastly, LG&E also submitted a depreciation study in support of its application and requests that its proposed depreciation rates be approved.

Pursuant to the Commission's December 13, 2016 Order, LG&E's new rates, which were proposed to become effective on January 1, 2017, were suspended for six months, up to and including June 30, 2017. The December 13, 2016 Order also established a procedural schedule, which provided for a deadline for filing intervention

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[28] *Id.*, ¶ 42.

[29] *Id.*

[30] *Id.*, ¶¶ 43-44.

[31] *Id.*, ¶ 45.

[32] Case No. 2015-00264, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for Declaratory Ruling* (Ky. PSC Nov. 24, 2015).

[33] Application, ¶ 45.

requests; two rounds of discovery upon LG&E's application; a deadline for the filing of intervenor testimony; one round of discovery upon any intervenor testimony; and an opportunity for LG&E to file rebuttal testimony.

The following parties were granted intervention in this proceeding: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kroger Company ("Kroger"); Wal-Mart Stores East, LP and Sam's East, Inc. (jointly "Wal-Mart"); Kentucky School Boards Association ("KSBA"); Kentucky Cable Telecommunications Association ("KCTA"); Amy Waters and Sierra Club (jointly "Sierra Club"); BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"); Department of Defense and all other Federal Executive Agencies ("DOD/FEA"); Association of Community Ministries ("ACM"); Metropolitan Housing Coalition ("MHC"); Louisville/Jefferson County Metro Government ("Louisville Metro"); and JBS Swift & Co. ("JBS").

Informal conferences ("IC") were held at the Commission's offices on April 12, 13, and 17, 2017, which resulted in all of the parties to this matter, with the exception of AT&T and KCTA, reaching a settlement agreement in principle on all issues other than those involving the Companies' proposed Rate PSA – Pole and Structure Attachment Charges.[34] On April 19, 2017, LG&E and KU filed a motion requesting leave to submit the written Stipulation and Recommendation ("First Stipulation") intended to address all of the issues, except for the proposed Rate PSA tariff, in the two respective rate cases. An additional IC was held on April 25, 2017, for the limited purpose of discussing and

[34] The informal conferences were jointly held to discuss issues in the instant matter and to discuss issues related to the KU rate case, Case No. 2016-00370.

possibly resolving the issues associated with the Companies' proposed Rate PSA tariff. The Companies, KCTA, and AT&T were able to reach an agreement in principle for the resolution of all material issues pertaining to the proposed Rate PSA tariff. On May 1, 2017, LG&E and KU filed a motion requesting leave to submit the written Second Stipulation and Recommendation ("Second Stipulation"), which addresses all of the issues related to the Companies' proposed Rate PSA tariff.

The Commission held information sessions and public meetings for the purpose of taking public comments on April 11, 2017, in Louisville, Kentucky, at Jefferson Community and Technical College, and on April 12, 2017, in Madisonville, Kentucky, at Madisonville Community College.

A formal hearing was held on May 9, 2017, for the purposes of cross-examination of all witnesses and for the consideration of the two stipulations.[35] Pursuant to a May 3, 2017 Order, the Commission required all of the Companies' employee witnesses as well as the Companies' consultant Steven Seelye, KIUC's witness Stephen Baron, and KSBA's witness Ronald Willhite to be present at the hearing.[36] The May 3, 2017 Order provided the parties to this matter an opportunity to cross-examine any of the other witnesses and, accordingly, directed the parties to the two cases to submit written notice on or before May 5, 2017, setting forth the name of each witness that party intended to cross-examine at the formal hearing.[37] The May 3, 2017 Order noted that in the absence of a notice identifying witnesses whose attendance was not required by the Commission,

[35] *See* May 3, 2017 Order at 2.

[36] *Id.* at 3.

[37] *Id.*

the parties would be deemed to have waived cross-examination of those witnesses. None of the parties submitted a notice, and the only witnesses presented for cross-examination were those set forth above as named in the May 3, 2017 Order.

LG&E filed responses to post-hearing data requests on May 26, 2017, and on June 9, 2017. KSBA filed responses to post-hearing data requests on May 26, 2017. All the parties also filed post-hearing statements indicating they would not object to, or withdraw from, the First Stipulation regardless of whether all schools, including non-public schools, are included in the optional pilot program for schools as set forth in Article IV, paragraph 4.11 of the First Stipulation. On May 31, 2017, the AG, Sierra Club, MHC, ACM, Louisville Metro, Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"), and Lexington-Fayette Urban County Government ("LFUCG")[38] filed a joint post-hearing brief in the instant matter and in the KU rate proceeding recommending approval of the Residential Basic Service Charge as set forth in the First Stipulation. On May 31, 2017, LG&E, KIUC, and Kroger filed their respective post-hearing briefs recommending approval of the First and Second Stipulations. On June 1, 2017, KSBA filed a separate post-hearing brief addressing the legality of the optional pilot school rate tariffs. LG&E and the AG filed their respective briefs on the pilot school tariff issue on June 2, 2017. KSBA and the AG contend that the school-related pilot tariffs do not violate KRS 278.035 because the proposed tariffs set forth a reasonable classification and would not be preferential, given the unique load characteristics and usage patterns of schools as compared to the other customers in their existing rate classes. The AG also pointed out that all public and private schools have similar load and usage

[38] CAC and LFUCG are parties to the KU rate case, Case No. 2016-00370.

characteristics, making them a homogenous group, which made it reasonable to include in the pilot school tariff private schools that might wish to participate. The AG opined that "[a]s long as potential school participants to the pilot electric school tariffs are afforded equal opportunity to participate, the pilot electrical tariffs cannot be said to be 'preferential' within the meaning of KRS 278.035."[39] Similarly, LG&E contends that the pilot school tariffs do not provide a publicly funded entity an entitlement to service under that rate, and because the pilot tariffs are a reasonable means of gathering data to determine whether such tariffs should be made generally available service offerings. KSBA, LG&E, and the AG all indicated that they did not object to modifying the First Stipulation to allow schools not covered by KRS 160.325, i.e., non-public schools, to participate in the pilot tariffs.

FIRST STIPULATION

The First Stipulation reflects the agreement of all of the parties to the two cases, with the exception of KCTA and AT&T, addressing all issues not related to pole attachments. A summary of the provisions contained in the First Stipulation is as follows:

- LG&E agrees to withdraw the CPCN request to implement the AMS project and will initiate an AMS collaborative involving the Companies and all interested parties to these proceedings to discuss any concerns about AMS.[40]

- LG&E will be issued a CPCN to implement the DA project.

- LG&E Electric revenue will increase by $59.4 million and LG&E Gas revenue will increase by $7.5 million.

- The stipulated level of revenue associated with the electric operations were adjusted by: 1) removal of AMS cost recovery; 2) reduction of Return on

[39] AG's Post-Hearing Brief Regarding School Board Pilot Tariff at 7–8.

[40] Because LG&E has agreed to withdraw its CPCN request to implement the AMS project, the company is also withdrawing its request to establish a regulatory asset for those electric meters that would have been retired as a result of the AMS project and the requests to deviate from certain regulations governing meter inspections and testing. *See* May 9, 2017 Hearing at 2:22:09.

Equity ("ROE") to 9.75 percent; 3) revised depreciation rates; 4) updated five-year average for uncollectible debt expense; 5) use of an eight-year average of generator outage expenses, based upon four-years' historical expenses and four-years' forecasted expenses; and 6) adjustment to construction work in progress capital slippage.

- The stipulated level of revenue associated with the LG&E gas operation was adjusted by: 1) removal of AMS cost recovery; 2) reduction of ROE to 9.75 percent; 3) revised depreciation rates; and 4) updated five-year average for uncollectible debt expense.

- The agreed-to revenue allocations are set forth in Exhibits 5 and 6 of the First Stipulation.

- The Basic Service Charge will increase to $11.50 effective July 1, 2017, and to $12.25 effective July 1, 2018, for LG&E Electric and KU Rates RS, VFD, RTOD-Energy and RTOD-Demand.

- The Basic Service Charge for LG&E Gas Rates RGS and VFD will increase to $16.35.

- Current CSR customers may choose between Option A and Option B.

  - Option A reflects the Companies' as-filed proposition.

  - Option B reflects the following modifications to the existing CSR tariff:

    - credits for both Companies of $6.00 per kVA-month (primary) and $5.90 per kVA-month (transmission);

    - LG&E may request physical curtailment when more than ten of the utility's primary combustion turbines ("CTs") are being dispatched, irrespective of whether the utility is making off-system sales. A CSR customer may avoid a physical curtailment by buying through at the Automatic Buy-Through Price.

- LG&E agrees to recover costs related to its proposed Transmission Modernization and Steel Service Line Replacement Programs through its GLT mechanism for five years ending June 30, 2022, after which time any remaining costs for such programs will be recovered through base rates.

- LG&E agrees to revise its proposed Rate Substitute Gas Sales Service such that monthly billing demand will be based on the greatest of (1) Maximum Daily Quantity ("MDQ"); (2) current month's highest daily volume of gas delivered; or (3) 70 percent of the highest daily volume of gas delivered during the previous 11 monthly billing periods.

- LG&E and KU agree to add a voluntary sports-field-lighting rate schedule, Pilot OSL – Outdoor Sports Lighting Service, on a pilot basis limited to 20 participants per company and will utilize a time-of-day rate structure.

- LG&E and KU agree not to split their residential and general service electric energy charges into Infrastructure and Variable components as proposed.

- LG&E and KU agree to file a study in their next rate cases regarding the impacts of 100 percent base demand ratchets for Rate TODS.

- For customers with their own generation, for 60 minutes following a utility-system fault, LG&E and KU agree to not use any demand data for a Rate TODP customer to set billing demand.

- LG&E and KU agree to add an optional pilot tariff for schools subject to KRS 160.325. LG&E's and KU's pilot rate provisions will be available to new participants until the total projected revenue reduction for each company is $750,000 annually, compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served.

- LG&E and KU agree to file an application no later than December 31, 2017 proposing a two-year extension of the School Energy Managers Program (from July 1, 2018, through June 30, 2020) with a proposed total annual level of funding of $725,000.

- LG&E and KU agree to fund a study concerning economical deployment of electric bus infrastructure in the Louisville and Lexington areas, as well as cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

- LG&E and KU agree to establish an LED Lighting Collaborative involving Louisville Metro, LFUCG and any other interested parties to these proceedings.

- LG&E agrees to continue its monthly residential Home Energy Assistance ("HEA") charge at $0.25 per month, which will remain effective until the effective date of new base rates for LG&E following its next general base rate case.

- LG&E and KU agree to commit to contribute a total of $1.45 million of shareholder funds per year, which will remain in effect through June 30, 2021. These shareholder funds will be applied as follows:
  - From KU, $100,000 for Wintercare and $470,000 for HEA. CAC administers both programs. KU agrees that up to 10 percent of its total contributions to CAC may be used for reasonable administrative expenses.
  - From LG&E, $700,000 to ACM for utility assistance and $180,000 for HEA. LG&E agrees that up to 10 percent of its total contributions to ACM may be used for reasonable administrative expenses.

The First Stipulation results in the monthly bill of an average LG&E electric residential customer increasing by $6.77, or 6.7 percent, and for an average residential gas customer by $1.47, or 2.44 percent. A summary of the impact of the First Stipulation on LG&E's revenue requirements for its electric and gas operations are as follows.

- **<u>Electric Operations</u>**. The parties agreed in the First Stipulation to reduce LG&E Electric's requested revenue increase from $94.1 million to $59.4 million. The adjustments to LG&E Electric's requested revenue requirement are discussed further below.

  A. <u>Advanced Metering System</u>. As previously discussed, LG&E requested that the Commission grant a CPCN to install AMS in its service territory. As part of the First Stipulation, the Companies agreed to withdraw their request for the CPCN and to establish a collaborative to discuss the parties' concerns and seek to address them. In the test year, the cumulative effect of the withdrawal of the CPCN on the revenue requirement of LG&E Electric is a reduction of $5.2 million.

  B. <u>Return on Equity</u>. The agreement to reduce the ROE to 9.75 percent results in a decrease to LG&E Electric's revenue requirement of $10.1 million.

  C. <u>Depreciation</u>. LG&E proposed to revise its depreciation rates based upon depreciation studies that were performed by John Spanos of the firm Gannett Fleming Valuation and Rate Consultants, LLC. The parties to the First Stipulation agreed to revise LG&E Electric's proposed depreciation rates, resulting in a revenue-requirement reduction of $10.1 million. The revised depreciation rates will also reduce LG&E Electric's environmental cost recovery revenue requirement by $16.8 million. The impact will be included in the environmental cost recovery filing made for the July 2017 expense month.

D. Uncollectibles Expense. LG&E Electric proposed to use uncollectible factors based on using a five-year average of write-offs to revenues for the period 2011 through 2015. The First Stipulation uses an updated five-year period, 2012 through 2016, to reduce LG&E Electric's revenue requirement by $0.3 million.

E. Normalize Generation Outage. LG&E Electric proposed $63.814 million in generation outage expense for the test year, which exceeded its five-year average of $58.873 million. In the First Stipulation, the parties agreed to use an eight-year average expense, four years of historical expenses and four years of forecasted expenses. This approach reduces LG&E Electric's revenue requirement by $8.5 million.

F. Construction Work In Progress Capital Slippage. The First Stipulation reflects a slippage factor to eliminate over estimation in construction budgeting. The slippage factor reduces LG&E Electric's requested revenue requirement by $0.4 million.

- **Gas Operations**. LG&E Gas requested a revenue increase of $13.4 million in its application, but the parties agreed to a reduced revenue increase of $7.5 million in the First Stipulation. The First Stipulation adjustments to LG&E Gas's requested revenue requirement are discussed further below.

A. AMS. The withdrawal of LG&E's request for a CPCN to install AMS reduces LG&E Gas's revenue requirement by $0.7 million.

B. Return on Equity. The parties to the First Stipulation agreed to a ROE of 9.75 percent resulting in a decrease to LG&E Gas's revenue requirement of $2.9 million.

C. Depreciation. The revised depreciation rates in the First Stipulation reduces LG&E Gas's revenue requirement by $2.9 million.

D. Uncollectibles Expense. The updated write-off period used in the First Stipulation reduces LG&E Gas's revenue requirement by $0.1 million.

- **First Stipulation Summary**. The table below reflects the impact each First Stipulation adjustment has on LG&E Electric and LG&E Gas.

	LG&E Electric	LG&E Gas
Proposed Revenue Requirement	$ 94.1 million	$ 13.4 million
Remove AMS	(5.2) million	(0.7) million
9.75% Return on Equity	(10.1) million	(2.9) million
Revised Depreciation Rates	(10.1) million	(2.1) million
KU Refined Coal Revenues	million	million
Uncollectible Expense	(0.3) million	(0.1) million
Generator Outage Expenses	(8.5) million	million
CWIP Capital Slippage	(0.4) million	million
Stipulated Revenue Requirements	$ 59.4 million	$ 7.5 million

SECOND STIPULATION

The Second Stipulation reflects the agreement of LG&E, AT&T, and KCTA as to the terms and conditions of LG&E's pole and structure attachment charges contained in Tariff PSA. The major substantive areas addressed in the Second Stipulation are as follows:

- Agreement on LG&E's attachment charges for pole-top wireless facilities;[41]
- Agreement on LG&E's attachment charges for mid-pole wireless facilities;[42]
- Amendment of the terms and conditions set forth in LG&E's proposed Tariff PSA rate schedule.[43]

[41] Second Stipulation, ¶ 1.2.

[42] *Id.* at ¶ 1.3.

[43] *Id.* at ¶ 1.4.

ANALYSIS AND FINDINGS

The Commission's statutory obligation when reviewing a rate application is to determine whether the proposed rates are "fair, just, and reasonable."[44] While numerous intervenors with significant experience in rate proceedings and collectively representing a diverse range of customer interests have participated in this case, the Commission cannot defer to the parties as to what constitutes fair, just, and reasonable rates. The Commission must review the record, including the two stipulations, and apply its expertise to make an independent decision as to the level of rates, including terms and conditions of service, that should be approved.

To satisfy its statutory obligation in this case, the Commission has performed its traditional ratemaking analysis, which consists of reviewing the reasonableness of each revenue and expense adjustment proposed or justified by the record, along with a determination of a fair ROE.

FIRST STIPULATION

Based upon its review of the First Stipulation, the attachments thereto, and the case record including intervenor testimony, the Commission finds that, with the modifications discussed below, the First Stipulation is reasonable and in the public interest. With those modifications, the Commission finds that the First Stipulation was the product of arm's-length negotiations among knowledgeable, capable parties and should be approved. Such approval is based solely on the reasonableness of the modified First Stipulation and does not constitute a precedent on any individual issue.

[44] KRS 278.030(1).

Employee Retirement Plans

LG&E maintains a Defined Dollar Benefit Retirement Plan for those employees hired prior to January 1, 2006 ("Pre 2006 DDB Plan").[45] This plan was closed to new participants and was replaced with a Retirement Income Account ("401(k) Plan") for those employees hired after January 1, 2006.[46] All employees that were hired prior to January 1, 2006, are eligible to participate in both the Pre 2006 DDB Plan and the 401(k) Plan.[47] LG&E contributes 100 percent of the Pre 2006 DDB Plan costs.[48] LG&E also contributes to the 401(k) Plan between 3 percent to 7 percent[49] of eligible employee compensation and a $0.70 per dollar match for employee contributions up to 6 percent of the employee's eligible contribution.[50]

The Commission finds that, for ratemaking purposes, it is not reasonable to include both LG&E Pre 2006 DDB Plan contributions and LG&E's matching contributions to the 401(k) Plan for the following employee categories: exempt, manager, non-exempt, and officer and director personnel. The Commission chooses not to address similar 401(k) Plan company matching contributions for hourly and bargaining unit employees in

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[45] See LG&E's response to Commission Staff's Fourth Request for Information ("Staff's Fourth Request"), Item 6.

[46] Refer to LG&E's response to Commission Staff's First Post-Hearing Request for Information dated May 12, 2017, Item 11. Although throughout this proceeding, LG&E made references to two separate post-2016 retirement plans, the Retirement Income Account and the 401(k) Savings Plan, they are actually the same plan.

[47] *Id.*

[48] Response to Staff's Fourth Request, Item 6.

[49] The percentage contribution rate depends on the employee's years of service as of January 1 of that year.

[50] Response to Staff's Fourth Request, Item 6.

this proceeding, as it is not within the Commission's authority to negotiate or modify bargaining agreements. The Commission will not make a distinction between represented and non-represented hourly groups at this time, but will instead provide an opportunity for LG&E to address these excessive costs for both employee classes prior to its next base rate case as rate recovery of these contributions will be evaluated for appropriateness as part of its next base rate case. Employees participating in the Pre 2006 DDB Plan enjoy generous retirement plan benefits, making the matching 401(k) Plan amounts excessive for ratemaking purposes. Accordingly, the Commission denies for recovery 401(k) Plan matching contributions in the amount of $1,246,499 before gross-up for LG&E's electric operations and $407,808 before gross-up for LG&E's gas operations.

Return on Equity

In its application, LG&E developed its ROE using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the empirical capital asset pricing model ("ECAPM"), the utility risk premium ("RP"), and the expected earnings approach.[51] Based on the results of the methods employed in its analysis, LG&E recommended an ROE range for its electric operations of 9.63 percent to 10.83 percent, including flotation cost.[52] LG&E recommended awarding the midpoint of this range, 10.23 percent, to maintain financial integrity, support additional capital investment and recognize flotation costs.[53] Direct testimony regarding ROE was provided by the AG, DOD/FEA, KIUC, and

[51] Direct Testimony of Adrien M. McKenzie, CFA ("McKenzie Direct Testimony") at 2.

[52] *Id.*, Exhibit No. 2, page 1 of 1.

[53] *Id.* at 5–6.

Louisville Metro and was subject to discovery by the Commission Staff and all parties.[54] Per paragraphs 2.2(B) and 3.2(B) of the First Stipulation, LG&E and the intervenors agreed that a ROE of 9.75 percent is reasonable for LG&E's electric and gas operations.[55] The following table presents the recommended ROEs from LG&E and the intervenors and the methods used to support each parties' findings:

Party	Recommendation	Methods
LG&E	10.23%	DCF, CAPM, ECAPM, RP
AG[56]	8.75% (electric) 8.70% (gas)	DCF, CAPM
DOD[57]	9.35%	DCF, CAPM, RP
KIUC[58]	9.0%	DCF, CAPM
Louisville Metro[59]	8.75 % (electric) 8.70% (gas)	DCF, CAPM
FIRST STIPULATION	**9.75%**	

In the First Stipulation, all parties agreed that the revenue requirement increases for LG&E's electric and gas operations will reflect a 9.75 percent ROE as applied to LG&E's capitalization and capital structure of the proposed electric and gas revenue requirement increases as modified through discovery. As a result, use of a 9.75 percent ROE reduced LG&E's proposed electric and gas revenue requirement increases by $10.1 million and $2.9 million, respectively.[60] For the reasons discussed below, the Commission finds a ROE of 9.75 percent to be unreasonable and higher than required by investors in

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[54] Walmart did not provide an ROE analysis, but pointed out that LG&E's proposed ROE was higher than natural trends and that average ROE awards of vertically integrated utilities in 2015 and 2016 was 9.76 percent.

[55] First Stipulation, at 5 and 9.

[56] AG Direct Testimony of Dr. J. Randall Woolridge, at 67.

[57] DOD Direct Testimony of Christopher C. Walters, at 60.

[58] KIUC Direct Testimony of Richard Baudino, at 28.

[59] Louisville Metro Direct Testimony of J. Randall Woolridge, PhD, at 4.

[60] First Stipulation at 5.

today's economic climate, and that this provision of the First Stipulation should be modified.

While the Commission does not rely on individual returns awarded in other states in determining the appropriate ROE for Kentucky jurisdictional utilities, the Commission does find it reasonable to expect that other state commissions, each with its own attributes, evaluate expert witness testimony which uses the same or similar cost-of-equity models as those presented by the parties participating in this rate proceeding, and reach conclusions based on the data provided in the records of individual cases. The Regulatory Research Associates ("RRA") reports introduced into the record of this proceeding[61] summarize the conclusions reached by state utility regulatory commissions, including this Commission, with regard to reasonable ROEs and contain explanatory reference points as to individual circumstances, all of which are available to investors. To the extent that investors' expectations are influenced by such publications, and we believe they are, we also find it appropriate to use that information to put their expectations in context. In fact, in LG&E's rebuttal testimony, LG&E agreed that allowed ROEs by other state commissions provide a general gauge of reasonableness for the outcome of a cost-of-equity analysis.[62]

The Commission takes notes of the fact that average annual ROE awards by state public service commissions for the last two years have ranged from 9.23 percent to 10.55 percent.[63] Furthermore, the average authorized ROEs reported by RRA for the fourth

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[61] *See* Rebuttal Testimony of Adrien M. McKenzie, CFA at 11.

[62] Id. at 10.

[63] *Id.*, Exhibit 12.

quarter of 2016 was 9.6 percent.[64] Authorized ROE data reported to investors by The Value Line Investment Survey for the specific firms in LG&E's proxy group indicates that state-allowed ROEs for those utilities were in a range of reasonableness of 9.00 to 12.50 percent.[65]

In 2017, the economic environment has shown signs of relative improvement. In response to increased economic growth and low unemployment, the Federal Reserve increased interest rates in March and June 2017, and current outlooks, including comments from government agencies, show that investors anticipate additional interest rate increases.[66] LG&E's own model produces an ROE, less flotation costs and adjustments, in the range of 9.5–10.7 percent.[67] Even with the current uptick in economic conditions, the economy remains in an era of historically low interest rates and slow economic growth. Therefore, irrespective of the agreement by the parties that a 9.75 percent ROE is appropriate for LG&E, the Commission finds that a slightly lower ROE is a better reflection of current economic conditions and investor expectations. Based on the entire record developed in this proceeding, we find that LG&E's required ROE falls within a range of 9.20 percent to 10.20 percent, with a midpoint of 9.70 percent. An ROE of 9.70 should be used for the purpose of base rate revenues and certain tariffs, as discussed later in this Order.

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[64] *Id.*, at 13.

[65] *Id.*, Exhibit 13.

[66] *Id.*, at 8.

[67] McKenzie Direct Testimony, Exhibit No. 2.

This reduction to the ROE from 9.75 percent to 9.70 percent reduces LG&E's net operating income before income taxes by $641,522 for LG&E's electric operations and by $187,156 for its gas operations.

Revenue Requirement

As discussed above, the Commission finds the First Stipulation to be reasonable only by eliminating LG&E's 401(k) Plan contributions for the following employee categories: exempt, manager, non-exempt and officer and director personnel, and by reducing the ROE from 9.75 percent to 9.70 percent. These modifications decrease the stipulated revenue requirement for LG&E's electric operations from $59,400,000 to $56,302,875, a decrease of $3,097,125. The stipulated revenue requirement for LG&E's gas operations are reduced from $7,500,000 to $6,524,016, a decrease of $975,984. The impact the modifications have on LG&E's stipulated revenue requirements are shown in the table below.

	LG&E	
	Electric	Gas
LG&E's 401(k) Plan	$ (1,246,499)	$ (407,808)
ROE from 9.75% to 9.7%	(641,522)	(187,156)
Impact to Net Operating Income Before Taxes	(1,888,021)	(594,964)
Multiplied by: Gross up Factor	1.640408	1.640408
Revenue Requirement Impact	(3,097,125)	(975,984)
Increase per Stipulation	59,400,000	7,500,000
Net Increase Granted by the Commission	$ 56,302,875	$ 6,524,016

Residential Basic Service Charge

The Commission believes an increase to the Residential Basic Service Charge is warranted, and we find the level of the Year 2 charge to be reasonable. We further find that the two-step increase to $11.50 in Year 1 and to $12.25 in Year 2 is unnecessary. The total increase in the Residential Basic Service Charge of $1.50 is a modest increase from the current level, and the Commission sees no reason to complicate the issue by using a two-step method, which could generate confusion among LG&E's residential customers. The First Stipulation is therefore modified with respect to the Residential Basic Service Charge, and the Year 2 charge of $12.25 should be approved for service rendered on and after July 1, 2017.

Optional Pilot Rates for Schools Subject to KRS 160.325

At the formal hearing in this matter, the parties were requested to file post-hearing briefs concerning the legality of the proposed school-related pilot rate tariffs, Rates SPS and STOD, with respect to the applicability of KRS 278.035, and to indicate whether they would object to the modification of the First Stipulation to include schools not covered by KRS 160.325. Briefs submitted by KSBA, LG&E, and the AG acknowledged that the inclusion of non-public schools in the pilot tariffs would avoid a possible violation of KRS 278.035. All parties to this proceeding submitted statements indicating that they had no objection to modification of the First Stipulation to include non-public schools in the pilots.

The Commission finds that the First Stipulation should be modified to include schools not covered by KRS 160.325. The inclusion of non-public schools would rectify any potential conflict with KRS 278.035 and would remove any element of preferential treatment of public schools that could be associated with the pilot tariffs. As previously stated, the pilot rate provisions will be available to new participants until the total projected revenue reduction is $750,000 annually for LG&E, compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served. The Commission notes that the parties to this proceeding agreed that the other ratepayers would assume the revenue shortfall resulting from the lower rates set forth in the pilot school tariffs. Therefore, the Commission will place a limit on the amount of time the pilot tariffs will be in effect and finds that the pilot tariffs should be effective for three years, or until LG&E files its next rate case, whichever is earlier. In the event that new base rates are not in effect by July 1, 2020, schools participating in the pilot tariffs should be returned to the tariffs under which they were formerly served. In addition, the Commission finds that LG&E should create a regulatory liability to record the difference between what the schools served under the pilot tariffs would have been billed under the pilot tariffs subsequent to July 1, 2020, and the amounts they are billed under the tariffs to which they are returned. The regulatory liability will be addressed in LG&E's next base rate proceeding. We further find that, within 30 days of the date of this Order, KSBA should file with the Commission the process by which KSBA will notify and select those schools, both public and non-public, that would be eligible to participate in the pilot tariffs.

With regard to the data gathered from the schools participating in the pilot tariffs, the Commission finds that LG&E should file reports with the Commission, beginning six months from the date of this Order and every six months thereafter, which set out details concerning monthly load information, individually and in the aggregate, and indicating preliminary findings as conclusions regarding the schools' load characteristics are reached. In the event that a future proposal is made either to extend the pilot school tariffs or to make them permanent, this load information will be used to determine whether the schools' load characteristics justify a special rate classification.

Collaborative Study Regarding Electric Buses

Although this provision will be funded by shareholder contributions and the Commission does not oppose it, this type of provision pertaining to an unrelated business transaction should be negotiated separately between the individual parties and has no bearing on LG&E's rates as found reasonable herein based on the record of this case. It is therefore superfluous to this regulatory proceeding, contributes nothing to the reasonableness of the First Stipulation, and should be omitted from future ratemaking proceedings.

LED Lighting and Electric Bus Study Collaboratives

Pursuant to the provisions of the First Stipulation, LG&E commits to engage in good faith with Louisville Metro, LFUCG, and any other interested parties to this proceeding and the KU rate proceeding in a collaborative to discuss issues related to LED lighting and electric bus infrastructure and rates. While the provisions limit participation to only those parties to the instant rate proceeding and the KU rate proceeding, the Commission finds that the collaboratives should also include the Kentucky Department of Energy Development and Independence, whose mission includes creating efficient, sustainable energy solutions and strategies.

Tariff Issues

Sheet No. 97 of LG&E's revised Electric tariff, which was filed with the First Stipulation, the Application for Service section, first paragraph, contained revisions that were not made to the corresponding Application for Service section on Sheet No. 97 of LG&E's Gas tariff. In response to a Commission Staff Request for Information, LG&E had stated that, due to an oversight, it failed to propose the same changes to both tariffs. The Commission finds that LG&E's compliance tariffs that it is directed to file in ordering paragraph 16 should include the same revisions to the Application for Service sections for both its Electric and Gas tariffs.

LG&E proposed a change to its Gas Supply Clause ("GSC") adjustment on six current rate schedules and one proposed rate schedule of its Gas tariff, to remove the GSC rate from each of the rate schedules that would have to change on a quarterly basis when the GSC is revised. LG&E stated that, should the Commission desire this information and require it at the conclusion of this proceeding, it would comply.[68] With respect to the continued inclusion of the GSC rate on its rate schedules, the Commission finds that it is reasonable for LG&E's customers to be able to find the total delivered commodity rate for sales gas on their respective tariff rate schedules, and that the compliance Gas tariff that LG&E is directed to file in ordering paragraph 16 should include no change to the location of the GSC rate on its gas sales rate schedules.

Gas Line Tracker Rate Calculation

Exhibit RMC-1 filed with the Stipulation Testimony of Robert Conroy is an Excel spreadsheet that calculates updated GLT rates. The "ROR" tab includes a Return on Equity component of 10 percent instead of the 9.75 percent included in the Settlement Agreement. In response to a Post-Hearing Request for Information, LG&E provided a

[68] LG&E's Response to Commission Staff's Third Request for Information, Item 32. This statement was reiterated by witness Robert Conroy at the May 9, 2017 hearing in this matter.

revised sheet showing the impact of using the 9.75 percent ROE in the capital structure. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the GLT rates should be further revised as set out in Appendix B to this Order to reflect the approved ROE. The Commission further finds that the 9.70 ROE should be used in LG&E's future adjustment of its GLT rates until a new ROE is approved or until the expiration of the GLT, whichever comes first.

SECOND STIPULATION

As mentioned previously, LG&E proposed certain changes to its pole attachment tariff in its application. LG&E currently offers the use of spaces on its poles for cable television attachments under Tariff CTAC, Cable Television Attachment Charges ("Tariff CTAC"). LG&E proposed to rename Tariff CTAC to Tariff PSA, Pole and Structure Attachment Charges ("Tariff PSA"), and to expand the tariff to include telecommunications wireline and wireless facilities' attachments, which are not currently covered under Tariff CTAC. LG&E also proposed to modify the rates, terms, and conditions of service for attaching wireline and wireless facilities to its poles.

The Second Stipulation includes the modifications proposed in the application, but also includes additional changes in the rates for pole space use and conditions of service for the placement of an attachment on LG&E's poles. As originally proposed, the Tariff PSA's rate schedule contained three charges: 1) an annual charge of $7.25 for each wireline pole attachment; 2) an annual charge of $0.81 for each linear foot of duct; and 3) an annual charge of $84.00 for each wireless facility attachment. AT&T and KCTA did not object to the charge for wireline and duct attachments, but did object to the annual charge for wireless facility attachments. LG&E estimated that wireless facilities occupy an average of 11.5 feet on its poles, and calculated the $84.00 wireless facility attachment charge based on the use of 11.5 feet of pole space at $7.25[69] per foot of pole. AT&T and KCTA did not challenge the $7.25 per foot factor in the calculation, but argued that wireless facility attachments occupy far less pole space. The Second Stipulation provides for a charge of $36.25, based upon a wireless facility attached to the top of a pole using five feet of the pole – one foot for the antenna and four feet of clearance above the power space to maintain a safe working distance between the electric facilities on the pole and the pole top antenna. The Second Stipulation also provides for rates for wireless facilities located mid-pole to be established on a case-by-case basis through special contracts. This provision is based upon the lack of requests for mid-pole wireless facilities, which resulted in a lack of evidence upon which to base a uniform rate for mid-pole wireless facilities.

Another modification is the requirement for a pole-loading study. As originally proposed, Tariff PSA required that a pole-loading study be submitted with each application as a safety and reliability measure. KCTA argued that requiring pole-loading studies for every application provides no appreciable safety or reliability benefit to LG&E, while unnecessarily increasing construction costs and preventing timely deployment of wireless facilities. The Second Stipulation provides that an attachment applicant may attach a pole-load study to the application or, in the alternative, assert that a pole's condition does not warrant the need for a pole-loading study. To confirm the assertion, LG&E may perform a visual inspection of the pole to which the facility is proposed to be

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[69] The Commission approved the rate of $7.25 per foot in Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric and Rates* (Ky. PSC June 30, 2015).

attached. If LG&E determines that a pole-loading study is needed, the attachment applicant has the option of conducting the pole-loading study itself or requesting that LG&E perform the study. The attachment applicant is responsible for the costs of any visual inspection or pole-loading study that LG&E performs. LG&E contends that the proposed revision to Tariff PSA does not sacrifice safety or system reliability.

The Commission finds that the proposed Tariff PSA with the modifications agreed to in the Second Stipulation is reasonable and that the Second Stipulation should be approved in its entirety.

OTHER ISSUES

Rate Adjustment

In setting the rates shown in Appendix B, the Commission maintained the basic service charges for each class that were included in the First Stipulation, with the exception that the Year 1 Residential Basic Service Charge was not approved as previously discussed, and is therefore not included. The reduction in LG&E's stipulated revenue increase as found reasonable herein was allocated solely to the electric energy charges and gas volumetric charges of those customer classes for which revenue increases were proposed in the First Stipulation. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set forth in the First Stipulation.

Electric Vehicle Supply Equipment Calculation

In response to a Post-Hearing Request for Information, LG&E provided a revised sheet showing the impact on the Electric Vehicle Supply Equipment ("EVSE"), Electric Vehicle Charging Service ("EVC"), and Electric Vehicle Supply Equipment ("EVSE-R") rates of using the 9.75 percent ROE in the capital structure. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the EVSE rates should be further revised to reflect the approved ROE. The Commission also finds that since the EVSE, EVC, and EVSE-R rates are based, in part, on the General Service ("GS") energy rate, the rates should be updated for the change in the GS energy rate approved with this Order. The EVSE, EVC, and EVSE-R rates set out in Appendix B to this Order reflect both revisions.

Solar Capacity Charge and Solar Energy Credits

In response to a Post-Hearing Request for Information, LG&E provided a revised sheet showing the impact on the Solar Capacity Charge and Solar Energy Credits of using the 9.75 percent ROE in the capital structure and under each of the corrected cost-of-service studies filed by LG&E in this proceeding. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the Solar Capacity Charge and Solar Energy Credits should be further revised to reflect the approved ROE. The Commission also finds that the Solar Energy Credits should be revised for Rate Schedules RS, VFD, RTOD-E, RTOD-D, and GS using the average of the amounts provided in response to the post-hearing information request,[70] but revised for the change in ROE and using the energy rates approved herein for Rate Schedules PS, TODS, and TODP. The rates set out in Appendix B to this Order reflect the revisions.

[70] Response to Commission Staff's First Post-Hearing Request for Information dated May 12, 2017, Item 6, Attachment LG&E-6-1 and Attachment LG&E-6-2.

Demand-Side Management ("DSM")

In response to a Commission Staff Information Request, LG&E stated that upon the implementation of new base rates, the DSM Revenue from Lost Sales component of its DSM cost-recovery mechanism would change to zero.[71] The Commission finds that LG&E compliance tariff that it is directed to file in ordering paragraph 16 should reflect this revision to its DSM cost-recovery mechanism.

Transmission System Improvement Plan

LG&E is currently implementing a Transmission System Improvement Plan ("Transmission Plan") aimed at reducing outage occurrence and duration and improving overall reliability of service to its customers.[72] LG&E states that the Transmission Plan contains two primary categories of investment: system integrity and reliability.[73] System integrity involves replacement of aging transmission assets to enhance reliability.[74] The reliability component involves several maintenance programs and capital investment in line sectionalization.[75] LG&E will spend approximately $28 million between the end of the last base-rate-case test period and the end of the forecasted test period (July 1, 2016 –June 30, 2018) on its Transmission Plan.[76] This spending is part of a total of $511 million

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[71] LG&E's response to Commission Staff's Second Request for Information, Item 11.

[72] Direct Testimony of Paul W. Thompson ("Thompson Testimony") at 25.

[73] *Id.* at 26.

[74] *Id.*

[75] *Id.*

[76] *Id.* at 27.

in transmission capital investments that LG&E and KU project to spend over the five-year period beginning 2017.[77]

In light of the significant investments that LG&E intends to make pursuant to the Transmission Plan, the Commission will require LG&E to file annual reports, over the five-year Transmission Plan period, detailing the progress on the spend out for the reporting period, the criteria utilized by LG&E to prioritize the various transmission projects, the impact on reliability or other benefits to LG&E's customers resulting from such investments, and outlining the expenditures for the following year.

Bullitt County Pipeline CPCN

LG&E included in its application information concerning its plans to construct a new natural gas pipeline in Bullitt County. The new 12-inch pipeline is to be approximately 10–12 miles long and is intended to improve reliability by mitigating the exposure of approximately 9,500 customers to a loss of gas supply from a current one-way feed. Additionally, the new pipeline is intended to allow LG&E to serve growth in Bullitt County by providing additional gas supply to existing gas infrastructure in those areas. LG&E plans to commence this project in 2017, with a targeted completion in early 2019. LG&E states that preliminary cost estimates for the project total approximately $27.6 million.

LG&E did not request a CPCN for the project, stating that it considers it to be an ordinary extension of its existing gas system in the usual course of business, and that a CPCN therefore is not required under KRS 278.020(1) or 807 KAR 5:001 Section 15. In its post-hearing brief, LG&E reiterated its position that the construction qualifies as an ordinary extension of its system in the usual course of business and requested that the

[77] *Id.*, 26–27.

Commission determine that no CPCN is required. In the alternative, LG&E pointed out that it had provided all the information necessary to support the award of a CPCN, and requested that the Commission grant it the CPCN authority to carry out the construction of the Bullitt County pipeline.[78] Due to the size of the project, and the fact that Duke Energy Kentucky, Inc. requested and was granted a CPCN by the Commission for similar construction in Case No. 2016-00168,[79] the Commission finds that the construction should be the subject of a CPCN finding.

LEGAL STANDARD

KRS 278.020(1) provides, in relevant part, that:

> No person, partnership, public or private corporation, or combination thereof shall commence providing utility service to or for the public or begin the construction of any plant, equipment, property, or facility for furnishing to the public any services enumerated in KRS 278.010 . . . and ordinary extensions of existing systems in the usual course of business, until that person has obtained from the Public Service Commission a certificate that public convenience and necessity require the service or construction.

> 807 KAR 5:001, Section 15(2), provides in part:

> New construction or extension. Upon application for a certificate that the present or future public convenience or necessity requires, or will require, the construction or extension of any plant, equipment, property, or facility, the applicant, in addition to complying with Section 14 of this administrative regulation, shall submit with its application:

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[78] LG&E May 31, 2017 Post Hearing Brief at 37.

[79] Case No. 2016-00168, *Application of Duke Energy Kentucky, Inc. for a Certificate of Public Convenience and Necessity Authorizing the Construction of a Gas Pipeline from Walton, Kentucky to Big Bone, Kentucky* (Ky. PSC Nov. 28, 2016).

> (a) The facts relied upon to show that the proposed construction or extension is or will be required by public convenience or necessity.

To obtain a CPCN, the utility must demonstrate a need for such facilities and an absence of wasteful duplication.[80]

"Need" requires:

> [a] showing of a substantial inadequacy of existing service involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed and operated.
>
> . . .
>
> The inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[81]

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[82] To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a thorough review of all alternatives has been performed.[83] Selection of a proposal that

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[80] Kentucky Utilities Co. v. Pub. Serv. Comm'n, 252 S.W.2d 885 (Ky. 1952).

[81] *Id.* at 890.

[82] *Id.*

[83] Case No. 2005-00142, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* (Ky. PSC Sept. 8, 2005).

ultimately costs more than an alternative does not necessarily result in wasteful duplication.[84]

In reviewing the record, the Commission finds that LG&E's construction of the Bullitt County pipeline would not be a wasteful duplication of any existing facilities and is necessary in order for LG&E to accommodate current and expected system requirements for safe and reliable natural gas service. Based upon the record as developed through discovery and being otherwise sufficiently advised, the Commission finds that a CPCN for construction of the pipeline should be approved, and that, no later than 90 days after the completion of the project, LG&E should file with the Commission a statement of the actual costs of the construction. Prior to incurring any long-term financing related to this project, pursuant to KRS 278.300, LG&E is required to seek Commission approval.

LG&E Tariffs

Commission regulation 807 KAR 5:011, Section 4(1), requires each utility to include an accurate index of the city, town, village, or district in which its rates are applicable. The first page of LG&E's electric tariffs reference its service as being available "[i]n the nine counties of the Louisville, Kentucky metropolitan area as depicted on territorial maps as filed with the Public service Commission of Kentucky." The first page of LG&E's gas tariffs reference its service being available "[i]n the seventeen counties of the Louisville, Kentucky metropolitan area as depicted on territorial maps as filed with the Public service Commission of Kentucky." Since those maps are not readily available to

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[84] *See* Kentucky Utilities Co. v. Pub. Serv. Comm'n, 390 S.W.2d, 175 (Ky. 1965). *See also* Case No. 2005-00089, *Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity to Construct a 138 kV Transmission Line in Rowan County, Kentucky* (Ky. PSC Aug. 19, 2005).

members of the public, LG&E should revise its tariffs to include a list of the communities in which it serves.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by LG&E are denied.

2. LG&E's motions for leave to file the First and Second Stipulations are granted.

3. The First and Second Stipulations, attached hereto as Appendix A, (without exhibits) are approved with the modifications discussed herein.

4. The rates and charges in Appendix B, attached hereto, are fair, just, and reasonable for LG&E to charge for service rendered on and after July 1, 2017.

5. LG&E is granted a CPCN to implement the DA project as described in the application.

6. Within 30 days of the date of this Order, KSBA shall file with the Commission the process by which it will notify and select those schools that are eligible to participate in the pilot tariffs approved herein.

7. LG&E shall file reports with the Commission as directed herein which set out details concerning the pilot school tariffs study.

8. Beginning June 1, 2018, and continuing over the five-year Transmission Plan period, LG&E shall file an annual Transmission Plan report as discussed herein.

9. LG&E is granted a CPCN for the construction of the Bullitt County natural gas pipeline as described in the application and further described in response to discovery.

10. LG&E shall provide copies of any permits related to the Bullitt County pipeline within ten days of obtaining each permit or approval.

11. LG&E shall, no later than 90 days after the completion of the Bullitt County pipeline, file with the Commission a statement of the actual costs of the construction.

12. LG&E shall file a copy of the "as-built" drawings and a certified statement from the engineer that the Bullitt County pipeline construction has been satisfactorily completed in accordance with the plans and specifications within 60 days of substantial completion of the construction certified herein.

13. LG&E shall require the Bullitt County pipeline construction to be inspected under the general supervision of a professional engineer licensed to practice in the Commonwealth of Kentucky in civil or mechanical engineering to ensure that the construction work is done in accordance with the drawings and specifications and in conformity with the best practices of the construction trades involved in the project.

14. LG&E shall notify the Commission one week prior to the actual start of the Bullitt County pipeline construction and at the 50 percent completion point.

15. LG&E shall not incur any long-term indebtedness associated with the Bullitt County pipeline without applying to the Commission for approval pursuant to KRS 278.300.

16. Within 20 days of the date of this Order, LG&E shall file with the Commission, using the Commission's electronic Tariff Filing System, its revised tariffs, including an index of communities served, as set forth in this Order reflecting that they were approved pursuant to this Order.

17. Any document filed pursuant to ordering paragraphs 6, 7, 8, 10, 11, 12, and 14 of this Order shall reference the number of this case and shall be retained in the utility's general correspondence file.

18. The Executive Director is delegated authority to grant reasonable extension of time for the filing of any documents required by ordering paragraphs 6, 7, 8, 10, 11, 12, and 14 of this Order upon LG&E's showing of good cause for such extension.

By the Commission

ENTERED
JUN 22 2017
KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Taline R. Mathews

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00371 DATED JUN 2 2 2017

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation ("Stipulation") is entered into this 19th day of April 2017 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); Association of Community Ministries, Inc. ("ACM"); Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"); Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); United States Department of Defense and All Other Federal Executive Agencies ("DoD"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky League of Cities ("KLC"); The Kroger Company ("Kroger"); Kentucky School Boards Association ("KSBA"); Lexington-Fayette Urban County Government ("LFUCG"); Louisville/Jefferson County Metro Government ("Louisville Metro"); Metropolitan Housing Coalition ("MHC"); Sierra Club, Alice Howell, Carl Vogel and Amy Waters (collectively "Sierra Club"); JBS Swift & Co. ("Swift"); and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart"). (Collectively, the Utilities, ACM, AG, CAC, DoD, KIUC, KLC, Kroger, KSBA, LFUCG, Louisville Metro, MHC, Sierra Club, Swift and Wal-Mart are the "Parties.")

WITNESSETH:

WHEREAS, on November 23, 2016, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00370 to review KU's base rate application, in which KU requested a revenue increase of $103.1 million;

WHEREAS, on November 23, 2016, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00371 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $93.6 million and a revenue increase of $13.8 million for its gas operations (Case Nos. 2016-00370 and 2016-00371 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, on February 20, 2017, LG&E filed with the Commission in Case No. 2016-00371 a Supplemental Response to Commission Staff's First Request for Information No. 54 in which LG&E corrected its requested revenue increases for its electric operations to be $94.1 million and for its gas operations to be $13.4 million;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00370 to the AG, BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"), CAC, Kentucky Cable Telecommunications Association ("KCTA"), KIUC, KLC, Kroger, KSBA, LFUCG, Sierra Club, and Wal-Mart;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00371 to ACM, AG, AT&T, DoD, KCTA, KIUC, Kroger, KSBA, Louisville Metro, MHC, Sierra Club, Swift and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of this Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 12, 13, and 17, 2017, at the offices of the Commission, which representatives of AT&T and KCTA also attended on April 12 and 13, and which representatives of KCTA also attended on April 17, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, the Parties hereto unanimously desire to settle all the issues pending before the Commission in the Rate Proceedings, notwithstanding that neither AT&T nor KCTA has agreed with, or entered into, this Stipulation, and therefore neither AT&T nor KCTA is one of the Parties as defined herein;

WHEREAS, it is understood by all Parties hereto that this Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Stipulation;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that this Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Stipulation, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. ADVANCED METERING SYSTEMS

1.1. Withdrawing Request for Certificates of Public Convenience and Necessity and Cost Recovery for Advanced Metering Systems. The Utilities agree to withdraw their requests for the Commission to grant certificates of public convenience and necessity ("CPCNs") and to approve cost recovery in these base rate proceedings for the Utilities' proposed full deployment of Advanced Metering Systems ("AMS"). The Parties agree that the Utilities' withdrawal of their requests for CPCNs and cost recovery for AMS in these proceedings does not preclude the Utilities from having full AMS deployment considered in future proceedings.

1.2. AMS Collaborative. The Parties agree that the Utilities and all interested Parties will participate in an AMS Collaborative to discuss the Parties' concerns about AMS and to seek to address them. The AMS Collaborative will begin at a mutually agreeable time after these proceedings conclude and will include only those Parties to these proceedings interested in participating in the collaborative. The Parties agree to engage in the collaborative in good faith not to exceed 15 months from the date the Commission issues orders in these proceedings.

ARTICLE II. ELECTRIC REVENUE REQUIREMENTS

2.1. Utilities' Electric Revenue Requirements. The Parties stipulate that the following increases in annual revenues for LG&E electric operations and for KU operations, for purposes of determining the rates of LG&E and KU in the Rate Proceedings, are fair, just and reasonable for the Parties and for all electric customers of LG&E and KU:

LG&E Electric Operations: $59,400,000.

KU Operations: $54,900,000.

The Parties agree that any increase in annual revenues for LG&E electric operations and for KU operations should be effective for service rendered on and after July 1, 2017.

2.2. Items Reflected in Stipulated Electric Revenue Requirement Increases. The Parties agree that the stipulated electric revenue requirement increases were calculated by beginning with the Utilities' electric revenue requirement increases as presented and supported by the Utilities in their applications in these proceedings and as revised through discovery ($103.1 million for KU; $94.1 million for LG&E electric) and adjusting them by the following items, which the Parties ask and recommend the Commission accept as reasonable without modification:

(A) **Removal of AMS Cost Recovery.** Because the Utilities are withdrawing their request for CPCNs and cost recovery for their proposed full deployment of AMS, recovery of AMS costs is being removed from the Utilities' electric revenue requirements. This reduces KU's proposed electric revenue requirement increase by $6.3 million, consisting of $3.2 million of operations and maintenance ("O&M") cost and $3.1 million of carrying cost and depreciation expense. Similarly, this reduces LG&E's proposed electric revenue requirement increase by $5.2 million, consisting of $3.0 million of O&M cost and $2.2 million of carrying cost and depreciation expense.

(B) **Return on Equity.** The Parties agree that a return on equity of 9.75% is reasonable for the Utilities' electric operations, and the agreed stipulated revenue requirement increases for the Utilities' electric operations reflect that return on equity as applied to the Utilities' capitalizations and capital structures underlying their originally proposed electric revenue requirement increases as modified through discovery. Use of a 9.75% return on equity reduces the Utilities' proposed electric revenue requirement increases by $15.3 million for KU and $10.1 million for LG&E.

(C) **Revised Depreciation Rates.** The stipulated revenue requirement increases reflect the revised depreciation rates shown in Stipulation Exhibits 1 (KU) and 2 (LG&E electric), which reduce the Utilities' proposed electric revenue requirement increases by $14.7 million for KU and $10.1 million for LG&E. In addition to contributing to reducing the Utilities' proposed electric revenue requirement increases in these proceedings, these revised depreciation rates will reduce environmental cost recovery ("ECR") revenue requirements by $19.1 million for KU and $16.8 million for LG&E relative to the Utilities' proposed depreciation rates as will be included in the ECR mechanism filings beginning with the July 2017 expense month.

(D) **KU Revenues Resulting from the Refined Coal Project at the Ghent Generating Station.** The stipulated revenue requirement increase for KU reflects a $9.1 million revenue-requirement reduction related to KU's contract proceeds resulting from KU's Refined Coal project at the Ghent Generating Station. KU discussed this issue at an Informal Conference held at the Commission on March 14, 2017, in the context of Case No. 2015-00264.

(E) **Updated Five-Year Average for Uncollectible Debt Expense.** The stipulated electric revenue requirement increases reflect the use of a five-year average (calendar years 2012-2016) for uncollectible debt expense, which is an update to the five-year average (2011-2015) that was available at the time the Utilities filed their applications in these proceedings. This approach reduces the Utilities' proposed electric revenue requirement increases by $0.5 million for KU and $0.3 million for LG&E.

(F) **Eight-Year Average for Generator Outage Expenses; Related Use of Regulatory Accounting.** The Parties agree to use an eight-year average of generator outage expenses in the Utilities' stipulated electric revenue requirement increases, where the average is of four historical years' expenses (2013-2016) and four years' forecasted expenses (2017-2020). This approach reduces the Utilities' proposed electric revenue requirement increases by $1.6 million for KU and $8.5 million for LG&E. Relatedly, the Parties agree to, and ask the Commission to approve, the Utilities' use of regulatory asset and liability accounting related to generator outage expenses that are greater or less than the eight-year average of the Utilities' generator outage expenses. This regulatory accounting will ensure the Utilities may collect, or will have to return to customers, through future base rates any amounts that are above or below the eight-year average embedded in the stipulated electric revenue requirement increases in these proceedings.

(G) **Adjustment Related to Construction Work in Progress Capital.** The Parties agree to adjust the Utilities' proposed electric revenue requirement increases to reflect differences ("slippage") between past projected and historical capital amounts for construction work in progress ("CWIP"). This adjustment reduces the Utilities' proposed electric revenue requirement increases by $0.7 million for KU and $0.4 million for LG&E.

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2.3. Summary Calculation of Electric Revenue Requirement Increases. The table below shows the calculation of the stipulated electric revenue requirement increases:

Item	KU	LG&E
Proposed electric revenue requirement increases	$103.1 million	$94.1 million
Remove AMS	($6.3 million)	($5.2 million)
9.75% return on equity	($15.3 million)	($10.1 million)
Revised depreciation rates	($14.7 million)	($10.1 million)
KU Refined Coal revenues	($9.1 million)	n/a
5-year average uncollectible expense	($0.5 million)	($0.3 million)
8-year average generator outage expense	($1.6 million)	($8.5 million)
CWIP capital slippage	($0.7 million)	($0.4 million)
Stipulated electric revenue requirement increases	$54.9 million	$59.4 million[1]

ARTICLE III. GAS REVENUE REQUIREMENT

3.1. LG&E Gas Revenue Requirement. The Parties stipulate and agree that, effective for service rendered on and after July 1, 2017, an increase in annual revenues for LG&E gas operations of $7,500,000, for purposes of determining the rates of LG&E gas operations in the Rate Proceedings, is fair, just and reasonable for the Parties and for all gas customers of LG&E.

[1] Stipulated LG&E electric revenue requirement increase differs from proposed revenue requirement increase less adjustments shown due to rounding.

3.2. Items Reflected in Stipulated Gas Revenue Requirement Increase. The Parties agree that the stipulated gas revenue requirement was calculated by beginning with LG&E's gas revenue requirement increase as presented and supported by LG&E in its application in Case No. 2016-00371 and as revised through discovery ($13.4 million) and adjusting the proposed gas revenue requirement increase by the following items, which the Parties ask and recommend the Commission accept as reasonable without modification:

(A) **Removal of AMS Cost Recovery.** Because the Utilities are withdrawing their request for CPCNs and cost recovery for their proposed full deployment of AMS, recovery of AMS costs is being removed from LG&E's gas revenue requirement. This reduces LG&E's proposed gas revenue requirement increase by $0.7 million, consisting solely of carrying cost and depreciation expense.

(B) **Return on Equity.** The Parties agree that a return on equity of 9.75% is reasonable for LG&E's gas operations, and the agreed stipulated revenue requirement increase for LG&E's gas operations reflect that return on equity as applied to LG&E's gas capitalization and capital structure underlying its originally proposed gas revenue requirement increase as modified through discovery. Use of a 9.75% return on equity reduces LG&E's proposed gas revenue requirement increase by $2.9 million.

(C) **Depreciation Rates.** The stipulated gas revenue requirement increase reflects the depreciation rates shown in Stipulation Exhibit 3, which reduce LG&E's proposed gas revenue requirement increase by $2.1 million.

(D) **Updated Five-Year Average for Uncollectible Debt Expense.** The stipulated gas revenue requirements increase reflects the use of a five-year average (calendar years 2012-2016) for uncollectible debt expense, which is an update to the five-year average

(2011-2015) that was available at the time LG&E filed its application in Case No. 2016-00371. This approach reduces LG&E's proposed gas revenue requirement increase by $0.1 million.

3.3. Summary Calculation of Gas Revenue Requirement Increase. The table below shows the calculation of the stipulated gas revenue requirement increase:

Item	LG&E Gas
Proposed gas revenue requirement increase	$13.4 million
Remove AMS	($0.7 million)
9.75% return on equity	($2.9 million)
Revised depreciation rates	($2.1 million)
5-year average uncollectible expense	($0.1 million)
Stipulated gas revenue requirement increase	$7.5 million[2]

ARTICLE IV. <u>REVENUE ALLOCATION AND RATE DESIGN</u>

4.1. Revenue Allocation. The Parties hereto agree that the allocations of the increases in annual revenues for KU and LG&E electric operations, and that the allocation of the increase in annual revenue for LG&E gas operations, as set forth on the allocation schedules designated Stipulation Exhibit 4 (KU), Stipulation Exhibit 5 (LG&E electric), and Stipulation Exhibit 6 (LG&E gas) attached hereto, are fair, just, and reasonable for the Parties and for all customers of LG&E and KU.

4.2. Tariff Sheets. The Parties hereto agree that, effective July 1, 2017, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Stipulation Exhibit 7

[2] Stipulated gas revenue requirement increase differs from proposed revenue requirement increase less adjustments shown due to rounding.

(KU), Stipulation Exhibit 8 (LG&E electric), and Stipulation Exhibit 9 (LG&E gas) attached hereto, which rates the Parties unanimously stipulate are fair, just, and reasonable, and should be approved by the Commission.

4.3. Basic Service Charges. The Parties agree that the following monthly basic service charge amounts shall be implemented on the schedule shown:

Rates	Effective July 1, 2017	Effective July 1, 2018
LG&E and KU Rates RS, VFD, RTOD-Energy, and RTOD-Demand	$11.50	$12.25
LG&E Rates RGS and VFD	$16.35	$16.35

All other basic service charges shall be the amounts reflected in the proposed tariff sheets attached hereto in Stipulation Exhibits 7 (KU), 8 (LG&E electric), and 9 (LG&E gas).

4.4. Curtailable Service Riders. Concerning the Utilities' Curtailable Service Riders ("CSR"), the Parties agree that CSR customers may choose between Options A and B as follows:

(A) Option A: The Utilities' proposed CSR credits and tariff provisions as filed in these proceedings.

(B) Option B: The Utilities' existing CSR tariff provisions with the modifications below:

(i) CSR credits for both Utilities of $6.00 per kVA-month (primary) and $5.90 per kVA-month (transmission).

(ii) A Utility may request physical curtailment when more than 10 of the Utilities' primary combustion turbines (CTs) (those with a capacity greater than 100 MW) are being dispatched, irrespective of whether the Utilities are making off-system sales. However, to avoid a physical curtailment a CSR customer may buy through a requested curtailment at the Automatic Buy-Through Price. If all available units have been dispatched or are being dispatched, the Utilities may request a physical curtailment of the CSR customer without a buy-through option.

(iii) A Utility may request physical curtailment of a CSR customer no more than 20 times per calendar year totaling no more than 100 hours. Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 hours of economic curtailments.

(iv) After receiving a physical curtailment request from the Utility where a buy-through option is available, a CSR customer will have 10 minutes to inform the Utility whether the customer elects to buy through or physically curtail. If the customer elects to physically curtail, the customer will have 30 minutes to carry out the required physical curtailment (i.e., a total of 40 minutes from the time the Utility requests curtailment to the time the customer must implement the curtailment). If a customer does not respond within 10 minutes of notice of a curtailment request from the Utility, the customer will be assumed to have elected to buy through the requested curtailment, subject to any prior written agreement with the customer.

(v) After receiving a physical curtailment request from the Utility when no buy-through option is available, a CSR customer will have 40 minutes to carry out the required physical curtailment.

(C) The Utilities will initially assign all existing CSR customers to Option B as described above. Following the initial assignment, a CSR customer may elect Option A at any time, which election will take effect beginning with the customer's first full billing cycle following the election. After a CSR makes its first election or any subsequent election, the customer must take service under the chosen option for at least 24 full billing cycles before a new election can become effective.

(D) LG&E will permit any customer interested in participating in CSR to give notice of interest by July 1, 2017; after that date, only those customers already participating in LG&E's CSR may continue their participation at their then-current levels. Customers that have given notice of interest on or before July 1, 2017, may elect to begin participating in CSR no later than January 1, 2019. LG&E's existing capacity cap will continue to apply, and all available CSR capacity will be available for participation on a first come, first served basis to those giving notice of interest by July 1, 2017.

(E) KU's CSR will be closed to new or increased participation as of July 1, 2017.

These proposed tariff changes are shown in Stipulation Exhibits 7 (KU) and 8 (LG&E electric) attached hereto.

4.5. Five-Year Limit to Gas Line Tracker Recovery for Transmission Modernization and Steel Service Line Replacement Programs. The Parties agree that LG&E will recover costs related to its proposed Transmission Modernization and Steel Service Line Replacement Programs through its Gas Line Tracker ("GLT") cost-recovery mechanism for five years ending June 30, 2022. Absent further action by the Commission concerning recovery of these programs' costs by June 30, 2022, any remaining costs for such programs will be recovered through base rates via a base-rate roll-in effective for service rendered on and after July 1, 2022. These proposed tariff changes are shown in Stipulation Exhibit 9 attached hereto. This provision does not preclude LG&E from seeking Commission approval to recover other appropriate costs through the GLT mechanism.

4.6. Revisions to Proposed Substitute Gas Sales Service (Rate SGSS). The Parties agree that LG&E will revise its proposed Rate SGSS such that monthly billing demand will be based on greatest of (1) Maximum Daily Quantity ("MDQ"), (2) current month's highest daily volume of gas delivered, or (3) 70 percent of the highest daily volume of gas delivered during the previous 11 monthly billing periods. Also, LG&E will revise the provision of Rate SGSS concerning setting the MDQ such that the MDQ for any customer taking service under Rate SGSS when it first becomes effective will be 70% of the highest daily volume projected by LG&E for the customer in the forecasted test year used by LG&E in Case No. 2016-00371. For all other customers that later begin taking service under Rate SGSS, the customer and LG&E may mutually agree to establish the level of the MDQ; provided, however, that in the event that the customer and LG&E cannot agree upon the MDQ, then the level of the MDQ will be equal to 70% of the highest daily volume used by the customer during the 12 months prior to the date the customer began receiving natural gas from another supplier with which the customer is physically connected; in the event that such daily gas usage is not available, then the MDQ will be equal to 70% of the customer's average daily use for the highest month's gas use in the 12 months prior to the date the customer began receiving natural gas from another supplier with which the customer is physically connected. In no case will the MDQ be greater than 5,000 Mcf/day. These proposed tariff changes are shown in Stipulation Exhibit 9 attached hereto.

4.7. Sports Field Lighting Pilot Tariff Provisions. The Parties agree that the Utilities will add to their electric tariffs a voluntary sports field lighting rate schedule, Pilot Rate OSL – Outdoor Sports Lighting Service, on a limited-participation pilot basis (limited to 20 pilot participants per Utility). The pilot rate uses a time-of-day rate structure. The purpose of the pilot is to determine if sports fields have sufficiently different service characteristics to support permanent sports field tariff offerings. The proposed tariff provisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.8. Agreement Not to Split Residential and General Service Electric Energy Charges in Tariffs. The Parties agree that the Utilities will not split their residential and general service electric energy charges into Infrastructure and Variable components as the Utilities had proposed in their applications in these proceedings. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.9. Agreement to File a Study Regarding 100% Base Demand Ratchets for Rate TODS. The Utilities will file in their next base-rate proceedings a study concerning the impacts of 100% base demand ratchets for Rate TODS.

4.10. Rate TODP 60-Minute Exemption from Setting Billing Demand Following Utility System Fault. For customers with their own generation, for 60 minutes immediately following a Utility-system fault, but not a Utility energy spike or a fault on a customer's system, the Utilities will not use any demand data for a Rate TODP customer to set billing demand. This 60-minute exemption from setting billing demand permits customers who have significant onsite generation (i.e., 1 MW or more) that comes offline due to a Utility-system fault to reset and bring back online their own generation before the Utilities will measure demand to be used for billing purposes. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.11. Optional Pilot Rates for Schools Subject to KRS 160.325. The Parties agree that the Utilities will add to their electric tariffs optional pilot tariff provisions for schools subject to KRS 160.325. The pilot rates will not be limited in the number of schools that may participate, but will be limited by the projected revenue impact to the Utilities. Each utility's pilot rate provisions will be available to new participants until the total projected revenue impact (reduction) for each Utility is $750,000 annually compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served. KSBA will be responsible for proposing schools for participation in the pilot rates and the order in which such schools are proposed; the Utilities will calculate and provide to KSBA the projected revenue impact of each proposed school's taking service under pilot rates. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

ARTICLE V. TREATMENT OF CERTAIN SPECIFIC ISSUES

5.1. Regulatory Accounting for Over- and Under-Recovery of Regulatory Assets. The Parties agree to, and ask the Commission to approve, the Utilities' continued use of regulatory asset accounting for regulatory assets embedded in the Utilities' proposed revenue requirement except that shorter-lived regulatory assets should be credited for the amounts collected through base rates even if such amortization results in changing such a regulatory asset to a regulatory liability with any remaining balances being addressed in the Utilities' next base rate case. This would include the regulatory assets for rate case expenses, 2011 summer storm expenses, and Green River. This will help ensure the Utilities only recover actual costs incurred and do not ultimately over-recover such regulatory assets as they are amortized and recovered through base rates.

5.2. Commitment to Apply for School Energy Managers Program ("SEMP") Extension. The Utilities commit to file with the Commission an application proposing a two-year extension of SEMP (for July 1, 2018, through June 30, 2020). The total annual level of funding to be proposed is $725,000; prior to filing the application, the Utilities will consult with

KSBA to determine an appropriate allocation of the total annual funds between KU and LG&E. The Utilities commit to file the above-described application with the Commission no later than December 31, 2017.

5.3. Commitment to File Lead-Lag Study in Next Base-Rate Cases. The Utilities commit to file a lead-lag study in their next base-rate cases.

5.4. Collaborative Study Regarding Electric Bus Infrastructure and Rates. The Utilities commit to fund a study concerning economical deployment of electric bus infrastructure in the Louisville and Lexington areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses. The Utilities commit to work collaboratively with Louisville Metro, LFUCG, and any other interested Parties to these proceedings to develop the parameters for the study, including reasonable cost and timing, and to review the study's results with representatives of Louisville Metro and LFUCG. The collaborative will include only those Parties to these proceedings interested in participating in the collaborative.

5.5. LED Lighting Collaborative. The Utilities commit to engage in good faith with Louisville Metro, LFUCG, and any other interested Parties to these proceedings in a collaborative to discuss issues related to LED lighting to determine what LED street lighting equipment and rate structures might be offered by the Utilities. The collaborative will include only those Parties to these proceedings interested in participating in the collaborative.

5.6. Home Energy Assistance Charges. The Parties agree that KU will increase its monthly residential charge for the Home Energy Assistance ("HEA") program from the current $0.25 per month to $0.30 per month, which shall remain effective through June 30, 2021, regardless of whether the Utilities file one or more base-rate cases during that commitment period. The Parties further agree that LG&E will continue its monthly residential charge (for gas and electric service) for the Home Energy Assistance ("HEA") program at $0.25 per month, which shall remain effective until the effective date of new base rates for the Utilities following their next general base-rate cases. The change to the KU HEA charge is reflected in the proposed tariff sheets attached hereto as Stipulation Exhibit 7.

5.7. Low-Income Customer Support. The Utilities commit to contribute a total of $1,450,000 of shareholder funds per year, which commitment will remain in effect through June 30, 2021, regardless of whether the Utilities file one or more base-rate cases during that commitment period.

(A) The total annual shareholder contribution from KU shall be as follows: $100,000 for Wintercare and $470,000 for HEA. CAC administers both programs.

(B) The total annual shareholder contribution from LG&E shall be as follows: $700,000 to ACM for utility assistance and $180,000 for HEA.

(C) KU agrees that up to 10% of its total contributions to CAC may be used for reasonable administrative expenses.

(D) LG&E agrees that up to 10% of its total contributions to ACM may be used for reasonable administrative expenses.

(E) None of the Utilities' shareholder contributions will be conditioned upon receiving matching funds from other sources.

(F) The Utilities commit not to seek reductions to their HEA charges that would become effective before June 30, 2021, for LG&E or KU regardless of whether the Utilities file one or more base-rate cases during that commitment period.

5.8. All Other Relief Requested by Utilities to Be Approved as Filed. The Parties agree and recommend to the Commission that, except as modified in this Stipulation and the exhibits attached hereto, the rates, terms, and conditions contained in the Utilities' filings in these Rate Proceedings, as well as the Companies' requests for CPCNs for their proposed Distribution Automation project, should be approved as filed.

ARTICLE VI. MISCELLANEOUS PROVISIONS

6.1. Except as specifically stated otherwise in this Stipulation, entering into this Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

6.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Stipulation.

6.3. Following the execution of this Stipulation, the Parties shall cause the Stipulation to be filed with the Commission on or about April 19, 2017, together with a request to the Commission for consideration and approval of this Stipulation for rates to become effective for service rendered on and after July 1, 2017.

6.4. This Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the Stipulation is a fair, just, and reasonable means of resolving all issues in these proceedings, and will clearly and definitively ask the Commission to accept and approve the Stipulation as such.

6.5. If the Commission issues an order adopting this Stipulation in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order. With regard to this provision, all of the Parties acknowledge that certain of the Parties, and in particular the Sierra Club, are entities with members who are not under a Party's control but who might purport to act for, or on behalf of, the Party. Therefore, the Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation. All Parties agree that no monetary damages will be sought or obtained from a Party if the Party is not in breach, but rather a non-Party purporting to act for the Party has sought rehearing or appeal of a Commission order adopting this Stipulation in its entirety and without additional conditions.

6.6. If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

6.7. If the Stipulation is voided or vacated for any reason after the Commission has approved the Stipulation, none of the Parties will be bound by the Stipulation.

6.8. The Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

6.9. The Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

6.10. The Stipulation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Stipulation.

6.11. The Parties hereto agree that, for the purpose of the Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

6.12. The Parties hereto agree that neither the Stipulation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Stipulation. This Stipulation shall not have any precedential value in this or any other jurisdiction.

6.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Stipulation and based upon the foregoing are authorized to execute this Stipulation on behalf of their respective Parties.

6.14. The Parties hereto agree that this Stipulation is a product of negotiation among all Parties hereto, and no provision of this Stipulation shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Stipulation, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Stipulation shall be implemented as written.

6.15. The Parties hereto agree that this Stipulation may be executed in multiple counterparts.

APPENDIX A: LIST OF STIPULATION EXHIBITS

Stipulation Exhibit 1: KU Depreciation Rates

Stipulation Exhibit 2: LG&E Electric Depreciation Rates

Stipulation Exhibit 3: LG&E Gas Depreciation Rates

Stipulation Exhibit 4: KU Revenue Allocation Schedule

Stipulation Exhibit 5: LG&E Electric Revenue Allocation Schedule

Stipulation Exhibit 6: LG&E Gas Revenue Allocation Schedule

Stipulation Exhibit 7: KU Tariff Sheets

Stipulation Exhibit 8: LG&E Electric Tariff Sheets

Stipulation Exhibit 9: LG&E Gas Tariff Sheets

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: ______________________
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (KRR w/permission)
Allyson K. Sturgeon

Association of Community Ministries, Inc.

HAVE SEEN AND AGREED:

By: ______________________

Lisa Kilkelly

Eileen Ordover

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By: ______________________

Kent Chandler
Lawrence W. Cook
Rebecca W. Goodman

Community Action Council for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE SEEN AND AGREED:

By:____________________________
Iris G. Skidmore

United States Department of Defense and All Other
Federal Executive Agencies

HAVE SEEN AND AGREED:

By: Emily W. Medlyn

Emily W. Medlyn
G. Houston Parrish

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: Michael L. Kurtz

Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn

Kentucky League of Cities

HAVE SEEN AND AGREED:

By: ______________________

Laura Ross

The Kroger Company

HAVE SEEN AND AGREED:

By: Robert C. Moore

Robert C. Moore

Kentucky School Boards Association

HAVE SEEN AND AGREED:

By: Matthew R Malone (KRR w/ permission)

Matthew R. Malone

William H. May, III

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: M. Todd Osterloh

James W. Gardner
M. Todd Osterloh
David J. Barberie
Andrea C. Brown
Janet M. Graham

Subject to ratification by the Urban County Council

Louisville/Jefferson County Metro Government

HAVE SEEN AND AGREED:

By: [signature]
Michael J. O'Connell,
Jefferson County Attorney

-and-

By: [signature]
Gregory T. Dutton,
Counsel for Louisville Metro

Metropolitan Housing Coalition

HAVE SEEN AND AGREED:

By: Tom FitzGerald (KRR w/ permission)
Tom FitzGerald

Sierra Club, Alice Howell, Carl Vogel
and Amy Waters

HAVE SEEN AND AGREED:

By: ______________________________
Joe F. Childers

____
Casey Roberts

____
Matthew E. Miller

JBS Swift & Co.

HAVE SEEN AND AGREED:

By:________________________________

Dennis G. Howard, II

Wal-Mart Stores East, LP and Sam's East, Inc.

HAVE SEEN AND AGREED:

By:______________________________
Barry N. Naum
Don C.A. Parker

SECOND STIPULATION AND RECOMMENDATION

This Second Stipulation and Recommendation ("Second Stipulation") is entered into this first day of May 2017 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"), and Kentucky Cable Telecommunications Association ("KCTA"). (Collectively, the Utilities, AT&T and KCTA are the "Parties.")

W I T N E S S E T H:

WHEREAS, on November 23, 2016, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00370 to review KU's base rate application, in which KU requested a revenue increase of $103.1 million;

WHEREAS, on November 23, 2016, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00371 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $93.6 million and a revenue increase of $13.8 million for its gas operations (Case Nos. 2016-00370 and 2016-00371 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, on February 20, 2017, LG&E filed with the Commission in Case No. 2016-00371 a Supplemental Response to Commission Staff's First Request for Information No. 54 in which LG&E corrected its requested revenue increases for its electric operations to be $94.1 million and for its gas operations to be $13.4 million;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00370 to the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"), AT&T, Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"), KCTA, Kentucky Industrial Utility Customers, Inc. ("KIUC"), Kentucky League of Cities ("KLC"), The Kroger Company ("Kroger"), Kentucky School Boards Association ("KSBA"), Lexington-Fayette Urban County Government ("LFUCG"), Sierra Club, Alice Howell, and Carl Vogel, and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart");

WHEREAS, the Commission has granted full intervention in Case No. 2016-00371 to Association of Community Ministries, Inc., AG, AT&T, United States Department of Defense and All Other Federal Executive Agencies, KCTA, KIUC, Kroger, KSBA, Louisville/Jefferson County Metro Government, Metropolitan Housing Coalition, Sierra Club and Amy Waters, JBS Swift & Co., and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of a stipulation and recommendation, attended by representatives of the Parties and the Commission Staff, took place on April 12, 13, and 17, 2017, at the offices of the Commission, which representatives of AT&T and KCTA also attended on April 12 and 13, and which representatives of KCTA also attended on April 17, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, all parties to these proceedings except AT&T and KCTA reached agreement and entered into a stipulation and recommendation ("First Stipulation"), which the Utilities filed with the Commission on April 19, 2017;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of this Second Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 25, 2017, at the offices of the Commission, during which a number of procedural and substantive issues were discussed;

WHEREAS, it is understood by all Parties hereto that this Second Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Second Stipulation;

WHEREAS, the Parties agree that this Second Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues addressed herein, and that the First and Second Stipulations, considered together, produce a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Second Stipulation, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. <u>RATE PSA MODIFICATIONS</u>

1.1. Attachment Charges for Wireline Facilities. The Parties stipulate that an annual attachment charge of $7.25 for a wireline facility is fair, just, and reasonable. The Commission previously approved this charge in the Utilities' most recent general rate case proceedings, Cases No. 2014-00371 and No. 2014-00372. The Utilities have not proposed to adjust this rate, which assumes that a wireline facility will require one foot of usable pole space. AT&T and KCTA have previously advised the Commission that they have no objections to this rate remaining in effect.

1.2. Attachment Charges for Pole-Top Wireless Facilities. The Parties stipulate that a fair, just, and reasonable rate for wireless facilities attached to the top of the Utilities' structures is $36.25 per year. They agree that for purposes of determining the annual charge, a pole-top wireless facility should be allocated five feet of usable pole space. The Utilities assert that this allocation is based upon the premise that, as the Utilities typically have electric facilities located at or near the top of their distribution poles, a pole top wireless facility, such as an antenna, requires a five foot taller pole to maintain a safe working distance of at least 48 inches between the electric facilities and the pole top antenna. Thus, the Utilities assert that the Wireless Facility owner is responsible for the top 5 feet of the pole: one foot for the antenna and four feet of clearance above the power space. Without adopting the Utilities' assertions set out in the preceding two sentences, AT&T agrees that an allocation of five feet of usable pole space is supported by evidence in the record. As the Commission has previously approved the annual rate of $7.25 for one foot of pole space, the use of five feet will produce an annual charge of $36.25.

1.3. Attachment Charges for Mid-Pole Wireless Facilities. The Parties stipulate and agree that, given the lack of information regarding the size and characteristic of wireless antennas and other devices that may be attached to an electric utility pole in the communications space, a uniform rate for such attachments cannot be easily developed and that the rate for such attachments should be developed on a case-by-case basis through special contracts until a sufficient number of such attachments have been made to the Utilities' structures to develop a tariffed rate. At the time of their next general rate applications, the Utilities will determine if they have sufficient evidence regarding mid-pole devices to determine whether a uniform rate is appropriate and, if so, revise the PSA Rate Schedule accordingly.

1.4. Terms and Conditions of Rate PSA. The Parties stipulate and agree that revisions to the originally proposed version of the PSA Rate Schedule are necessary to afford sufficient flexibility for Attachment Customers to permit them to operate effectively in the unregulated, market-based telecommunications industry. The revised PSA Rate Schedules, which are shown in Exhibits 1 and 2 to this Second Stipulation, with the proposed additions and deletions clearly marked, appropriately balance an Attachment Customer's need for flexibility with the public's interest in reliable and safe electric service. The Parties stipulate that, as revised, the terms and conditions set forth in the proposed PSA Rate Schedule are fair, just, and reasonable, will promote public safety, enhance the reliability of electric service, and ensure fair and uniform treatment of Attachment Customers as well as promote the deployment and adoption of advanced communications services.

ARTICLE II. FIRST STIPULATION

2.1. No objections. AT&T and KCTA have reviewed the First Stipulation filed with the Commission on April 19, 2017 and have no objections to it, except to the extent the First

Stipulation's electric tariff exhibits contained PSA Rate Schedules inconsistent with this Second Stipulation and its exhibits, in which case the latter should control.

2.2. AMS Collaborative. The Parties agree that the Utilities shall notify AT&T and KCTA if and when it engages in any AMS Collaborative pursuant to the First Stipulation § 1.2 and that AT&T and KCTA may, at their option, participate in any or all phases of the AMS Collaborative.

ARTICLE III. MISCELLANEOUS PROVISIONS

3.1. Except as specifically stated otherwise in this Second Stipulation, entering into this Second Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

3.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Second Stipulation.

3.3. Following the execution of this Second Stipulation, the Parties shall cause it to be filed with the Commission on or about May 1, 2017, together with a request to the Commission for consideration and approval of this Second Stipulation for rates to become effective for service rendered on and after July 1, 2017.

3.4. This Second Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Second Stipulation and the First Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the First and Second Stipulations, taken together, produce a fair, just, and reasonable means of resolving all issues in these proceedings, and will clearly and definitively ask the Commission to accept and approve the First and Second Stipulations as such.

3.5. If the Commission issues an order adopting this Second Stipulation in its entirety and without additional conditions, irrespective of whether the Commission approves the terms of the First Stipulation, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to the portions of such order that concern this Second Stipulation. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation. All Parties agree that no monetary damages will be sought or obtained from a Party if the Party is not in breach, but rather a non-Party purporting to act for the Party has sought rehearing or appeal of a Commission order adopting this Second Stipulation in its entirety and without additional conditions.

3.6. If the Commission does not accept and approve this Second Stipulation in its entirety and without additional conditions, then any adversely affected Party may withdraw from the Second Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all

Parties that have not withdrawn will continue to be bound by the terms of the Second Stipulation as modified by the Commission's order.

3.7. If the Second Stipulation is voided or vacated for any reason after the Commission has approved the Second Stipulation, none of the Parties will be bound by the Second Stipulation.

3.8. The Second Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

3.9. The Second Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

3.10. The Second Stipulation, including its Exhibits, constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Second Stipulation.

3.11. The Parties hereto agree that, for the purpose of the Second Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

3.12. The Parties hereto agree that neither the Second Stipulation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Second Stipulation. This Second Stipulation shall not have any precedential value in this or any other jurisdiction.

3.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Second

Stipulation and based upon the foregoing are authorized to execute this Second Stipulation on behalf of their respective Parties.

3.14. The Parties hereto agree that this Second Stipulation is a product of negotiation among all Parties hereto, and no provision of this Second Stipulation shall be strictly construed in favor of or against any party.

3.15. The Parties hereto agree that this Second Stipulation may be executed in multiple counterparts.

(This space intentionally left blank.)

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (with permission KRR)
Allyson K. Sturgeon

BellSouth Telecommunications, LLC d/b/a AT&T Kentucky

HAVE SEEN AND AGREED:

By: Cheryl R Winn

Cheryl R. Winn

Kentucky Cable Telecommunications Association

HAVE SEEN AND AGREED:

By: ______________________________

Gardner F. Gillespie
Paul Werner
Megan Grant

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00371 DATED JUN 2 2 2017

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

SCHEDULE RS
RESIDENTIAL SERVICE

Basic Service Charge per Month	$12.25
Energy Charge per kWh	$ .09153

SCHEDULE RTOD-ENERGY
RESIDENTIAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Month	$12.25
Energy Charge per kWh	
Off Peak Hours	$ .06653
On Peak Hours	$ .23263

SCHEDULE RTOD-DEMAND
RESIDENTIAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Month	$12.25
Energy charge per kWh	$ 0.04956
Demand Charge per kW	
Off Peak Hours	$ 3.51
On Peak Hours	$ 7.68

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT

Basic Service Charge per Month	$12.25
Energy Charge per kWh	$ .09153

SCHEDULE GS
GENERAL SERVICE RATE

Basic Service Charge per Month – Single Phase	\$ 31.50
Basic Service Charge per Month – Three Phase	\$ 50.40
Energy Charge per kWh	\$ .09935

SCHEDULE PS
POWER SERVICE

Secondary Service:	
Basic Service Charge per Month	\$ 90.00
Demand Charge per kW:	
Summer Rate	\$ 20.21
Winter Rate	\$ 17.56
Energy Charge per kWh	\$ .04047

Primary Service:	
Basic Service Charge per Month	\$240.00
Demand Charge per kW:	
Summer Rate	\$ 17.55
Winter Rate	\$ 15.03
Energy Charge per kWh	\$ .03903

SCHEDULE TODS
TIME-OF-DAY SECONDARY SERVICE

Basic Service Charge per Month	\$200.00
Maximum Load Charge per kW:	
Base Demand Period	\$ 4.61
Intermediate Demand Period	\$ 4.91
Peak Demand Period	\$ 6.70
Energy Charge per kWh	\$ .04029

SCHEDULE TODP
TIME-OF-DAY PRIMARY SERVICE

Basic Service Charge per Month	\$330.00
Maximum Load Charge per kVA:	
Base Demand Period	\$ 3.01
Intermediate Demand Period	\$ 4.76
Peak Demand Period	\$ 6.49
Energy Charge per kWh	\$ .03797

SCHEDULE RTS
RETAIL TRANSMISSION SERVICE

Basic Service Charge per Month	$1,500.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.43
Intermediate Demand Period	$ 4.82
Peak Demand Period	$ 6.57
Energy Charge per kWh	$ .03670

SCHEDULE FLS
FLUCTUATING LOAD SERVICE

Primary:

Basic Service Charge per Month	$ 330.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.68
Intermediate Demand Period	$ 4.24
Peak Demand Period	$ 5.96
Energy Charge per kWh	$ .03797

Transmission:

Basic Service Charge per Month	$1,500.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.27
Intermediate Demand Period	$ 4.30
Peak Demand Period	$ 6.03
Energy Charge per kWh	$ .03671

SCHEDULE LS
LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

Overhead:

	Fixture Only
High Pressure Sodium:	
16,000 Lumens - Cobra Head	$13.78
28,500 Lumens - Cobra Head	$16.17
50,000 Lumens - Cobra Head	$18.61
16,000 Lumens - Directional	$14.73
50,000 Lumens - Directional	$19.44
9,500 Lumens - Open Bottom	$11.93

Metal Halide

32,000 Lumens - Directional		$19.89	

Light Emitting Diode (LED):

8,179 Lumens - Cobra Head		$14.36	
14,166 Lumens - Cobra Head		$17.43	
23,214 Lumens - Cobra Head		$26.75	
5,007 Lumens - Open Bottom		$9.48	

Underground:

	Fixture Only	Decorative Smooth	Historic Fluted
High Pressure Sodium:			
5,800 Lumens - Colonial, 4-Sided		$21.32	
9,500 Lumens - Colonial, 4-Sided		$22.08	
16,000 Lumens - Colonial, 4-Sided		$22.21	
5,800 Lumens - Acorn		$21.72	
9,500 Lumens - Acorn		$24.20	
16,000 Lumens - Acorn		$24.20	
5,800 Lumens - London			$37.11
9,500 Lumens - London			$37.15
5,800 Lumens - Victorian			$34.79
9,500 Lumens – Victorian			$36.94
4,000 Lumens - Dark Sky		$25.33	
9,500 Lumens - Dark Sky		$25.98	
Victorian/London Bases - Westchester/Norfolk			$ 3.71
16,000 Lumens - Cobra Head		$28.49	
28,500 Lumens - Cobra Head		$30.81	
50,000 Lumens - Cobra Head		$36.78	
16,000 Lumens - Contemporary	$17.42	$32.18	
28,500 Lumens - Contemporary	$19.37	$34.78	
50,000 Lumens - Contemporary	$23.55	$40.59	

Metal Halide

32,000 Lumens - Contemporary	$21.67	$32.77	

Light Emitting Diode (LED):

8,179 Lumens - Cobra Head	\$52.66
14,166 Lumens - Cobra Head	\$55.73
23,214 Lumens - Cobra Head	\$65.05
5,665 Lumens - Colonial	\$45.46

SCHEDULE RLS
RESTRICTED LIGHTING SERVICE

Overhead:

	Fixture Only	Fixture and Wood Pole	Fixture and Ornamental Pole
Mercury Vapor:			
8,000 Lumens - Cobra/O.B.	\$10.50		
13,000 Lumens - Cobra Head	\$11.97		
25,000 Lumens - Cobra Head	\$14.76		
60,000 Lumens - Cobra Head	\$30.17		
25,000 Lumens - Directional	\$16.84		
60,000 Lumens - Directional	\$31.40		
4,000 Lumens - Open Bottom	\$ 8.98		
Metal Halide			
12,000 Lumens - Directional	\$13.81	\$16.48	
32,000 Lumens - Directional		\$22.18	\$29.64
107,800 Lumens - Directional	\$42.04	\$45.23	
Wood Pole:			
Installed Before 3/1/2010	\$11.32		
Installed Before 7/1/2004	\$ 2.15		

Underground:

	Fixture Only	Decorative Smooth
High Pressure Sodium:		
16,000 Lumens - Cobra/Contemporary		\$26.96
28,500 Lumens - Cobra/Contemporary		\$29.65
50,000 Lumens - Cobra/Contemporary		\$34.03
5,800 Lumens - Coach/Acorn		\$15.84

9,500 Lumens - Coach/Acorn		$19.04
16,000 Lumens - Coach/Acorn		$23.67
120,000 Lumens - Contemporary	$45.11	$76.24
9,500 Lumens - Acorn, Bronze		$25.35
16,000 Lumens - Acorn, Bronze		$26.94
5,800 Lumens - Victorian	$21.28	
9,500 Lumens - Victorian	$22.33	
5,800 Lumens - London	$21.44	
9,500 Lumens - London	$22.83	
5,800 Lumens - London		$35.08
9,500 Lumens - London		$36.02
5,800 Lumens - Victorian		$34.11
9,500 Lumens - Victorian		$36.26
<u>Victorian/London Bases</u>:		
Old Town		$ 3.62
Chesapeake		$ 3.82
<u>Poles</u>:		
10' Smooth Pole		$10.82
10' Fluted Pole		$12.91
<u>Mercury Vapor</u>:		
8,000 Lumens - Cobra Head		$18.53
13,000 Lumens - Cobra Head		$20.41
25,000 Lumens - Cobra Head		$24.43
25,000 Lumens - Cobra (State of KY Pole)	$23.84	
4,000 Lumens - Coach		$13.39
8,000 Lumens - Coach		$15.27
<u>Metal Halide</u>:		
12,000 Lumens - Contemporary	$15.44	$25.91
107,800 Lumens - Contemporary	$45.01	$56.09
<u>Incandescent</u>:		
1,500 Lumens - Continental Jr.		$ 9.57
6,000 Lumens - Continental Jr.		$ 13.93

SCHEDULE TE
TRAFFIC ENERGY SERVICE

Basic Service Charge per Month	$4.00
Energy Charge per kWh	$ .08277

SCHEDULE PSA
POLE AND STRUCTURE ATTACHMENT CHARGES

Per Year for Each Attachment to Pole	$ 7.25
Per Year for Each Linear Foot of Duct	$ .81
Per Year for Each Wireless Facility	$36.25

RATE CSR-1
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	$ 3.56	$ 3.67
Non-compliance Charge Per kVA	$16.00	$16.00

RATE CSR-2
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	$ 5.90	$ 6.00
Non-compliance Charge Per kVA	$ 16.00	$ 16.00

RC
REDUNDANT CAPACITY

Charge per kW/kVA per month	
Secondary Distribution	$ 1.59
Primary Distribution	$ 1.44

SPECIAL CONTRACTS

Fort Knox

Basic Service Charge per Month	$330.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 3.01
Intermediate Demand Period	$ 4.76
Peak Demand Period	$ 6.49
Energy Charge per kWh	$ .03797

Louisville Water Company

Demand Charge per kW:	$ 12.89
Energy Charge per kWh	$ .03853

EVSE
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:	
Single Charger	$180.46
Dual Charger	$302.04

EVC
ELECTRIC VEHICLE CHARGING SERVICE

Fee per Hour	$ 2.86

EVSE-R
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:	
Single Charger	$132.00
Dual Charger	$205.15

SSP
SOLAR SHARE PROGRAM RIDER

Monthly Charge:	
Solar Capacity Charge	$ 6.24

Solar Energy Credit per kWh of Pro Rata Energy Produced:	
RS	$ .03698
RTOD-Energy	$ .03698
RTOD-Demand	$ .03698
VFD	$ .03698
GS	$ .03698
PS Secondary	$ .04047
PS Primary	$ .03903
TODS	$ .04029
TODP	$ .03797

SPS
SCHOOL POWER SERVICE

Secondary Service:

Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Summer Rate	$16.73
Winter Rate	$14.53
Energy Charge per kWh	$ .04071

STOD
SCHOOL TIME-OF-DAY SERVICE

Basic Service Charge per Month	$200.00
Maximum Load Charge per kW:	
Base Demand Period	$ 4.13
Intermediate Demand Period	$ 4.64
Peak Demand Period	$ 6.13
Energy Charge per kWh	$ .04049

OSL
OUTDOOR SPORTS LIGHTING SERVICE

Secondary Service:

Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Peak Demand Period	$ 14.37
Base Demand Period	$ 4.29
Energy Charge per kWh	$ .04070

Primary Service:

Basic Service Charge per Month	$240.00
Demand Charge per kW:	
Peak Demand Period	$ 13.07
Base Demand Period	$ 3.01
Energy Charge per kWh	$ .03924

UNAUTHORIZED RECONNECT CHARGE

Tampering or Unauthorized Connection or Reconnection Fee:	
Meter Replacement Not Required	$ 70.00
Single Phase Standard Meter Replacement Required	$ 90.00
Single Phase AMR Meter Replacement Required	$ 110.00
Single Phase AMS Meter Replacement Required	$ 174.00

Three Phase Meter Replacement Required	$ 177.00

HEA
HOME ENERGY ASSISTANCE PROGRAM

Per Month	$ .25

GAS SERVICE RATES

RATE RGS
RESIDENTIAL GAS SERVICE

Basic Service Charge per Month	$ 16.35
Distribution Charge per Ccf	$ .36208

RATE VFD
VOLUNTEER FIRE DEPARTMENT SERVICE

Basic Service Charge per Month	$ 16.35
Distribution Charge per Ccf	$ .36208

RATE CGS
FIRM COMMERCIAL GAS SERVICE

Basic Service Charge per Month	
Meters < 5000 cf/hr	$ 60.00
Meters >= 5000 cf/hr	$ 285.00
Distribution Charge per Ccf	
	$ .25058 on peak
	$ .20058 off peak

Rider TS-2 Gas Transportation Service

Administrative Charge per Month	$ 550.00
Distribution Charge per Mcf	$ 2.5058 on peak
	$ 2.0058 off peak

RATE IGS
FIRM INDUSTRIAL GAS SERVICE

Basic Service Charge per Month	
Meters < 5000 cf/hr	$ 165.00
Meters >= 5000 cf/hr	$ 750.00
Distribution Charge per Ccf	$ .21929 on peak
	$ .16929 off peak

Rider TS-2 Gas Transportation Service

Administrative Charge per Month	$ 550.00
Customer Charge per Month	
Meters >= 5000 cf/hr	$ 750.00
Distribution Charge per Mcf	$ 2.1929 on peak
	$ 1.6929 off peak

RATE AAGS
AS-AVAILABLE GAS SERVICE

Basic Service Charge per Month	$ 500.00
Distribution Charge per Mcf	$ 1.0644

Rider TS-2 Gas Transportation Service

Administrative Charge per Month	$ 550.00
Customer Charge per Month	$ 500.00
Distribution Charge per Mcf	$ 1.0644

RATE DGGS
DISTRIBUTED GENERATION GAS SERVICE

Basic Service Charge per Month	
Meters < 5000 cf/hr	$ 165.00
Meters >= 5000 cf/hr	$ 750.00
Demand Charge per Ccf of Monthly Billing Demand	$ 1.08978
Distribution Charge per Ccf	$ .02992

RATE FT
FIRM TRANSPORTATION SERVICE

Administrative Charge per Month	$ 550.00
Distribution Charge per Mcf	$ .4435

RATE SGSS
SUBSTITUTE GAS SALES SERVICE

Customer Charge per Month	$ 285.00
Demand Charge per Mcf	$ 5.9809
Distribution Charge per Mcf	$ .3593

RATE LGDS
LOCAL GAS DELIVERY SERVICE

Administrative Charge per Month	$ 550.00
Basic Service Charge per Month	$1,310.00
Demand Charge per Mcf	$ 2.57
Distribution Charge per Mcf	$ .0388

INTRA-COMPANY SPECIAL CONTRACTS

Customer Charge per Month	$ 750.00
Demand Charge per Mcf	$ 10.8978
Distribution Charge per Mcf	$ .29920

GLT
GAS LINE TRACKER

	Distribution Projects (\$/delivery point)	Transmission Projects (\$/Ccf)
RGS – Residential Gas Service	$ .71	.00065
VFD – Volunteer Fire Department Service	$ .71	.00065
CGS – Commercial Gas Service	$ 3.53	.00050
IGS – Industrial Gas Service	$ 43.93	.00020
AAGS – As-Available Gas Service	$ 43.93	.00020
DGGS – Distributed Generation Gas Service	$ 43.93	.00020
SGSS – Substitute Gas Sales Service	$ 3.53	.00050
FT – Firm Transportation	$ 0.00	.00003
LGDS – Local Gas Delivery Service	$ 0.00	.00003

HEA
HOME ENERGY ASSISTANCE

Per Month	$ .25

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DEK EXHIBIT 4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF OF PUBLIC CONVENIENCE AND NECESSITY	))))	CASE NO. 2016-00370

ORDER

Kentucky Utilities Company ("KU") is a jurisdictional electric utility that generates, transmits, distributes, and sells electricity to consumers in portions of 77 counties in central, northern, southeastern, and western Kentucky.[1] Its most recent general rate increase was granted in Case No. 2014-00371.[2]

BACKGROUND

On October 21, 2016, KU filed a notice of its intent to file an application for approval of an increase in its electric rates based on a forecasted test year ending June 30, 2018. On November 23, 2016, KU filed its application, which included new rates to be effective January 1, 2017, based on a request to increase its electric revenues by $103.1 million, or 6.4 percent per year for the forecasted test period ending June 30, 2018, as compared to the operating revenues for the forecasted test period under existing electric rates.[3] The proposed increase would raise the monthly bill

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[1] *See* KU's Application, ¶ 2 for a list of the counties served.

[2] Case No. 2014-00371, *Application of Kentucky Utilities for an Adjustment of Its Electric Rates* (Ky. PSC June 30, 2015).

[3] Application, ¶ 6.

of an average residential customer by $7.16, or 5.9 percent.[4] The average KU residential customer consumes approximately 1,179 kilowatt-hours ("kWh") of electricity monthly.[5] KU's application included requests for Certificates of Public Convenience and Necessity ("CPCNs") to implement an Advanced Meter System ("AMS") and a Distribution Automation system ("DA"). KU stated that the AMS project would involve replacing approximately 530,000 existing electric meters in its service territory with AMS meters, which have two-way communications and remote service switching capabilities.[6] The estimated capital cost of the AMS project is $138.8 million.[7] The estimated incremental operating and maintenance cost during the deployment phase is approximately $13.7 million.[8] The deployment period was expected to begin in late 2017 and to be completed by the end of 2019.[9] KU also requested authority to establish a regulatory asset for the remaining net book value of the electric meters retired as a result of the proposed AMS project.[10] KU estimated that the amount of this regulatory asset would be approximately $26.9 million.[11] In connection with the proposed AMS project, KU also sought deviations from certain regulations dealing with meter inspections and testing.

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[4] *Id.*, ¶ 7.

[5] *Id.*

[6] *Id.*, ¶ 14.

[7] *Id.*

[8] *Id.*

[9] *Id.*

[10] *Id.*, ¶ 33.

[11] *Id.*

According to KU, the proposed DA project involves the extension of intelligent control over electric power grid functions to the distribution system level.[12] The project will enable KU's distribution system to provide real-time information and allow for remote monitoring, remote control, and automation of distribution line equipment.[13] For both KU and Louisville Gas & Electric Company ("LG&E"), KU's sister company,[14] the total capital cost of the proposed DA project is approximately $112 million.[15] The project will be completed in approximately seven years.[16] Of the total capital expenditure, KU estimated $23 million to be incurred before the end of the forecasted test year on June 30, 2018.[17] KU and LG&E (jointly "Companies") estimated the operations and maintenance ("O&M") expense related to the proposed DA project to be $6 million over the seven-year implementation period, $1.16 million of which will be incurred before the end of the forecasted test year.[18] The DA project will affect approximately 20 percent of the Companies' circuits, 40 percent of the Companies' distribution line miles, and 50 percent of the Companies' customers.[19]

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[12] *Id.*, ¶ 23.

[13] *Id.*

[14] LG&E has also filed a base rate application seeking, among other things, an increase in its electric and gas rates. That application is docketed as Case No. 2016-00371, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity* (Application filed Nov. 23, 2016).

[15] Application, ¶ 30.

[16] *Id.*

[17] *Id.*

[18] *Id.*, ¶ 31.

[19] *Id.*, ¶ 23.

KU estimated that it will receive approximately $861,843 of jurisdictional reservation and termination fees in connection with agreements related to the refined coal production facilities at the Companies' Ghent, Mill Creek, and Trimble County Generating Stations.[20] Pursuant to Case No. 2015-00264,[21] KU has been recording these proceeds as a regulatory liability and it now proposes to amortize this regulatory liability over three years.[22]

Lastly, KU also submitted a depreciation study in support of its application and requests that its proposed depreciation rates be approved.

Pursuant to the Commission's December 13, 2016 Order, KU's new rates, which were proposed to become effective on January 1, 2017, were suspended for six months, up to and including June 30, 2017. The December 13, 2016 Order also established a procedural schedule, which provided for a deadline for filing intervention requests; two rounds of discovery upon KU's application; a deadline for the filing of intervenor testimony; one round of discovery upon any intervenor testimony; and an opportunity for KU to file rebuttal testimony.

The following parties were granted intervention in this proceeding: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kroger Company ("Kroger"); Wal-Mart Stores East, LP and Sam's East, Inc. (jointly "Wal-Mart"); Kentucky School Boards Association ("KSBA"); Kentucky Cable Telecommunications

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[20] *Id.*, ¶ 39.

[21] Case No. 2015-00264, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for Declaratory Ruling* (Ky. PSC Nov. 24, 2015).

[22] Application, ¶ 39.

Association ("KCTA"); Alice Howell, Carl Vogel, and Sierra Club (jointly "Sierra Club"); BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"); Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"); Lexington-Fayette Urban County Government ("LFUCG"); and Kentucky League of Cities ("KLC").

Informal conferences ("IC") were held at the Commission's offices on April 12, 13, and 17, 2017, which resulted in all of the parties to this matter, with the exception of AT&T and KCTA, reaching a settlement agreement in principle on all issues other than those involving the Companies' proposed Rate PSA – Pole and Structure Attachment Charges.[23] On April 19, 2017, KU and LG&E filed a motion requesting leave to submit the written Stipulation and Recommendation ("First Stipulation") intended to address all of the issues, except for the proposed Rate PSA tariff, in the two respective rate cases. An additional IC was held on April 25, 2017, for the limited purpose of discussing and possibly resolving the issues associated with the Companies' proposed Rate PSA tariff. The Companies, KCTA, and AT&T were able to reach an agreement in principle for the resolution of all material issues pertaining to the proposed Rate PSA tariff. On May 1, 2017, KU and LG&E filed a motion requesting leave to submit the written Second Stipulation and Recommendation ("Second Stipulation"), which addresses all of the issues related to the Companies' proposed Rate PSA tariff.

The Commission held information sessions and public meetings for the purpose of taking public comments on April 11, 2017, in Louisville, Kentucky, at Jefferson Community and Technical College; on April 12, 2017, in Madisonville, Kentucky, at

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[23] The informal conferences were jointly held to discuss issues in the instant matter and to discuss issues related to the LG&E rate case, Case No. 2016-00371.

Madisonville Community College; and on April 18, 2017, in Lexington, Kentucky, at the Lexington Public Library – Northside Branch.

A formal hearing was held on May 9, 2017, for the purposes of cross-examination of all witnesses and for the consideration of the two stipulations.[24] Pursuant to a May 3, 2017 Order, the Commission required all of the Companies' employee witnesses as well as the Companies' consultant Steven Seelye, KIUC's witness Stephen Baron, and KSBA's witness Ronald Willhite to be present at the hearing.[25] The May 3, 2017 Order provided the parties to this matter an opportunity to cross-examine any of the other witnesses and, accordingly, directed the parties to the two cases to submit written notice on or before May 5, 2017, setting forth the name of each witness that each party intended to cross-examine at the formal hearing.[26] The May 3, 2017 Order noted that in the absence of a notice identifying witnesses whose attendance was not required by the Commission, the parties would be deemed to have waived cross-examination of those witnesses. None of the parties submitted a notice, and the only witnesses presented for cross-examination were those set forth above as named in the May 3, 2017 Order.

KU filed responses to post-hearing data requests on May 26, 2017, and on June 9, 2017. KSBA filed responses to post-hearing data requests on May 26, 2017. All the parties also filed post-hearing statements indicating they would not object to, or withdraw from, the First Stipulation, regardless whether all schools, including non-public

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[24] *See* May 3, 2017 Order at 2.

[25] *Id.* at 3.

[26] *Id.*

schools, are included in the optional pilot program for schools as set forth in Article IV, paragraph 4.11 of the First Stipulation. On May 31, 2017, the AG, Sierra Club, CAC, LFUCG, Metropolitan Housing Coalition ("MHC"), Association of Community Ministries ("ACM"), and Louisville/Jefferson County Metro Government ("Louisville Metro"),[27] filed a joint post-hearing brief in the instant matter and in the LG&E rate case proceeding recommending approval of the Residential Basic Service Charge as set forth in the First Stipulation. On May 31, 2017, KU, KIUC, and Kroger filed their respective post-hearing briefs recommending approval of the First and Second Stipulations. On June 1, 2017, KSBA filed a separate post-hearing brief addressing the legality of the optional pilot school rate tariffs. KU and the AG filed their respective briefs on the pilot school tariff issue on June 2, 2017. KSBA and the AG contend that the school-related pilot tariffs do not violate KRS 278.035 because the proposed tariffs set forth a reasonable classification and would not be preferential, given the unique load characteristics and usage patterns of schools as compared to the other customers in their existing rate classes. The AG also pointed out that all public and private schools have similar load and usage characteristics making them a homogenous group, which made it reasonable to include in the pilot school tariff private schools that might wish to participate. The AG opined that "[a]s long as potential school participants to the pilot electric school tariffs are afforded equal opportunity to participate, the pilot electrical tariffs cannot be said to be 'preferential' within the meaning of KRS 278.035."[28] Similarly, KU contends that the pilot school tariffs do not provide a publicly funded entity an entitlement to service under

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[27] MHC, ACM, and Louisville Metro are parties only to the LG&E rate case, Case No. 2016-00371.

[28] AG's Post-Hearing Brief Regarding School Board Pilot Tariff at 7-8.

that rate, and that the pilot tariffs are a reasonable means of gathering data to determine whether such tariffs should be made generally available service offerings. KSBA, KU, and the AG all indicated that they did not object to modifying the First Stipulation to allow schools not covered by KRS 160.325, i.e., non-public schools, to participate in the pilot tariffs.

FIRST STIPULATION

The First Stipulation reflects the agreement of all of the parties to the two cases, with the exception of KCTA and AT&T, addressing all of the issues not related to pole attachments. A summary of the provisions contained in the First Stipulation is as follows:

- KU agrees to withdraw the CPCN request to implement the AMS project and will initiate an AMS collaborative involving the Companies and all interested parties to these proceedings to discuss any concerns about AMS.[29]

- KU will be issued a CPCN to implement the DA project.

- KU revenue will increase by $54.9 million.

- The stipulated level of revenue associated with the electric operations were adjusted by: 1) removal of AMS cost recovery; 2) reduction of Return on Equity ("ROE") to 9.75 percent; 3) revised depreciation rates; 4) revenues from refined coal agreements at Ghent; 5) updated five-year average for uncollectible debt expense; 6) use of an eight-year average of generator outage expenses, based upon four-years' historical expenses and four-years' forecasted expenses; and 7) adjustment to construction work in progress capital slippage.

- The agreed-to revenue allocation is set forth in Exhibit 4 of the First Stipulation.

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[29] Because KU has agreed to withdraw its CPCN request to implement the AMS project, the company is also withdrawing its request to establish a regulatory asset for those electric meters that would have been retired as a result of the AMS project and the requests to deviate from certain regulations governing meter inspections and testing. *See* May 9, 2017 Hearing at 2:22:09.

- The Basic Service Charge will increase to $11.50 effective July 1, 2017, and to $12.25 effective July 1, 2018, for KU and LG&E Electric Rates RS, VFD, RTOD-Energy and RTOD-Demand.

- Current CSR customers may choose between Option A and Option B.

    - Option A reflects the Companies' as-filed proposition.

    - Option B reflects the following modifications to the existing CSR tariff:
        - credits for both Companies of $6.00 per kVA-month (primary) and $5.90 per kVA-month (transmission);

        - KU may request physical curtailment when more than ten of the utility's primary combustion turbines ("CTs") are being dispatched, irrespective of whether the utility is making off-system sales. A CSR customer may avoid a physical curtailment by buying through at the Automatic Buy-Through Price.

- KU and LG&E agree to add a voluntary sports-field-lighting rate schedule, Pilot OSL – Outdoor Sports Lighting Service, on a pilot basis limited to 20 participants per company and will utilize a time-of-day rate structure.

- KU and LG&E agree not to split their residential and general service electric energy charges into Infrastructure and Variable components as proposed.

- KU and LG&E agree to file a study in their next rate cases regarding the impacts of 100 percent base demand ratchets for Rate TODS.

- For customers with their own generation, for 60 minutes following a utility-system fault, KU and LG&E agree to not use any demand data for a Rate TODP customer to set billing demand.

- KU and LG&E agree to add an optional pilot tariff for schools subject to KRS 160.325. The Companies' pilot rate provisions will be available to new participants until the total projected revenue reduction is $750,000 annually for each company, compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served.

- KU and LG&E agree to file an application no later than December 31, 2017, proposing a two-year extension of the School Energy Managers Program (from July 1, 2018, through June 30, 2020) with a proposed total annual level of funding of $725,000.

- KU and LG&E agree to fund a study concerning economical deployment of electric bus infrastructure in the Lexington area, as well as cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

- KU and LG&E agree to establish an LED Lighting Collaborative involving Louisville Metro, LFUCG, and any other interested parties to these proceedings.

- KU agrees to increase its monthly residential Home Energy Assistance ("HEA") charge from $0.25 per month to $0.30 per month, which will remain effective through June 30, 2021.

- KU and LG&E agree to commit to contribute a total of $1.45 million of shareholder funds per year, which will remain in effect through June 30, 2021. These shareholder funds will be applied as follows:

  - From KU, $100,000 for Wintercare and $470,000 for HEA. CAC administers both programs. KU agrees that up to 10 percent of its total contributions to CAC may be used for reasonable administrative expenses.

  - From LG&E, $700,000 to ACM for utility assistance and $180,000 for HEA. LG&E agrees that up to 10 percent of its total contributions to ACM may be used for reasonable administrative expenses.

The First Stipulation results in the monthly bill of an average KU residential customer increasing by $4.20, or 3.49 percent. A summary of the impact of the First Stipulation on KU's revenue requirement is as follows.

- **<u>Electric Operations</u>**. The parties agreed in the First Stipulation to reduce KU's requested revenue increase from $103.1 million to $54.9 million. The adjustments to KU's requested revenue requirement are discussed further below.

  A. <u>Advanced Metering System</u>. As previously discussed, KU requested that the Commission grant a CPCN to install AMS in its service territory. As part of the First Stipulation, the Companies agreed to withdraw their requests for the CPCN and to establish a collaborative to discuss the parties' concerns and seek to address them. In the test year, the cumulative effect of the withdrawal of the CPCN on the revenue requirement of KU is a reduction of $6.3 million.

B. Return on Equity. The agreement to reduce the ROE to 9.75 percent results in a decrease to KU's revenue requirement of $15.3 million.

C. Depreciation. KU proposed to revise its depreciation rates based upon depreciation studies that were performed by John Spanos of the firm Gannett Fleming Valuation and Rate Consultants, LLC. The parties to the First Stipulation agreed to revise KU's proposed depreciation rates resulting in a revenue-requirement reduction of $14.7 million. The revised depreciation rates will also reduce KU's environmental cost recovery revenue requirement by $19.1 million. The impact will be included in the environmental cost recovery filing made for the July 2017 expense month.

D. KU Refined Coal Revenues. The First Stipulation reflects a $9.1 million reduction in KU's revenue requirement related to KU's contract proceeds from the Refined Coal project at the Ghent Generating Station.

E. Uncollectibles Expense. KU proposed to use uncollectible factors based on using a five-year average of write-offs to revenues for the period 2011 through 2015. The First Stipulation uses an updated five-year period, 2012 through 2016, to reduce KU's revenue requirement by $0.5 million.

F. Normalize Generation Outage. KU proposed $90.201 million in generation outage expense for the test year, which exceeded its five-year average of $77.384 million. In the First Stipulation, the parties agreed to use an eight-year average expense, four years of historical expenses, and four years of forecasted expenses. This approach reduces KU's revenue requirement by $1.6 million.

G. Construction Work in Progress Capital Slippage. The First Stipulation reflects a slippage factor to eliminate over estimation in construction budgeting. The slippage factor reduces KU's requested revenue requirement by $0.7 million.

- **Stipulation Summary**. The table below reflects the impact each Stipulation adjustment has on KU.

	KU
Proposed Revenue Requirement	$ 103.1 million
Remove AMS	(6.3) million
9.75% Return on Equity	(15.3) million
Revised Depreciation Rates	(14.7) million
KU Refined Coal Revenues	(9.1) million
Uncollectible Expense	(0.5) million
Generator Outage Expenses	(1.6) million
CWIP Capital Slippage	(0.7) million
Stipulated Revenue Requirements	$ 54.9 million

SECOND STIPULATION

The Second Stipulation reflects the agreement of KU, AT&T, and KCTA as to the terms and conditions of KU's pole and structure attachment charges contained in Tariff PSA. The major substantive areas addressed in the Second Stipulation are as follows:

- Agreement on KU's attachment charges for pole-top wireless facilities;[30]
- Agreement on KU's attachment charges for mid-pole wireless facilities;[31]
- Amendment of the terms and conditions set forth in KU's proposed Tariff PSA rate schedule.[32]

ANALYSIS AND FINDINGS

The Commission's statutory obligation when reviewing a rate application is to determine whether the proposed rates are "fair, just, and reasonable."[33] While numerous intervenors with significant experience in rate proceedings and collectively

[30] Second Stipulation, paragraph 1.2.

[31] *Id.* at paragraph 1.3.

[32] *Id.* at paragraph 1.4.

[33] KRS 278.030(1).

representing a diverse range of customer interests have participated in this case, the Commission cannot defer to the parties as to what constitutes fair, just, and reasonable rates. The Commission must review the record, including the two stipulations, and apply its expertise to make an independent decision as to the level of rates, including terms and conditions of service, that should be approved.

To satisfy its statutory obligation in this case, the Commission has performed its traditional ratemaking analysis, which consists of reviewing the reasonableness of each revenue and expense adjustment proposed or justified by the record, along with a determination of a fair ROE.

FIRST STIPULATION

Based upon its review of the First Stipulation, the attachments thereto, and the case record including intervenor testimony, the Commission finds that, with the modifications discussed below, the First Stipulation is reasonable and in the public interest. With those modifications, the Commission finds that the First Stipulation was the product of arm's-length negotiations among knowledgeable, capable parties and should be approved. Such approval is based solely on the reasonableness of the modified First Stipulation and does not constitute a precedent on any individual issue.

Employee Retirement Plans

KU maintains a Defined Dollar Benefit Retirement Plan for those employees hired prior to January 1, 2006 ("Pre 2006 DDB Plan").[34] This plan was closed to new participants and was replaced with a Retirement Income Account ("401(k) Plan") for

[34] See KU's response to Commission Staff's Fourth Request for Information ("Staff's Fourth Request"), Item 6.

those employees hired after January 1, 2006.[35] All employees that were hired prior to January 1, 2006, are eligible to participate in both the Pre 2006 DDB Plan and the 401(k) Plan.[36] KU contributes 100 percent of the Pre 2006 DDB Plan costs.[37] KU also contributes to the 401(k) Plan between 3 percent to 7 percent[38] of eligible employee compensation and $0.70 per dollar match for employee contributions up to 6 percent of the employee's eligible contribution.[39]

The Commission finds that, for ratemaking purposes, it is not reasonable to include both KU's Pre 2006 DDB plan contributions and KU's matching contributions to the 401(k) Plan for the following employee categories: exempt, manager, non-exempt, and officer and director personnel. The Commission chooses not to address similar 401(k) Plan company matching contributions for hourly and bargaining unit employees in this proceeding, as it is not within the Commission's authority to negotiate or modify bargaining agreements. The Commission will not make a distinction between represented and non-represented hourly groups at this time, but will instead provide an opportunity for KU to address these excessive costs for both employee classes prior to its next base rate case, as rate recovery of these contributions will be evaluated for appropriateness as part of its next base rate case. Employees participating in the Pre

[35] Refer to KU's response to Commission Staff's First Post-Hearing Request for Information dated May 12, 2017, Item 11. Although throughout this proceeding, KU made references to two separate post-2016 retirement plans, the Retirement Income Account and the 401(k) Savings Plan, they are actually the same plan.

[36] *Id.*

[37] Response to Staff's Fourth Request, Item 6.

[38] The percentage contribution rate depends on the employee's years of service as of January 1 of that year.

[39] Response to Staff's Fourth Request, Item 6.

2006 DDB Plan enjoy generous retirement plan benefits, making the matching 401(k) Plan amounts excessive for ratemaking purposes. Accordingly, the Commission denies for recovery 401(k) Plan matching contributions in the amount of $1,720,383 before gross-up.

Return on Equity

In its application, KU developed its ROE using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the empirical capital asset pricing model ("ECAPM"), the utility risk premium ("RP"), and the expected earnings approach.[40] Based on the results of the methods employed in its analysis, KU recommended an ROE range for its electric operations of 9.63 percent to 10.83 percent, including flotation cost.[41] KU recommended awarding the midpoint of this range, 10.23 percent, to maintain financial integrity, support additional capital investment and recognize flotation costs.[42] Direct testimony regarding ROE was provided by the AG and KIUC, and was subject to discovery by the Commission Staff and all parties.[43] Per paragraphs 2.2(B) and 3.2(B) of the First Stipulation, KU and the intervenors agreed that a ROE of 9.75 percent is reasonable for KU's electric operations.[44] The following table presents the recommended ROEs from KU and the interveners and the methods used to support each parties' findings:

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[40] Direct Testimony of Adrien M. McKenzie, CFA ("McKenzie Direct Testimony"), at 2.

[41] *Id.*, Exhibit No. 2, page 1 of 1.

[42] *Id.*, at 5–6.

[43] Walmart did not provide an ROE analysis, but pointed out that KU's proposed ROE was higher than natural trends, and that average ROE awards of vertically integrated utilities in 2015 and 2016 was 9.76 percent.

[44] First Stipulation, at 5 and 9.

Party	Recommendation	Methods
KU	10.23%	DCF, CAPM, ECAPM, RP
AG[45]	8.75%	DCF, CAPM
KIUC[46]	9.0%	DCF, CAPM
FIRST STIPULATION	**9.75%**	

In the First Stipulation, all parties agreed that the revenue requirement increases for KU's electric operations will reflect a 9.75 percent ROE as applied to KU's capitalization and capital structure of the proposed electric revenue requirement increases as modified through discovery. As a result, use of a 9.75 percent ROE reduced KU's proposed electric revenue requirement by $15.3 million.[47] For the reasons discussed below, the Commission finds a ROE of 9.75 percent to be unreasonable and higher than required by investors in today's economic climate, and that this provision of the First Stipulation should be modified.

While the Commission does not rely on individual returns awarded in other states in determining the appropriate ROE for Kentucky jurisdictional utilities, the Commission does find it reasonable to expect that other state commissions, each with its own attributes, evaluate expert witness testimony which uses the same or similar cost-of-equity models as those presented by the parties participating in this rate proceeding, and reach conclusions based on the data provided in the records of individual cases. The Regulatory Research Associates ("RRA") reports introduced into the record of this

[45] Direct Testimony of Dr. J. Randall Woolridge at 67.

[46] Direct Testimony of Richard Baudino at 28.

[47] First Stipulation at 5.

proceeding[48] summarize the conclusions reached by state utility regulatory commissions, including this Commission, with regard to reasonable ROEs and contain explanatory reference points as to individual circumstances, all of which are available to investors. To the extent that investors' expectations are influenced by such publications, and we believe they are, we also find it appropriate to use that information to put their expectations in context. In fact, in KU's rebuttal testimony, KU agreed that allowed ROEs by other state commissions provide a general gauge of reasonableness for the outcome of a cost-of-equity analysis.[49]

The Commission takes notes of the fact that average annual ROE awards by state public service commissions for the last two years have ranged from 9.23 percent to 10.55 percent.[50] Furthermore, the average authorized ROEs reported by RRA for the fourth quarter of 2016 was 9.6 percent.[51] Authorized ROE data reported to investors by The Value Line Investment Survey for the specific firms in KU's proxy group indicates that state-allowed ROEs for those utilities were in a range of reasonableness of 9.00 to 12.50 percent.[52]

In 2017, the economic environment has shown signs of relative improvement. In response to increased economic growth and low unemployment, the Federal Reserve increased interest rates in March and June 2017, and current outlooks, including comments from government agencies, show that investors anticipate additional interest

[48] *See* Rebuttal Testimony of Adrien M. McKenzie, CFA, at 11.

[49] *Id.* at 10.

[50] *Id.*, Exhibit 12.

[51] *Id.* at 13.

[52] *Id.*, Exhibit 13.

rate increases.[53] KU's own model produces an ROE, less flotation costs and adjustments, to be in the range of 9.5 percent to 10.7 percent.[54] Even with the current uptick in economic conditions, the economy remains in an era of historically low interest rates and slow economic growth. Therefore, irrespective of the agreement by the parties that a 9.75 percent ROE is appropriate for KU, the Commission finds that a slightly lower ROE is a better reflection of current economic conditions and investor expectations. Based on the entire record developed in this proceeding, we find that KU's required ROE falls within a range of 9.20 percent to 10.20 percent with a midpoint of 9.70 percent. An ROE of 9.70 should be used for the purpose of base rate revenues and certain tariffs, as discussed later in this Order.

This revision to the First Stipulation reduces KU's net operating income before income taxes by $969,324.

Revenue Requirement

As discussed above, the Commission finds the First Stipulation to be reasonable only by eliminating KU's 401(k) Plan contributions for the following employee categories: exempt, manager, non-exempt and officer and director personnel, and by reducing the ROE from 9.75 percent to 9.70 percent. These modifications decrease the stipulated revenue requirement from $54,900,000 to $50,484,652 a decrease of $4,415,348, as calculated in the table below.

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[53] *Id.* at 8.

[54] McKenzie Direct Testimony, Exhibit No. 2.

	KU
KU's 401(k) Plan	$ (1,720,383)
ROE from 9.75% to 9.7%	(969,324)
Impact to Net Operating Income Before Taxes	(2,689,707)
Multiplied by: Gross up Factor	1.641572
Revenue Requirement Impact	(4,415,348)
Increase per Stipulation	54,900,000
Net Increase Granted by the Commission	$ 50,484,652

Residential Basic Service Charge

The Commission believes an increase to the Residential Basic Service Charge is warranted, and we find the level of the Year 2 charge to be reasonable. We further find that the two-step increase to $11.50 in Year 1 and to $12.25 in Year 2 is unnecessary. The total increase in the Residential Basic Service Charge of $1.50 is a modest increase from the current level, and the Commission sees no reason to complicate the issue by using a two-step method, which could generate confusion among KU's residential customers. The First Stipulation is therefore modified with respect to the Residential Basic Service Charge, and the Year 2 charge of $12.25 should be approved for service rendered on and after July 1, 2017.

Optional Pilot Rates for Schools Subject to KRS 160.325

At the formal hearing in this matter, the parties were requested to file post-hearing briefs concerning the legality of the proposed school-related pilot rate tariffs, Rates SPS and STOD, with respect to the applicability of KRS 278.035, and to indicate whether they would object to the modification of the First Stipulation to include schools not covered by KRS 160.325. Briefs submitted by KSBA, KU, and the AG acknowledged that the inclusion of non-public schools in the pilot tariffs would avoid a possible violation of KRS 278.035. All parties to this proceeding submitted statements indicating that they had no objection to modification of the First Stipulation to include non-public schools in the pilots.

The Commission finds that the First Stipulation should be modified to include schools not covered by KRS 160.325. The inclusion of non-public schools would rectify any potential conflict with KRS 278.035 and would remove any element of preferential treatment of public schools that could be associated with the pilot tariffs. As previously stated, the pilot rate provisions will be available to new participants until the total projected revenue reduction is $750,000 annually for KU, compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served. The Commission notes that the parties to this proceeding agreed that the other ratepayers would assume the revenue shortfall resulting from the lower rates set forth in the pilot school tariffs. Therefore, the Commission will place a limit on the amount of time the pilot tariffs will be in effect and finds that the pilot tariffs should be effective for three years, or until KU files its next rate case, whichever is earlier. In the event that new base rates are not in effect by July 1, 2020, schools participating in the pilot tariffs should be returned to the tariffs under which they were formerly served. In addition, the Commission finds that KU should create a regulatory liability to record the difference between what the schools served under the pilot tariffs would have been billed under the pilot tariffs subsequent to July 1, 2020, and the amounts they are billed under the tariffs to which they are returned. The regulatory liability will be addressed in KU's next base rate proceeding. We further find that, within

30 days of the date of this Order, KSBA should file with the Commission the process by which KSBA will notify and select those schools, both public and non-public, that would be eligible to participate in the pilot tariffs.

With regard to the data gathered from the schools participating in the pilot tariffs, the Commission finds that KU should file reports with the Commission, beginning six months from the date of this Order and every six months thereafter, which set out details concerning monthly load information, individually and in the aggregate, and indicating preliminary findings as conclusions regarding the schools' load characteristics are reached. In the event that a future proposal is made either to extend the pilot school tariffs or to make them permanent, this load information will be used to determine whether the schools' load characteristics justify a special rate classification.

Collaborative Study Regarding Electric Buses

Although this provision will be funded by shareholder contributions and the Commission does not oppose it, this type of provision pertaining to an unrelated business transaction should be negotiated separately between the individual parties and has no bearing on KU's rates as found reasonable herein based on the record of this case. It is therefore superfluous to this regulatory proceeding, contributes nothing to the reasonableness of the First Stipulation, and should be omitted from future ratemaking proceedings.

LED Lighting and Electric Bus Study Collaboratives

Pursuant to the provisions of the First Stipulation, KU commits to engage in good faith with Louisville Metro, LFUCG, and any other interested parties to this proceeding and the LG&E rate proceeding in a collaborative to discuss issues related to LED lighting and electric bus infrastructure and rates. While the provisions limit participation to only those parties to the instant rate proceeding and the LG&E rate proceeding, the Commission finds that the collaboratives should also include the Kentucky Department of Energy Development and Independence, whose mission includes creating efficient, sustainable energy solutions and strategies.

SECOND STIPULATION

As mentioned previously, KU proposed certain changes to its pole attachment tariff in its application. KU currently offers the use of spaces on its poles for cable television attachments under Tariff CTAC, Cable Television Attachment Charges ("Tariff CTAC"). KU proposed to rename Tariff CTAC to Tariff PSA, Pole and Structure Attachment Charges ("Tariff PSA"), and to expand the tariff to include telecommunications wireline and wireless facilities' attachments, which are not currently covered under Tariff CTAC. KU also proposed to modify the rates, terms, and conditions of service for attaching wireline and wireless facilities to its poles.

The Second Stipulation includes the modifications proposed in the application, but also includes additional changes in the rates for pole space use and conditions of service for the placement of an attachment on KU's poles. As originally proposed, the Tariff PSA's rate schedule contained three charges: 1) an annual charge of $7.25 for each wireline pole attachment; 2) an annual charge of $0.81 for each linear foot of duct; and 3) an annual charge of $84.00 for each wireless facility attachment. AT&T and KCTA did not object to the charge for wireline and duct attachments, but did object to the annual charge for wireless facility attachments. KU estimated that wireless facilities occupy an average of 11.5 feet on its poles, and calculated the $84.00 wireless facility attachment charge based on the use of 11.5 feet of pole space at $7.25[55] per foot of pole. AT&T and KCTA did not challenge the $7.25 per foot factor in the calculation, but argued that wireless facility attachments occupy far less pole space. The Second Stipulation provides for a charge of $36.25, based upon a wireless facility attached to the top of a pole using five feet of the pole—one foot for the antenna and four feet of clearance above the power space to maintain a safe working distance between the electric facilities on the pole and the pole top antenna. The Second Stipulation also provides for rates for wireless facilities located mid-pole to be established on a case-by-case basis through special contracts. This provision is based upon the lack of requests for mid-pole wireless facilities, which resulted in a lack of evidence upon which to base a uniform rate for mid-pole wireless facilities.

Another modification is the requirement for a pole-loading study. As originally proposed, Tariff PSA required that a pole-loading study be submitted with each application as a safety and reliability measure. KCTA argued that requiring pole-loading studies for every application provides no appreciable safety or reliability benefit to KU, while unnecessarily increasing construction costs and preventing timely deployment of wireless facilities. The Second Stipulation provides that an attachment applicant may include a pole-load study with the application or, in the alternative, assert that a pole's condition does not warrant the need for a pole-loading study. To confirm the assertion, KU may perform a visual inspection of the pole to which the facility is proposed to be attached. If KU determines that a pole-loading study is needed, the attachment applicant has the option of conducting the pole-loading study itself or requesting that KU

[55] The Commission approved the rate of $7.25 per foot in Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric and Rates* (Ky. PSC June 30, 2015).

perform the study. The attachment applicant is responsible for the costs of any visual inspection or pole-loading study that KU performs. KU contends that the proposed revision to Tariff PSA does not sacrifice safety or system reliability.

The Commission finds that the proposed Tariff PSA with the modifications agreed to in the Second Stipulation is reasonable and that the Second Stipulation should be approved in its entirety.

OTHER ISSUES

Rate Adjustment

In setting the rates shown in Appendix B, the Commission maintained the basic service charges for each class that were included in the First Stipulation, with the exception that the Year 1 Residential Basic Service Charge was not approved as previously discussed, and is therefore not included. The reduction in KU's stipulated revenue increase as found reasonable herein was allocated to the energy charges of those customer classes for which revenue increases were proposed in the First Stipulation. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set forth in the First Stipulation.

Electric Vehicle Supply Equipment Calculation

In response to a Post-Hearing Request for Information, KU provided a revised sheet showing the impact on the Electric Vehicle Supply Equipment ("EVSE"), Electric Vehicle Charging Service ("EVC"), and Electric Vehicle Supply Equipment ("EVSE-R") rates of using the 9.75 percent ROE in the capital structure. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the EVSE rates should be further revised to reflect the approved ROE. The Commission also finds that since the

EVSE, EVC, and EVSE-R rates are based, in part, on the General Service ("GS") energy rate, the rates should be updated for the change in the GS energy rate approved with this Order. The EVSE, EVC, and EVSE-R rates set out in Appendix B to this Order reflect both revisions.

Solar Capacity Charge and Solar Energy Credits

In response to a Post-Hearing Request for Information, KU provided a revised sheet showing the impact on the Solar Capacity Charge and Solar Energy Credits of using the 9.75 percent ROE in the capital structure and under each of the corrected cost-of-service studies filed by KU in this proceeding. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the Solar Capacity Charge and Solar Energy Credits should be further revised to reflect the approved ROE. The Commission also finds that the Solar Energy Credits should be revised for Rate Schedules RS, VFD, RTOD-E, RTOD-D, AES, and GS using the average of the amounts provided in response to the post-hearing information request,[56] but revised for the change in ROE and using the energy rates approved herein for Rate Schedules PS, TODS, and TODP. The rates set out in Appendix B to this Order reflect the revisions.

Demand-Side Management ("DSM")

In response to a Commission Staff Information Request, KU stated that upon the implementation of new base rates, the DSM Revenue from Lost Sales component of its DSM cost-recovery mechanism would change to zero.[57] The Commission finds that

[56] Response to Commission Staff's First Post-Hearing Request for Information dated May 12, 2017, Item 6, Attachment KU-6-1 and Attachment KU-6-2.

[57] KU's response to Commission Staff's Second Request for Information, Item 10.

KU's compliance tariff that it is directed to file in ordering paragraph 10 should reflect this revision to its DSM cost-recovery mechanism.

Loss of Municipal Load

The Commission takes notice that nine municipal utilities will be terminating their wholesale power contracts with KU effective, at the latest, April 30, 2019.[58] The combined load of those nine departing wholesale customers is approximately 325 megawatts ("MW").[59] At the formal hearing, Victor Staffieri, KU's Chairman, Chief Executive Officer, and President, testified that KU had not secured new customers to purchase the generation that would be available when the nine municipal utilities terminate their contracts with KU, but that the company would take into account any growth in load as potential replacement for the loss of municipal load.[60] Mr. Staffieri also stated that it is not known what impact the loss of municipal load would have on KU's rates when the company files its next rate case.[61] David Sinclair, KU's Vice President, Energy Supply and Analysis, also testified at the formal hearing that, beginning in 2019 and 2020, KU would have a reserve margin of approximately 24 percent, which would be above the upper end of KU's target reserve margin range.[62]

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[58] *See* Case No. 2014-0002, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station* (Ky. PSC Dec. 19, 2014), final Order at 2–3.

[59] The nine municipal wholesale customers are Barbourville, Bardwell, Berea, Corbin, Falmouth, Frankfort, Madisonville, Paris, and Providence.

[60] May 9, 2017 Hearing at 1:37:37.

[61] *Id.* at 1:38:40.

[62] May 10, 2017 Hearing at 9:37:30.

In light of the significant loss of load in connection with the nine municipal customers' leaving KU's system in April 2019, the Commission finds that KU should develop and implement a formal plan to address how KU will mitigate the loss of the approximately 325 MW municipal load, including, but not limited to, how KU will market the excess capacity and energy resulting from the municipals departing the system, the types of measures KU will implement to attract new or expanding load, and whether joining a regional transmission organization would be beneficial in its efforts to market the excess capacity and energy.

Transmission System Improvement Plan

KU is currently implementing a Transmission System Improvement Plan ("Transmission Plan") aimed at reducing outage occurrence and duration and improving overall reliability of service to its customers.[63] KU states that the Transmission Plan contains two primary categories of investment: system integrity and reliability.[64] System integrity involves replacement of aging transmission assets to enhance reliability.[65] The reliability component involves several maintenance programs and capital investment in line sectionalization.[66] KU will spend approximately $149 million between the end of the last base-rate-case test period and the end of the forecasted test period (July 1, 2016 – June 30, 2018) on its Transmission Plan.[67] This spending is part of a total of $511

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[63] Direct Testimony of Paul W. Thompson ("Thompson Testimony") at 25.

[64] *Id.* at 26.

[65] *Id.*

[66] *Id.*

[67] *Id.* at 27.

million in transmission capital investments that KU and LG&E project to spend over the five-year period beginning 2017.[68]

In light of the significant investments that KU intends to make pursuant to the Transmission Plan, the Commission will require KU to file annual reports, over the five-year Transmission Plan period, detailing the progress on the spend out for the reporting period, the criteria utilized by KU to prioritize the various transmission projects, the impact on reliability or other benefits to KU's customers resulting from such investments, and outlining the expenditures for the following year.

KU's Tariffs

Commission regulation 807 KAR 5:011, Section 4(1), requires each utility to include an accurate index of the city, town, village, or district in which its rates are applicable. The first page of KU's tariffs references its service as being available "[i]n seventy-seven counties in the Commonwealth of Kentucky as depicted on territorial maps as filed with the Public Service Commission of Kentucky." Because those maps are not readily available to members of the public, KU should revise its tariffs to include a list of the communities in which it serves.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by KU are denied.

2. KU's motions for leave to file the First and Second Stipulations are granted.

3. The First and Second Stipulations, attached hereto as Appendix A, (without exhibits) are approved with the modifications discussed herein.

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[68] *Id.* at 26–27.

4. The rates and charges in Appendix B, attached hereto, are fair, just, and reasonable for KU to charge for service rendered on and after July 1, 2017.

5. KU is granted a CPCN to implement the DA project as described in the application.

6. Within 30 days of the date of this Order, KSBA shall file with the Commission the process by which it will notify and select those schools that are eligible to participate in the pilot tariffs approved herein.

7. KU shall file reports with the Commission as directed herein which set out details concerning the pilot school tariffs study.

8. Within 90 days of the date of this Order, KU shall file a formal plan addressing how KU will mitigate the loss of the approximately 325 MW municipal load as discussed herein.

9. Beginning June 1, 2018, and continuing over the five-year Transmission Plan period, KU shall file an annual Transmission Plan report as discussed herein.

10. Within 20 days of the date of this Order, KU shall file with the Commission, using the Commission's electronic Tariff Filing System, its revised tariffs, including an index of communities served, as set forth in this Order reflecting that they were approved pursuant to this Order.

11. Any document filed pursuant to ordering paragraphs 6, 7, 8, and 9 of this Order shall reference the number of this case and shall be retained in the utility's general correspondence file.

12. The Executive Director is delegated authority to grant reasonable extension of time for the filing of any documents required by ordering paragraphs 6, 7, 8, and 9 of this Order upon KU's showing of good cause for such extension.

By the Commission

ENTERED

JUN 22 2017

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00370 DATED JUN 2 2 2017

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation ("Stipulation") is entered into this 19th day of April 2017 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); Association of Community Ministries, Inc. ("ACM"); Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"); Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); United States Department of Defense and All Other Federal Executive Agencies ("DoD"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky League of Cities ("KLC"); The Kroger Company ("Kroger"); Kentucky School Boards Association ("KSBA"); Lexington-Fayette Urban County Government ("LFUCG"); Louisville/Jefferson County Metro Government ("Louisville Metro"); Metropolitan Housing Coalition ("MHC"); Sierra Club, Alice Howell, Carl Vogel and Amy Waters (collectively "Sierra Club"); JBS Swift & Co. ("Swift"); and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart"). (Collectively, the Utilities, ACM, AG, CAC, DoD, KIUC, KLC, Kroger, KSBA, LFUCG, Louisville Metro, MHC, Sierra Club, Swift and Wal-Mart are the "Parties.")

WITNESSETH:

WHEREAS, on November 23, 2016, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00370 to review KU's base rate application, in which KU requested a revenue increase of $103.1 million;

WHEREAS, on November 23, 2016, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00371 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $93.6 million and a revenue increase of $13.8 million for its gas operations (Case Nos. 2016-00370 and 2016-00371 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, on February 20, 2017, LG&E filed with the Commission in Case No. 2016-00371 a Supplemental Response to Commission Staff's First Request for Information No. 54 in which LG&E corrected its requested revenue increases for its electric operations to be $94.1 million and for its gas operations to be $13.4 million;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00370 to the AG, BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"), CAC, Kentucky Cable Telecommunications Association ("KCTA"), KIUC, KLC, Kroger, KSBA, LFUCG, Sierra Club, and Wal-Mart;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00371 to ACM, AG, AT&T, DoD, KCTA, KIUC, Kroger, KSBA, Louisville Metro, MHC, Sierra Club, Swift and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of this Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 12, 13, and 17, 2017, at the offices of the Commission, which representatives of AT&T and KCTA also attended on April 12 and 13, and which representatives of KCTA also attended on April 17, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, the Parties hereto unanimously desire to settle all the issues pending before the Commission in the Rate Proceedings, notwithstanding that neither AT&T nor KCTA has agreed with, or entered into, this Stipulation, and therefore neither AT&T nor KCTA is one of the Parties as defined herein;

WHEREAS, it is understood by all Parties hereto that this Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Stipulation;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that this Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Stipulation, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. ADVANCED METERING SYSTEMS

1.1. Withdrawing Request for Certificates of Public Convenience and Necessity and Cost Recovery for Advanced Metering Systems. The Utilities agree to withdraw their requests for the Commission to grant certificates of public convenience and necessity ("CPCNs") and to approve cost recovery in these base rate proceedings for the Utilities' proposed full deployment of Advanced Metering Systems ("AMS"). The Parties agree that the Utilities' withdrawal of their requests for CPCNs and cost recovery for AMS in these proceedings does not preclude the Utilities from having full AMS deployment considered in future proceedings.

1.2. AMS Collaborative. The Parties agree that the Utilities and all interested Parties will participate in an AMS Collaborative to discuss the Parties' concerns about AMS and to seek to address them. The AMS Collaborative will begin at a mutually agreeable time after these proceedings conclude and will include only those Parties to these proceedings interested in participating in the collaborative. The Parties agree to engage in the collaborative in good faith not to exceed 15 months from the date the Commission issues orders in these proceedings.

ARTICLE II. ELECTRIC REVENUE REQUIREMENTS

2.1. Utilities' Electric Revenue Requirements. The Parties stipulate that the following increases in annual revenues for LG&E electric operations and for KU operations, for purposes of determining the rates of LG&E and KU in the Rate Proceedings, are fair, just and reasonable for the Parties and for all electric customers of LG&E and KU:

LG&E Electric Operations: $59,400,000.

KU Operations: $54,900,000.

The Parties agree that any increase in annual revenues for LG&E electric operations and for KU operations should be effective for service rendered on and after July 1, 2017.

2.2. Items Reflected in Stipulated Electric Revenue Requirement Increases. The Parties agree that the stipulated electric revenue requirement increases were calculated by beginning with the Utilities' electric revenue requirement increases as presented and supported by the Utilities in their applications in these proceedings and as revised through discovery ($103.1 million for KU; $94.1 million for LG&E electric) and adjusting them by the following items, which the Parties ask and recommend the Commission accept as reasonable without modification:

(A) **Removal of AMS Cost Recovery.** Because the Utilities are withdrawing their request for CPCNs and cost recovery for their proposed full deployment of AMS, recovery of AMS costs is being removed from the Utilities' electric revenue requirements. This reduces KU's proposed electric revenue requirement increase by $6.3 million, consisting of $3.2 million of operations and maintenance ("O&M") cost and $3.1 million of carrying cost and depreciation expense. Similarly, this reduces LG&E's proposed electric revenue requirement increase by $5.2 million, consisting of $3.0 million of O&M cost and $2.2 million of carrying cost and depreciation expense.

(B) **Return on Equity.** The Parties agree that a return on equity of 9.75% is reasonable for the Utilities' electric operations, and the agreed stipulated revenue requirement increases for the Utilities' electric operations reflect that return on equity as applied to the Utilities' capitalizations and capital structures underlying their originally proposed electric revenue requirement increases as modified through discovery. Use of a 9.75% return on equity reduces the Utilities' proposed electric revenue requirement increases by $15.3 million for KU and $10.1 million for LG&E.

(C) **Revised Depreciation Rates.** The stipulated revenue requirement increases reflect the revised depreciation rates shown in Stipulation Exhibits 1 (KU) and 2 (LG&E electric), which reduce the Utilities' proposed electric revenue requirement increases by $14.7 million for KU and $10.1 million for LG&E. In addition to contributing to reducing the Utilities' proposed electric revenue requirement increases in these proceedings, these revised depreciation rates will reduce environmental cost recovery ("ECR") revenue requirements by $19.1 million for KU and $16.8 million for LG&E relative to the Utilities' proposed depreciation rates as will be included in the ECR mechanism filings beginning with the July 2017 expense month.

(D) **KU Revenues Resulting from the Refined Coal Project at the Ghent Generating Station.** The stipulated revenue requirement increase for KU reflects a $9.1 million revenue-requirement reduction related to KU's contract proceeds resulting from KU's Refined Coal project at the Ghent Generating Station. KU discussed this issue at an Informal Conference held at the Commission on March 14, 2017, in the context of Case No. 2015-00264.

(E) **Updated Five-Year Average for Uncollectible Debt Expense.** The stipulated electric revenue requirement increases reflect the use of a five-year average (calendar years 2012-2016) for uncollectible debt expense, which is an update to the five-year average (2011-2015) that was available at the time the Utilities filed their applications in these proceedings. This approach reduces the Utilities' proposed electric revenue requirement increases by $0.5 million for KU and $0.3 million for LG&E.

(F) **Eight-Year Average for Generator Outage Expenses; Related Use of Regulatory Accounting.** The Parties agree to use an eight-year average of generator outage expenses in the Utilities' stipulated electric revenue requirement increases, where the average is of four historical years' expenses (2013-2016) and four years' forecasted expenses (2017-2020). This approach reduces the Utilities' proposed electric revenue requirement increases by $1.6 million for KU and $8.5 million for LG&E. Relatedly, the Parties agree to, and ask the Commission to approve, the Utilities' use of regulatory asset and liability accounting related to generator outage expenses that are greater or less than the eight-year average of the Utilities' generator outage expenses. This regulatory accounting will ensure the Utilities may collect, or will have to return to customers, through future base rates any amounts that are above or below the eight-year average embedded in the stipulated electric revenue requirement increases in these proceedings.

(G) **Adjustment Related to Construction Work in Progress Capital.** The Parties agree to adjust the Utilities' proposed electric revenue requirement increases to reflect differences ("slippage") between past projected and historical capital amounts for construction work in progress ("CWIP"). This adjustment reduces the Utilities' proposed electric revenue requirement increases by $0.7 million for KU and $0.4 million for LG&E.

(This space intentionally left blank.)

2.3. Summary Calculation of Electric Revenue Requirement Increases. The table below shows the calculation of the stipulated electric revenue requirement increases:

Item	KU	LG&E
Proposed electric revenue requirement increases	\$103.1 million	\$94.1 million
Remove AMS	(\$6.3 million)	(\$5.2 million)
9.75% return on equity	(\$15.3 million)	(\$10.1 million)
Revised depreciation rates	(\$14.7 million)	(\$10.1 million)
KU Refined Coal revenues	(\$9.1 million)	n/a
5-year average uncollectible expense	(\$0.5 million)	(\$0.3 million)
8-year average generator outage expense	(\$1.6 million)	(\$8.5 million)
CWIP capital slippage	(\$0.7 million)	(\$0.4 million)
Stipulated electric revenue requirement increases	\$54.9 million	\$59.4 million[1]

ARTICLE III. GAS REVENUE REQUIREMENT

3.1. LG&E Gas Revenue Requirement. The Parties stipulate and agree that, effective for service rendered on and after July 1, 2017, an increase in annual revenues for LG&E gas operations of \$7,500,000, for purposes of determining the rates of LG&E gas operations in the Rate Proceedings, is fair, just and reasonable for the Parties and for all gas customers of LG&E.

[1] Stipulated LG&E electric revenue requirement increase differs from proposed revenue requirement increase less adjustments shown due to rounding.

3.2. Items Reflected in Stipulated Gas Revenue Requirement Increase. The Parties agree that the stipulated gas revenue requirement was calculated by beginning with LG&E's gas revenue requirement increase as presented and supported by LG&E in its application in Case No. 2016-00371 and as revised through discovery ($13.4 million) and adjusting the proposed gas revenue requirement increase by the following items, which the Parties ask and recommend the Commission accept as reasonable without modification:

(A) **Removal of AMS Cost Recovery.** Because the Utilities are withdrawing their request for CPCNs and cost recovery for their proposed full deployment of AMS, recovery of AMS costs is being removed from LG&E's gas revenue requirement. This reduces LG&E's proposed gas revenue requirement increase by $0.7 million, consisting solely of carrying cost and depreciation expense.

(B) **Return on Equity.** The Parties agree that a return on equity of 9.75% is reasonable for LG&E's gas operations, and the agreed stipulated revenue requirement increase for LG&E's gas operations reflect that return on equity as applied to LG&E's gas capitalization and capital structure underlying its originally proposed gas revenue requirement increase as modified through discovery. Use of a 9.75% return on equity reduces LG&E's proposed gas revenue requirement increase by $2.9 million.

(C) **Depreciation Rates.** The stipulated gas revenue requirement increase reflects the depreciation rates shown in Stipulation Exhibit 3, which reduce LG&E's proposed gas revenue requirement increase by $2.1 million.

(D) **Updated Five-Year Average for Uncollectible Debt Expense.** The stipulated gas revenue requirements increase reflects the use of a five-year average (calendar years 2012-2016) for uncollectible debt expense, which is an update to the five-year average

(2011-2015) that was available at the time LG&E filed its application in Case No. 2016-00371. This approach reduces LG&E's proposed gas revenue requirement increase by $0.1 million.

3.3. Summary Calculation of Gas Revenue Requirement Increase. The table below shows the calculation of the stipulated gas revenue requirement increase:

Item	LG&E Gas
Proposed gas revenue requirement increase	$13.4 million
Remove AMS	($0.7 million)
9.75% return on equity	($2.9 million)
Revised depreciation rates	($2.1 million)
5-year average uncollectible expense	($0.1 million)
Stipulated gas revenue requirement increase	$7.5 million[2]

ARTICLE IV. REVENUE ALLOCATION AND RATE DESIGN

4.1. Revenue Allocation. The Parties hereto agree that the allocations of the increases in annual revenues for KU and LG&E electric operations, and that the allocation of the increase in annual revenue for LG&E gas operations, as set forth on the allocation schedules designated Stipulation Exhibit 4 (KU), Stipulation Exhibit 5 (LG&E electric), and Stipulation Exhibit 6 (LG&E gas) attached hereto, are fair, just, and reasonable for the Parties and for all customers of LG&E and KU.

4.2. Tariff Sheets. The Parties hereto agree that, effective July 1, 2017, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Stipulation Exhibit 7

[2] Stipulated gas revenue requirement increase differs from proposed revenue requirement increase less adjustments shown due to rounding.

(KU), Stipulation Exhibit 8 (LG&E electric), and Stipulation Exhibit 9 (LG&E gas) attached hereto, which rates the Parties unanimously stipulate are fair, just, and reasonable, and should be approved by the Commission.

4.3. Basic Service Charges. The Parties agree that the following monthly basic service charge amounts shall be implemented on the schedule shown:

Rates	Effective July 1, 2017	Effective July 1, 2018
LG&E and KU Rates RS, VFD, RTOD-Energy, and RTOD-Demand	$11.50	$12.25
LG&E Rates RGS and VFD	$16.35	$16.35

All other basic service charges shall be the amounts reflected in the proposed tariff sheets attached hereto in Stipulation Exhibits 7 (KU), 8 (LG&E electric), and 9 (LG&E gas).

4.4. Curtailable Service Riders. Concerning the Utilities' Curtailable Service Riders ("CSR"), the Parties agree that CSR customers may choose between Options A and B as follows:

(A) Option A: The Utilities' proposed CSR credits and tariff provisions as filed in these proceedings.

(B) Option B: The Utilities' existing CSR tariff provisions with the modifications below:

(i) CSR credits for both Utilities of $6.00 per kVA-month (primary) and $5.90 per kVA-month (transmission).

(ii) A Utility may request physical curtailment when more than 10 of the Utilities' primary combustion turbines (CTs) (those with a capacity greater than 100 MW) are being dispatched, irrespective of whether the Utilities are making off-system sales. However, to avoid a physical curtailment a CSR customer may buy through a requested curtailment at the Automatic Buy-Through Price. If all available units have been dispatched or are being dispatched, the Utilities may request a physical curtailment of the CSR customer without a buy-through option.

(iii) A Utility may request physical curtailment of a CSR customer no more than 20 times per calendar year totaling no more than 100 hours. Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 hours of economic curtailments.

(iv) After receiving a physical curtailment request from the Utility where a buy-through option is available, a CSR customer will have 10 minutes to inform the Utility whether the customer elects to buy through or physically curtail. If the customer elects to physically curtail, the customer will have 30 minutes to carry out the required physical curtailment (i.e., a total of 40 minutes from the time the Utility requests curtailment to the time the customer must implement the curtailment). If a customer does not respond within 10 minutes of notice of a curtailment request from the Utility, the customer will be assumed to have elected to buy through the requested curtailment, subject to any prior written agreement with the customer.

(v) After receiving a physical curtailment request from the Utility when no buy-through option is available, a CSR customer will have 40 minutes to carry out the required physical curtailment.

(C) The Utilities will initially assign all existing CSR customers to Option B as described above. Following the initial assignment, a CSR customer may elect Option A at any time, which election will take effect beginning with the customer's first full billing cycle following the election. After a CSR makes its first election or any subsequent election, the customer must take service under the chosen option for at least 24 full billing cycles before a new election can become effective.

(D) LG&E will permit any customer interested in participating in CSR to give notice of interest by July 1, 2017; after that date, only those customers already participating in LG&E's CSR may continue their participation at their then-current levels. Customers that have given notice of interest on or before July 1, 2017, may elect to begin participating in CSR no later than January 1, 2019. LG&E's existing capacity cap will continue to apply, and all available CSR capacity will be available for participation on a first come, first served basis to those giving notice of interest by July 1, 2017.

(E) KU's CSR will be closed to new or increased participation as of July 1, 2017.

These proposed tariff changes are shown in Stipulation Exhibits 7 (KU) and 8 (LG&E electric) attached hereto.

4.5. Five-Year Limit to Gas Line Tracker Recovery for Transmission Modernization and Steel Service Line Replacement Programs. The Parties agree that LG&E will recover costs related to its proposed Transmission Modernization and Steel Service Line Replacement Programs through its Gas Line Tracker ("GLT") cost-recovery mechanism for five years ending June 30, 2022. Absent further action by the Commission concerning recovery of these programs' costs by June 30, 2022, any remaining costs for such programs will be recovered through base rates via a base-rate roll-in effective for service rendered on and after July 1, 2022. These proposed tariff changes are shown in Stipulation Exhibit 9 attached hereto. This provision does not preclude LG&E from seeking Commission approval to recover other appropriate costs through the GLT mechanism.

4.6. Revisions to Proposed Substitute Gas Sales Service (Rate SGSS). The Parties agree that LG&E will revise its proposed Rate SGSS such that monthly billing demand will be based on greatest of (1) Maximum Daily Quantity ("MDQ"), (2) current month's highest daily volume of gas delivered, or (3) 70 percent of the highest daily volume of gas delivered during the previous 11 monthly billing periods. Also, LG&E will revise the provision of Rate SGSS concerning setting the MDQ such that the MDQ for any customer taking service under Rate SGSS when it first becomes effective will be 70% of the highest daily volume projected by LG&E for the customer in the forecasted test year used by LG&E in Case No. 2016-00371. For all other customers that later begin taking service under Rate SGSS, the customer and LG&E may mutually agree to establish the level of the MDQ; provided, however, that in the event that the customer and LG&E cannot agree upon the MDQ, then the level of the MDQ will be equal to 70% of the highest daily volume used by the customer during the 12 months prior to the date the customer began receiving natural gas from another supplier with which the customer is physically connected; in the event that such daily gas usage is not available, then the MDQ will be equal to 70% of the customer's average daily use for the highest month's gas use in the 12 months prior to the date the customer began receiving natural gas from another supplier with which the customer is physically connected. In no case will the MDQ be greater than 5,000 Mcf/day. These proposed tariff changes are shown in Stipulation Exhibit 9 attached hereto.

4.7. Sports Field Lighting Pilot Tariff Provisions. The Parties agree that the Utilities will add to their electric tariffs a voluntary sports field lighting rate schedule, Pilot Rate OSL – Outdoor Sports Lighting Service, on a limited-participation pilot basis (limited to 20 pilot participants per Utility). The pilot rate uses a time-of-day rate structure. The purpose of the pilot is to determine if sports fields have sufficiently different service characteristics to support permanent sports field tariff offerings. The proposed tariff provisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.8. Agreement Not to Split Residential and General Service Electric Energy Charges in Tariffs. The Parties agree that the Utilities will not split their residential and general service electric energy charges into Infrastructure and Variable components as the Utilities had proposed in their applications in these proceedings. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.9. Agreement to File a Study Regarding 100% Base Demand Ratchets for Rate TODS. The Utilities will file in their next base-rate proceedings a study concerning the impacts of 100% base demand ratchets for Rate TODS.

4.10. Rate TODP 60-Minute Exemption from Setting Billing Demand Following Utility System Fault. For customers with their own generation, for 60 minutes immediately following a Utility-system fault, but not a Utility energy spike or a fault on a customer's system, the Utilities will not use any demand data for a Rate TODP customer to set billing demand. This 60-minute exemption from setting billing demand permits customers who have significant onsite generation (i.e., 1 MW or more) that comes offline due to a Utility-system fault to reset and bring back online their own generation before the Utilities will measure demand to be used for billing purposes. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.11. Optional Pilot Rates for Schools Subject to KRS 160.325. The Parties agree that the Utilities will add to their electric tariffs optional pilot tariff provisions for schools subject to KRS 160.325. The pilot rates will not be limited in the number of schools that may participate, but will be limited by the projected revenue impact to the Utilities. Each utility's pilot rate provisions will be available to new participants until the total projected revenue impact (reduction) for each Utility is $750,000 annually compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served. KSBA will be responsible for proposing schools for participation in the pilot rates and the order in which such schools are proposed; the Utilities will calculate and provide to KSBA the projected revenue impact of each proposed school's taking service under pilot rates. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

ARTICLE V. TREATMENT OF CERTAIN SPECIFIC ISSUES

5.1. Regulatory Accounting for Over- and Under-Recovery of Regulatory Assets. The Parties agree to, and ask the Commission to approve, the Utilities' continued use of regulatory asset accounting for regulatory assets embedded in the Utilities' proposed revenue requirement except that shorter-lived regulatory assets should be credited for the amounts collected through base rates even if such amortization results in changing such a regulatory asset to a regulatory liability with any remaining balances being addressed in the Utilities' next base rate case. This would include the regulatory assets for rate case expenses, 2011 summer storm expenses, and Green River. This will help ensure the Utilities only recover actual costs incurred and do not ultimately over-recover such regulatory assets as they are amortized and recovered through base rates.

5.2. Commitment to Apply for School Energy Managers Program ("SEMP") Extension. The Utilities commit to file with the Commission an application proposing a two-year extension of SEMP (for July 1, 2018, through June 30, 2020). The total annual level of funding to be proposed is $725,000; prior to filing the application, the Utilities will consult with

KSBA to determine an appropriate allocation of the total annual funds between KU and LG&E. The Utilities commit to file the above-described application with the Commission no later than December 31, 2017.

5.3. Commitment to File Lead-Lag Study in Next Base-Rate Cases. The Utilities commit to file a lead-lag study in their next base-rate cases.

5.4. Collaborative Study Regarding Electric Bus Infrastructure and Rates. The Utilities commit to fund a study concerning economical deployment of electric bus infrastructure in the Louisville and Lexington areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses. The Utilities commit to work collaboratively with Louisville Metro, LFUCG, and any other interested Parties to these proceedings to develop the parameters for the study, including reasonable cost and timing, and to review the study's results with representatives of Louisville Metro and LFUCG. The collaborative will include only those Parties to these proceedings interested in participating in the collaborative.

5.5. LED Lighting Collaborative. The Utilities commit to engage in good faith with Louisville Metro, LFUCG, and any other interested Parties to these proceedings in a collaborative to discuss issues related to LED lighting to determine what LED street lighting equipment and rate structures might be offered by the Utilities. The collaborative will include only those Parties to these proceedings interested in participating in the collaborative.

5.6. Home Energy Assistance Charges. The Parties agree that KU will increase its monthly residential charge for the Home Energy Assistance ("HEA") program from the current \$0.25 per month to \$0.30 per month, which shall remain effective through June 30, 2021, regardless of whether the Utilities file one or more base-rate cases during that commitment period. The Parties further agree that LG&E will continue its monthly residential charge (for gas and electric service) for the Home Energy Assistance ("HEA") program at $0.25 per month, which shall remain effective until the effective date of new base rates for the Utilities following their next general base-rate cases. The change to the KU HEA charge is reflected in the proposed tariff sheets attached hereto as Stipulation Exhibit 7.

5.7. Low-Income Customer Support. The Utilities commit to contribute a total of $1,450,000 of shareholder funds per year, which commitment will remain in effect through June 30, 2021, regardless of whether the Utilities file one or more base-rate cases during that commitment period.

(A) The total annual shareholder contribution from KU shall be as follows: $100,000 for Wintercare and $470,000 for HEA. CAC administers both programs.

(B) The total annual shareholder contribution from LG&E shall be as follows: $700,000 to ACM for utility assistance and $180,000 for HEA.

(C) KU agrees that up to 10% of its total contributions to CAC may be used for reasonable administrative expenses.

(D) LG&E agrees that up to 10% of its total contributions to ACM may be used for reasonable administrative expenses.

(E) None of the Utilities' shareholder contributions will be conditioned upon receiving matching funds from other sources.

(F) The Utilities commit not to seek reductions to their HEA charges that would become effective before June 30, 2021, for LG&E or KU regardless of whether the Utilities file one or more base-rate cases during that commitment period.

5.8. All Other Relief Requested by Utilities to Be Approved as Filed. The Parties agree and recommend to the Commission that, except as modified in this Stipulation and the exhibits attached hereto, the rates, terms, and conditions contained in the Utilities' filings in these Rate Proceedings, as well as the Companies' requests for CPCNs for their proposed Distribution Automation project, should be approved as filed.

ARTICLE VI. MISCELLANEOUS PROVISIONS

6.1. Except as specifically stated otherwise in this Stipulation, entering into this Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

6.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Stipulation.

6.3. Following the execution of this Stipulation, the Parties shall cause the Stipulation to be filed with the Commission on or about April 19, 2017, together with a request to the Commission for consideration and approval of this Stipulation for rates to become effective for service rendered on and after July 1, 2017.

6.4. This Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the Stipulation is a fair, just, and reasonable means of resolving all issues in these proceedings, and will clearly and definitively ask the Commission to accept and approve the Stipulation as such.

6.5. If the Commission issues an order adopting this Stipulation in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order. With regard to this provision, all of the Parties acknowledge that certain of the Parties, and in particular the Sierra Club, are entities with members who are not under a Party's control but who might purport to act for, or on behalf of, the Party. Therefore, the Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation. All Parties agree that no monetary damages will be sought or obtained from a Party if the Party is not in breach, but rather a non-Party purporting to act for the Party has sought rehearing or appeal of a Commission order adopting this Stipulation in its entirety and without additional conditions.

6.6. If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

6.7. If the Stipulation is voided or vacated for any reason after the Commission has approved the Stipulation, none of the Parties will be bound by the Stipulation.

6.8. The Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

6.9. The Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

6.10. The Stipulation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Stipulation.

6.11. The Parties hereto agree that, for the purpose of the Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

6.12. The Parties hereto agree that neither the Stipulation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Stipulation. This Stipulation shall not have any precedential value in this or any other jurisdiction.

6.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Stipulation and based upon the foregoing are authorized to execute this Stipulation on behalf of their respective Parties.

6.14. The Parties hereto agree that this Stipulation is a product of negotiation among all Parties hereto, and no provision of this Stipulation shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Stipulation, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Stipulation shall be implemented as written.

6.15. The Parties hereto agree that this Stipulation may be executed in multiple counterparts.

APPENDIX A: LIST OF STIPULATION EXHIBITS

Stipulation Exhibit 1: KU Depreciation Rates

Stipulation Exhibit 2: LG&E Electric Depreciation Rates

Stipulation Exhibit 3: LG&E Gas Depreciation Rates

Stipulation Exhibit 4: KU Revenue Allocation Schedule

Stipulation Exhibit 5: LG&E Electric Revenue Allocation Schedule

Stipulation Exhibit 6: LG&E Gas Revenue Allocation Schedule

Stipulation Exhibit 7: KU Tariff Sheets

Stipulation Exhibit 8: LG&E Electric Tariff Sheets

Stipulation Exhibit 9: LG&E Gas Tariff Sheets

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (KRR w/permission)
Allyson K. Sturgeon

Association of Community Ministries, Inc.

HAVE SEEN AND AGREED:

By: Lisa Kilkelly ______________________

Lisa Kilkelly
Eileen Ordover

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By:______________________________

Kent Chandler
Lawrence W. Cook
Rebecca W. Goodman

Community Action Council for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE SEEN AND AGREED:

By:______________________
Iris G. Skidmore

United States Department of Defense and All Other Federal Executive Agencies

HAVE SEEN AND AGREED:

By: Emily W. Medlyn
Emily W. Medlyn
G. Houston Parrish

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: Michael L. Kurtz

Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn

Kentucky League of Cities

HAVE SEEN AND AGREED:

By: ______________________

Laura Ross

The Kroger Company

HAVE SEEN AND AGREED:

By: Robert C. Moore
Robert C. Moore

Kentucky School Boards Association

HAVE SEEN AND AGREED:

By: Matthew R Malone (KRR with permission)

Matthew R. Malone
William H. May, III

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: M. Todd Osterloh

James W. Gardner
M. Todd Osterloh
David J. Barberie
Andrea C. Brown
Janet M. Graham

Subject to ratification by the Urban County Council

Louisville/Jefferson County Metro Government

HAVE SEEN AND AGREED:

By: ______________________
Michael J. O'Connell,
Jefferson County Attorney

-and-

By: ______________________
Gregory T. Dutton,
Counsel for Louisville Metro

Metropolitan Housing Coalition

HAVE SEEN AND AGREED:

By: Tom FitzGerald (KRR w/ permission)
Tom FitzGerald

Sierra Club, Alice Howell, Carl Vogel
and Amy Waters

HAVE SEEN AND AGREED:

By:________________________________
Joe F. Childers

Casey Roberts

____
Casey Roberts

Matthew E. Miller

____
Matthew E. Miller

JBS Swift & Co.

HAVE SEEN AND AGREED:

By:________________________________
Dennis G. Howard, II

Wal-Mart Stores East, LP and Sam's East, Inc.

HAVE SEEN AND AGREED:

By: ______________________

Barry N. Naum
Don C.A. Parker

SECOND STIPULATION AND RECOMMENDATION

This Second Stipulation and Recommendation ("Second Stipulation") is entered into this first day of May 2017 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"), and Kentucky Cable Telecommunications Association ("KCTA"). (Collectively, the Utilities, AT&T and KCTA are the "Parties.")

WITNESSETH:

WHEREAS, on November 23, 2016, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00370 to review KU's base rate application, in which KU requested a revenue increase of $103.1 million;

WHEREAS, on November 23, 2016, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00371 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $93.6 million and a revenue increase of $13.8 million for its gas operations (Case Nos. 2016-00370 and 2016-00371 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, on February 20, 2017, LG&E filed with the Commission in Case No. 2016-00371 a Supplemental Response to Commission Staff's First Request for Information No. 54 in which LG&E corrected its requested revenue increases for its electric operations to be $94.1 million and for its gas operations to be $13.4 million;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00370 to the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"), AT&T, Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"), KCTA, Kentucky Industrial Utility Customers, Inc. ("KIUC"), Kentucky League of Cities ("KLC"), The Kroger Company ("Kroger"), Kentucky School Boards Association ("KSBA"), Lexington-Fayette Urban County Government ("LFUCG"), Sierra Club, Alice Howell, and Carl Vogel, and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart");

WHEREAS, the Commission has granted full intervention in Case No. 2016-00371 to Association of Community Ministries, Inc., AG, AT&T, United States Department of Defense and All Other Federal Executive Agencies, KCTA, KIUC, Kroger, KSBA, Louisville/Jefferson County Metro Government, Metropolitan Housing Coalition, Sierra Club and Amy Waters, JBS Swift & Co., and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of a stipulation and recommendation, attended by representatives of the Parties and the Commission Staff, took place on April 12, 13, and 17, 2017, at the offices of the Commission, which representatives of AT&T and KCTA also attended on April 12 and 13, and which representatives of KCTA also attended on April 17, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, all parties to these proceedings except AT&T and KCTA reached agreement and entered into a stipulation and recommendation ("First Stipulation"), which the Utilities filed with the Commission on April 19, 2017;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of this Second Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 25, 2017, at the offices of the Commission, during which a number of procedural and substantive issues were discussed;

WHEREAS, it is understood by all Parties hereto that this Second Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Second Stipulation;

WHEREAS, the Parties agree that this Second Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues addressed herein, and that the First and Second Stipulations, considered together, produce a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Second Stipulation, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. <u>RATE PSA MODIFICATIONS</u>

1.1. Attachment Charges for Wireline Facilities. The Parties stipulate that an annual attachment charge of $7.25 for a wireline facility is fair, just, and reasonable. The Commission previously approved this charge in the Utilities' most recent general rate case proceedings, Cases No. 2014-00371 and No. 2014-00372. The Utilities have not proposed to adjust this rate, which assumes that a wireline facility will require one foot of usable pole space. AT&T and KCTA have previously advised the Commission that they have no objections to this rate remaining in effect.

1.2. Attachment Charges for Pole-Top Wireless Facilities. The Parties stipulate that a fair, just, and reasonable rate for wireless facilities attached to the top of the Utilities' structures is $36.25 per year. They agree that for purposes of determining the annual charge, a pole-top wireless facility should be allocated five feet of usable pole space. The Utilities assert that this allocation is based upon the premise that, as the Utilities typically have electric facilities located at or near the top of their distribution poles, a pole top wireless facility, such as an antenna, requires a five foot taller pole to maintain a safe working distance of at least 48 inches between the electric facilities and the pole top antenna. Thus, the Utilities assert that the Wireless Facility owner is responsible for the top 5 feet of the pole: one foot for the antenna and four feet of clearance above the power space. Without adopting the Utilities' assertions set out in the preceding two sentences, AT&T agrees that an allocation of five feet of usable pole space is supported by evidence in the record. As the Commission has previously approved the annual rate of $7.25 for one foot of pole space, the use of five feet will produce an annual charge of $36.25.

1.3. Attachment Charges for Mid-Pole Wireless Facilities. The Parties stipulate and agree that, given the lack of information regarding the size and characteristic of wireless antennas and other devices that may be attached to an electric utility pole in the communications space, a uniform rate for such attachments cannot be easily developed and that the rate for such attachments should be developed on a case-by-case basis through special contracts until a sufficient number of such attachments have been made to the Utilities' structures to develop a tariffed rate. At the time of their next general rate applications, the Utilities will determine if they have sufficient evidence regarding mid-pole devices to determine whether a uniform rate is appropriate and, if so, revise the PSA Rate Schedule accordingly.

1.4. Terms and Conditions of Rate PSA. The Parties stipulate and agree that revisions to the originally proposed version of the PSA Rate Schedule are necessary to afford sufficient flexibility for Attachment Customers to permit them to operate effectively in the unregulated, market-based telecommunications industry. The revised PSA Rate Schedules, which are shown in Exhibits 1 and 2 to this Second Stipulation, with the proposed additions and deletions clearly marked, appropriately balance an Attachment Customer's need for flexibility with the public's interest in reliable and safe electric service. The Parties stipulate that, as revised, the terms and conditions set forth in the proposed PSA Rate Schedule are fair, just, and reasonable, will promote public safety, enhance the reliability of electric service, and ensure fair and uniform treatment of Attachment Customers as well as promote the deployment and adoption of advanced communications services.

ARTICLE II. FIRST STIPULATION

2.1. No objections. AT&T and KCTA have reviewed the First Stipulation filed with the Commission on April 19, 2017 and have no objections to it, except to the extent the First

Stipulation's electric tariff exhibits contained PSA Rate Schedules inconsistent with this Second Stipulation and its exhibits, in which case the latter should control.

2.2. AMS Collaborative. The Parties agree that the Utilities shall notify AT&T and KCTA if and when it engages in any AMS Collaborative pursuant to the First Stipulation § 1.2 and that AT&T and KCTA may, at their option, participate in any or all phases of the AMS Collaborative.

ARTICLE III. MISCELLANEOUS PROVISIONS

3.1. Except as specifically stated otherwise in this Second Stipulation, entering into this Second Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

3.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Second Stipulation.

3.3. Following the execution of this Second Stipulation, the Parties shall cause it to be filed with the Commission on or about May 1, 2017, together with a request to the Commission for consideration and approval of this Second Stipulation for rates to become effective for service rendered on and after July 1, 2017.

3.4. This Second Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Second Stipulation and the First Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the First and Second Stipulations, taken together, produce a fair, just, and reasonable means of resolving all issues in these proceedings, and will clearly and definitively ask the Commission to accept and approve the First and Second Stipulations as such.

3.5. If the Commission issues an order adopting this Second Stipulation in its entirety and without additional conditions, irrespective of whether the Commission approves the terms of the First Stipulation, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to the portions of such order that concern this Second Stipulation. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation. All Parties agree that no monetary damages will be sought or obtained from a Party if the Party is not in breach, but rather a non-Party purporting to act for the Party has sought rehearing or appeal of a Commission order adopting this Second Stipulation in its entirety and without additional conditions.

3.6. If the Commission does not accept and approve this Second Stipulation in its entirety and without additional conditions, then any adversely affected Party may withdraw from the Second Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all

Parties that have not withdrawn will continue to be bound by the terms of the Second Stipulation as modified by the Commission's order.

3.7. If the Second Stipulation is voided or vacated for any reason after the Commission has approved the Second Stipulation, none of the Parties will be bound by the Second Stipulation.

3.8. The Second Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

3.9. The Second Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

3.10. The Second Stipulation, including its Exhibits, constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Second Stipulation.

3.11. The Parties hereto agree that, for the purpose of the Second Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

3.12. The Parties hereto agree that neither the Second Stipulation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Second Stipulation. This Second Stipulation shall not have any precedential value in this or any other jurisdiction.

3.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Second

Stipulation and based upon the foregoing are authorized to execute this Second Stipulation on behalf of their respective Parties.

3.14. The Parties hereto agree that this Second Stipulation is a product of negotiation among all Parties hereto, and no provision of this Second Stipulation shall be strictly construed in favor of or against any party.

3.15. The Parties hereto agree that this Second Stipulation may be executed in multiple counterparts.

(This space intentionally left blank.)

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (with permission KRR)
Allyson K. Sturgeon

BellSouth Telecommunications, LLC d/b/a AT&T Kentucky

HAVE SEEN AND AGREED:

By: Cheryl R Winn

Cheryl R. Winn

Kentucky Cable Telecommunications Association

HAVE SEEN AND AGREED:

By: ______________________________

Gardner F. Gillespie
Paul Werner
Megan Grant

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00370 DATED JUN 2 2 2017

The following rates and charges are prescribed for the customers in the area served by Kentucky Utilities Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

SCHEDULE RS
RESIDENTIAL SERVICE

Basic Service Charge per Month	$12.25
Energy Charge per kWh	$ .09070

SCHEDULE RTOD-ENERGY
RESIDENTIAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Month	$12.25
Energy Charge per kWh	
Off Peak Hours	$ .05916
On Peak Hours	$ .27646

SCHEDULE RTOD-DEMAND
RESIDENTIAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Month	$12.25
Energy charge per kWh	$ 0.04504
Demand Charge per kW	
Off Peak Hours	$ 3.44
On Peak Hours	$ 7.87

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT

Basic Service Charge per Month	$12.25
Energy Charge per kWh	$ .09070

SCHEDULE GS
GENERAL SERVICE RATE

Basic Service Charge per Month – Single Phase	$31.50
Basic Service Charge per Month – Three Phase	$50.40
Energy Charge per kWh	$ .10428

SCHEDULE AES
ALL ELECTRIC SCHOOL

Basic Service Charge per Month – Single Phase	$ 85.00
Basic Service Charge per Month – Three Phase	$140.00
Energy Charge per kWh	$ .08306

SCHEDULE PS
POWER SERVICE

Secondary Service:

Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Summer Rate	$ 20.17
Winter Rate	$ 17.95
Energy Charge per kWh	$ .03547

Primary Service:

Basic Service Charge per Month	$240.00
Demand Charge per kW:	
Summer Rate	$ 20.35
Winter Rate	$ 18.16
Energy Charge per kWh	$ .03448

SCHEDULE TODS
TIME-OF-DAY SECONDARY SERVICE

Basic Service Charge per Month	$200.00
Maximum Load Charge per kW:	
Base Demand Period	$ 2.73
Intermediate Demand Period	$ 6.11
Peak Demand Period	$ 7.79
Energy Charge per kWh	$ .03508

SCHEDULE TODP
TIME-OF-DAY PRIMARY SERVICE

Basic Service Charge per Month	$ 330.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.75
Intermediate Demand Period	$ 5.03
Peak Demand Period	$ 6.43
Energy Charge per kWh	$ .03415

SCHEDULE RTS
RETAIL TRANSMISSION SERVICE

Basic Service Charge per Month	$1,500.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.99
Intermediate Demand Period	$ 4.94
Peak Demand Period	$ 6.31
Energy Charge per kWh	$ .03338

SCHEDULE FLS
FLUCTUATING LOAD SERVICE

Primary:	
Basic Service Charge per Month	$ 330.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.45
Intermediate Demand Period	$ 4.48
Peak Demand Period	$ 5.91
Energy Charge per kWh	$ .03415
Transmission:	
Basic Service Charge per Month	$1,500.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.53
Intermediate Demand Period	$ 2.29
Peak Demand Period	$ 3.25
Energy Charge per kWh	$ .03315

SCHEDULE LS
LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

Overhead:

	Fixture Only	Ornamental
High Pressure Sodium:		
5,800 Lumens - Cobra Head	$ 9.86	$ 13.52
9,500 Lumens - Cobra Head	$ 10.34	$ 14.21
22,000 Lumens - Cobra Head	$ 16.08	$ 20.22
50,000 Lumens - Cobra Head	$ 25.61	$ 28.37
9,500 Lumens - Directional	$ 10.19	
22,000 Lumens - Directional	$ 15.42	
50,000 Lumens - Directional	$ 21.95	
9,500 Lumens - Open Bottom	$ 8.87	
Metal Halide		
32,000 Lumens - Directional	$ 22.80	
Light Emitting Diode (LED)		
8,179 Lumens - Cobra Head	$ 14.92	
14,166 Lumens - Cobra Head	$ 18.09	
23,214 Lumens - Cobra Head	$ 27.63	
5,007 Lumens - Open Bottom	$ 9.94	

Underground:

	Fixture Only	Decorative Smooth	Historic Fluted
High Pressure Sodium:			
5,800 Lumens - Colonial		$ 12.59	
9,500 Lumens - Colonial		$ 12.92	
5,800 Lumens - Acorn		$ 17.18	$ 24.50
9,500 Lumens - Acorn		$ 17.63	$ 25.09
5,800 Lumens - Victorian			$ 34.07
9,500 Lumens - Victorian			$ 34.39
5,800 Lumens - Contemporary	$ 17.12	$ 19.35	
9,500 Lumens - Contemporary	$ 17.00	$ 23.94	

22,000 Lumens - Contemporary	$ 19.84	$ 30.82
50,000 Lumens - Contemporary	$ 24.15	$ 38.09
4,000 Lumens - Dark Sky Lantern		$ 24.87
9,500 Lumens - Dark Sky Lantern		$ 25.99
Metal Halide		
32,000 Lumens - Contemporary	$ 24.68	$ 38.87
Light Emitting Diode (LED)		
8,179 Lumens - Cobra Head		$ 35.44
14,166 Lumens - Cobra Head		$ 38.61
23,214 Lumens - Cobra Head		$ 48.14
5,665 Lumens - Open Bottom		$ 37.51

SCHEDULE RLS
RESTRICTED LIGHTING SERVICE

Overhead:

	Fixture Only	Fixture and Pole
High Pressure Sodium:		
4,000 Lumens - Cobra Head	$ 8.84	$ 12.16
50,000 Lumens - Cobra Head	$ 14.06	
5,800 Lumens - Open Bottom	$ 8.54	
Metal Halide		
12,000 Lumens - Directional	$ 16.13	$ 20.89
32,000 Lumens - Directional		$ 27.56
107,800 Lumens - Directional	$ 47.70	$ 52.45
Mercury Vapor:		
7,000 Lumens - Cobra Head	$ 10.83	$ 13.34
10,000 Lumens - Cobra Head	$ 12.84	$ 15.07
20,000 Lumens - Cobra Head	$ 14.53	$ 17.01
7,000 Lumens - Open Bottom	$ 11.87	
Incandescent:		
1,000 Lumens - Tear Drop	$ 3.81	
2,500 Lumens - Tear Drop	$ 5.11	
4,000 Lumens - Tear Drop	$ 7.63	
6,000 Lumens - Tear Drop	$ 10.19	

Underground:

		Decorative Smooth	Historic Fluted
Metal Halide			
12,000 Lumens - Directional		$ 31.20	
32,000 Lumens - Directional		$ 36.99	
107,800 Lumens - Directional		$ 61.66	
12,000 Lumens - Contemporary	$ 17.45	$ 31.42	
107,800 Lumens - Contemporary	$ 51.32	$ 65.28	
High Pressure Sodium:			
4,000 Lumens - Acorn		$ 15.69	$ 23.13
4,000 Lumens - Colonial		$ 11.18	
5,800 Lumens - Coach		$ 34.07	
9,500 Lumens - Coach		$ 34.39	
16,000 Lumens - Granville		$ 62.30	

SCHEDULE TE
TRAFFIC ENERGY SERVICE

Basic Service Charge per Month	$ 4.00
Energy Charge per kWh	$ .09013

SCHEDULE PSA
POLE AND STRUCTURE ATTACHMENT CHARGES

Per Year for Each Attachment to Pole	$ 7.25
Per Year for Each Linear Foot of Duct	$ .81
Per Year for Each Wireless Facility	$36.25

RATE CSR-1
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	$ 3.20	$ 3.31
Non-compliance Charge Per kVA	$16.00	$16.00

RATE CSR-2
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	\$ 5.90	\$ 6.00
Non-compliance Charge Per kVA	\$ 16.00	\$ 16.00

RC
REDUNDANT CAPACITY

Charge per kW/kVA per month	
Secondary Distribution	\$ 1.04
Primary Distribution	\$ .86

EVSE
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:	
Single Charger	\$182.27
Dual Charger	\$306.01

EVC
ELECTRIC VEHICLE CHARGING SERVICE

Fee per Hour	\$ 2.84

EVSE-R
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:	
Single Charger	\$131.41
Dual Charger	\$204.31

SSP
SOLAR SHARE PROGRAM RIDER

Monthly Charge:	
Solar Capacity Charge	\$ 6.24
Solar Energy Credit per kWh of Pro Rata Energy Produced:	
RS	\$ .03520
RTOD-Energy	\$ .03520
RTOD-Demand	\$ .03520
VFD	\$ .03520

GS	$	.03524
AES	$	.03526
PS Secondary	$	.03547
PS Primary	$	.03448
TODS	$	.03508
TODP	$	.03415

SPS
SCHOOL POWER SERVICE

Secondary Service:

Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Summer Rate	$ 17.89
Winter Rate	$ 15.92
Energy Charge per kWh	$ .03572

STOD
SCHOOL TIME-OF-DAY SERVICE

Basic Service Charge per Month	$200.00
Maximum Load Charge per kW:	
Base Demand Period	$ 4.83
Intermediate Demand Period	$ 4.25
Peak Demand Period	$ 5.76
Energy Charge per kWh	$ .03527

OSL
OUTDOOR SPORTS LIGHTING SERVICE

Secondary Service:

Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Peak Demand Period	$ 16.15
Base Demand Period	$ 2.73
Energy Charge per kWh	$ .03571

Primary Service:

Basic Service Charge per Month	$240.00
Demand Charge per kW:	
Peak Demand Period	$ 16.32
Base Demand Period	$ 2.75
Energy Charge per kWh	$ .03472

UNAUTHORIZED RECONNECT CHARGE

Tampering or Unauthorized Connection or Reconnection Fee:	
Meter Replacement Not Required	$ 70.00
Single Phase Standard Meter Replacement Required	$ 90.00
Single Phase AMR Meter Replacement Required	$ 110.00
Single Phase AMS Meter Replacement Required	$ 174.00
Three Phase Meter Replacement Required	$ 177.00

HEA
HOME ENERGY ASSISTANCE PROGRAM

Per Month	$ .30

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Atlanta, GEORGIA 30308

DEK
Exhibit 6

Average Rates

(in cents/kilowatthour)

Ranking of Total Retail Average Rates

12 Months Ending 6/30/17

169	MidAmerican Energy	SD	5.80
168	Southwestern Public Service	TX	6.21
167	Entergy Louisiana, LLC (formerly Entergy Gulf	LA	6.54
166	Entergy Louisiana, Inc.	LA	6.60
165	Southwestern Public Service	NM	6.81
164	Public Service Company of Oklahoma	OK	6.83
163	Black Hills Power, Inc. d/b/a Black Hills Energ	MT	6.98
162	AEP (Wheeling Power Rate Area)	WV	7.03
161	MidAmerican Energy - East System	IA	7.04
160	Montana-Dakota Utilites Company	MT	7.06
159	Entergy Texas	TX	7.13
158	OG&E Electric Services	AR	7.17
157	We Energies (formerly Wisconsin Electric)	MI	7.35
156	Sierra Pacific Power Company - NV Energy	NV	7.35
155	PacifiCorp	WY	7.47
154	Minnesota Power Company	MN	7.54
153	Southwestern Electric Power Company	AR	7.56
152	Otter Tail Power Company	SD	7.67
151	Duke Energy Kentucky	KY	7.71
150	Southwestern Electric Power Company	TX	7.71
149	AEP (Kingsport Power Rate Area)	TN	7.73
148	Duke Energy Carolinas	SC	7.74
147	Superior Water, Light & Power Company	WI	7.76
146	Entergy Mississippi, Inc.	MS	7.84
145	Idaho Power Company	OR	7.95
144	Otter Tail Power Company	MN	7.95
143	PacifiCorp	ID	8.05
142	Avista Corp.	ID	8.06
141	Dominion North Carolina Power	NC	8.06
140	Duke Energy Progress, Inc.	SC	8.17
139	Idaho Power Company	ID	8.18
138	OG&E Electric Services	OK	8.19
137	MidAmerican Energy	IL	8.22
136	Otter Tail Power Company	ND	8.22
135	Duke Energy Carolinas	NC	8.28
134	Entergy Arkansas, Inc.	AR	8.31
133	PacifiCorp	WA	8.35
132	Empire District Electric Company	AR	8.40
131	Kentucky Utilities Company	KY	8.43
130	PacifiCorp	UT	8.46
129	Empire District Electric Company	OK	8.49
128	AEP (Indiana Michigan Power)	IN	8.56
127	Wisconsin Public Service Corporation	MI	8.57
126	Dominion Virginia Power	VA	8.63
125	Avista Corp.	WA	8.76
124	Ameren Missouri	MO	8.80
123	Duke Energy Progress, Inc.	NC	8.83
122	Monongahela Power Company	WV	8.88
121	West Penn Power Company	PA	8.90
120	Southwestern Electric Power Company	LA	8.99
119	Wisconsin Public Service Corporation	WI	9.07
118	Montana-Dakota Utilities Company	WY	9.13
117	Duke Energy Indiana	IN	9.14
116	Louisville Gas & Electric Company	KY	9.15
115	Toledo Edison Company	OH	9.16
114	Mississippi Power Company	MS	9.19
113	AEP (Appalachian Power Rate Area)	VA	9.23
112	Nevada Power Company - NV Energy	NV	9.27
111	Northern States Power Company (MN)	ND	9.34
110	Georgia Power Company	GA	9.37
109	Dayton Power & Light Company	OH	9.38
108	Montana-Dakota Utilities Company	ND	9.46
107	Kansas City Power & Light - GMO	MO	9.50
106	Black Hills Power, Inc. d/b/a Black Hills Energ	WY	9.50
105	AEP (Appalachian Power Rate Area)	WV	9.53
104	Public Service Company of Colorado	CO	9.58
103	Florida Power & Light Company	FL	9.60
102	PacifiCorp	OR	9.63
101	Northwestern Energy	SD	9.72
100	Indianapolis Power & Light Company	IN	9.77
99	Portland General Electric Company	OR	9.77
98	Westar Energy-KGE	KS	9.81
97	Entergy New Orleans, Inc.	LA	9.83
96	Pennsylvania Power Company	PA	9.86
95	Northern Indiana Public Service Company	IN	9.92
94	AEP (Kentucky Power Rate Area)	KY	9.93

Average Rates

(in cents/kilowatthour)

Ranking of Total Retail Average Rates

12 Months Ending 6/30/17

93	AEP (Indiana Michigan Power combined MI ra	MI	9.93
92	Interstate Power & Light	IA	9.95
91	Montana-Dakota Utilities Company	SD	9.96
90	Ohio Edison Company	OH	9.96
89	Potomac Edison Company	WV	9.98
88	Old Dominion Power Company	VA	9.98
87	Cleveland Electric Illuminating Company	OH	10.00
86	Tampa Electric Company	FL	10.07
85	Alabama Power Company	AL	10.09
84	Empire District Electric Company	KS	10.10
83	El Paso Electric Company	TX	10.17
82	Northern States Power Company (MN)	SD	10.22
81	Potomac Edison Company	MD	10.27
80	CLECO Power LLC	LA	10.34
79	Cheyenne Light, Fuel & Power d/b/a Black Hill	WY	10.35
78	Metropolitan Edison Company	PA	10.36
77	PPL Utilities Corp.	PA	10.42
76	Northern States Power Company (WI)	WI	10.43
75	Puget Sound Energy	WA	10.43
74	Duke Energy Florida	FL	10.47
73	WP&L	WI	10.51
72	Northern States Power Company (MN)	MN	10.51
71	Westar Energy-KPL	KS	10.56
70	Public Service Company of New Mexico	NM	10.59
69	UGI Utilities, Inc.	PA	10.63
68	Kansas City Power & Light Company	MO	10.70
67	AEP (Ohio Power Rate Area)	OH	10.72
66	AEP (Columbus Southern Power Rate Area)	OH	10.73
65	USA		10.74
64	Pennsylvania Electric Company	PA	10.84
63	Southern Indiana Gas & Electric Company	IN	10.94
62	NorthWestern Energy (formerly Montana Pow	MT	10.98
61	Unisource Electric Company	AZ	11.05
60	Northern States Power Company (WI)	MI	11.05
59	Commonwealth Edison Company	IL	11.11
58	Duquesne Light Company	PA	11.15
57	El Paso Electric Company	NM	11.20
56	New York State Electric & Gas Corporation	NY	11.20
55	Tucson Electric Power Company	AZ	11.26
54	Duke Energy Ohio	OH	11.28
53	South Carolina Electric & Gas Company	SC	11.37
52	Empire District Electric Company	MO	11.39
51	Gulf Power Company	FL	11.44
50	Delmarva Power	DE	11.51
49	DTE Electric Company	MI	11.54
48	Northwestern Wisconsin Electric Company	WI	11.67
47	Kansas City Power & Light Company	KS	11.67
46	We Energies (formerly Wisconsin Electric)	WI	11.83
45	National Grid (Niagara Mohawk Power Corpor	NY	11.97
44	Arizona Public Service Company	AZ	11.97
43	Potomac Electric Power Company	DC	12.04
42	Madison Gas & Electric Company	WI	12.22
41	PECO Energy	PA	12.25
40	Emera Maine - Maine Public District	ME	12.26
39	Black Hills Power, Inc. d/b/a Black Hills Energ	SD	12.40
38	Consumers Energy	MI	12.49
37	Rochester Gas & Electric Corporation	NY	12.85
36	Black Hills/Colorado Electric	CO	12.95
35	Baltimore Gas & Electric Company	MD	12.96
34	Jersey Central Power & Light Company	NJ	13.15
33	Delmarva Power	MD	13.49
32	Unitil Energy Systems, Inc.	NH	13.51
31	Potomac Electric Power Company	MD	13.52
30	Florida Public Utilities Company	FL	13.96
29	Green Mountain Power	VT	13.97
28	PacifiCorp	CA	14.13
27	Southern California Edison	CA	14.38
26	Public Service Electric & Gas Company	NJ	14.44
25	Upper Peninsula Power Company	MI	14.96
24	Central Hudson Gas & Electric Corporation	NY	15.23
23	Cambridge Electric Company	MA	15.57
22	Emera Maine - Bangor Hydro District	ME	15.68
21	Western Massachusetts Electric Company	MA	16.02
20	Rockland Electric Company	NJ	16.36
19	Narragansett Electric Company	RI	16.58
18	Pacific Gas & Electric Company	CA	16.80

Average Rates

(in cents/kilowatthour)

Ranking of Total Retail Average Rates

12 Months Ending 6/30/17

17	Connecticut Light & Power Company	CT	16.86
16	National Grid (Massachusetts Electric Compa	MA	17.46
15	Atlantic City Electric Company	NJ	17.47
14	Boston Edison Company	MA	17.62
13	Fitchburg Gas & Electric Light Company	MA	17.79
12	Public Service Company of New Hampshire d/	NH	17.89
11	LIPA	NY	17.95
10	Orange & Rockland Utilities, Inc.	NY	18.35
9	Commonwealth Electric Company	MA	18.72
8	United Illuminating Company	CT	18.90
7	San Diego Gas & Electric Company	CA	19.80
6	Consolidated Edison Company of New York	NY	22.46
5	Hawaiian Electric Company	HI	23.23
4	Maui Electric Company (Maui)	HI	28.46
3	Hawaii Electric Light Company	HI	30.55
2	Maui Electric Company (Molokai)	HI	33.35
1	Maui Electric Company (Lanai)	HI	34.82

Average Rates

(in cents/kilowatthour)

Ranking of Residential Average Rates

12 Months Ending 6/30/2017

172	Black Hills Power, Inc. d/b/a Black Hills Energ	MT	7.03
171	MidAmerican Energy	SD	7.92
170	Entergy Mississippi, Inc.	MS	8.54
169	OG&E Electric Services	AR	8.63
168	Entergy Louisiana, Inc.	LA	8.65
167	Entergy Louisiana, LLC (formerly Entergy Gulf	LA	8.68
166	Duke Energy Kentucky	KY	8.69
165	Montana-Dakota Utilites Company	MT	8.85
164	PacifiCorp	WA	8.93
163	AEP (Kingsport Power Rate Area)	TN	9.00
162	Otter Tail Power Company	ND	9.02
161	Avista Corp.	WA	9.10
160	Public Service Company of Oklahoma	OK	9.12
159	Avista Corp.	ID	9.13
158	Otter Tail Power Company	SD	9.35
157	Southwestern Electric Power Company	AR	9.36
156	Empire District Electric Company	OK	9.64
155	Southwestern Electric Power Company	TX	9.70
154	Entergy Texas	TX	9.82
153	Southwestern Electric Power Company	LA	10.02
152	Idaho Power Company	OR	10.05
151	Kentucky Utilities Company	KY	10.06
150	Sierra Pacific Power Company - NV Energy	NV	10.09
149	Southwestern Public Service	NM	10.11
148	Duke Energy Carolinas	NC	10.24
147	Montana-Dakota Utilities Company	ND	10.28
146	Entergy Arkansas, Inc.	AR	10.30
145	Idaho Power Company	ID	10.31
144	Southwestern Public Service	TX	10.36
143	MidAmerican Energy - East System	IA	10.36
142	PacifiCorp	ID	10.42
141	Old Dominion Power Company	VA	10.42
140	Montana-Dakota Utilities Company	WY	10.48
139	Duke Energy Progress, Inc.	SC	10.48
138	Louisville Gas & Electric Company	KY	10.52
137	Northern States Power Company (MN)	ND	10.52
136	Otter Tail Power Company	MN	10.57
135	Duke Energy Progress, Inc.	NC	10.57
134	Dominion North Carolina Power	NC	10.57
133	Ameren Missouri	MO	10.59
132	Florida Power & Light Company	FL	10.63
131	OG&E Electric Services	OK	10.66
130	Empire District Electric Company	KS	10.70
129	Duke Energy Carolinas	SC	10.71
128	Dayton Power & Light Company	OH	10.71
127	Montana-Dakota Utilities Company	SD	10.71
126	Northwestern Energy	SD	10.73
125	Minnesota Power Company	MN	10.77
124	PacifiCorp	OR	10.78
123	Entergy New Orleans, Inc.	LA	10.81
122	Indianapolis Power & Light Company	IN	10.85
121	MidAmerican Energy	IL	10.95
120	AEP (Indiana Michigan Power combined MI ra	MI	11.04
119	Potomac Edison Company	MD	11.06
118	NorthWestern Energy (formerly Montana Pow	MT	11.07
117	Potomac Edison Company	WV	11.08
116	Puget Sound Energy	WA	11.12
115	Dominion Virginia Power	VA	11.12
114	UGI Utilities, Inc.	PA	11.12
113	Kansas City Power & Light - GMO	MO	11.13
112	Ameren Illinois Rate Zone I (formerly CIPS)	IL	11.15
111	West Penn Power Company	PA	11.20
110	Tampa Electric Company	FL	11.21
109	PacifiCorp	WY	11.26
108	Monongahela Power Company	WV	11.26
107	Ameren Illinois Rate Zone II (formerly CILCO)	IL	11.27
106	PacifiCorp	UT	11.29
105	Unisource Electric Company	AZ	11.33
104	AEP (Appalachian Power Rate Area)	VA	11.39
103	Duke Energy Indiana	IN	11.40
102	CLECO Power LLC	LA	11.44
101	Portland General Electric Company	OR	11.46
100	New York State Electric & Gas Corporation	NY	11.57
99	Ameren Illinois Rate Zone III (formerly IP)	IL	11.58
98	Public Service Company of Colorado	CO	11.61
97	Superior Water, Light & Power Company	WI	11.61

Average Rates
(in cents/kilowatthour)

Ranking of Residential Average Rates

12 Months Ending 6/30/2017

96	AEP (Indiana Michigan Power)	IN	11.62
95	Empire District Electric Company	AR	11.73
94	Duke Energy Ohio	OH	11.73
93	Ohio Edison Company	OH	11.75
92	Nevada Power Company - NV Energy	NV	11.87
91	AEP (Appalachian Power Rate Area)	WV	12.00
90	Wisconsin Public Service Corporation	MI	12.01
89	Potomac Electric Power Company	DC	12.07
88	Cleveland Electric Illuminating Company	OH	12.09
87	Northern States Power Company (MN)	SD	12.13
86	Duke Energy Florida	FL	12.18
85	AEP (Wheeling Power Rate Area)	WV	12.26
84	El Paso Electric Company	NM	12.26
83	AEP (Kentucky Power Rate Area)	KY	12.26
82	Georgia Power Company	GA	12.36
81	Tucson Electric Power Company	AZ	12.36
80	Toledo Edison Company	OH	12.39
79	Commonwealth Edison Company	IL	12.43
78	Northern States Power Company (WI)	MI	12.50
77	Black Hills Power, Inc. d/b/a Black Hills Energ	WY	12.65
76	El Paso Electric Company	TX	12.67
75	Pennsylvania Power Company	PA	12.75
74	Westar Energy-KGE	KS	13.01
73	AEP (Columbus Southern Power Rate Area)	OH	13.06
72	Westar Energy-KPL	KS	13.09
71	Rochester Gas & Electric Corporation	NY	13.10
70	Kansas City Power & Light Company	MO	13.11
69	PECO Energy	PA	13.11
68	USA		13.13
68	Metropolitan Edison Company	PA	13.13
66	Northwestern Wisconsin Electric Company	WI	13.14
65	Alabama Power Company	AL	13.14
64	Kansas City Power & Light Company	KS	13.20
63	Arizona Public Service Company	AZ	13.23
62	Wisconsin Public Service Corporation	WI	13.24
61	Public Service Company of New Mexico	NM	13.26
60	National Grid (Niagara Mohawk Power Corpor	NY	13.28
59	Gulf Power Company	FL	13.29
58	Mississippi Power Company	MS	13.40
57	Empire District Electric Company	MO	13.45
56	Northern States Power Company (MN)	MN	13.50
55	Northern States Power Company (WI)	WI	13.55
54	WP&L	WI	13.62
53	Delmarva Power	DE	13.62
52	PacifiCorp	CA	13.64
51	PPL Utilities Corp.	PA	13.69
50	AEP (Ohio Power Rate Area)	OH	13.73
49	Jersey Central Power & Light Company	NJ	13.78
48	Black Hills Power, Inc. d/b/a Black Hills Energ	SD	13.93
47	Northern Indiana Public Service Company	IN	14.02
46	Emera Maine - Maine Public District	ME	14.05
45	Florida Public Utilities Company	FL	14.54
44	Baltimore Gas & Electric Company	MD	14.58
43	Potomac Electric Power Company	MD	14.64
42	South Carolina Electric & Gas Company	SC	14.73
41	Delmarva Power	MD	14.84
40	Pennsylvania Electric Company	PA	14.92
39	Interstate Power & Light	IA	14.98
38	Unitil Energy Systems, Inc.	NH	15.01
37	Southern Indiana Gas & Electric Company	IN	15.17
36	We Energies (formerly Wisconsin Electric)	WI	15.28
35	Cheyenne Light, Fuel & Power d/b/a Black Hill	WY	15.49
34	Duquesne Light Company	PA	15.52
33	Consumers Energy	MI	15.68
32	We Energies (formerly Wisconsin Electric)	MI	15.80
31	DTE Electric Company	MI	15.86
30	Black Hills/Colorado Electric	CO	16.01
29	Public Service Electric & Gas Company	NJ	16.27
28	Central Hudson Gas & Electric Corporation	NY	16.50
27	Southern California Edison	CA	16.54
26	Madison Gas & Electric Company	WI	16.66
25	Rockland Electric Company	NJ	16.89
24	Green Mountain Power	VT	16.98
23	Narragansett Electric Company	RI	17.34
22	Emera Maine - Bangor Hydro District	ME	17.61
21	Atlantic City Electric Company	NJ	17.95

Average Rates
(in cents/kilowatthour)

Ranking of Residential Average Rates

12 Months Ending 6/30/2017

20	Western Massachusetts Electric Company	MA	18.37
19	Connecticut Light & Power Company	CT	18.92
18	National Grid (Massachusetts Electric Compa	MA	19.07
17	Pacific Gas & Electric Company	CA	19.33
16	LIPA	NY	19.56
15	Public Service Company of New Hampshire d/	NH	19.73
14	Orange & Rockland Utilities, Inc.	NY	20.23
13	Boston Edison Company	MA	20.24
12	Commonwealth Electric Company	MA	20.87
11	San Diego Gas & Electric Company	CA	21.58
10	Cambridge Electric Company	MA	21.65
9	Fitchburg Gas & Electric Light Company	MA	21.81
8	United Illuminating Company	CT	22.57
7	Upper Peninsula Power Company	MI	24.26
6	Consolidated Edison Company of New York	NY	25.10
5	Hawaiian Electric Company	HI	27.15
4	Maui Electric Company (Maui)	HI	29.87
3	Hawaii Electric Light Company	HI	33.07
2	Maui Electric Company (Molokai)	HI	34.32
1	Maui Electric Company (Lanai)	HI	34.76

Average Rates
(in cents/kilowatthour)

Ranking of Commercial Average Rates

12 Months Ending 6/30/2017

172	Public Service Company of Oklahoma	OK	7.00
171	MidAmerican Energy	SD	7.07
170	OG&E Electric Services	AR	7.29
169	Southwestern Public Service	TX	7.35
168	Dominion Virginia Power	VA	7.36
167	Entergy Texas	TX	7.40
166	Duke Energy Kentucky	KY	7.48
165	Southwestern Electric Power Company	AR	7.56
164	Entergy Louisiana, LLC (formerly Entergy Gulf	LA	7.60
163	Idaho Power Company	ID	7.63
162	Sierra Pacific Power Company - NV Energy	NV	7.67
161	Duke Energy Carolinas	NC	7.69
160	Southwestern Electric Power Company	TX	7.73
159	MidAmerican Energy - East System	IA	7.77
158	Ameren Missouri	MO	7.89
157	MidAmerican Energy	IL	7.95
156	Idaho Power Company	OR	8.03
155	Entergy Mississippi, Inc.	MS	8.06
154	OG&E Electric Services	OK	8.11
153	Montana-Dakota Utilites Company	MT	8.13
152	Entergy Arkansas, Inc.	AR	8.21
151	Southwestern Public Service	NM	8.33
150	Duke Energy Carolinas	SC	8.38
149	Avista Corp.	ID	8.39
148	PacifiCorp	WA	8.40
147	Empire District Electric Company	OK	8.41
146	Duquesne Light Company	PA	8.42
145	Florida Power & Light Company	FL	8.45
144	Duke Energy Progress, Inc.	NC	8.58
143	Entergy Louisiana, Inc.	LA	8.59
142	Dominion North Carolina Power	NC	8.59
141	PacifiCorp	UT	8.61
140	Nevada Power Company - NV Energy	NV	8.70
139	Ameren Illinois Rate Zone III (formerly IP)	IL	8.73
138	Southwestern Electric Power Company	LA	8.74
137	Ameren Illinois Rate Zone I (formerly CIPS)	IL	8.76
136	AEP (Indiana Michigan Power)	IN	8.86
135	PacifiCorp	ID	8.90
134	Kansas City Power & Light - GMO	MO	8.93
133	AEP (Appalachian Power Rate Area)	VA	8.95
132	Duke Energy Progress, Inc.	SC	8.99
131	PacifiCorp	WY	9.02
130	Ameren Illinois Rate Zone II (formerly CILCO)	IL	9.04
129	Duke Energy Florida	FL	9.05
128	PPL Utilities Corp.	PA	9.07
127	Superior Water, Light & Power Company	WI	9.09
126	Otter Tail Power Company	ND	9.09
125	PacifiCorp	OR	9.13
124	AEP (Wheeling Power Rate Area)	WV	9.15
123	Otter Tail Power Company	SD	9.18
122	Northern States Power Company (MN)	ND	9.20
121	Commonwealth Edison Company	IL	9.20
120	AEP (Appalachian Power Rate Area)	WV	9.22
119	Tampa Electric Company	FL	9.22
118	Portland General Electric Company	OR	9.25
117	Montana-Dakota Utilities Company	WY	9.26
116	Avista Corp.	WA	9.29
115	Wisconsin Public Service Corporation	WI	9.30
114	Empire District Electric Company	AR	9.32
113	AEP (Kingsport Power Rate Area)	TN	9.37
112	Duke Energy Indiana	IN	9.42
111	Dayton Power & Light Company	OH	9.43
110	Public Service Company of Colorado	CO	9.45
109	Louisville Gas & Electric Company	KY	9.50
108	Entergy New Orleans, Inc.	LA	9.51
107	National Grid (Niagara Mohawk Power Corpor	NY	9.52
106	Georgia Power Company	GA	9.54
105	AEP (Columbus Southern Power Rate Area)	OH	9.54
104	Monongahela Power Company	WV	9.54
103	Pennsylvania Power Company	PA	9.58
102	Delmarva Power	DE	9.66
101	Northern States Power Company (MN)	SD	9.66
100	Minnesota Power Company	MN	9.68
99	Old Dominion Power Company	VA	9.68
98	PECO Energy	PA	9.68
97	Westar Energy-KGE	KS	9.72

Average Rates
(in cents/kilowatthour)

Ranking of Commercial Average Rates

12 Months Ending 6/30/2017

96	Westar Energy-KPL	KS	9.76	58	South Carolina Electric & Gas Company	SC	11.35
95	Puget Sound Energy	WA	9.80	57	WP&L	WI	11.41
94	West Penn Power Company	PA	9.84	56	Toledo Edison Company	OH	11.48
93	AEP (Indiana Michigan Power combined MI ra	MI	9.84	55	Madison Gas & Electric Company	WI	11.49
92	Kentucky Utilities Company	KY	9.84	54	Cleveland Electric Illuminating Company	OH	11.53
91	Potomac Edison Company	MD	9.86	53	Montana-Dakota Utilities Company	ND	11.59
90	Metropolitan Edison Company	PA	9.92	52	We Energies (formerly Wisconsin Electric)	WI	11.61
89	Potomac Edison Company	WV	10.01	51	Potomac Electric Power Company	MD	11.71
88	UGI Utilities, Inc.	PA	10.05	50	El Paso Electric Company	NM	11.76
87	Duke Energy Ohio	OH	10.06	49	Alabama Power Company	AL	11.89
86	Northwestern Energy	SD	10.13	48	Delmarva Power	MD	11.90
85	Pennsylvania Electric Company	PA	10.15	47	Potomac Electric Power Company	DC	12.02
84	Northern States Power Company (WI)	WI	10.16	46	Wisconsin Public Service Corporation	MI	12.10
83	Northern States Power Company (MN)	MN	10.19	45	AEP (Kentucky Power Rate Area)	KY	12.17
82	Otter Tail Power Company	MN	10.26	44	Rochester Gas & Electric Corporation	NY	12.28
81	CLECO Power LLC	LA	10.32	43	Emera Maine - Maine Public District	ME	12.34
80	Mississippi Power Company	MS	10.33	42	Cheyenne Light, Fuel & Power d/b/a Black Hill	WY	12.35
79	DTE Electric Company	MI	10.33	41	Southern Indiana Gas & Electric Company	IN	12.37
78	Kansas City Power & Light Company	MO	10.34	40	Consumers Energy	MI	12.43
77	Gulf Power Company	FL	10.41	39	Southern California Edison	CA	12.46
76	Kansas City Power & Light Company	KS	10.45	38	Black Hills Power, Inc. d/b/a Black Hills Energ	WY	12.49
75	Black Hills Power, Inc. d/b/a Black Hills Energ	MT	10.59	37	Black Hills Power, Inc. d/b/a Black Hills Energ	SD	12.52
74	Public Service Company of New Mexico	NM	10.59	36	Jersey Central Power & Light Company	NJ	12.55
73	Montana-Dakota Utilities Company	SD	10.63	35	Central Hudson Gas & Electric Corporation	NY	12.69
72	New York State Electric & Gas Corporation	NY	10.63	34	Black Hills/Colorado Electric	CO	12.74
71	USA		10.64	33	Northern Indiana Public Service Company	IN	12.77
70	El Paso Electric Company	TX	10.75	32	National Grid (Massachusetts Electric Compa	MA	12.83
69	Interstate Power & Light	IA	10.78	31	Public Service Electric & Gas Company	NJ	13.18
68	Baltimore Gas & Electric Company	MD	10.79	30	Northwestern Wisconsin Electric Company	WI	13.41
67	Empire District Electric Company	MO	10.99	29	Florida Public Utilities Company	FL	13.50
66	Ohio Edison Company	OH	10.99	28	Tucson Electric Power Company	AZ	13.57
65	AEP (Ohio Power Rate Area)	OH	11.13	27	Green Mountain Power	VT	14.24
64	Unisource Electric Company	AZ	11.15	26	Unitil Energy Systems, Inc.	NH	14.30
63	Empire District Electric Company	KS	11.19	25	We Energies (formerly Wisconsin Electric)	MI	14.51
62	NorthWestern Energy (formerly Montana Pow	MT	11.20	24	Western Massachusetts Electric Company	MA	14.69
61	Indianapolis Power & Light Company	IN	11.20	23	Cambridge Electric Company	MA	14.75
60	Arizona Public Service Company	AZ	11.25	22	Orange & Rockland Utilities, Inc.	NY	14.88
59	Northern States Power Company (WI)	MI	11.29	21	Narragansett Electric Company	RI	14.90

Average Rates

(in cents/kilowatthour)

Ranking of Commercial Average Rates

12 Months Ending 6/30/2017

20	PacifiCorp	CA	15.08
19	Rockland Electric Company	NJ	15.13
18	Emera Maine - Bangor Hydro District	ME	15.43
17	Connecticut Light & Power Company	CT	15.46
16	United Illuminating Company	CT	16.00
15	LIPA	NY	16.21
14	Boston Edison Company	MA	16.53
13	Commonwealth Electric Company	MA	16.59
12	Public Service Company of New Hampshire d/	NH	17.06
11	Pacific Gas & Electric Company	CA	17.26
10	Upper Peninsula Power Company	MI	17.35
9	Fitchburg Gas & Electric Light Company	MA	17.81
8	Atlantic City Electric Company	NJ	17.95
7	Consolidated Edison Company of New York	NY	19.60
6	San Diego Gas & Electric Company	CA	20.33
5	Hawaiian Electric Company	HI	23.93
4	Maui Electric Company (Maui)	HI	29.62
3	Hawaii Electric Light Company	HI	31.18
2	Maui Electric Company (Molokai)	HI	35.65
1	Maui Electric Company (Lanai)	HI	37.64

Average Rates
(in cents/kilowatthour)

Ranking of Industrial Average Rates

12 Months Ending 06/30/2017

166	West Penn Power Company	PA	3.27
165	Public Service Company of Oklahoma	OK	4.33
164	MidAmerican Energy	SD	4.55
163	Southwestern Public Service	TX	4.63
162	Entergy Texas	TX	4.84
161	Sierra Pacific Power Company - NV Energy	NV	4.88
160	Entergy Louisiana, Inc.	LA	4.90
159	Entergy Louisiana, LLC (formerly Entergy Gulf	LA	4.94
158	Southwestern Public Service	NM	5.15
157	MidAmerican Energy - East System	IA	5.16
156	Duke Energy Carolinas	SC	5.20
155	OG&E Electric Services	OK	5.43
154	PPL Utilities Corp.	PA	5.46
153	Dominion North Carolina Power	NC	5.46
152	Commonwealth Edison Company	IL	5.47
151	Public Service Company of New Mexico	NM	5.51
150	National Grid (Niagara Mohawk Power Corpor	NY	5.52
149	Duke Energy Progress, Inc.	SC	5.58
148	Georgia Power Company	GA	5.61
147	Entergy Mississippi, Inc.	MS	5.69
146	Avista Corp.	ID	5.70
145	MidAmerican Energy	IL	5.71
144	Idaho Power Company	ID	5.74
143	OG&E Electric Services	AR	5.81
142	We Energies (formerly Wisconsin Electric)	MI	5.82
141	Dominion Virginia Power	VA	5.84
140	Cleveland Electric Illuminating Company	OH	5.86
139	Wisconsin Public Service Corporation	WI	5.94
138	AEP (Wheeling Power Rate Area)	WV	5.96
137	Idaho Power Company	OR	5.99
136	Duke Energy Carolinas	NC	6.01
135	AEP (Kingsport Power Rate Area)	TN	6.03
134	Southwestern Electric Power Company	AR	6.04
133	PacifiCorp	UT	6.07
132	Southwestern Electric Power Company	TX	6.09
131	Kentucky Utilities Company	KY	6.14
130	Montana-Dakota Utilites Company	MT	6.14
129	Pennsylvania Power Company	PA	6.23
128	Duke Energy Progress, Inc.	NC	6.27
127	Entergy Arkansas, Inc.	AR	6.31
126	Florida Power & Light Company	FL	6.36
125	Avista Corp.	WA	6.38
124	Duke Energy Kentucky	KY	6.41
123	Ameren Missouri	MO	6.44
122	Wisconsin Public Service Corporation	MI	6.44
121	AEP (Indiana Michigan Power)	IN	6.46
120	New York State Electric & Gas Corporation	NY	6.48
119	Public Service Company of Colorado	CO	6.48
118	Alabama Power Company	AL	6.53
117	Portland General Electric Company	OR	6.56
116	PacifiCorp	WY	6.56
115	Otter Tail Power Company	SD	6.58
114	Minnesota Power Company	MN	6.59
113	Kansas City Power & Light - GMO	MO	6.62
112	Empire District Electric Company	AR	6.63
111	Louisville Gas & Electric Company	KY	6.69
110	Nevada Power Company - NV Energy	NV	6.71
109	AEP (Appalachian Power Rate Area)	VA	6.74
108	Otter Tail Power Company	MN	6.74
107	AEP (Kentucky Power Rate Area)	KY	6.77
106	Mississippi Power Company	MS	6.77
105	Interstate Power & Light	IA	6.78
104	Monongahela Power Company	WV	6.79
103	Duquesne Light Company	PA	6.80
102	Southwestern Electric Power Company	LA	6.80
101	AEP (Appalachian Power Rate Area)	WV	6.84
100	DTE Electric Company	MI	6.85
99	PECO Energy	PA	6.86
98	Northwestern Energy	SD	6.86
97	USA		6.88
96	Duke Energy Florida	FL	6.93
95	Superior Water, Light & Power Company	WI	6.94
94	Black Hills Power, Inc. d/b/a Black Hills Energ	MT	6.97
93	Montana-Dakota Utilities Company	WY	7.00
92	Cheyenne Light, Fuel & Power d/b/a Black Hill	WY	7.03
91	Westar Energy-KGE	KS	7.05

Average Rates

(in cents/kilowatthour)

Ranking of Industrial Average Rates

12 Months Ending 06/30/2017

90	Empire District Electric Company	OK	7.06	52	Gulf Power Company	FL	8.16
89	Southern California Edison	CA	7.07	51	Tucson Electric Power Company	AZ	8.18
88	South Carolina Electric & Gas Company	SC	7.09	50	NorthWestern Energy (formerly Montana Pow	MT	8.25
87	Toledo Edison Company	OH	7.11	49	We Energies (formerly Wisconsin Electric)	WI	8.27
86	PacifiCorp	ID	7.17	48	Black Hills Power, Inc. d/b/a Black Hills Energ	WY	8.35
85	Duke Energy Indiana	IN	7.18	47	Arizona Public Service Company	AZ	8.38
84	PacifiCorp	WA	7.20	46	Unisource Electric Company	AZ	8.39
83	Northern Indiana Public Service Company	IN	7.24	45	Montana-Dakota Utilities Company	SD	8.40
82	Northern States Power Company (MN)	ND	7.24	44	Delmarva Power	DE	8.41
81	Upper Peninsula Power Company	MI	7.25	43	AEP (Indiana Michigan Power combined MI ra	MI	8.42
80	Northern States Power Company (WI)	MI	7.26	42	Indianapolis Power & Light Company	IN	8.50
79	Ohio Edison Company	OH	7.33	41	UGI Utilities, Inc.	PA	8.58
78	Otter Tail Power Company	ND	7.37	40	Pennsylvania Electric Company	PA	8.62
77	CLECO Power LLC	LA	7.49	39	El Paso Electric Company	NM	8.68
76	Potomac Edison Company	WV	7.50	38	Montana-Dakota Utilities Company	ND	8.78
75	Metropolitan Edison Company	PA	7.64	37	Duke Energy Ohio	OH	8.91
74	Northern States Power Company (WI)	WI	7.64	36	Black Hills/Colorado Electric	CO	9.04
73	Southern Indiana Gas & Electric Company	IN	7.69	35	Old Dominion Power Company	VA	9.18
72	Dayton Power & Light Company	OH	7.69	34	Northwestern Wisconsin Electric Company	WI	9.25
71	Kansas City Power & Light Company	MO	7.69	33	Puget Sound Energy	WA	9.28
70	Madison Gas & Electric Company	WI	7.74	32	Jersey Central Power & Light Company	NJ	9.52
69	Northern States Power Company (MN)	SD	7.76	31	Kansas City Power & Light Company	KS	9.72
68	Northern States Power Company (MN)	MN	7.79	30	Green Mountain Power	VT	9.78
67	PacifiCorp	OR	7.82	29	Unitil Energy Systems, Inc.	NH	9.90
66	Entergy New Orleans, Inc.	LA	7.86	28	Rochester Gas & Electric Corporation	NY	9.94
65	Empire District Electric Company	KS	7.89	27	Emera Maine - Maine Public District	ME	10.03
64	WP&L	WI	7.92	26	Pacific Gas & Electric Company	CA	10.06
63	Delmarva Power	MD	7.95	25	Public Service Electric & Gas Company	NJ	10.09
62	AEP (Ohio Power Rate Area)	OH	7.96	24	Central Hudson Gas & Electric Corporation	NY	10.13
61	Black Hills Power, Inc. d/b/a Black Hills Energ	SD	7.97	23	Baltimore Gas & Electric Company	MD	10.79
60	Orange & Rockland Utilities, Inc.	NY	7.98	22	Emera Maine - Bangor Hydro District	ME	11.42
59	Westar Energy-KPL	KS	7.99	21	Florida Public Utilities Company	FL	12.38
58	El Paso Electric Company	TX	8.01	20	Fitchburg Gas & Electric Light Company	MA	12.72
57	Tampa Electric Company	FL	8.06	19	Cambridge Electric Company	MA	12.76
56	Potomac Edison Company	MD	8.08	18	Commonwealth Electric Company	MA	13.07
55	AEP (Columbus Southern Power Rate Area)	OH	8.11	17	United Illuminating Company	CT	13.29
54	Consumers Energy	MI	8.12	16	PacifiCorp	CA	13.72
53	Empire District Electric Company	MO	8.16	15	Western Massachusetts Electric Company	MA	13.87

Average Rates

(in cents/kilowatthour)

Ranking of Industrial Average Rates

12 Months Ending 06/30/2017

14	National Grid (Massachusetts Electric Compa	MA	14.32
13	Narragansett Electric Company	RI	14.41
12	Connecticut Light & Power Company	CT	14.50
11	Rockland Electric Company	NJ	14.83
10	Boston Edison Company	MA	15.10
9	Public Service Company of New Hampshire d/	NH	15.17
8	San Diego Gas & Electric Company	CA	16.02
7	Consolidated Edison Company of New York	NY	17.05
6	Hawaiian Electric Company	HI	20.53
5	Atlantic City Electric Company	NJ	23.39
4	Hawaii Electric Light Company	HI	25.69
3	Maui Electric Company (Maui)	HI	26.01
2	Maui Electric Company (Molokai)	HI	26.44
1	Maui Electric Company (Lanai)	HI	33.15

DEK
Exhibit 7

When placed in the proper context, the Company's proposed fixed monthly customer charge is in line with what the Commission has previously approved. The table below shows that Company's proposed customer charge compares favorably with many other electric utilities in the state. Clearly, the proposed customer charge is reasonable. It is smaller than the current customer charges of twenty (20) other Kentucky utilities.

Kentucky Electric Utility Residential Customer Charges**		
	Utility Name	**RS Customer Charge**
1	Owen Electric Cooperative	$ 20.00
2	Kenergy	$ 18.20
3	Meade County Rural Electric Coop *	$ 17.16
4	Jackson Energy Coop	$ 16.64
5	Big Sandy RECC	$ 15.00
6	Fleming-Mason Energy Coop	$ 15.00
7	Grayson Rural Electric Coop	$ 15.00
8	Big Sandy RECC	$ 15.00
9	Shelby Energy Cooperative Inc.	$ 15.00
10	Kentucky Power – Pending Settlement	$ 14.00
11	Farmers Rural Electric	$ 14.00
12	Licking Valley Rural Electric	$ 14.00
13	Blue Grass RECC	$ 13.85
14	Nolin RECC	$ 13.50
15	South Kentucky RECC	$ 12.82
16	Jackson Purchase Energy Corp	$ 12.45
17	Clark Energy Cooperative	$ 12.43
18	LG&E	$ 12.25
19	Kentucky Utilities	$ 12.25
20	Cumberland Valley Electric	$ 12.00
21	Duke Energy Kentucky – Proposed	$ 11.22
22	Kentucky Power - Current	$ 11.00
23	Taylor County Rural Electric Coop Corp	$ 9.82
24	Inter-County Energy	$ 8.97
25	Salt River Electric	$ 8.84
26	Duke Energy Kentucky – Current	$ 4.50

* Meade's customer charge is a 'daily' charge adjusted here.

** Sourced from a review of the KYPSC website in early Jan. 2018.

Survey of Regional Customer Charges

State	Company	Customer Charge ($/month) Residential		Commercial	
KY	Kentucky Power Company	$	11.00	$	17.50
AL	Alabama Power Company	$	14.50		N.A.
MO	Ameren Missouri	$	9.00	$	11.19
VA	Appalachian Power Company	$	8.35	$	10.25
WV	Appalachian Power Company	$	8.00	$	9.50
NC	Duke Energy Carolinas, LLC	$	11.80	$	19.39
SC	Duke Energy Carolinas, LLC	$	8.29	$	10.52
KY	Duke Energy Kentucky, Inc.	$	4.50	$	7.50
NC	Duke Energy Progress	$	11.13	$	16.45
SC	Duke Energy Progress	$	9.06	$	9.91
AR	Entergy Arkansas, Inc.	$	8.40	$	24.25
MS	Entergy Mississippi, Inc.	$	6.75	$	7.67
KY	Kentucky Utilities Company	$	12.25	$	31.50
KY	Louisville Gas and Electric Company	$	12.25	$	31.50
SC	South Carolina Electric & Gas Company	$	10.00	$	22.75
NC	Virginia Electric and Power Company	$	10.96	$	19.79
VA	Virginia Electric and Power Company	$	7.00	$	12.40

Note: Appalachian Power Company's charges are based on Distribution Charges only.
Source: Company tariffs.

DEK
Exhibit 8

DEK
Exhibit 9

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	CASE NO. 2014-00371

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	CASE NO. 2014-00372

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2015

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

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BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Please state your occupation and employer.

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, the Institute of Management Accounting, and the Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions, including numerous proceedings before the Kentucky Public Service Commission involving Kentucky Utilities Company ("KU"), Louisville Gas and Electric Company ("LG&E"), Kentucky Power Company, East Kentucky Power Company and Big Rivers Electric Corporation. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service at retail from KU and LG&E (also referred to individually as "Company" or collectively as "Companies"). The members of KIUC participating in this proceeding are: Carbide Industries LLC, Cemex, Clopay Plastics Products Co., Inc., Corning Incorporated, Dow Corning Corporation, E.I. DuPont de Nemours & Co., Ford Motor Co., AAK, USA K2 LLC, Lexmark International, Inc., MeadWestvaco, NewPage Corp., North American Stainless, Solae, Schneider Electric USA, and Toyota Motor Engineering and Manufacturing North America, Inc.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to 1) address the magnitude of the Companies' rate increases within the context of the steady and significant increases in customer rates over the last ten years; 2) address the need for additional scrutiny of the Companies' claimed revenue deficiencies due to their use of forecast test years for the first time; 3) summarize the KIUC revenue requirement recommendations; 4) address specific issues that affect each Company's revenue requirement; and 5) quantify the effect on the revenue requirements of the cost of long term debt and return on equity recommendation of KIUC witness Mr. Richard Baudino.

Q. Please summarize your testimony.

A. The Companies' rates charged to customers have increased significantly over the last ten years. The Commission should carefully scrutinize the Companies' requests in these proceedings in order to minimize the increases. The Companies have filed their cases for the first time using a forecast test year. The forecast test year relies on models, assumptions, and estimates of the future. The Commission should carefully scrutinize these models, assumptions, and estimates to ensure that the costs are just and reasonable, and reflect efficient management, particularly compared to the actual costs incurred in prior periods.

I recommend that the Commission increase KU's base rates by no more than $48.081 million, a reduction of $105.363 million compared to its requested increase of $153.444 million. I recommend that the Commission decrease LG&E's electric base rates by at least $39.447 million, a reduction of $69.733 million compared to its requested increase of $30.286 million.

The following table lists each KIUC adjustment and the effect on the claimed revenue deficiency for each Company. The amounts for KU are shown on a Kentucky retail jurisdictional basis and the amounts for LG&E are for electric only. I address in greater detail the reasons for each of the adjustments reflected in the table, except for the cost of long-term debt and the return on common equity, which are addressed by Mr. Baudino.

Kentucky Utilities Company and Louisville Gas & Electric Company
Summary of Revenue Requirement Adjustments-Jurisdictional Electric Operations
Recommended by KIUC
Case Nos. 2014-00371 and 2014-00372
For the Test Year Ended June 30, 2016
($ Millions)

	KU Amount	LG&E Amount
Increase Requested by Company	153.444	30.286
KIUC Adjustments:		
Operating Income Issues		
Reduce Payroll and Related Benefits Expenses	(9.295)	(6.620)
Remove Nonrecurring O&M for the Retiring Green River 3 and 4 Units	(10.101)	
Remove Incentive Compensation Tied to Financial Performance	(5.863)	(4.961)
Reduce Pension Expense	(10.682)	(12.627)
Reduce Uncollectible Expense to 5-Year Average	(1.174)	(0.237)
Increase Late Payment Revenues	(2.533)	(2.007)
Remove Property Tax Expense Associated with CWIP	(2.067)	(2.343)
Extend Amortization Period on Deferred Costs	(1.183)	(0.809)
Reduce Cane Run 7 Depreciation Expense Related to Net Salvage	(0.514)	(0.164)
Revise Section 199 Income Tax Exp. Deduction for Bonus Depr. Extension	0.541	2.052
Reflect Other Operating Income Effects of Utilizing CWIP Slippage Factor	(0.247)	(0.170)
Cost of Capital Issues		
Reduce Capitalization for CWIP Slippage	(0.653)	(0.568)
Reduce Capitalization to Reflect 50% Bonus Depreciation Extension	(3.024)	(4.812)
Reduce Capitalization Associated With Paddy's Run Demolition Costs		(1.235)
Reduce Cost of Short Term Debt	(0.645)	(0.561)
Reduce Cost of Long Term Debt	(1.250)	(1.076)
Reflect Return on Equity of 8.6%	(56.674)	(33.596)
Total KIUC Adjustments to Company Request	(105.363)	(69.733)
KIUC Recommended Change in Base Rates	48.081	(39.447)

The amounts on the preceding table do not reflect the updates filed by the Companies on February 27, 2014, less than one week prior to the date for filing intervenor testimony. There was insufficient time and data to address the changes reflected in the updates. I reserve the right to update my recommendations to reflect the updated information.

In addition, the increase in rates described above for KU may be greater depending on whether the Commission directs KU to defer the nonrecurring operating expenses for Green River 3 and 4 for consideration in KU's next base rate case or adopts a new retirement rider to recover these expenses.

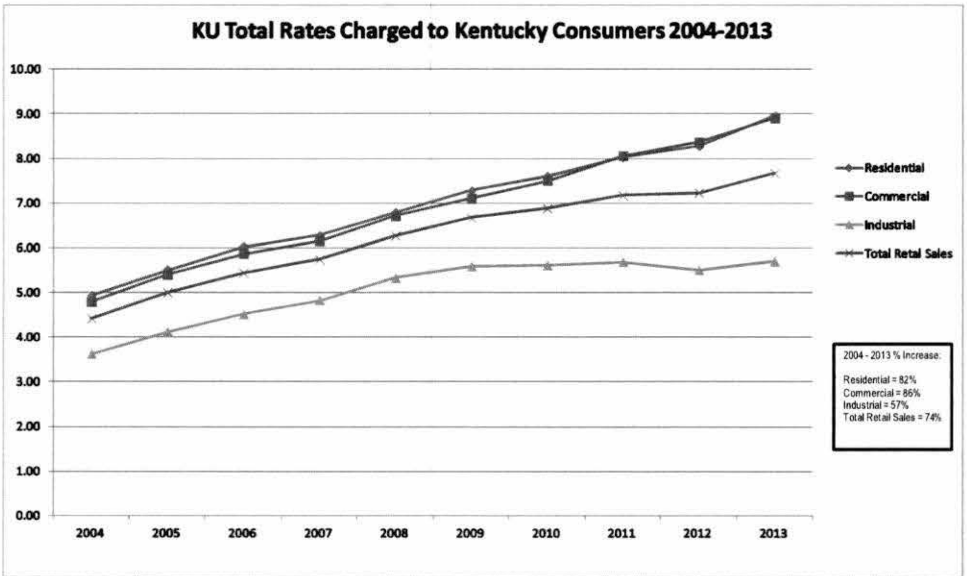
The revenue requirement effects of the expense adjustments shown on the preceding table are slightly greater than the amounts cited in my testimony because they reflect a gross-up due to uncollectible accounts expense and the Commission assessment.

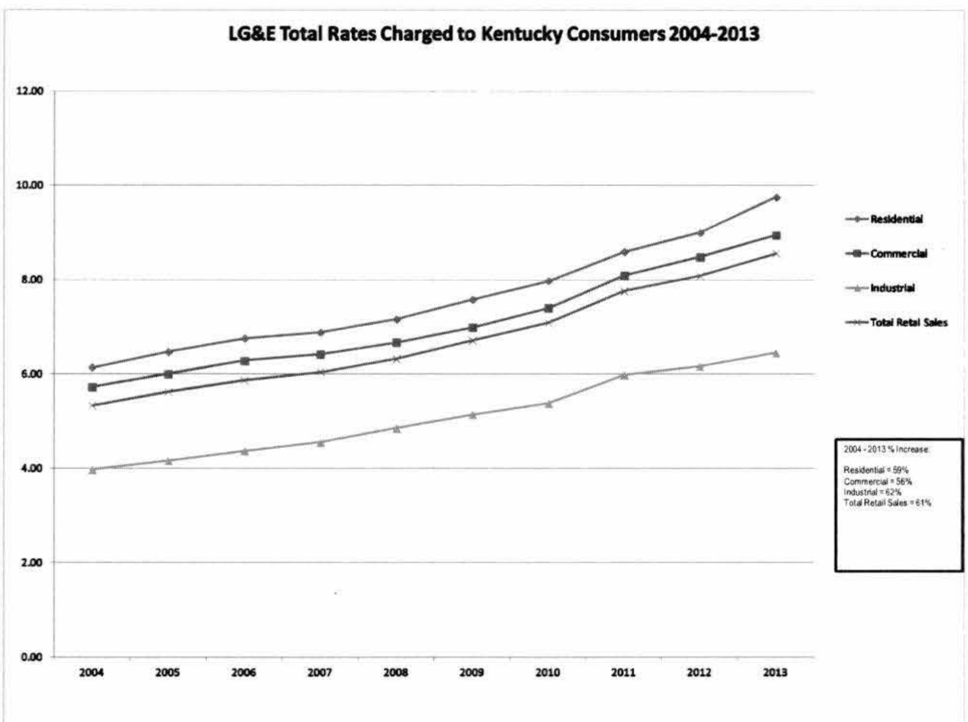
In the following sections of my testimony, I describe the significant increases in customer rates in the last ten years and the significant increases in KU's operation and maintenance expenses since 2013. I next address numerous adjustments that are necessary to ensure that the rates set in this proceeding are just and reasonable. I follow the sequence of the issues shown on the preceding table. Finally, I quantify the effects of Mr. Baudino's recommendations regarding the cost of long-term debt and the return on equity.

II. SIGNIFICANT INCREASES IN CUSTOMER RATES

Q. Please describe the significant increases in customer rates over the last ten years.

A. The Companies' rates have increased steadily and significantly over the last ten years. KU's rates have increased an average of 74% over all customer classes. LG&E's rates have increased an average of 61% over all customer classes. The following charts graphically portray these increases for each Company and each customer class from 2004 through 2013.


KU Total Rates Charged to Kentucky Consumers 2004-2013
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Residential
Commercial
Industrial
Total Retail Sales
2004 - 2013 % Increase:
Residential = 82%
Commercial = 86%
Industrial = 57%
Total Retail Sales = 74%


LG&E Total Rates Charged to Kentucky Consumers 2004-2013
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Residential
Commercial
Industrial
Total Retail Sales
2004 - 2013 % Increase:
Residential = 59%
Commercial = 56%
Industrial = 62%
Total Retail Sales = 61%

Q. Why are the historic increases in customer rates relevant in this proceeding?

A. First, they provide context for the increases that the Companies' seek in this proceeding. These rate increases impact real customers in residential households, schools and other government agencies, and small and large businesses. These customers need electric service and generally do not have economically realistic alternatives.

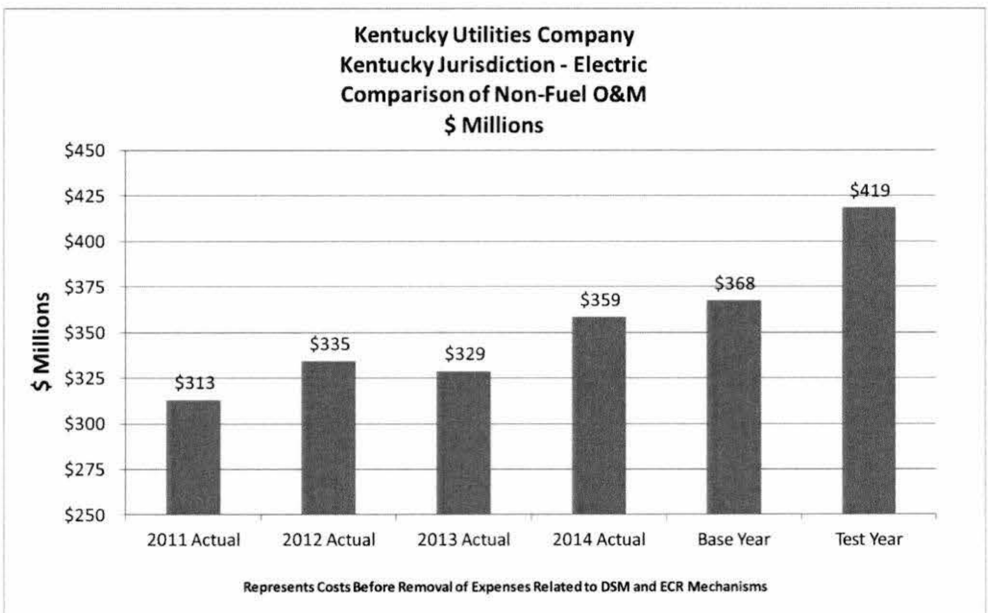
Second, these increases affect household budgets/expenses, government budgets/expenses, and business budgets/expenses, as well as business competitiveness and viability. Each of these customers must manage their income and expenses efficiently. The Commission should insist that the Companies are managed and operated efficiently to minimize their costs and that the costs allowed recovery reflect the least reasonable cost.

Third, the Companies' requested increases reflect projected costs in a forecast test year for the first time. Projected costs necessarily rely on models of the future based on assumptions and estimates, not the actual costs relied on in a historic test year. The use of a forecast test year is necessarily more subjective than the use of a historic test year. Thus, the Commission should carefully scrutinize the Companies' estimates and assumptions to ensure that they are not inefficient, unreasonable, excessive, or erroneous.

III. COSTS PROJECTED IN FORECAST TEST YEAR DESERVE CAREFUL SCRUTINY

Q. How do the projected operation and maintenance expenses in the test year compare to the Companies' recent actual expenses?

A. KU's O&M expenses are substantially greater and demonstrate an exceptional rate of growth compared to actual historic levels. The following chart shows this graphically:[1]



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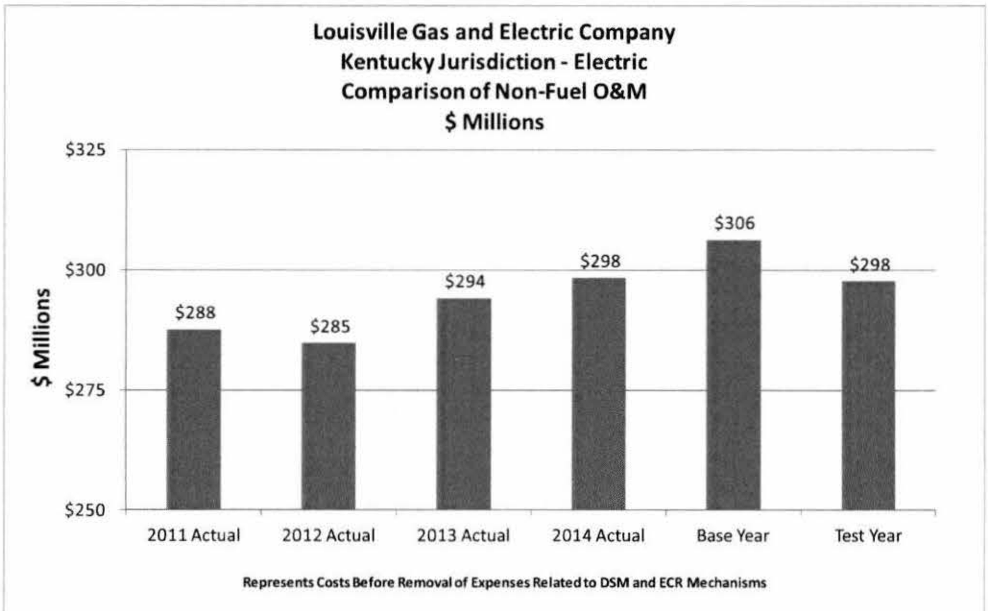
[1]The data underlying this chart by FERC O&M and A&G expense accounts is provided in my Exhibit___(LK-2).

In contrast to KU, LG&E's O&M expenses have been relatively stable and show little growth compared to prior years. The following chart shows this graphically:[2]



Q. Do these comparisons of the test year to the actual O&M expenses in prior years demonstrate that KU's O&M expense is unreasonable or that LG&E's O&M expense is reasonable?

A. No. However, it does highlight the fact that projections in forecast test years deserve special scrutiny because they are based on projections and estimates, tend to reflect expenses that may not actually be incurred if they were restrained by the discipline of actual cost management, and can be used to increase the "ask" with

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2 The data underlying this chart by FERC O&M and A&G expense accounts is provided in my Exhibit___(LK-3).

virtually no downside risk by utility management. After all, if the Commission does not authorize revenues based on the "ask," then the Companies may not actually incur the expenses they projected. If the Commission does authorize revenues based on the "ask," then the Companies still may not actually incur the expenses or incur them at the same level they projected.

Q. How do these increases in expense compare to the Companies' load growth?

A. The Companies' load growth has been flat and is projected to remain so. In his testimony, Mr. Staffieri cites the lack of load growth as a major factor in the need for the requested increases. Mr. Staffieri states that "the Companies continue to anticipate low growth in native system demand. In the past, the Companies have been able to rely on both off system sales and native load growth to defray the impact of rising costs between rate cases. Because this is no longer possible, the Companies must now adjust rates to earn a reasonable return"[3] The following graphs portray the Company's actual and projected test year load growth.

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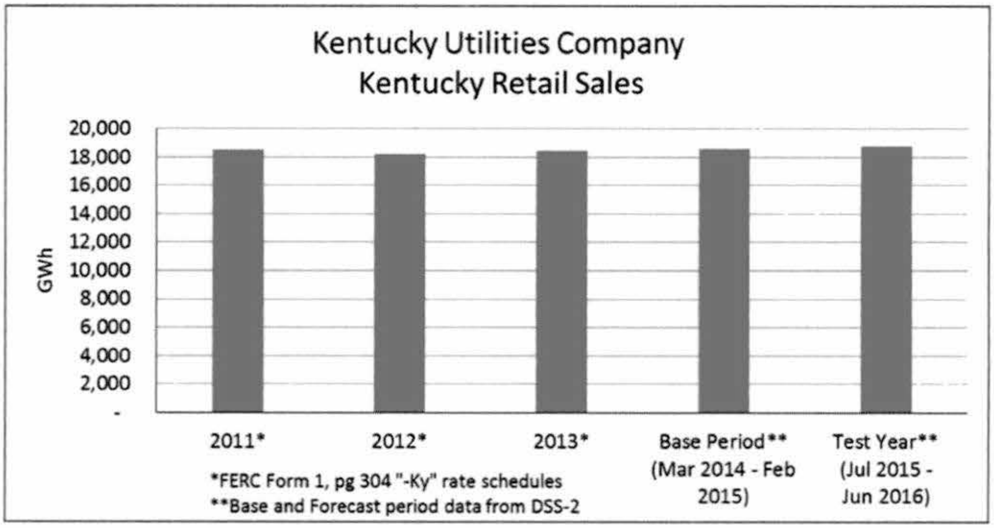
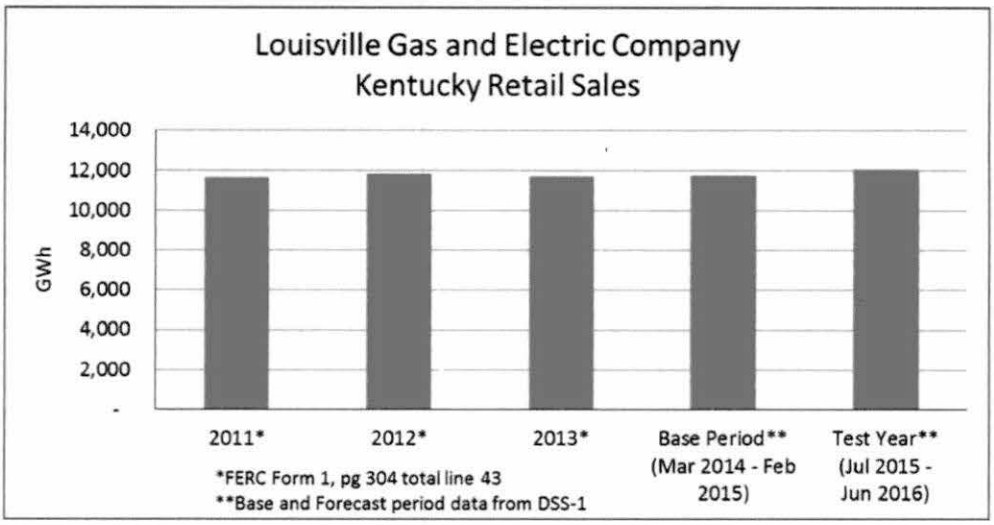
[3] Direct Testimony of Victor A. Staffieri at 11.





Q. What is the significance of the Companies' flat load growth?

A. It demonstrates that load growth is not the driver of the increases in O&M expense. Rather, other factors are driving these O&M expense increases, including management decisions.

It means that the increases in staffing levels and payroll and related expenses that I address in the next section of my testimony, were not and cannot be caused by actual or projected load growth. It also means that the Companies should be encouraged to operate more efficiently given their status as mature utilities with almost no load growth. In addition, it means that the Companies arguably should be limited to the same number of employees to achieve the same level of utility operations in the test year as in 2010, before the PPL acquisition, adjusted only for known and measurable changes in activities, such as KU's retirement of Green River 3 and 4 and LG&E's retirement of the coal-fired Cane Run generating units and the commercial operation of Cane Run 7.

Again, the Commission should ensure that the expenses in the test year are just and reasonable, prudent and necessary in order to minimize the impact on customers.

Q. What are some of the reasons for the increases in expenses that the Commission should carefully scrutinize?

A. The Companies have been engaged in a hiring frenzy since the end of the test year in their last base rate cases (March 31, 2012), as highlighted in Mr. Thompson's and other witnesses' testimony, even though the Companies have experienced almost no load growth. This increase in staffing results in significant inefficiencies and unnecessary payroll and related expenses. Adding duplicative employees is not a necessity; it is a luxury, the cost of which should not be imposed on customers.

The Companies have and are engaged in shutting down approximately 800 MW of coal-fired generation, which is labor-intensive. The shutdowns should result in significant expense reductions in the test year compared to prior years even with the commercial operation of Cane Run 7. Cane Run 7 is a natural gas-fired combined cycle facility, which is much less labor-intensive than coal-fired generation. Although the Companies have reflected some savings from the shutdown of the coal-fired generation, the reductions in KU's expenses from retiring Green River 3 and 4 have been offset by increases due to one-time expenses to shut down the units in the test year.

The Companies have significantly increased their pension expense to reflect recent changes to the mortality tables used to project their future pension payments and reductions in the discount rate used to calculate their pension benefit obligations.

The Companies have increased their uncollectible accounts expense and reduced their late payment revenues compared to recent actual expenses and revenues.

IV. OPERATING INCOME ISSUES

Reduce Payroll and Related Expenses To Reflect Efficient Staffing Levels

Q. Please describe the growth in staffing levels since 2010 and continuing through the test year.

A. The Companies have significantly increased employee staffing levels since 2010 and PPL's acquisition of the utility operations of E.ON U.S. and propose even greater staffing levels for the test year. The Companies not only incur the payroll and related costs for their own employees, but also incur payroll and related costs allocated from LG&E and KU Services Company ("LKS").

In January 2011, KU had 1,667 employees, including those allocated to KU from LKS. LG&E had 1,558 employees, including those allocated to LG&E from LKS.[4]

In their filings, in June 2016, KU projects that it will have 1,868 employees, including those allocated from LKS, which is an increase of 12.1% despite the reductions from retiring the Green River 3 and 4 generating units. LG&E projects that it will have 1,786 employees, including those allocated from LKS, which is an increase of 14.6% despite the reductions from retiring Tyrone and the coal-fired Cane Run generating units. As I noted previously, the Companies are significantly increasing employee levels despite the fact that their loads are barely growing.

The Companies quantified a net increase of 293 positions after March 31, 2012, the end of the test year in their last base rate cases, and June 30, 2016, the end of the test year in the pending cases.[5]

The following chart portrays the increase in staffing levels from 2008 through the test year (all historic years are at year end).[6]

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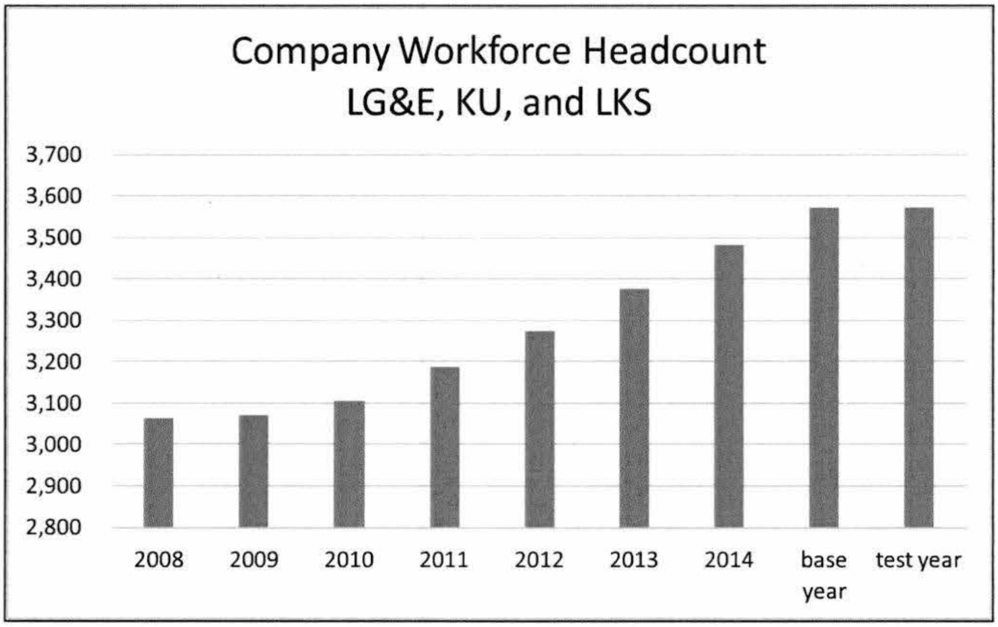
[4] KU's and LG&E's responses to Staff 1-32. I have attached a copy of KU's response as my Exhibit___(LK-4) and LG&E's response as my Exhibit___(LK-5).

[5] KU and LG&E Responses to KIUC 1-10. I have attached a copy of the KU response to KIUC 1-10 as my Exhibit___(LK-6).

[6] KU's and LG&E's responses to KIUC 1-9. I have attached a copy of KU's response to KIUC 1-9 as my Exhibit___(LK-7).



Q. What are the reasons cited by the Companies for the increases after March 31, 2012?

A. The primary reason cited by the Companies is "core skill building/knowledge retention and transfer." The Companies cited this as the reason for 200 of the 293 added positions. The other reasons cited include "capital projects," "regulatory compliance," "corporate reorganization," "plant retirement," and "customer service."[7]

Q. Does the addition of additional employees for "core skill building/knowledge retention and transfer" increase efficiency and productivity?

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[7] *Id.*

A. No. The contrary is true. First, the additional employees are duplicative, almost by definition. The Companies do not deny this. The employee increases for "core skill building/knowledge retention and transfer" do not displace existing staffing; they are in addition to the existing staffing. In other words, although the workload is unchanged, it now will take more employees to accomplish the same activities. This is the definition of negative productivity. Adding duplicative employees is not a necessity; it is a luxury, the cost of which should not be imposed on customers.

Second, these employees are being hired before there is an actual need for them to replace employees who will retire or otherwise leave the Companies. The Companies have failed to demonstrate that there is a need to hire these redundant employees so many years in advance of the retirement of older employees. The Companies have performed no workforce staffing study, other than a generalized study that highlights the need to plan for future retirements.

Third, the new employees are being hired outside of and in addition to the normal employee replenishment process. The normal process is to hire younger and less experienced employees to perform lower level jobs and then to promote them when they are more experienced and there are job openings. This is the normal process of knowledge building and skill retention as older and more experienced employees train and develop younger and less experienced employees. Instead, the Companies have overlaid another round of hiring in addition to the normal process. This is inefficient and results in excessive payroll and related expenses. It offsets and overwhelms any benefits the Companies actually achieved from additional investment to achieve efficiencies and to reduce staffing.

Fourth, the Companies have provided no evidence that hiring these additional employees is justified on the basis of cost savings or efficiency improvements.

Q. Is there any compelling need to accelerate hiring in the manner undertaken by the Companies and projected to extend into the test year?

A. No. The Companies have steadily increased their hiring since 2010 and in 2014 accelerated it even more. The Companies plan to stabilize their staffing in 2016 and future years, notably after the peak in staffing is reflected in the test year.

Q. Is there another staffing issue that the Commission should address?

A. Yes. KU proposes that 11 of the employees from the retiring Green River 3 and 4 generating units be added to staffing in the Metering department, ostensibly to replace contractor expense incurred for reading meters. While commendable, this unnecessarily adds additional expenses to the Companies' revenue requirement.

Q. What is your recommendation?

A. I recommend that the Commission disallow the payroll and related expenses for the positions added for "core skill building/knowledge retention and transfer" and disallow the payroll and related expenses for the 11 employees transferred from the Green River units offset by an increase in contractor expense. Such employee additions result in unnecessary and inefficient staffing. The Companies' business customers cannot afford the luxury of redundant employees. The Companies' customers have had to become more efficient and learn to do more with less. The Commission should hold KU and LG&E to no lower standard.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's O&M expense of $9.247 million and a reduction in LG&E's O&M expense of $6.586 million.[8]

Q. Is there another concern that you have identified with the Companies' projected staffing levels in the test year?

A. Yes. The Companies based their staffing levels on budgets and projections for the test year. However, their experience is that actual staffing always is less than their budgeted staffing. Over the three historical years (2011 – 2013), this slippage has averaged 2.01% for KU and 2.95% for LG&E.[9]

Q. Do you have an alternative recommendation if the Commission does not adopt your recommendation to disallow the payroll and related expenses for the added positions for "core skill building/knowledge retention and

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[8] The calculations and sources of data used for the calculations are provided for KU on my Exhibit___(LK-8) and for LG&E on my Exhibit___(LK-9).

[9] KU's and LG&E's responses to Staff 1-32. The responses provided actual and budgeted staffing levels by month for 2011 through October 2014. I have attached a copy of KU's response as my Exhibit___(LK-4) and LG&E's response as my Exhibit___(LK-5).

transfer" and for employees transferred from the Green River units to Metering?

A. Yes. I recommend that the Commission disallow the payroll and related expenses for the positions that the Companies' actual experience indicates will not be filled due to "slippage." If the positions are not filled, then the Companies will not incur the expenses.

Q. What are the effects of your alternative recommendation?

A. The effects are a reduction in the KU payroll and related expenses of $3.348 million and a reduction in the LG&E expenses of $3.688 million.[10]

<u>Remove Nonrecurring Operating Expenses for Retiring Generating Units from the Base Revenue Requirement</u>

Q. Please describe the Companies' plans to retire certain of their coal-fired generating units.

A. KU plans to retire Green River 3 and 4 in April 2016, although the retirement date may be extended to April 2017 under the Mercury and Air Toxics Standards if grid reliability concerns are present. The last operating unit at Tyrone was retired in 2013. LG&E plans to retire the coal-fired units at Cane Run in May 2015 when Cane Run 7 achieves commercial operation.[11]

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[10] The calculations and sources of data used for the calculations are provided for KU on my Exhibit___(LK-10) and for LG&E on my Exhibit___(LK-11).

[11] Thompson Direct at 22.

KU provided its actual and projected operating expenses (operation and maintenance expenses, administrative and general expenses and other taxes expense) for Green River 3, 4 and common in its response to KIUC 1-7.[12] Starting in January 2015, KU projected operating expenses for the units on a combined basis, except for severance expenses, which it projected for each unit. KU provided its actual and projected labor expenses for Green River 3 and 4 and common in its response to KIUC 1-8.[13]

LG&E provided its actual and projected operating expenses for Cane Run 4, 5, 6 and common in its response to KIUC 1-7.[14] Starting in May 2015, LG&E projected operating expenses for the units on a combined basis. LG&E provided its actual and projected labor expenses for Cane Run 4, 5, 6 and common in its response to KIUC 1-8.[15]

Q. Are the operating expenses for the retiring KU units in the test year recurring?

A. No. Except for nominal amounts for ongoing safety and site monitoring, the operating expenses no longer will be incurred after the facilities are shut down and the site is secured. KU projects that it will incur expenses through December

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[12] I have attached a copy of the KU's response to KIUC 1-7 as my Exhibit___(LK-12).

[13] I have attached a copy of KU's response to KIUC 1-8 as my Exhibit___(LK-13).

[14] I have attached a copy of LG&E's response to KIUC 1-7 as my Exhibit___(LK-14).

[15] I have attached a copy of LG&E's response to KIUC 1-8 as my Exhibit___(LK-15).

2016 to shutdown and secure the facilities, after which these expenses will drop to approximately $0.050 million per month for ongoing safety and site monitoring and maintenance.

Q. In contrast to the retiring KU units, are the operating expenses for the retiring LG&E units in the test year recurring?

A. It appears that they are. LG&E incurred expenses to shut down the facilities and secure the site prior to the test year.

Q. Are there specific one-time expenses related to the retirement of the retiring KU units included in the test year?

A. Yes. The expenses included in the test year include one-time expenses related to shutting down the facilities and securing the site and employee severance expenses.

Q. Please describe how the Companies reflected the operating expenses and capitalization of the retiring generating units in the test year revenue requirement.

A. The Companies included these operating expenses and all capital-related costs, including depreciation expense and the return on capitalization, in the test year revenue requirements

Q. Is it appropriate to include the retiring KU units' operating expenses in the base revenue requirement?

A. No. These are nonrecurring expenses and should be removed from the KU base revenue requirement. If the expenses are included in the base revenue requirement, then KU will continue to recover the expenses long after they no longer are incurred or are incurred at a much lower level. KU's rates will not be reasonable and it will obtain excessive recovery.

Q. If the retiring KU units' operating expenses are removed from the base revenue requirement, are there recovery alternatives available that are compensatory, but do not provide excessive recovery?

A. Yes. There are at least two alternatives available. The first alternative is to authorize KU to defer and amortize the operating expenses in excess of the approximately $0.050 million recurring expense. The deferral would be based on the actual operating expenses incurred, less the $0.050 million recurring expense, and would be subject to review and recovery through amortization expense in the Companies' next base rate cases. The amortization should be over a reasonably short time period, such as three to five years.

The second alternative is to authorize KU to implement a new retirement cost rider similar to the Big Sandy Retirement Rider authorized by the Commission for Kentucky Power Company in Case No. 2012-00578. KU would recover its actual operating expenses as incurred, except for one-time expenses, such as severance expenses, which should be deferred and amortized over three to five years, and except for the approximately \$0.050 million recurring expense. By January 2017, the expenses recovered through the retirement cost rider would diminish to the amount of the amortization expense and after three to five years would diminish to \$0 and be terminated.

Q. **Should the Commission continue to allow recovery of the depreciation and return on both Companies' retiring units through the base revenue requirement?**

A. Yes. The Commission should adopt the Companies' proposal to recover the remaining net book value of the retiring plants over the lives of their other coal-fired generating assets through depreciation expense included in the base revenue requirement.[16] This proposal is reasonable because it provides a lengthy recovery period and minimizes the impact on the revenue requirement. It also avoids any arguments or decisions in this proceeding as to the final disposition of the retired units, the potential costs of dismantling and site remediation if they are not retired in place, and the time period over and the manner in which such costs will be recovered.

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[16] The Companies will follow the FERC Uniform System of Accounts for retirements of plant costs, and debit the accumulated depreciation and credit the plant in service accounts by the amount of the gross plant that is retired. The remaining net book value of the retired units will be reflected in the net book value of the operating units in the next depreciation study and recovered over the remaining service lives of the operating units through slightly greater depreciation rates.

Q. Please summarize your recommendations regarding the retiring coal-fired generating units.

A. I recommend that the Commission remove the nonrecurring operating expenses for Green River 3 and 4 from KU's revenue requirement and either defer these expenses for consideration in KU's next base rate case or adopt a new retirement rider to recover these costs.

Eliminate Incentive Compensation Tied to Financial Performance

Q. Please describe the incentive compensation tied to financial performance included in the Companies' O&M expense and revenue requirements.

A. KU included \$6.474 million (total Company) and LG&E included \$5.967 million (total Company) in incentive compensation expense tied to PPL earnings per share ("EPS") and LKE net income, two of the four metrics pursuant to the PPL Team Incentive Award ("TIA").[17] These amounts were incurred to "motivate and direct employees toward the achievement of [PPL's] strategic goals." In a 2012 Employee Bulletin, Mr. Blake, a witness for the Companies in these two proceedings, stated: "EPS reflects an important part of PPL's mission, which includes providing shareholders with best-in-sector returns."[18]

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[17] Response to KIUC 2-14 for KU and LG&E in each case, respectively. Sum of the amounts expensed in the test year based on the Financial – PPL EPS and Financial – LKE Net Income metrics. A copy of each response is attached as Exhibit___(LK-16) and Exhibit___(LK-17), respectively. The Companies provided a copy of the TIA in response to AG 1-74 in each case, respectively. A copy of KU's response to AG 1-74 is attached as my Exhibit___(LK-18).

[18] Response to AG 1-74, page 9 of 11 in each case, respectively.

Q. Should the incentive compensation tied to financial performance be included in the Companies' revenue requirement?

A. No. First, the Commission precedent is to remove these expenses from the revenue requirement. In its order in Kentucky-American Water Company Case No. 2010-00036, the Commission disallowed incentive compensation expense tied to "financial goals that primarily benefited shareholders."[19] This expense falls clearly within that category and should be a shareholder cost, not a customer cost.

Second, this form of incentive compensation is directed toward achieving shareholder goals, not customer goals. In its order in Atmos Energy Corporation Case No. 2013-00148, the Commission stated "Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in the hearing on this matter, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plants. . . It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures."[20] Thus, the cost should be borne by shareholders, not customers.

Third, this form of profit-maximizing incentive compensation incentivizes the Companies to seek greater rate increases from customers to improve PPL EPS and LKE net income. The greater the rate increases and revenues, the greater the

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[19] Order in Kentucky American Water Company Case No. 2010-00036 at 14.
[20] Order in Atmos Energy Corporation Case No. 2013-00148 at 9.

PPL EPS and LKE net income and the greater the incentive compensation expense. There is an inherent conflict between lower rates to customers and greater financial performance for shareholders and incentive compensation for executives and other employees. This expense should be a shareholder cost.

Fourth, including incentive compensation expenses in the revenue requirement itself increases the PPL EPS and LKE net income and ensures that the incentive compensation expense will be incurred; essentially, it is a self-fulfilling expense, all else equal. If the Companies are ensured recovery of the expense from customers, then there is no performance that is at risk or that must be achieved in order to recover that expense. This expense should be a shareholder cost.

<u>Pension Expense to Reflect Amortization of Net Actuarial Loss Over A Longer Period</u>

Q. Please describe the Companies' request for pension expense.

A. The Companies seek significant increases in pension expense in the test year compared to calendar year 2014 and compared to the base year. KU seeks an increase of $15.316 million (total Company) compared to calendar year 2014 and of $12.467 million compared to the base year.[21] LG&E seeks an increase of $16.659 million (total Company) compared to calendar year 2014 and of $13.366 million compared to the base year.[22] These projected increases were based on

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[21] KU's Response to KIUC 1-20. I have attached a copy of this response as my Exhibit____(LK-19).

[22] LG&E's Response to KIUC 1-20. I have attached a copy of this response as my

preliminary estimates developed by Towers Perrin, an actuarial firm retained by the Companies.[23]

Q. What are the reasons for these significant increases?

A. The only witness who addressed these increases was Mr. Blake. The only reason cited by Mr. Blake was the presumed use by the Companies' actuaries of recently developed new mortality tables, which reflect "mortality improvements," or longer participant lives. Mr. Blake is not an actuary. Instead, he relied on preliminary estimates from Towers Perrin for the pension expenses included in the test year. These estimates were based on the new mortality tables as well as incorporating the effects of various other changes in assumptions. The result of the new mortality tables and other changes in assumptions is a huge increase in the Companies' future pension benefit obligations ("PBO") and the resulting net actuarial loss, a significant portion of which must be amortized and reflected in pension expense over some amortization period. The Companies amortized the net actuarial loss to expense using an extremely short year amortization period of less than 9 years.

Exhibit____(LK-20).

[23] Excerpts from the Towers Perrin report were provided in KU and LG&E's responses to KIUC 1-15 and 1-16. I have attached a copy of KU's response as my Exhibit___(LK-21).

Although it was not cited by Mr. Blake, another reason for the increase in pension expense is an increase in the PBO and the resulting net actuarial loss due to a reduction in the discount rate used to calculate the PBO. This reason is cited in the Towers Perrin report wherein it provided the preliminary estimates of pension expense relied on by the Companies in their filings. The discount rate is used to calculate the net present value of future pension payments to plan participants. The lower the discount rate, the greater the PBO, the greater the net actuarial loss, and the greater the pension expense, all else equal.

Q. How is the increase in the net actuarial loss reflected in the pension expense?

A. In addition to several other components, the pension expense calculation includes an amortization of a significant portion of the net actuarial loss in the 2015 and 2016 calendar years used to develop the pension expense for the test year. If the net actuarial loss increases, as it did from the use of the new mortality tables and the reduction in the discount rate, then the amortization included in the pension expense increases, all else equal. Similarly, if the amortization period is shortened, then the amortization included in the pension expense increases, all else equal. In future years, as the net actuarial loss is reduced, the amortization included in the pension expense will decline, all else equal.

Q. Is the essence of pension expense a statistical allocation of the future pension payments to plan participants over their lives?

A. Yes. Pension expense is nothing more than a statistical allocation of estimated future benefit payments. It requires estimates of the future pension payments, but is trued-up each year to reflect actual experience in the prior year and further adjusted to reflect changes in estimates of future payments to plan participants.

Consequently, the pension plan expense is properly viewed as a "self-truing" expense that is updated each year over the remaining lives of the plan participants. The estimates will change each year based on actual experience, the assumptions used and the allocation methods that are applied. Nevertheless, the sum of the pension expense necessarily will equal the sum of the pension benefit payments until the last plan participant or qualified dependent dies.

The Companies' defined benefit pension plans are now closed to new employees. The future pension payments to plan participants over their lives will not be known with certainty until the last plan participant dies and the plan is terminated. Until the termination of the plan, the pension expense each year requires an estimate of the future pension payments and an allocation of that expense over the remaining years of the plan.

This important point is confirmed in the Towers Perrin actuarial report provided in response to KIUC 1-16. Towers Perrin correctly notes that the variability in expense from estimate to estimate is due to changes in assumptions, but ultimately does not affect the pension expense incurred over time.

As an example of how assumptions can be used or changed to affect the pension expense calculated by the actuary for any year, the Companies successfully reduced their pension expense last year when they raised the discount rate by 90 basis points. Now they plan to reduce the discount rate by 50 basis points for the projected test year. If interest rates increase in future years, then the Companies will increase the discount rate again, which will reduce pension expense in those future years to levels below what their actuary projects today.

As another example of how the Companies used assumptions to increase pension expense in the projected test year in the pending cases, the Companies directed Towers Perrin to assume that there would be *no* earnings on the pension fund assets after March 31, 2014 until December 31, 2014. December 31, 2014 was the date used to value the pension assets and the PBO and the net actuarial loss used to calculate the pension expense for 2015. This assumption reduced the pension fund assets and increased the pension expense due to an increase in in the net actuarial loss for 2015 and all subsequent years that were projected. In effect, the Companies increased their pension expense in the test year through a apparently unsupported assumption.

Q. Have the Companies projected their pension expense after the end of the test year?

A. Yes. Towers Perrin projected the Companies' pension expense for each year 2015 through 2019.[24] After the increase in 2015, the projected expenses decline in each subsequent year 2016 through 2019. This occurs primarily because the amortization included in the pension expense declines as the funding deficiency and the net actuarial loss are reduced each year.

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[24] KU's and LG&E's response to KIUC 1-16. I have attached a copy of KU's response as part of my Exhibit___(LK-21).

Q. What is the significance of the declines in pension expense after the test year?

A. If the Commission adopts the Companies' proposed pension expense, then the base revenue requirement will include pension expense at its peak and will not reflect the declines in each subsequent year. This will result in the Companies' recovering more than the pension expense they actually incur until their next base rate cases. This is inequitable and can and should be avoided.

Q. Is the Commission obligated to use the Companies' proposed pension expenses for ratemaking purposes?

A. No. The Commission is required to set the pension expense at a level that it determines is reasonable for ratemaking purposes. This may not be the same as the Companies' estimates for accounting and financial reporting purposes. As I noted previously, pension expense is an estimate that is self-truing over time. The pension expense estimates are extremely sensitive to the models and assumptions that are used to calculate the expenses. All of these assumptions are approved by the Companies.

Thus, if the Commission determines that different estimates are reasonable for ratemaking purposes based on different assumptions, such as a longer amortization period or higher discount rate, then those estimates can and will be trued up in subsequent rate cases.

To the extent that the Companies' pension expense allowed for ratemaking is different than it reports for accounting and financial reporting, it is considered a timing difference under Generally Accepted Accounting Principles ("GAAP") and the Companies can defer the difference (either as an asset or a liability). These deferrals will converge to $0 when the final pension expense is determined and the plan is terminated. The use of deferral accounting ensures that the Companies' earnings will not be affected if the Commission adopts a longer amortization period.

Q. What is your recommendation?

A. I recommend that the Commission set pension expense to reflect a 30 year amortization of the net acturarial losses rather than the less than 9 year amortization periods used by the Companies. The longer amortization more closely matches the period over which pension payments will be made (up to 60 or more years) than the unduly short amortization period reflected in the Companies' amortization. The longer amortization period will reduce the volatility caused by changes in the mortality tables, the discount rate, and market returns on pension assets, not only in the pending cases, but also in future cases. The longer amortization period also will levelize the pension expense over the life of the pension plan compared to the Companies' proposal, which front-loads the amortization and thus, the pension expense. Finally, the longer amortization period will minimize the excess recoveries from customers as the Companies' pension expense declines in future years.

Q. What are the effects of your recommendation?

A. The effects are a reduction in KU's pension expense of $10.627 million and a reduction in LG&E's electric expense of $12.562 million.[25]

<u>Reduce Uncollectible Expense to Reflect Recent Experience</u>

Q. How does the uncollectible accounts expense included by the Companies in the test year compare to their actual experience over the most recent five years?

A. KU included $6.441 million in uncollectible expense in the test year compared to a five year average for 2010 through 2014 of $5.273 million. The five year average was driven sharply upward by abnormally high residential accruals in 2010 and 2014.[26] KU claims that the test year uncollectible expense is 0.40% of total revenues, which it claims is "not unreasonable when compared to the five year average."[27]

LG&E included $4.028 million in uncollectible accounts expense in the test year compared to a five year average for 2010 through 2014 of $3.730 million. The five year average was driven sharply upward by abnormally high residential accruals in 2010 and 2014.[28] LG&E claims that the test year

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[25] The calculations for KU and LG&E are attached as Exhibit___(LK-22) and Exhibit___(LK-23), respectively.

[26] KU's response to AG 1-3. I have attached a copy of this response as my Exhibit___(LK-24).

[27] KU's response to AG 2-3. I have attached a copy of this response as my Exhibit___(LK-25).

[28] LG&E's response to AG 1-3. I have attached a copy of this response as my Exhibit___(LK-26).

uncollectible expense is 0.28% of total revenues, which it claims is "not unreasonable when compared to the five year average."[29]

Q. Is the uncollectible accounts expenses included by each Company in its revenue requirement excessive?

A. Yes. The Commission must determine what a reasonable level of expense is for the forecast test year. The best way to do that is to compare it to each Company's recent experience. A five year average provides the best evidence of each Company's actual experience, including the effects of any anomalies. As I noted previously, it is not appropriate to compare the test year level to the most recent calendar year alone because the residential expense accruals were abnormally high in 2014.

As to the Companies' claim that the projected test year expense "is not unreasonable compared to the five year average," the numbers do not support that claim. The Companies' projections are substantially in excess of the five year averages and they are not reasonable.

Q. What is your recommendation?

A. I recommend that the Commission use the five year average for each Company. The Companies have offered no justification to increase the projected test year

[29] LG&E's response to AG 2-3. I have attached a copy of this response as my Exhibit___(LK-27).

expense to the proposed levels. The uncollectibles account expense is volatile and it should reflect each Company's average actual experience.

Q. What are the effects of your recommendation?

A. The effect is a reduction in KU's uncollectible accounts expense of $1.168 million and a reduction in LG&E's electric expense of $0.236 million.

<u>Increase Customer Late Payment Revenues to Reflect Recent Experience</u>

Q. Please describe the late payment revenues reflected by the Companies in the test year and how those "other revenues" compare to the Companies' recent actual five year experience.

A. KU reflected $3.786 million in the test year compared to a five year average for 2010 through 2014 of $6.306 million.[30] LG&E reflected $2.475 million (electric) in the test year compared to a five year average for 2010 through 2014 of $4.471 million.[31]

Q. Should the Commission use the five year average for late payment revenues in the same manner as you recommend for uncollectible accounts expense?

A. Yes, and for the same reasons.

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[30] KU's response to AG 1-3. A copy of this response is attached as my Exhibit___(LK-24).

[31] LG&E's response to AG 1-3. A copy of this response is attached as my Exhibit___(LK-26).

Q. What are the effects of your recommendation?

A. The effect is an increase in KU's late payment revenues of $2.520 million and an increase in LG&E's revenues of $1.996 million.

Remove Property Tax Expense on Construction Work In Progress and Direct the Companies to Capitalize the Expense

Q. Did the Companies capitalize any property tax expense in the test year to construction work in progress ("CWIP")?

A. No. The Companies reflected all property tax expense as an operating expense in the revenue requirement. The Companies' calculations of property tax expense in included construction work in progress ("CWIP") as well as plant in service.[32]

Q. Please describe the Companies' property tax expense capitalization policy.

A. The Companies capitalize property tax expense only on the "original construction costs of coal-fired generating units."[33] There is no construction of new coal-fired generating units in the test year, so the Companies did not capitalize any of the projected property tax expense. However, there is significant other construction, some of which is reflected in base rates and some of which is reflected in the environmental surcharge.

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[32] KU's and LG&E's response to KIUC 1-36. I have attached a copy of the summary tabs from each Company's response to KIUC 1-36 as my Exhibit___(LK-28).

[33] KU's and LG&E's response to KIUC 2-10. I have attached a copy of the KU response as my Exhibit___(LK-29).

Q. Is this capitalization policy appropriate?

A. No. It is not appropriate for accounting or ratemaking purposes. There is no justification for the Companies to expense the property taxes on the construction costs of environmental and all other additions to coal-fired generating units, gas-fired generating units, transmission, and distribution assets. The property tax expense on these construction costs is a cost of construction, not a current period expense. In fact, the FERC Uniform System of Accounts ("USOA") requires that such taxes be capitalized during construction.[34] The property tax expense should be treated no differently than the cost of labor, materials, contractors, and other costs that are incurred to construct the assets and to prepare them for service.

In the past, prior to the Companies' massive environmental capital expenditures and prior to their construction of gas-fired generation units instead of new coal-fired units, there may have been little difference whether the property taxes on CWIP were capitalized or not. However, circumstances have changed significantly from those days and the accounting and ratemaking practices of the past should be updated to reflect present reality. The Companies' accounting practices also should be modified to conform with the requirements of the FERC USOA Plant Instructions.

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[34] FERC USOA Electric Plant Instructions #3A. *Components of Construction Cost* states that "For Major utilities, the cost of construction property includible in the electric plant accounts shall include, where applicable, the direct and overhead cost as listed and defined hereunder:" The list of such costs includes #16 *Taxes,* which states: "*Taxes* includes taxes on physical property (including land) during the period of construction and other taxes properly includible in construction costs before the facilities become available for service."

Further, it is particularly important to capitalize property tax expense on CWIP in a forecast test year. There may have been an argument in the past when using a historic test year that regulatory lag justified treating all property tax expense as a current period expense for ratemaking recovery, at least with respect to property tax expense on minor generating unit additions or short-term transmission and distribution construction projects. That argument is no longer relevant now that the Companies have switched to a forecast test year.

Q. What are the effects of your recommendation?

A. The effect is a reduction in KU's property tax expense of $2.056 million and a reduction in LG&E's electric expense of $2.331 million.[35]

<u>Extend The Amortization Period for Deferred Costs That Will Be Fully Amortized Shortly After The Test Year</u>

Q. Please describe the amortization expense for deferred costs included in the test year.

A. The Companies provided a list of each deferred cost and the annual amortization expense in response to KIUC discovery in these proceedings.[36] For certain of these deferred costs, the amortization will be completed within one or two years after the end of the test year.

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[35] The calculation of the KU adjustment is shown on my Exhibit___(LK-30). The calculation of the LG&E adjustment is shown on my Exhibit___(LK-31).

[36] See KU's and LG&E's response to KIUC 1-29. I have attached a copy of each Company's response as my Exhibit___(LK-32) and Exhibit___(LK-33), respectively.

More specifically, KU's Mountain Storm deferred costs will be fully amortized in October 2016, a mere four months after the end of the test year. The amortization expense is $1.208 million. However, at the end of the test year, the unamortized cost is only $0.403 million. In other words, if this amortization expense is "baked-in" to the revenue requirement without modification, KU will recover $0.805 million more than the amortization expense in the twelve months after the test year and $1.208 million more than the amortization expense each year thereafter.

KU's MISO Exit Fee deferred costs will be fully amortized in June 2017, only twelve months after the end of the test year. The amortization expense is $0.484 million. However, at the end of the test year, the unamortized cost is only $0.482 million. In other words, if this amortization expense is "baked-in" to the revenue requirement without modification, KU will recover $0.484 million more than the amortization expense every twelve months starting in July 2017.

LG&E's 2011 Summer Storm will be fully amortized in December 2017, only 18 months after the end of the test year. The amortization expense is $1.610 million. However, at the end of the test year, the unamortized cost is only $2.416 million. In other words, LG&E will recover $1.610 million more than the amortization expense each year starting in January 2018.

Q. What is your recommendation to address this problem and the overrecovery that will occur within mere months after the end of the test year?

A. I recommend that the Commission reset the amortization period to five years for the deferred costs that I identified. This will reduce the likelihood that the Companies will overrecover, but still provides the Companies full recovery of the deferred costs.

Q. What are the effects of your recommendation?

A. KU's amortization expense will be reduced by $1.177 million for the Mountain Storm and MISO Exit Fee deferred costs.[37] LG&E's amortization expense will be reduced by $0.805 million for the 2011 Summer Storm deferred costs.[38]

<u>Eliminate Terminal Net Salvage from the Cane Run 7 Depreciation Rates</u>

Q. Please describe the net salvage that the Companies included in the proposed Cane Run 7 depreciation rates.

A. The Companies propose net salvage of negative 5% for plant accounts 342 and 343, negative 10% for account 344, and negative 5% for account 345[39] for Cane Run 7. Mr. Spanos developed these proposed net negative salvage rates by performing a statistical review of the historic *interim* retirements and *interim* net salvage of the Companies' other gas-fired generating units.[40] Mr. Spanos did not perform any review of *terminal* retirements or *terminal* net salvage for the Companies' other gas-fired generating units or for Cane Run 7 specifically and

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[37] The calculations for KU are shown on my Exhibit___(LK-34).

[38] The calculations for LG&E are shown on my Exhibit___(LK-35).

[39] These net salvage rates for each plant account are shown on Exhibit JJS-1 attached to Mr. Spanos' Direct Testimony for each company. I have attached a copy of KU's and LG&E's schedule as my Exhibit___(LK-36) and Exhibit___(LK-37), respectively, for ease of reference.

[40] Spanos Direct at 5-6.

claims that he did not "include a terminal net salvage component in the proposed rates since no plans have been established for how the facility would be dismantled."[41]

Q. Please distinguish between net salvage on interim retirements and net salvage on terminal retirements.

A. The plant balances represent the cost of the assets, in this case the Cane Run 7 generating unit. Some of the components of the asset will be replaced and retired before the entire asset is retired. These retirements are considered to be *interim* retirements. The net cost to remove these *interim* retirements, offset by any salvage income, is referred to as net negative salvage on *interim* retirements.

However, the bulk of the components and the cost of the components will remain in service from the first day of operation to the last day when the generating unit is shut down and retired. These retirements are considered to be *terminal* retirements. If the facilities are retired in place, then there is no cost to remove those components, net of any salvage income. If the facilities are dismantled and the site is remediated, then there is a cost to remove these components and remediate the site. The net cost to do so is referred to as net negative salvage on *terminal* retirements.[42]

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[41] KU's and LG&E's responses to KIUC 2-12. A copy of these responses is attached as my Exhibit___(LK-38).

[42] Mr. Spanos provides a description of interim and terminal retirements in his Direct Testimony at 7-8.

The distinction between interim and terminal retirements and the net negative salvage related to each may be illustrated through an analogy to a car. Assume that Betty buys a new car. Over the years, she replaces the tires and some of the engine components, such as the alternator and the power steering pump. Those are analogous to the interim retirements that Cane Run 7 will experience over its life. The costs that she incurred to pay her mechanic to remove and replace these parts are considered net negative salvage on those interim retirements. Years later, the car reaches the end of its life and Betty decides to permanently retire it. She has the car towed to the salvage yard and is paid nothing for it. The costs that she paid the towing company are considered net negative salvage on terminal retirements. The terminal retirement of the car is analogous to Cane Run 7. At the end of its life, the entire remaining plant balances will be retired. There may be no net negative salvage if the unit is retired in place or there may be net negative salvage if it is dismantled and removed and the site is remediated.

Q. How did Mr. Spanos apply the net negative salvage that he developed for *interim* retirements when he calculated the depreciation rate for Cane Run 7?

A. Mr. Spanos applied the *interim* net negative salvage to the *entire* Cane Run plant balance rather than only the *interim* portion of the plant balance. He acknowledged that he did so in response to discovery.[43] Returning to my car analogy, he assumed that the roof, hood, trunk, and chassis of the car all would have to be replaced on the same regular basis as tires, the alternator and the power steering pump.

Q. What is the proportion of the plant balance for Cane Run 7 that is subject to interim retirements?

A. Mr. Spanos provided the Cane Run 7 plant balances by account that would be subject to interim retirements in response to discovery.[44] That response shows that only 25% (on average across all plant accounts) of the total plant balances for each Company will be subject to interim retirement.[45] Yet, Mr. Spanos applied the interim net salvage to 100% of the total plant balances, both the interim portion and the terminal portion.

Q. Was this a calculation error?

A. Yes. First, the Companies claim that they included ***NO*** terminal net salvage in the proposed Cane Run 7 depreciation rates. However, that claim is incorrect. By applying the interim net salvage rate to the terminal retirements in addition to the interim retirements, the Companies included net negative salvage on terminal

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[43] KU's and LG&E's responses to KIUC 2-13. I have attached a copy of these responses as my Exhibit___(LK-39).

[44] *Id.*

[45] The 25% is an average across all plant accounts. The responses to KIUC 2-13 indicate that interim retirements compared to total plant balances for both Companies are 18% for account 341, 16% for account 342, 19% for account 343, 30% for account 344, 33% for account 345, and 34% for account 346.

retirements, despite denying that they did so and denying that they even could do so.

Second, the Companies provided no estimate of terminal net salvage and no support for including terminal net salvage, let alone any evidence that terminal net salvage would be anything other than 0%. Mr. Spanos included the following Question and Answer in his testimony as follows:

> **Q. DID YOU INCLUDE A NET SALVAGE COMPONENT FOR DISMANTLEMENT IN THE DEPRECIATION CALCULATIONS?**
>
> A. No. Although it is important to establish the full service value of the facility at the early stages, including an amount at this time is premature. There is analysis of the facility and site that needs to be performed before an adequate estimate of dismantlement costs assigned for recovery. Once the study is completed, the dismantlement component will be included in future depreciation rates.

Mr. Spanos testified that not only had he ***NOT*** included terminal net salvage, but that he could not do so until he had "an adequate estimate of dismantlement costs."

In Case Nos. 2012-00221 and 2012-00222, the settlement adopted by the Commission limited terminal net salvage to negative 2% on all of the Companies' generating units.[46] Methodologically, the Companies weighted the interim and terminal net salvage by the interim and terminal portions of the plant balance.[47] If Mr. Spanos had done a similar weighting for Cane Run 7 with a 0% terminal net

[46] In their responses to KIUC 2-12, the Companies provide the weighting of the interim and terminal net salvage rates into a combined net salvage rate applied to the entire plant balances. The terminal net salvage for all plant accounts is shown as negative 2% in accordance with the settlement term.

[47] *Id.*

salvage for the terminal portion of the plant balances, then the weighted net salvage would be one-fourth of the net salvage rate that he applied.

Q. What is your recommendation?

A. I recommend that the Commission correct this error in the Companies' calculation of the proposed Cane Run 7 depreciation rates and remove the terminal net salvage from the calculations.

Q. What are the effects of your recommendation?

A. The Cane Run 7 depreciation rates should be reduced to 2.62% for accounts 341 and 342, 2.68% for account 343, 2.91% for account 344, 2.88% for account 345, and 2.82% for account 346. KU's depreciation expense should be reduced by \$0.511 million and LG&E's by \$0.164 million.[48] I used the Companies' methodology for its other generating units to weight the interim net salvage and the terminal net salvage (using 0% for Cane Run 7) to develop the net salvage rate applied to the Cane Run 7 plant balances. These reductions to depreciation expense and the associated rate increases will not affect the earnings of the Companies.

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[48] The calculations of the corrected depreciation rates and the corrections to the KU and LG&E depreciation expense are shown on my Exhibit___(LK-40) and Exhibit___(LK-41), respectively.

V. CAPITALIZATION ISSUES

Reduce The Revenue Requirement to Reflect A "Slippage Factor" Applied to Construction Expenditures

Q. The Staff asked the Companies to quantify a construction expenditure "slippage factor" and the resulting reduction in revenue requirements.[49] Please describe the concept of a "slippage factor" and the Companies' responses.

A. A "slippage factor" in this context refers the percentage by which the actual construction expenditures tend to underrun the budgeted construction expenditures. The Commission has applied slippage factors in other utility base rate cases where there has been a forecast test year. In its order in Union Light, Heat and Power Company Case No. 2005-00042, the Commission adopted a "slippage factor" adjustment for the forecast test year, which it described as follows:

> As part of the capital budgeting process, utilities will estimate the level of capital construction that will be undertaken during the year. Because of delays, weather conditions, or other events, the actual level of construction will often vary from the level budgeted. The difference between the actual and budgeted levels is reflected in the calculation of a "slippage factor," which serves as an indicator of the utility's accuracy in predicting the cost of its utility plant additions and when new plant will be placed into service. The Commission has routinely applied a slippage factor in the forward-looking test period rate cases for Kentucky-American Water Company. The Commission has usually utilized a slippage factor calculated by determining the annual slippage during the most recent 10-year period and then calculating the mathematic average of the annual

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[49] KU's response to Staff 2-75 and LG&E's response to Staff 2-89.

> slippage factors. The slippage factor is normally applied to the utility plant in service balance and the construction work in progress ("CWIP") balance to determine the slippage adjustment.[50] (footnote omitted).

Similarly, in its order in Case No. 2004-00103, the Commission adopted "slippage factor" adjustments for the forecast test year, which it described "as an indicator of Kentucky-American's accuracy in predicting the cost of its utility plant additions."[51]

In these proceedings, KU quantified a 97.803% slippage factor and a reduction of $0.900 million in its base revenue requirement if the slippage factor is applied to its projected construction expenditures.[52,53] LG&E quantified a 97.728% slippage factor and a reduction of $0.738 million in its electric base revenue requirement if the slippage factor is applied to its projected construction expenditures.[54,55]

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[50] Order in Union Light, Heat and Power Company Case No. 2005-00042 at 8.

[51] Order in Kentucky American Water Case No. 2004-00103 at 2.

[52] KU's responses to Staff 2-75. I have attached a copy of this response as my Exhibit___(LK-42).

[53] I have reflected the effects on capitalization of KU's calculations in Section II on my Exhibit___(LK-43) in order that the subsequent changes in capitalization and costs of each component will be properly calculated in a sequential manner. KU's calculation also affect operating income. I have included both effects on the same line item under Capitalization issues on the table in the Summary section of my testimony.

[54] LG&E's response to Staff 2-89. I have attached a copy of this response as my Exhibit___(LK-44).

[55] I have reflected the effects on capitalization of LG&E's calculations in Section II on my Exhibit___(LK-45) in order that the subsequent changes in capitalization and costs of each component will be properly calculated in a sequential manner. LG&E's calculation also affect operating income. I have included both effects on the same line item under Capitalization issues on the table in the Summary section of my testimony.

The quantifications provided by the Companies include not only the effect on capitalization, but also the capital-related effects on operating income.

Q. Should the Commission apply the slippage factors calculated by the Companies and reduce capitalization?

A. Yes. The Commission's precedent is to apply slippage factors, which the Companies have acknowledged.

<u>Reduce The Companies' Capitalization and Income Tax Expense to Reflect the Extension of Bonus Depreciation Enacted After the Companies Made Their Filings</u>

Q. Please describe the "tax extender" bill passed by the U.S. Congress in December 2014.

A. In December 2014, the Congress passed Public Law No. 113-295, entitled "The Tax Increase Prevention Act of 2014" ("Act"). The Act provided for the extension of 50% bonus tax depreciation in 2014 for qualified property while also providing 50% bonus tax depreciation in 2015 for long-production-period property.[56]

Under the law, the Companies may elect out of the bonus depreciation and instead use MACRS depreciation. If the Companies apply bonus depreciation on qualified property, they both will be able to deduct the additional bonus tax depreciation in excess of the MACRS tax depreciation. The additional tax

[56] KU's response to AG 1-27 and LG&E's response to AG 1-26.

depreciation will significantly increase their accumulated deferred income taxes ("ADIT").

Q. What are the implications of the Act in these proceedings?

A. The Act was passed and signed into law after the Companies made their filings in these proceedings. Consequently, the effects of the additional tax depreciation are not reflected in their filings.

The effects are two-fold. First, the Companies are able to deduct additional depreciation compared to the MACRS depreciation they reflected in their filings. However, they may elect out of the bonus depreciation and instead use MACRS depreciation if that results in a better outcome. Further, they may use bonus depreciation for 2014, but elect out for 2015. To the extent that the Companies use bonus depreciation, they will have greater accumulated deferred income taxes and reduced capitalization. This will result in a reduction in their revenue requirements, all else equal.

Second, the amount of bonus depreciation deducted results in lower taxable income and lower Section 199 deductions, which are based on taxable income. A reduction in the Section 199 deduction results in greater income tax expense and an increase in the revenue requirement, all else equal.

Thus, the Companies must optimize between the use of bonus depreciation in 2014 and 2015 and the potential loss of the Section 199 deduction in each of those years.

Q. Have the Companies each performed an analysis to optimize the revenue requirement benefit of the bonus depreciation against the loss of the Section 199 deduction?

A. Yes. The Companies each performed four analyses that included not only the effects on their base revenue requirements, but also on their environmental surcharge revenue requirements in order to optimize the effects of the Act. KU determined that its best option will be to utilize bonus depreciation for 2014, but to elect out of it 2015.[57] LG&E determined that its best option will be to utilize bonus depreciation for both 2014 and 2015.[58]

Q. Did the Companies quantify the effects on the Section 199 deduction and the capitalization (due to the greater ADIT) for the test year?

A. Yes. KU quantified a reduction in capitalization due to the additional ADIT of $28.234 million and a reduction in income tax expense due to an increase in the Section 199 deduction of $0.350 million. LG&E quantified a reduction in capitalization due to the additional ADIT of $54.238 million and an increase in income tax expense due to a reduction in the Section 199 deduction of $1.606 million, both total company.

Q. What is the effect of reflecting these changes in capitalization and income tax expense on each Company's revenue requirement?

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[57] KU's response to AG 1-27. See Tab 1 – Summary and Tab 3 – Opt Out 2015. I have attached a copy of the response and the relevant tabs as my Exhibit___(LK-46).

[58] LG&E's response to AG 1-26. See Tab 1 – Summary and Tab 4 – Elect Bonus w Rev. I have attached a copy of the response and the relevant tabs as my Exhibit___(LK-47).

A. The effect is a reduction in KU's base revenue requirement of $2.483 million and a reduction in LG&E's electric base revenue requirement of $2.760 million.[59] There also are significant effects of these changes on each Company's environmental surcharge revenue requirement, which the Commission should ensure are properly incorporated in each Company's environmental surcharge filings.

<u>Reduce LG&E's Capitalization to Remove The Paddy's Run Demolition Costs</u>

Q. Please describe LG&E's proposal to demolish the retired Paddy's Run generating plant.

A. LG&E proposes to demolish the retired Paddy's Run generating plant in the test year. It has been retired in place for many years. LG&E proposes to incur $11.5 million starting April 2015 and finishing in June 2016, all of which it included in the test year capitalization. The cost estimate was prepared by AMEC Environment & Infrastructure, Inc.[60]

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[59] The calculations for the effect on KU's revenue requirement due to the reduction in capitalization are shown on Section III of my Exhibit___(LK-43) and for the effect on LG&E's revenue requirement due to the reduction in capitalization are shown on Section III of my Exhibit___(LK-45). The effect on KU's base revenue requirement due to the increase in the Section 199 deduction is $0.541 million. The effect on LG&E's electric base revenue requirement due to the reduction in the Section 199 deduction is $2.052 million.

[60] LG&E's response to KIUC 1-6. The response to part (a) provides the projected expenditures by month. The responses to parts (b) through (d) provide other information on the status of the plant, the accounting for the demolition costs, and whether there is any legal obligation to demolish the plant. The response to part (e) provides a copy of the AMEC "Conceptual Phase Study Demolition with Clean Fill Option." I have attached a copy of the response as my Exhibit___(LK-48), although I have provided only the cover and table of contents of the AMEC study report.

Q. Is there any legal obligation to demolish Paddy's Run?

A. No.[61]

Q. Should the Commission include this proposed demolition cost in LG&E capitalization?

A. No. There is no legal obligation to incur the cost. The Company has not demonstrated that it is necessary to incur the cost in the test year.

Q. What is the effect of your recommendation?

A. The effect is a reduction in the LG&E revenue requirement of $1.235 million.[62]

VI. COST OF SHORT TERM DEBT

Reduce the Cost of Short Term Debt to Reflect A More Reasonable Assumption About Future Interest Rates

Q. Please describe the cost of short term debt proposed by the Companies in the test year.

A. The Companies propose a rate of 0.905%, which reflects a projected rate of 0.636% for the July 2015 through December 2015 portion of the test year and a rate of 1.585% for the January 2016 through June 2016 portion of the test year.

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[61] *Id.*, response to part (d)(i): "There is no legal requirement to demolish the units."

[62] The calculations and sources of data used for the calculations are detailed in Section IV on my Exhibit___(LK-45).

Q. Are these rates reasonable?

A. No. They are excessive. The present rate for 90 day commercial paper is 0.15%. The present rates for 240 day to 270 day commercial paper range from 0.33% to 0.36%.[63]

Q. What is your recommendation?

A. I recommend that the Commission use a short term debt rate of 0.30%, near the top of the range, although a lower rate also would be reasonable.

Q. What is the effect of your recommendation?

A. The effect is a reduction in KU's revenue requirement of $0.645 million and a reduction in LG&E's revenue requirement of $0.561 million.[64]

VII. COST OF LONG TERM DEBT ISSUED AFTER DECEMBER 2014

Q. Have you quantified the effect of Mr. Baudino's recommendation to reduce the cost of the new debt issuances projected by the Companies?

A. Yes. I have used the long term debt interest rates proposed by Mr. Baudino for each Company's projected new debt issuances.

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[63] See attached excerpt from February 26, 2015 Wall Street Journal reflecting rates.

[64] The calculations for KU are detailed in Section IV on my Exhibit___(LK-43) and for LG&E in Section V on my Exhibit___(LK-45).

Q. What are the effects of Mr. Baudino's recommendations?

A. The effects are a reduction in KU's revenue requirement of $1.250 million and a reduction in LG&E's revenue requirement of $1.076 million.[65]

VIII. RETURN ON EQUITY

Q. Have you quantified the effect of Mr. Baudino's recommended return on common equity?

A. Yes. Mr. Baudino recommends a return on equity of 8.6% compared to the Companies' requested return on equity of 10.50%. Mr. Baudino's recommended return on equity for KU is 13.69% when grossed up for income taxes, bad debt expense, and Commission assessment, compared to KU's requested return on equity of 16.71% when grossed-up for income taxes, bad debt expense, and Commission assessment. Mr. Baudino's recommended return on equity for LG&E is 13.83% when grossed up for income taxes, bad debt expense, and Commission assessment compared to LG&E's return on equity of 16.89% when grossed-up for income taxes, bad debt expense, and Commission assessment. It is the grossed-up return on equity that is recovered in customer rates.

Q. What are the effects of Mr. Baudino's recommendations?

A. The effects are a reduction in KU's revenue requirement of $56.674 million and a reduction in LG&E's revenue requirement of $33.596 million.[66]

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[65] The calculations for KU are detailed in Section V on my Exhibit___(LK-43) and for LG&E in Section VI on my Exhibit___(LK-45).

Q. Have you quantified the effects of a 1.0% change in the return on common equity for each Company?

A. Yes. For KU, each 1.0% return on equity equals $29.828 million in revenue requirements. For LG&E, each 1.0% return on equity equals $17.682 million in revenue requirements. These quantifications reflect the reductions in capitalization for each Company that I recommend.[67]

IX. OFF-SYSTEM SALES MARGIN RIDER

Q. Please describe the off-system sales ("OSS") margins included by the Companies in their revenue requirements?

A. KU reflected OSS margins of $0.5 million as a reduction to its revenue requirement and LG&E reflected $2.7 million in its revenue requirement. These margins are significantly lower than OSS margins reflected in the revenue requirement in prior cases and the actual OSS margins earned by the Companies.

Q. Are OSS margins subject to the same or greater volatility as fuel and purchased power expenses?

A. Yes. The same factors that affect fuel and purchased power expenses also affect OSS margins. In addition, there are many other factors that affect OSS margins, including market clearing prices, the availability of other parties' generation,

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[66] The calculations for KU are detailed in Section VI on my Exhibit___(LK-43) and for LG&E in Section VII on my Exhibit___(LK-45).

[67] The quantifications of each 1.0% change in the return on equity are shown for KU on my Exhibit___(LK-43) and for LG&E on my Exhibit___(LK-45).

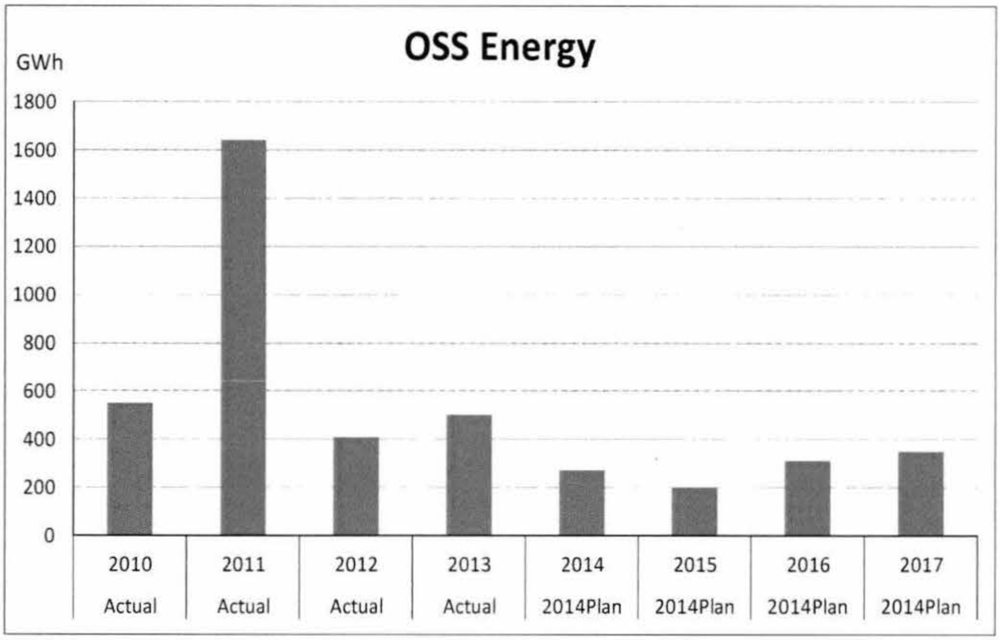
other parties' demand at the market clearing prices, the Companies' loads under unpredictable weather conditions, and the availability of the Companies' generating units, including the effects of planned, forced, and deration outages of generating units. Assumptions regarding the following factors must be made in order to predict OSS margins in a future test year:

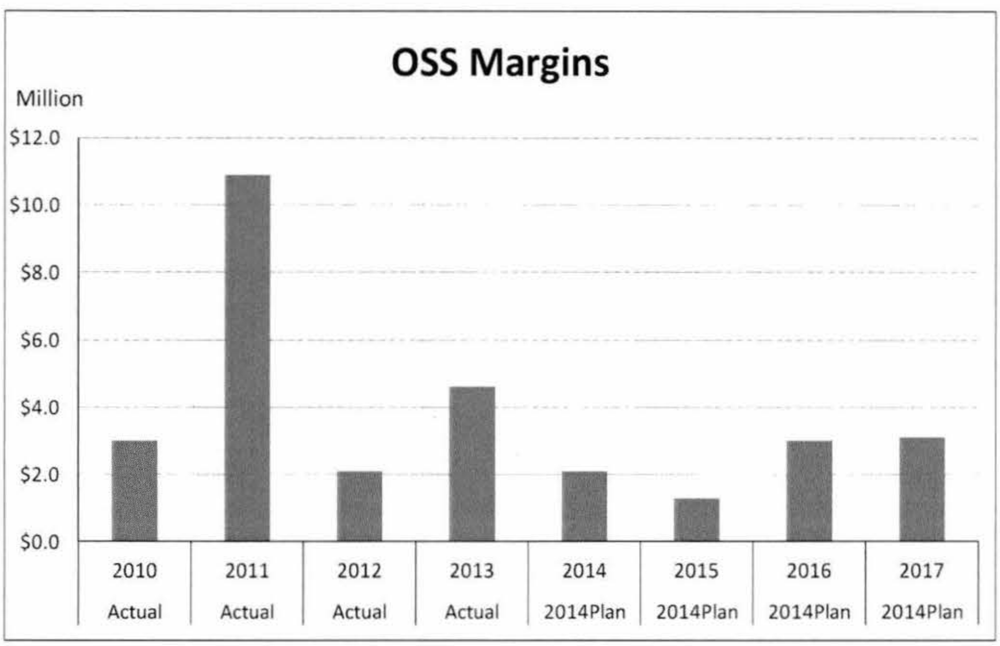
- Hourly dispatched generation by unit
- Hourly native load
- Hourly energy sales
- Hourly economic minimum and emergency minimum capacity levels
- Data required to calculate both incremental dispatch costs and actual dispatch costs include:
- Quadratic heat rate coefficients
- Fuel costs ($/MBTU)
- Fuel Handling Costs ($/MBTU or $/MWh)
- Other costs such as for lime ($/MBTU or $/Ton)
- Dispatch penalty factor
- Variable O&M costs ($/MWh)
- SO_2 and NO_X emissions costs ($/MWh)

Q. How have OSS and OSS margins varied in recent years?

A. The following charts show the volatility and variability of both OSS and OSS margins over the last five years.[68]

[68] OSS Energy obtained from page 2 of 71 in response to 807 KAR 5:001Section 16(7)(c) provided with each Company's filing. OSS Margins obtained from Thompson Direct in KU at 25.


OSS Energy
GWh
1800
1600
1400
1200
1000
800
600
400
200
0
2010 Actual
2011 Actual
2012 Actual
2013 Actual
2014 2014Plan
2015 2014Plan
2016 2014Plan
2017 2014Plan


OSS Margins
Million
$12.0
$10.0
$8.0
$6.0
$4.0
$2.0
$0.0
2010 Actual
2011 Actual
2012 Actual
2013 Actual
2014 2014Plan
2015 2014Plan
2016 2014Plan
2017 2014Plan

Q. Is it possible to accurately and reliably project OSS margins?

A. No. OSS margins are more difficult to project than fuel and purchased power expenses.

Q. Does the volatility and the inability to accurately and reliably project OSS margins indicate the need for an OSS tracker as a means of truing-up the OSS margins reflected in the base revenue requirement?

A. Yes. Fuel and purchased power expenses, although included in the base revenue requirement on a projected basis, are trued-up to actual costs through the Fuel Adjustment Clause ("FAC"). That true-up through the FAC is necessary because these expenses are volatile, vary considerably from month to month and from year to year, and cannot be accurately or reliably projected. Those same reasons argue for a true-up of the OSS margins through the FAC.

Q. Has the Commission previously approved an OSS tracker in the FAC for another utility?

A. Yes. The Commission authorized an OSS tracker in the FAC for Kentucky Power Company, which is identified as the System Sales Clause. It is used to true-up the OSS margins included in Kentucky Power Company's base rates and to share the true-up differences between Kentucky Power Company and its customers.

Q. Should the Commission adopt a similar OSS tracker in the FAC for KU and LG&E?

A. Yes. First, an OSS tracker will address the volatility and variability in OSS, and the inability to accurately or precisely project these expenses in an equitable and fair manner so that neither the Companies nor their customers are unduly harmed or benefitted from factors largely beyond their control.

Second, both KU and LG&E are planning to retire old and inefficient generating units in 2015 and 2016. They expect to commence operation of the new and highly efficient Cane Run 7 natural gas combined cycle plant in the next few months. These events will affect the availability of energy and the cost to sell energy off-system.

Third, an OSS tracker will mitigate the effects of disagreements on methodologies used to allocate fuel and purchased power expense between native load and OSS.

Q. What sharing factors should the Commission adopt?

A. I recommend that the Commission adopt 90% to customers and 10% to the Companies sharing factors for the differences between actual OSS margins and the OSS margins included in the base revenue requirement. For example, if actual OSS margins are \$1 million more than included in the base revenue requirement, then customers would be allocated \$900,000 and shareholders would be allocated \$100,000. On the other hand, if OSS margins are \$1 million less, then customers would "pay" \$900,000 and shareholders effectively would "pay" \$100,000.

The 90%/10% sharing percentages are appropriate for the following reasons:

- OSS margins are subject to greater volatility and variability than fuel and purchased power expenses.

- OSS margins are directly related to fuel and purchased power expense and should be allocated entirely to customers in the same manner that fuel and purchased power expenses are allocated entirely to customers.

- Customers pay all the fixed costs of the generating units, the dispatch organization, including affiliate charges, and all related overheads.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this 6th day of March 2015.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

DEK
Exhibit 10

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	CASE NO. 2014-00371

INDEX

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	CASE NO. 2014-00371

ORDER

Kentucky Utilities Company ("KU"), a subsidiary of LG&E and KU Energy LLC, is a jurisdictional electric utility that generates, transmits, distributes, and sells electricity to approximately 515,000 consumers in portions of 77 counties in Central, Northern, Southeastern, and Western Kentucky.[1] Its most recent general rate increase was granted in Case No. 2012-00221.[2]

BACKGROUND

On October 22, 2014, KU filed a notice of its intent to file an application for approval of an increase in its electric rates based on a forecasted test year ending June 30, 2016. On November 26, 2014, KU filed its Application, which included new rates to be effective January 1, 2015, based on a request to increase its electric revenues by $153 million.[3] Determining that an investigation would be necessary regarding the reasonableness of KU's proposed rates, the Commission suspended the proposed

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[1] *See* KU's Application at 1–2 for a list of the counties served.

[2] Case No. 2012-00221, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (Ky. PSC Dec. 20, 2012).

[3] KU's affiliate, Louisville Gas and Electric Company ("LG&E"), filed a concurrent application, which was docketed as Case No. 2014-00372, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates* (filed Nov. 26, 2014).

rates for six months from their effective date, pursuant to KRS 278.190(2), up to and including June 30, 2015.

The following parties requested and were granted full intervention: the Kentucky Industrial Utility Customers, Inc. ("KIUC"); the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention; the Kentucky School Boards Association; the Kentucky Cable Television Association; Kroger Co.; the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"), Wal-Mart Stores East, LP and Sam's East, Inc.; Lexington-Fayette Urban County Government ("LFUCG"), and Alice Howell, Carl Vogel, and the Sierra Club. On December 12, 2014, the Commission issued a Procedural Order establishing the schedule for processing this case. The schedule provided for discovery, intervenor testimony, rebuttal testimony by KU, a formal evidentiary hearing, and an opportunity for the parties to file post-hearing briefs.[4] All intervenor testimonies were filed by March 6, 2015, and KU's rebuttal testimony was filed jointly with that of LG&E on April 14, 2015.[5]

Parties in this case and the LG&E rate case participated an informal conference at the Commission's offices on April 16, 17, and 20, 2015, to discuss procedural matters and the possible resolution of pending issues.[6]

On April 20, 2015, KU and LG&E filed a Settlement Agreement, Stipulation and Recommendation ("Settlement") intended to address all of the issues raised in the two

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[4] Two public meetings were conducted in the LG&E and KU service territories: in Louisville on March 30, 2015; and in Lexington on April 13, 2015.

[5] LFUCG did not file testimony.

[6] For administrative efficiency, the informal conference was a joint conference for this case and the LG&E rate case, Case No. 2014-00372.

cases. Under the terms of the Settlement, the utilities and intervenors agreed to forego cross-examination of each other's witnesses at the formal evidentiary hearing, which was held at the Commission's offices on April 21, 2015.

SETTLEMENT TERMS

The Settlement reflects the agreement of the parties on all issues raised in this case as well as the LG&E rate case. The major provisions of the Settlement as they relate to KU's revenues and rates are as follows:

- KU's base rate revenues should be increased by $125 million to be effective for service rendered on and after July 1, 2015.
- Other rate and tariff changes include deleting the Low Emission Vehicle tariff and adding two optional Residential Time-of-Day rate classes, as proposed in KU's Application, with April and October added to the summer pricing period. The changes are set forth in Settlement Exhibit 4.
- The allocation of the increase in KU's electric revenues is set forth in Settlement Exhibit 1.
- The electric rates for KU resulting from the Settlement are set forth in Exhibit 4 to the Settlement.
- The monthly residential electric customer charge should remain at $10.75.
- A reasonable return on equity ("ROE") to be used in KU's monthly environmental cost recovery filings is 10.00 percent.
- The Curtailable Service Riders ("CSR10" and "CSR30") should be combined into a single CSR, which will be similar to the existing CSR10 except that:

- CSR credits should be \$6.50 per kilovolt-ampere ("kVA") month (primary) and \$6.40 per kVA month (transmission);

- The required notice period to CSR customers should be 60 minutes;

- KU may request up to 100 hours of physical curtailment from CSR customers annually, but such requests may be made only when all available KU and LG&E generating units have been dispatched or are being dispatched and all off-system sales have been or are being curtailed; and

- Each CSR customer will certify annually its ability to interrupt load in its CSR contract.

- An Off-System Sales ("OSS") tracker should be implemented under which electric OSS margins will be shared on a 75 percent–25 percent basis between customers and KU. OSS margins should be credited to customers through the fuel adjustment clause.

- KU's Pole Attachment Rates should be reset to \$7.25 per attachment per year.

All parties to this case agreed that the amount of increase in electric revenues, the allocation of the increase, and the proposed rates, all as set forth in the Settlement, are fair, just and reasonable for KU. The Settlement addresses several other issues, including regulatory accounting, contributions to various low-income assistance programs, and tariffs. The remaining provisions of the Settlement affecting KU's operations are as follows:

- The Commission should authorize regulatory asset treatment for the difference between: (1) KU's pension expense booked in accordance with its accounting policy on file with the Securities and Exchange Commission and Generally Accepted Accounting Principles; and (2) pension expense with actuarial gains and losses amortized over 15 years.

- The Commission should authorize regulatory asset treatment for complete recovery of costs incurred by Green River Units 3 and 4 during the forecasted test period through retirement of the units. The asset should be amortized over three years, beginning with the effective date of new rates resulting from this proceeding.

- Depreciation rates for Cane Run Unit 7 for ratemaking purposes should be based on a 40-year service life.

- KU's contribution for low-income customer support will be increased to $470,000 annually starting in 2015, with $100,000 for Wintercare and $370,000 for the Home Energy Assistance ("HEA") program, both of which are administered by CAC. Up to 10 percent of the total contribution to CAC may be used for reasonable administrative expenses.

- The HEA program approved in Case No. 2010-00204[7] should be made permanent, and the monthly HEA charge to residential customers should continue at $0.25 per meter until the effective date of new base rates for KU following its next base rate case.

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[7] Case No. 2010-00204, *Joint Application of PPL Corporation, E.ON AG, E.ON US Investments Corp., E.ON U.S. LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of Acquisition of Ownership and Control of Utilities* (Ky. PSC Sept. 30, 2010).

- The period in which a residential customer may pay in full any required deposit should be extended from four months to six months.

- The School Energy Management Program ("SEMP") approved in Case No. 2013-00067[8] should be extended through June 30, 2016, to be funded with the balance of $475,000 in funds not yet requested by the schools in the SEMP's first two years. KU and LG&E should file an application with the Commission; (1) to extend the SEMP through June 30, 2018, at the funding levels approved in Case No. 2013-00067; and (2) for approval of a demand-side management ("DSM") and energy efficiency ("EE") program to provide $1.0 million in grants to schools to fund EE projects.

- KU and LG&E will instruct the vendor for their industrial DSM–EE study to commence work immediately, and they will not seek DSM cost recovery of the cost of the study. The study will be completed by May 1, 2016, and will be filed with the Commission 30 days later in accordance with the final order in Case No. 2014-00003.[9] Thereafter, KU and LG&E commit that they will begin the DSM Advisory Group meeting process to discuss the results of the study. KU and LG&E also commit to address opt-out criteria for industrial customers, as well as the definition of "industrial" in their first DSM/EE application following completion of the industrial DSM/EE study.

- Except as modified in the Stipulation and the exhibits attached thereto, the rates, terms and conditions proposed in KU's Application should be approved as filed.

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[8] Case No. 2013-00067, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for the Review and Approval of a Two-Year Demand Side Program Related to School Energy Management and Associated Cost Recovery* (Ky. PSC Apr. 30, 2013).

[9] Case No. 2014-00003, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs* (Ky. PSC Nov. 14, 2014).

ANALYSIS AND FINDINGS ON SETTLEMENT

The Commission's statutory obligation when reviewing a rate application is to determine whether the proposed rates are "fair, just and reasonable."[10] While numerous intervenors with significant experience in rate proceedings and collectively representing a diverse range of customer interests have participated in this case, the Commission cannot defer to the parties as to what constitutes "fair, just and reasonable" rates. The Commission must review the record, including the Settlement, and apply its expertise to make an independent decision as to the level of rates (including terms and conditions of service) that should be approved.

To satisfy its statutory obligation in this case, the Commission has performed its traditional ratemaking analysis, which consists of reviewing the reasonableness of each revenue and expense adjustment proposed or justified by the record, along with a determination of a fair ROE. Based on the Commission's analysis of KU's revenues and expenses, as well as a determination of a reasonable ROE range for KU, we conclude that the provisions in the Settlement will produce a revenue requirement and increase in base rates consistent with those justified by our traditional ratemaking analysis.

[10] KRS 278.030(1).

OTHER ISSUES

Industrial DSM Study Issues

In Case No. 2011-00375,[11] we directed KU and LG&E to commission an EE potential study. KU and LG&E, nonetheless, took it upon themselves to not examine EE usage in the industrial class of customers, which constitutes 30 percent of their load.

Once this omission was brought to our attention during KU's and LG&E's most recent DSM case,[12] the Commission held that KRS 278.285(3) does not provide for a categorical industrial opt-out of utility-offered DSM or EE programs targeted at industrial customers.[13] Further, the Commission stated that that the statute employs a two-part analysis before an industrial customer may opt out: first, the industrial customer must be an energy-intensive customer; second, the energy-intensive customer must have adopted cost-effective EE measures. We then expressly directed KU and LG&E to "commission an industrial potential or market characterization study."

In the case at bar, we learned that the industrial DSM/EE study, although "commissioned," had not yet begun. Furthermore, a review of KU's responses to discovery requests in this case reveals that the number of industrial customers provided to the Commission in Case No. 2014-00003 was not accurate for DSM purposes.[14]

[11] Case No. 2011-00375, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC, in LaGrange, Kentucky* (Ky. PSC May 3, 2012).

[12] Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities Company* (filed Jan. 17, 2014).

[13] *Id.* (Ky. PSC Nov. 14, 2014), Order at 27-30.

[14] *See* Attachment to KU's March 27, 2015 Supplemental Response to Commission Staff's Third Request for Information, Item 15.

The Settlement provision with respect to the industrial DSM/EE study seems to have cured KU's and LG&E's previous failings on this issue as follows:

1. KU and LG&E will immediately instruct their vendor to commence work on this study.

2. KU and LG&E will not seek cost recovery for same.

3. The study will be completed by May 1, 2016, and filed with the Commission by May 31, 2016.

4. Thereafter the DSM Advisory Group will begin meeting to discuss the results of the study.

5. No later than the filing of the first DSM/EE application after completion of the industrial DSM/EE potential study, KU and LG&E will set forth a proposed definition of the term "industrial" as that term is used in KRS 278.285(3) and develop criteria which will be used to determine whether an industrial customer qualifies for the DSM exemption under KRS 278.285(3).

In addition to the above items, which are approved herein as part of the Settlement, the Commission, with this Order, directs that KIUC be given the opportunity to participate as a member of the KU/LG&E DSM Advisory Group. KU and LG&E shall further use their best efforts to secure the participation of small- or medium-sized industrial customers in the DSM Advisory Group.

Once the DSM Advisory Group begins meeting to examine the definition of "industrial" and the criterion for industrial customers to opt out, KU and LG&E should file with the Commission monthly status reports on the DSM Advisory Group's work pending the first DSM/EE application after completion of the DSM/EE potential study.

Low Emission Vehicle Tariff Deletion

KU proposed in its application to delete its Low Emission Vehicle ("LEV") tariff. As noted previously, this tariff deletion is included as part of the Settlement. In its application, KU stated that it would "make all reasonable efforts to contact Rate LEV customers to advise them of their new rate options after the Commission approves the new rates but before they take effect (at which time Rate LEV will terminate)."[15] For those customers who do not inform KU which rate schedule they would like to take service under, KU proposed to automatically transfer those customers to its proposed Residential Time-of-Day – Energy ("RTOD–Energy") tariff.

During discovery in this proceeding, it was determined that some LEV customers would receive a lesser percentage rate increase by being transferred to KU's standard Residential Service tariff rather than to the RTOD–Energy tariff. At the hearing in this matter, KU stated that it would provide information to LEV customers that would include the customer's load profile and tariff options, and the impact of selecting each option.[16] When asked whether KU would be agreeable to transferring customers who do not make a choice to the residential tariff that would result in the lesser percentage increase, KU stated that it would transfer those customers to their lowest rate.[17]

Given that KU will not have time to inform LEV customers of their options between the date of this Order and the date the Settlement rates go into effect, the Commission finds that KU should transfer each LEV customer to the residential rate that will result in the least percentage increase based on the customer's load profile. The

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[15] Application, Testimony of Robert M. Conroy, filed Nov. 26, 2014, at 27.

[16] April 21, 2015 Hearing video at 11:58:59.

[17] *Id.* at 12:01:00.

Commission also finds that KU should provide written information to each LEV customer of the tariff to which the customer has been transferred and provide LEV customers with their load profiles, tariff options, and the impact of selecting each option. This information should assist each former LEV customer in making an informed decision to either remain on the tariff that KU has determined to be appropriate or to transfer to a different tariff.

New Optional Residential Time-of-Day Tariffs

Included in KU's Application and the Settlement is the establishment of two new optional time-of-day residential tariffs, the RTOD–Energy previously mentioned, and a Residential Time-of-Day – Demand ("RTOD–Demand") tariff. At the hearing in this matter, KU was asked how these new tariffs would be advertised to customers. In a post-hearing response,[18] KU stated that, if the tariffs were approved, it would file with the Commission a copy of the information that would be provided to customers. The Commission finds that KU should file with the Commission its plans for advertising the RTOD–Energy and RTOD–Demand tariffs as well as a copy of the information that will be provided to customers.

ORDERING PARAGRAPHS

Based on the evidence of record and the findings contained herein, the Commission HEREBY ORDERS that:

1. The rates and charges proposed by KU are denied.

2. All provisions of the Settlement, which are set forth in Appendix A hereto (without exhibits), are approved.

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[18] The joint response of LG&E and KU to the Commission's Post-Hearing Data Request, Item 7.

3. The rates and charges for KU, as set forth in Appendix B hereto, are the fair, just and reasonable rates for KU, and these rates are approved for service rendered on and after July 1, 2015.

4. KU shall file monthly status reports with the Commission on the status of the work of the DSM Advisory Group concerning the industrial DSM issues discussed herein.

5. KU shall transfer each LEV customer to the residential rate that will result in the least percentage increase based on the customer's load profile. KU shall inform each LEV customer in writing of the tariff to which the customer has been transferred and provide LEV customers with their load profiles, tariff options, and the impact of selecting each option.

6. Within 30 days of the date of this Order, KU shall file with the Commission its plans for advertising the RTOD–Energy and RTOD–Demand tariffs to its residential customers and a copy of the information that will be provided to customers.

7. KU shall file within 20 days of the date of this Order, using the Commission's electronic Tariff Filing System, new tariff sheets setting forth the rates, charges, and revisions approved herein and reflecting their effective date and that they were approved pursuant to this Order.

8. Any document filed pursuant to ordering paragraphs 4 and 6 of this Order shall reference the number of this case and shall be retained in the utility's general correspondence file.

By the Commission

ENTERED

JUN 3 0 2015

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Stephanie Bell for TD

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2014-00371 DATED JUN 30 2015

SETTLEMENT AGREEMENT, STIPULATION, AND RECOMMENDATION

This Settlement Agreement, Stipulation, and Recommendation ("Settlement Agreement") is entered into this 20th day of April 2015 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); Association of Community Ministries, Inc. ("ACM"); Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"); Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); United States Department of Defense and All Other Executive Agencies ("DoD"); Kentucky Cable Telecommunications Association ("KCTA"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); The Kroger Co. ("Kroger"); Kentucky School Boards Association ("KSBA"); Lexington-Fayette Urban County Government ("LFUCG"); Metropolitan Housing Coalition ("MHC"); Sierra Club, Alice Howell, Carl Vogel and Wallace McMullen (collectively "Sierra Club"); and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart"). (Collectively, the Utilities, ACM, AG, CAC, DoD, KCTA, KIUC, Kroger, KSBA, LFUCG, MHC, Sierra Club and Wal-Mart are the "Parties.")

W I T N E S S E T H:

WHEREAS, on November 26, 2014, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, and the Commission has established Case No. 2014-00371 to review KU's base rate application, in which KU requested a revenue increase of $153.4 million;

WHEREAS, on November 26, 2014, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, and the Commission has established Case No. 2014-00372 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $30.3 million and a revenue increase of $14.3 million for its gas operations. (Case Nos. 2014-00371 and 2014-00372 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, the Commission has granted full intervention in Case No. 2014-00371 to the AG, CAC, KCTA, KIUC, Kroger, KSBA, LFUCG, Sierra Club, and Wal-Mart;

WHEREAS, the Commission has granted full intervention in Case No. 2014-00372 to ACM, the AG, DoD, KCTA, KIUC, Kroger, KSBA, MHC, Sierra Club, and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement, attended by representatives of the Parties and the Commission Staff took place on April 16 and 17, 2015, at the offices of the Commission, during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, a prehearing informal conference for the purpose of discussing the text of this Settlement Agreement, attended by representatives of the Parties and the Commission Staff took place on April 20, 2015, at the offices of the Commission;

WHEREAS, all of the Parties hereto unanimously desire to settle all the issues pending before the Commission in the Rate Proceedings;

WHEREAS, the adoption of this Settlement Agreement as a fair, just, and reasonable disposition of the issues in this case will eliminate the need for the Commission and the Parties to expend significant resources litigating these Rate Proceedings, and eliminate the possibility of, and any need for, rehearing or appeals of the Commission's final order herein;

WHEREAS, it is understood by all Parties hereto that this Settlement Agreement is subject to the approval of the Commission, insofar as it constitutes an agreement by all Parties to the Rate Proceedings for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Settlement Agreement;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that this Settlement Agreement, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information support this Settlement Agreement, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. REVENUE REQUIREMENTS

1.1. Utilities' Electric Revenue Requirements. The Parties stipulate that the following increases in annual revenues for LG&E electric operations and for KU operations, for purposes of determining the rates of LG&E and KU in the Rate Proceedings, are fair, just and reasonable for the Parties and for all electric customers of LG&E and KU:

LG&E Electric Operations: $0.

KU Operations: $125,000,000.

The Parties agree that any increase in annual revenues for LG&E electric operations and for KU operations should be effective for service rendered on and after July 1, 2015.

1.2. LG&E Gas Revenue Requirement. The Parties stipulate and agree that, effective for service rendered on and after July 1, 2015, an increase in annual revenues for LG&E gas operations of $7,000,000, for purposes of determining the rates of LG&E gas operations in the Rate Proceedings, is fair, just and reasonable for the Parties and for all gas customers of LG&E.

1.3. Environmental Cost Recovery Mechanism Return on Equity. The Parties agree that, effective as of the expense month that includes July 1, 2015, the return on equity that shall apply to the Utilities' recovery under their environmental cost recovery ("ECR") mechanism is 10.00% for all environmental compliance plans.

1.4. Gas Line Tracker Return on Equity. The Parties agree that, effective as of July 1, 2015, the return on equity that shall apply to LG&E's Gas Line Tracker ("GLT") is 10.00%. Because the GLT is billed on a prospective basis and its charge is determined annually, for the period July 1, 2015, through and including December 31, 2015, the reduced GLT return on equity will be reflected in the GLT balancing adjustment for calendar year 2015, which adjustment will be included in GLT billings in 2016.

1.5. Green River Regulatory Asset and Amortization. The Parties hereto agree that the Commission should approve regulatory-asset treatment for the complete recovery of Green River Units 3 and 4 costs incurred during the forecast test year through the retirement of those units. The asset should be amortized over three years, beginning with the effective date of the new base rates resulting from these proceedings.

1.6. Pension Expense Regulatory Asset and Amortization. The Parties hereto agree that the Commission should approve regulatory-asset treatment for the difference between (1) the Utilities' pension expense booked according to its accounting policy on record with the Securities and Exchange Commission and in accordance with Generally Accepted Accounting Principles ("GAAP") and (2) pension expense with actuarial gains and losses amortized over 15 years.

1.7. Cane Run Unit 7 Depreciation. The Utilities will use the depreciation rates set forth in Exhibit JJS-1 of the Direct Testimony of John J. Spanos in the record in Case No. 2014-00371 and Exhibit JJS-1 of the Direct Testimony of John J. Spanos in the record in Case No. 2014-00372 which includes the assignment of a 40-year service life to the Cane Run Unit 7 for determining the unit's depreciation expense for ratemaking purposes when the facility goes on-line in 2015.

ARTICLE II. REVENUE ALLOCATION AND RATE DESIGN

2.1. Revenue Allocation. The Parties hereto agree that the allocations of the increases in annual revenues for KU and LG&E electric operations, and that the allocation of the increase in annual revenue for LG&E gas operations, as set forth on the allocation schedules designated Settlement Exhibit 1 (KU), Settlement Exhibit 2 (LG&E electric), and Settlement Exhibit 3 (LG&E gas) attached hereto, are fair, just, and reasonable for the Parties and for all customers of LG&E and KU.

2.2. Tariff Sheets. The Parties hereto agree that, effective July 1, 2015, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Settlement Exhibit 4 (KU), Settlement Exhibit 5 (LG&E electric), and Settlement Exhibit 6 (LG&E gas) attached hereto, which rates the Parties unanimously stipulate are fair, just, and reasonable, and should be approved by the Commission.

2.3. Basic Service Charges. The Parties agree that the existing monthly basic service charge amounts shall be continued:

LG&E and KU Rates RS and VFD:	$10.75
LG&E Rates RGS and VFD:	$13.50

All other basic service charges shall be the amounts proposed by the Utilities in their Applications and supporting exhibits in these proceedings. These basic service charges are reflected in the proposed tariff sheets attached hereto in Settlement Exhibits 4, 5, and 6.

2.4. Optional Residential Time-of-Day ("RTOD") Rates. The Parties agree that the Utilities will add the months of April and October to the summer pricing periods set forth in their proposed RTOD-Demand and RTOD-Energy rate schedules. The Parties further agree that the following Basic Service Charge amount shall be implemented for RTOD-Demand and RTOD-Energy: $10.75. These changes are reflected in the proposed tariff sheets attached hereto as Settlement Exhibits 4 and 5.

2.5. Curtailable Service Riders. The Parties agree that LG&E and KU will combine their current Curtailable Service Riders, CSR10 and CSR30, into a single rider CSR. The new rider CSR will be substantively identical to the Utilities' current CSR10 tariff sheets, including the buy-through provision, except:

(A) CSR credits will be $6.50 per kVA-month (primary) and $6.40 per kVA-month (transmission).

(B) The Utilities' notice to CSR customers for requesting or canceling a curtailment will be extended from 10 minutes to 60 minutes.

(C) Each Utility may request up to 100 hours of physical curtailment from CSR customers. A Utility may request physical curtailment only when (1) all of the Utilities' available generating units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed.

(D) Each CSR customer will certify annually its ability to interrupt the load specified in its CSR contract.

These proposed tariff changes are shown in Settlement Exhibits 4 and 5 attached hereto.

2.6. Off-System Sales ("OSS") Tracker. The Parties agree that the Utilities will remove from base-rate calculations all OSS margins and will implement an OSS tracker for each electric Utility. (The revenue-requirement increases stated in Article 1.1 above reflect the necessary removal of OSS margins.) The proposed OSS trackers will share OSS margins on a 75%-25% basis, with 75% of OSS margins being credited to customers through the Utilities' Fuel Adjustment Clauses ("FAC") and resulting FAC credits or charges. Calculations of the OSS margins credited to customers will be reviewed during the Commission's six-month and two-year reviews of the Utilities' FAC calculations pursuant to 807 KAR 5:056.

2.7. Pole Attachment Rates (Rate CTAC).

(A) The Parties agree that the Utilities will change their Rate CTAC charges for pole attachments to $7.25 per attachment per year for both utilities, which proposed tariff changes are shown in Settlement Exhibits 4 and 5 attached hereto.

(B) The Parties commit that they will not challenge, through rate complaints or otherwise, the negotiated $7.25 pole-attachment rate until the Utilities file their next base-rate applications. The Utilities commit to propose new Rate CTAC charges in their next base-rate proceedings to help ensure there is an adequate record in those proceedings for the Commission to adjudicate any disputes between the parties concerning the appropriate methodology for the Utilities to use to calculate Rate CTAC charges in the future.

(C) The Utilities further agree to meet with KCTA at the offices of the Commission to discuss methodological differences between the Utilities' and KCTA's approaches to calculating pole-attachment charges within 90 days of the date of the Commission's Order approving this Settlement Agreement. Commission Staff will attend the meetings. The Utilities and KCTA commit to work in good faith to resolve their methodological differences to arrive at an agreed methodology for the Utilities to use when proposing new Rate CTAC charges in their next base-rate applications, though the Parties recognize that even good-faith negotiations might not lead to such a result.

ARTICLE III. <u>TREATMENT OF CERTAIN SPECIFIC ISSUES</u>

3.1. School-Related Demand-Side Management Program Proposals.

(A) In Case No. 2013-00067, the Commission approved a two-year demand-side management and energy-efficiency ("DSM-EE") program, the School Energy Management Program ("SEMP"), to help fund energy management programs for schools affected by KRS 160.325. The annual levels of funding proposed and approved in that proceeding were $500,000 for KU and $225,000 for LG&E. To date, a total of $975,000 has been requested for, and provided through, SEMP ($815,000 for KU and $160,000 for LG&E). The Parties agree the Commission should approve an extension of the current SEMP through June 30, 2016, to be funded with the remaining $475,000 that was not requested during the first two SEMP program years, with $410,000 of the funding for KU and $65,000 for LG&E.

(B) The Utilities commit to file with the Commission an application proposing a two-year extension of SEMP (for July 1, 2016, through June 30, 2018). The total annual level of funding to be proposed is $725,000; prior to filing the application, the Utilities will consult with KSBA to determine an appropriate allocation of the total annual funds between KU and

LG&E. In the same application, the Utilities will propose a DSM-EE program to provide $1 million for grants to schools to fund energy-efficiency projects. With input from KSBA and other stakeholders, the Utilities commit to file the above-described application with the Commission no later than December 31, 2015.

3.2. Commitment to Evaluate Schools' Rates upon Request. The Utilities commit that, upon a KSBA member's request, the serving Utility will evaluate each of the member's schools to determine if the school is eligible to take service under a more favorable tariffed rate.

3.3. Industrial DSM-EE Matters.

(A) The Utilities commit to instruct the vendor for their industrial-DSM-EE-potential study to commence work on the study immediately, and will not seek DSM cost recovery of the study's cost. The Utilities further commit that the study will be completed by May 1, 2016, and filed with the Commission thirty days later in accordance with the Commission's final order in Case No. 2014-00003. Thereafter, Utilities commit that they will commence the DSM Advisory Group meeting process to discuss the results of the industrial study.

(B) The Utilities commit to address opt-out criteria for industrial customers, as well as the definition of "industrial," including whether the NAICS code should be used to define "industrial," in their first DSM-EE application following completion of their industrial-DSM-EE-potential study.

3.4. Low-Income Customer Support. The Utilities commit to contribute a total of $1,150,000 of shareholder funds per year, which commitment will remain in effect until the effective date of new base rates for the Utilities following their next general base-rate cases.

(A) The total annual shareholder contribution from KU shall be as follows: $100,000 for Wintercare and $370,000 for HEA. CAC administers both programs.

(B) The total annual shareholder contribution from LG&E shall be as follows: $500,000 to ACM for utility assistance and $180,000 for HEA.

(C) KU agrees that up to 10% of its total contributions to CAC may be used for reasonable administrative expenses.

(D) LG&E agrees that up to 10% of its total contributions to ACM may be used for reasonable administrative expenses.

(E) None of the Utilities' shareholder contributions will be conditioned upon receiving matching funds from other sources.

3.5. Home Energy Assistance Program Authority. The Parties hereto agree that the authority for the Utilities' Home Energy Assistance ("HEA") Program most recently approved by the Commission in Case No. 2010-00204 should be made permanent and recommend the Commission make such authority permanent in the Commission's Order approving this Settlement Agreement. This change in the HEA's Program authority is reflected in the proposed tariff sheets attached hereto as Settlement Exhibits 4, 5, and 6.

3.6. Home Energy Assistance Charges. The Parties agree that the Utilities will continue their monthly residential meter charge (for gas and electric meters) for the Home Energy Assistance ("HEA") program at $0.25 per meter, which shall remain effective until the effective date of new base rates for the Utilities following their next general base-rate cases. These changes are reflected in the proposed tariff sheets attached hereto as Settlement Exhibits 4, 5, and 6.

3.7. CAC-Related HEA Issues. KU commits to work with CAC on the HEA program terms to better serve low-income customers. This shall include regular meetings between KU and CAC to review the HEA fund balance, number of available slots, number of persons enrolled, and the wait list, in order to maximize the number of low-income customers served and to limit the amount of unspent surplus funds. KU commits to have its first meeting with CAC to begin this process of improved coordination within 60 days of the date of the Commission's Order approving this Settlement Agreement.

3.8. Commitments to Meet and Work with ACM to Address Certain Issues.

(A) LG&E commits to meet and work in good faith with ACM to discuss Winter Hardship Reconnection procedures, including identifying ways ACM could obtain authority to issue certificates of need for Winter Hardship Reconnections.

(B) LG&E also commits to meet and work in good faith with ACM to explore potential non-information-technology-based means, if any, of permitting third-party assistance payments to be used to pay only amounts owing on the non-deposit portions of assistance recipients' LG&E bills.

3.9. Extending Period for Paying Residential Deposits. The Parties agree that the Utilities will extend the period for a residential customer to pay in full any required deposit from the current four months to six months. These changes are reflected in the proposed tariff sheets attached hereto as Settlement Exhibits 4, 5, and 6.

3.10. The Parties agree that, except as modified in this Settlement Agreement and the exhibits attached hereto, the rates, terms, and conditions contained in the Utilities' filings in these Rate Proceedings shall be approved as filed.

ARTICLE IV. MISCELLANEOUS PROVISIONS

4.1. Except as specifically stated otherwise in this Settlement Agreement, entering into this Settlement Agreement shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

4.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Settlement Agreement.

4.3. Following the execution of this Settlement Agreement, the Parties shall cause the Settlement Agreement to be filed with the Commission on or about April 20, 2015, together with a request to the Commission for consideration and approval of this Settlement Agreement for rates to become effective for service rendered on and after July 1, 2015.

4.4. Each of the Parties waives all cross-examination of the other Parties' witnesses unless the Commission disapproves this Settlement Agreement, and each party further stipulates and recommends that the Notice of Intent, Notice, Application, testimony, pleadings, and responses to data requests filed in the Rate Proceedings be admitted into the record. The Parties stipulate that after the date of this Settlement Agreement they will not otherwise contest the Utilities' proposals, as modified by this Settlement Agreement, in the hearing of the Rate Proceedings regarding the subject matter of the Settlement Agreement, and that they will refrain from cross-examination of the Utilities' witnesses during the hearing, except insofar as such cross-examination is in support of the Settlement Agreement.

4.5. This Settlement Agreement is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Settlement Agreement be accepted and approved.

4.6. If the Commission issues an order adopting this Settlement Agreement in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order.

4.7. If the Commission does not accept and approve this Settlement Agreement in its entirety, then: (a) this Settlement Agreement shall be void and withdrawn by the Parties from further consideration by the Commission and none of the Parties shall be bound by any of the provisions herein, provided that none of the Parties is precluded from advocating any position contained in this Settlement Agreement; (b) any of the Parties may request a hearing on any or all of the issues in the Proceedings; and (c) neither the terms of this Settlement Agreement nor any matters raised during the settlement negotiations shall be binding on any of the Parties or be construed against any of the Parties.

4.8. If the Settlement Agreement is voided or vacated for any reason after the Commission has approved the Settlement Agreement, none of the Parties will be bound by the Settlement Agreement.

4.9. The Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

4.10. The Settlement Agreement shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

4.11. The Settlement Agreement constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Settlement Agreement.

4.12. The Parties hereto agree that, for the purpose of the Settlement Agreement only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

4.13. The Parties hereto agree that neither the Settlement Agreement nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Settlement Agreement. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

4.14. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Settlement Agreement and based upon the foregoing are authorized to execute this Settlement Agreement on behalf of their respective Parties.

4.15. The Parties hereto agree that this Settlement Agreement is a product of negotiation among all Parties hereto, and no provision of this Settlement Agreement shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Settlement Agreement, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Settlement Agreement shall be implemented as written.

4.16. The Parties hereto agree that this Settlement Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By:
Kendrick R. Riggs

-and-

By:
Allyson K. Sturgeon

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By: Gregory T. Dutton

Gregory T. Dutton
Lawrence W. Cook
Angela M. Goad
Stefanie J. Kingsley

The Kroger Co.

HAVE SEEN AND AGREED:

By: ______________________
David C. Brown

Kentucky School Boards Association

HAVE SEEN AND AGREED:

By: Matthew Malone

Matthew R. Malone,
William H. May, II

Community Action Council for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE SEEN AND AGREED:

By: ______________________
Iris G. Skidmore

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: ______________________

David J. Barberie
Andrea C. Brown
Janet M. Graham

Subject to ratification
by Urban County Council

Association of Community Ministries, Inc.

HAVE SEEN AND AGREED:

By: Lisa Kilkelly

Lisa Kilkelly

Eileen Ordover

Kentucky Cable Telecommunications Association

HAVE SEEN AND AGREED:

By ______________________________
Lawrence J. Zielke
Janice M. Theriot
Gardner F. Gillespie
Amanda M. Lanham
Stephen Gilson

Sierra Club, Alice Howell, Carl Vogel and
Wallace McMullen

HAVE SEEN AND AGREED:

By ______________________

Joe F. Childers
Laurie Williams
Casey Roberts
Joshua Smith

Wal-Mart Stores East, LP and Sam's East, Inc.

HAVE SEEN AND AGREED:

By ______________________
Don C.A. Parker
Derrick Price Williamson

Metropolitan Housing Coalition

HAVE SEEN AND AGREED:

By ______________________________
Tom FitzGerald

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2014-00371 DATED JUN 30 2015

The following rates and charges are prescribed for the customers in the area served by Kentucky Utilities Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

SCHEDULE RS
RESIDENTIAL SERVICE

Basic Service Charge per Month	$10.75
Energy Charge per kWh	$ .08508

SCHEDULE RTOD–ENERGY
RESIDENTIAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Month	$10.75
Energy Charge per kWh	
Off Peak Hours	$ .05378
On Peak Hours	$ .27284

SCHEDULE RTOD–DEMAND
RESIDENTIAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Month	$10.75
Energy Charge per kWh	$ 0.04008
Demand Charge per kW	
Off Peak Hours	$ 3.70
On Peak Hours	$13.05

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT

Basic Service Charge per Month	$10.75
Energy Charge per kWh	$ .08508

SCHEDULE GS
GENERAL SERVICE RATE

Basic Service Charge per Month – Single Phase	$25.00
Basic Service Charge per Month – Three Phase	$40.00
Energy Charge per kWh	$ .09874

SCHEDULE AES
ALL ELECTRIC SCHOOL

Basic Service Charge per Month – Single Phase	$25.00
Basic Service Charge per Month – Three Phase	$40.00
Energy Charge per kWh	$ .08094

SCHEDULE PS
POWER SERVICE

Secondary Service:	
Basic Service Charge per Month	$90.00
Demand Charge per kW:	
Summer Rate	$17.55
Winter Rate	$15.45
Energy Charge per kWh	$ .03572
Primary Service:	
Basic Service Charge per Month	$200.00
Demand Charge per kW:	
Summer Rate	$ 18.01
Winter Rate	$ 15.91
Energy Charge per kWh	$ .03446

SCHEDULE TODS
TIME-OF-DAY SECONDARY SERVICE

Basic Service Charge per Month	$200.00
Maximum Load Charge per kW:	
Peak Demand Period	$ 5.75
Intermediate Demand Period	$ 4.15
Base Demand Period	$ 4.82
Energy Charge per kWh	$ .03527

SCHEDULE TODP
TIME-OF-DAY PRIMARY SERVICE

Basic Service Charge per Month	$ 300.00
Maximum Load Charge per kVA:	
Peak Demand Period	$ 5.59
Intermediate Demand Period	$ 4.09
Base Demand Period	$ 3.04
Energy Charge per kWh	$ .03432

SCHEDULE RTS
RETAIL TRANSMISSION SERVICE

Basic Service Charge per Month	$1,000.00
Maximum Load Charge per kVA:	
Peak Demand Period	$ 4.47
Intermediate Demand Period	$ 4.37
Base Demand Period	$ 2.84
Energy Charge per kWh	$ .03357

SCHEDULE FLS
FLUCTUATING LOAD SERVICE

Primary:	
Basic Service Charge per Month	$1,000.00
Maximum Load Charge per kVA:	
Peak Demand Period	$ 2.86
Intermediate Demand Period	$ 1.97
Base Demand Period	$ 2.02
Energy Charge per kWh	$ .03643
Transmission:	
Basic Service Charge per Month	$1,000.00
Maximum Load Charge per kVA:	
Peak Demand Period	$ 2.86
Intermediate Demand Period	$ 1.97
Base Demand Period	$ 1.27
Energy Charge per kWh	$ .03344

SCHEDULE LS
LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

Overhead:

	Fixture Only	Ornamental
High Pressure Sodium:		
5,800 Lumens – Cobra Head	$ 9.38	$ 12.56
9,500 Lumens – Cobra Head	$ 9.90	$ 13.32
22,000 Lumens – Cobra Head	$ 15.43	$ 18.85
50,000 Lumens – Cobra Head	$ 24.73	$ 26.49
9,500 Lumens – Directional	$ 9.75	
22,000 Lumens – Directional	$14.77	
50,000 Lumens – Directional	$21.07	
9,500 Lumens – Open Bottom	$ 8.49	
Metal Halide		
12,000 Lumens – Directional	$ 15.43	
32,000 Lumens – Directional	$ 21.87	
107,800 Lumens – Directional	$ 45.86	

Underground:

	Fixture Only	Decorative Smooth	Historic Fluted
High Pressure Sodium:			
5,800 Lumens – Colonial		$ 11.66	
9,500 Lumens – Colonial		$ 12.08	
5,800 Lumens – Acorn		$ 16.09	$ 23.15
9,500 Lumens – Acorn		$ 16.63	$ 23.82
5,800 Lumens – Victorian			$ 33.39
9,500 Lumens – Victorian			$ 33.81
5,800 Lumens – Contemporary	$ 16.64	$ 18.18	
9,500 Lumens – Contemporary	$ 16.62	$ 22.71	
22,000 Lumens – Contemporary	$ 19.19	$ 29.08	
50,000 Lumens – Contemporary	$ 23.27	$ 35.86	
4,000 Lumens – Dark Sky Lantern		$ 24.35	
9,500 Lumens – Dark Sky Lantern		$ 25.45	

Metal Halide

12,000 Lumens – Contemporary	$ 16.75	$ 30.72
32,000 Lumens – Contemporary	$ 23.75	$ 37.71
107,800 Lumens – Contemporary	$ 49.48	$ 63.44

SCHEDULE RLS
RESTRICTED LIGHTING SERVICE

Overhead:

	Fixture Only	Fixture and Pole
High Pressure Sodium:		
4,000 Lumens – Cobra Head	$ 8.16	$ 11.36
50,000 Lumens – Cobra Head	$12.68	
5,800 Lumens – Open Bottom	$ 8.06	
Metal Halide		
12,000 Lumens – Directional		$ 20.19
32,000 Lumens – Directional		$ 26.63
107,800 Lumens – Directional		$ 50.61
Mercury Vapor:		
7,000 Lumens – Cobra Head	$ 10.35	$ 12.85
10,000 Lumens – Cobra Head	$ 12.26	$ 14.47
20,000 Lumens – Cobra Head	$ 13.87	$ 16.33
7,000 Lumens – Open Bottom	$ 11.45	
Incandescent:		
1,000 Lumens – Tear Drop	$ 3.67	
2,500 Lumens – Tear Drop	$ 4.92	
4,000 Lumens – Tear Drop	$ 7.34	$ 8.38
6,000 Lumens – Tear Drop	$ 9.81	

Underground:

	Decorative Smooth	Historic Fluted
Metal Halide		
12,000 Lumens – Directional	$ 29.40	
32,000 Lumens – Directional	$ 35.84	
107,800 Lumens – Directional	$ 59.82	

High Pressure Sodium:		
4,000 Lumens – Acorn	$ 14.74	$ 21.94
4,000 Lumens – Colonial	$ 10.42	
5,800 Lumens – Coach	$ 33.39	
9,500 Lumens – Coach	$ 33.81	
16,000 Lumens – Granville	$ 59.91	

SCHEDULE LE
LIGHTING ENERGY SERVICE

Energy Charge per kWh	$ .06912

SCHEDULE TE
TRAFFIC ENERGY SERVICE

Basic Service Charge per Month	$4.00
Energy Charge per kWh	$ .08324

SCHEDULE CTAC
CABLE TELEVISION ATTACHMENT CHARGES

Per Year for Each Attachment to Pole	$ 7.25

RATE CSR
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	$ 6.40	$ 6.50
Non-compliance Charge Per kVA	$ 16.00	$ 16.00

RC
REDUNDANT CAPACITY

Charge per kW/kVA per month	
Secondary Distribution	$ 1.12
Primary Distribution	$ 1.11

SS
SUPPLEMENTAL OR STANDBY SERVICE

Charge per kW/kVA per month		
Secondary	$	12.84
Primary	$	11.63
Transmission	$	10.58

CUSTOMER DEPOSITS

Residential Customers	$ 160.00
General Service Customers	$ 240.00

HEA
HOME ENERGY ASSISTANCE PROGRAM

Per Month per Meter	$	.25

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462 South Fourth Avenue
Louisville, KENTUCKY 40202

DEK
Exhibit 11

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE TO ACQUIRE CERTAIN GENERATION RESOURCES AND RELATED PROPERTY; FOR APPROVAL OF CERTAIN PURCHASE POWER AGREEMENTS; FOR APPROVAL OF CERTAIN ACCOUNTING TREATMENT; AND FOR APPROVAL OF DEVIATION FROM REQUIREMENTS OF KRS 278.2207 AND 278.2213(6)	)))))))))	CASE NO. 2003-00252

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE TO ACQUIRE CERTAIN GENERATION RESOURCES AND RELATED PROPERTY; FOR APPROVAL OF CERTAIN PURCHASE POWER AGREEMENTS; FOR APPROVAL OF CERTAIN ACCOUNTING TREATMENT; AND FOR APPROVAL OF DEVIATION FROM REQUIREMENTS OF KRS 278.2207 AND 278.2213(6)	)	CASE NO. 2003-00252

INTERIM ORDER

On July 21, 2003, The Union Light, Heat and Power Company ("ULH&P") applied for a certificate of public convenience to acquire 1,105 megawatts ("MW") of generating capacity from its parent company, The Cincinnati Gas and Electric Company ("CG&E"), and approval of: (1) certain purchase power agreements with CG&E; (2) certain accounting and rate-making treatments related to the proposed acquisition, and (3) a request to deviate from certain statutory requirements related to affiliate transactions.

The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"), is the only intervenor in this proceeding. ULH&P responded to two rounds of interrogatories by the AG and Commission Staff. The AG filed testimony of his expert witnesses on September 26, 2003 and responded to one round of interrogatories by ULH&P and Commission Staff. Informal conferences were held at the Commission's offices on October 15, 21, and 24, 2003. On October 29, ULH&P filed an amendment to its application that changed several of the accounting and rate-making treatments proposed in its original application.

A public hearing was held on October 29 and 30, 2003. ULH&P and the AG filed responses to hearing data requests on November 7, 2003. Post-hearing briefs were received on November 19, 2003, and the case now stands submitted for decision.

SUMMARY OF DECISION

Having considered and thoroughly analyzed the evidence, we find that the proposed transfer is in the best interests of ULH&P and its ratepayers and should be approved, with some clarification and modification, subject to the Commission's review and approval of all transaction documents in their final form.[1] While this Commission cannot, in this transfer proceeding, render a decision on certain requests that will be binding on a future Commission in a ULH&P general rate case, we find that the related accounting and rate-making treatments proposed by ULH&P appear, at this time, to be reasonable.[2] We also find that ULH&P's requests to deviate from the Commission's statutory requirements regarding affiliate transactions and from our requirement that it analyze bids for purchased power in conjunction with its next Integrated Resource Plan ("IRP") filing are reasonable and should be granted.

---

[1] Based on the evidence in this record, it appears that the proposed transaction is in the best interests of ULH&P's customers. The Commission urges that the federal agencies that must approve this transfer, the Federal Energy Regulatory Commission ("FERC") and the Securities and Exchange Commission ("SEC"), will give consideration to our findings in this proceeding when rendering their decisions.

[2] We recognize, however, that a change in law or compelling evidence to the contrary may require Commission consideration in ULH&P's next general rate case.

BACKGROUND

In Case No. 2001-00058, the Commission approved a wholesale power contract under which ULH&P purchases power from CG&E as a full requirements customer.[3] That contract, scheduled to run through 2006, provides for ULH&P to purchase power from CG&E at a fixed price containing a market price component.[4] In its approval Order in that proceeding, the Commission expressed its interest in ULH&P acquiring generation in order to insulate itself from the impacts of market prices for wholesale power on a going-forward basis. The Commission also required ULH&P to file a stand-alone IRP no later than June 30, 2004 as a means of evaluating its future resource supply needs.[5] In its December 21, 2001 Order in Administrative Case No. 387, the Commission reiterated its concern regarding ULH&P's potential exposure to market prices in the future and also expressed concern that ULH&P had no announced plans for meeting its customers' power needs after the termination date of the current wholesale power contract.[6]

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[3] Case No. 2001-00058, The Application of The Union Light, Heat and Power Company for Certain Findings Under 15 U.S.C. § 79Z, final Order dated May 11, 2001, at 17.

[4] ULH&P and CG&E are both part of the Cinergy Corp. ("Cinergy") system. CG&E's rates to ULH&P include a market component due to its generating facilities being deregulated under Ohio's electric industry restructuring and FERC's mandate that wholesale rates be market-based rather than cost-based.

[5] In Case No. 2001-00058 ULH&P also agreed to freeze retail rate components that recover wholesale generation and transmission costs through December 31, 2006.

[6] Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System, final Order dated December 21, 2001, at 39-40.

ULH&P states that this application is its response to the concerns expressed by the Commission in those prior proceedings. Its proposal includes the acquisition of CG&E's 69 percent share of East Bend No. 2,[7] a 648 MW base load, coal-fired generating unit located in Rabbit Hash, Kentucky; Miami Fort No. 6, a 168 MW intermediate load, coal-fired generating unit located in North Bend, Ohio; and the 490 MW Woodsdale Generating Station, consisting of six peak load, gas or propane-fired generating units located in Trenton, Ohio.[8] Along with its application, ULH&P filed an independent due diligence assessment of the subject facilities, which was performed by Burns & McDonnell Engineering Company ("B&McD").[9]

<u>ULH&P'S PROPOSAL</u>

Under the amended application, the specific generating units will be transferred from CG&E to ULH&P at what is commonly referred to as net book value which, from a utility regulatory perspective, is defined as original cost less accumulated depreciation, with the original cost and the accumulated depreciation being carried forward to the accounting records of the acquiring entity. Because FERC and the SEC must rule upon the proposed transaction before it can be consummated, ULH&P and CG&E anticipate that the proposed transaction will not be completed until mid 2004. Although ULH&P

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[7] The Dayton Power and Light Company owns the remaining 31 percent.

[8] Under Ohio's electric industry restructuring plan, all the units proposed to be transferred were deregulated effective January 1, 2001. See Transcript of Evidence ("T.E."), Vol. I, October 29, 2003, at 221-222.

[9] Information on the facilities subject to the proposed transfer and B&McD's due diligence study of the facilities are included in Appendix A to this Order.

will acquire ownership of these units, Cinergy's generation fleet, including these units, will continue to be operated and dispatched on a system-wide, centralized basis.

ULH&P requests approval of a back-up power sale agreement ("PSA") under which CG&E will provide power to ULH&P when ULH&P's generation is not available to meet its system demand. It also requests approval of a purchase, sale and operation agreement ("PSOA") which will govern the terms of energy transfers between ULH&P and CG&E that occur for economic rather than reliability reasons. In addition to these agreements, ULH&P requests approval of assignment from CG&E of existing contracts governing the natural gas supply, propane fuel supply and propane storage at the Woodsdale site. The parties to these contracts are Cinergy Marketing and Trading, LP ("CMT"), Ohio River Valley Propane LLC ("ORVP"), affiliates within Cinergy, and TE Products Pipeline Company ("TEPPCO"), a non-affiliate company.[10]

In conjunction with the proposed acquisition of these generating units, ULH&P proposes specific accounting and rate-making treatments for certain revenues and costs, treatments it claims are necessary to make the transaction acceptable to CG&E and to maintain benefits that CG&E and Cinergy presently realize under the units' deregulated status. These accounting and rate-making treatments, as set forth in the amendment to ULH&P's application, are:

(1) Fixing, for rate-making purposes, the value of the facilities being transferred at original cost less accumulated depreciation;

(2) Deferring until ULH&P's next rate case a maximum of $2.45 million in transaction costs incurred by ULH&P and CG&E related to the transfer of the specific units, with such costs amortized over 5 years without carrying charges;

[10] ULH&P also requests approval of assignment from CG&E of the existing coal supply contracts for East Bend and Miami Fort No. 6.

(3) Including in ULH&P's future base rates the capacity charges set out in the back-up PSA;

(4) Including in ULH&P's future Fuel Adjustment Clause ("FAC") the costs of energy charges assessed under the back-up PSA and the costs of energy transfers from CG&E assessed under the PSOA;

(5) Authorizing ULH&P to record accumulated deferred investment tax credits ("ADITC") and accumulated deferred income taxes ("deferred income taxes") transferred from CG&E "below the line" and to exclude the ADITC and deferred income taxes from retail rate-making in its next general rate case; and

(6) In its next general rate case, permitting ratepayers to retain the first $1 million in profits from off-system sales and 50 percent of profits above $1 million, with ULH&P retaining the other 50 percent of any off-system sales profits in excess of $1 million.[11]

ULH&P also requests approval to modify the IRP that it is required to file by June 30, 2004 to eliminate the requirement that the IRP include an evaluation of purchased power alternatives. In its amendment to its application, ULH&P commits to submit to the Commission for review and approval all final transaction documents prior to closing.

ULH&P requests approval to deviate from the affiliate transaction requirements of KRS 278.2207 through 278.2213 in order to effect the acquisition of the specific units and establish the proposed agreements with CG&E, CMT and OVRP. ULH&P also proposes to continue the rate freeze ordered in Case No. 2001-00058. It will honor its commitment to continue its rate freeze through 2006, and its commitment will apply to base rates, FAC charges, and environmental surcharges.

[11] Off-system sales profits will be calculated by subtracting the incremental costs of such sales, as listed in paragraph 1.10 of the proposed PSOA, from the revenues generated through off-system sales.

THE AG'S POSITION

The AG takes issue with certain aspects of ULH&P's proposal. Those are as follows:

(1) The fact that ULH&P did not issue a Request for Proposals ("RFP") seeking offers of generating assets, purchase power agreements, or combinations thereof, to meet its future needs;

(2) The request to fix the value of the facilities being transferred for future rate-making purposes;

(3) The proposed deferral and recovery of transaction costs;

(4) The proposal to record ADITC and deferred income taxes "below the line" and exclude them for retail rate-making in ULH&P's next general rate case;

(5) ULH&P's proposed sharing of off-system sales profits; and

(6) The FAC treatment of energy transfers made under the proposed PSOA.

The aspects of the proposal which the AG contests, or with which the AG disagrees, are discussed individually in the following paragraphs.

Need for an RFP

The AG commends ULH&P and CG&E for working to provide a means by which ULH&P's rates can remain stable and ratepayers can be sheltered from the impact of market price fluctuations. However, he argues that without an RFP, ULH&P and the Commission cannot be assured that the offer from CG&E represents the least cost alternative for meeting ULH&P's future power supply needs. Among other things, the AG cites KRS 278.2207(2), arguing that ULH&P has not demonstrated that the pricing for the transfer and related agreements is at CG&E's or its other affiliates' fully distributed costs, but in no event greater than market. The AG also contends that ULH&P has not demonstrated that the requested pricing is reasonable.

The AG cites the recent experiences of East Kentucky Power Cooperative, Inc. ("East Kentucky") and Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") in support of his argument. He refers to East Kentucky's recent application for approval to construct two combustion turbines ("CTs") based on the low bid it received in response to an RFP for peaking power. He also cites LG&E/KU's use of an RFP to demonstrate that purchasing CTs from a non-regulated affiliate was the least cost alternative for meeting their need for additional peaking capacity. The AG argues that an RFP is especially warranted when the transaction involves affiliates. He states that the acquisition price of the Woodsdale units exceeds the prices of the CTs acquired recently by East Kentucky and LG&E/KU; therefore, he concludes the price ULH&P is paying exceeds market.

ULH&P states that it did not issue an RFP for several reasons. First, it cites the recent and ongoing financial problems that have resulted in significant downgrades in the credit ratings of numerous electric industry participants, both regulated and non-regulated. Such downgrades have greatly increased credit risk concerns within the industry. Second, ULH&P indicates that the electricity market today focuses primarily on short-term contractual arrangements and that such a focus likely means that it would need to be back in the market for power within three to five years if it entered into a purchase power agreement at this time. Third, while acknowledging that a market exists for peaking generation such as CTs, ULH&P notes that there is not a comparable market for base load capacity.[12] It also notes that there are no recent transactions similar to the proposed transaction, wherein a distribution utility attempted to acquire generation to supply its entire system or where facilities originally regulated, which were later deregulated, would go back under regulation.[13] Although an active market for base load capacity similar to the market for peaking capacity does not exist, ULH&P engaged ICF Consulting ("ICF")[14] to prepare an analysis of the market value of the generating capacity that is the subject of the proposed transaction.[15] ICF's analysis includes a base case scenario that shows the market value of the assets being transferred to be more than twice their book value. It also includes 11 sensitivities to reflect changes in assumptions such as demand levels, fuel prices, environmental regulations, and/or combinations of changes in various assumptions. Under each of the 11 sensitivities, the market value of the generating assets exceeds their book value.[16]

ULH&P points to the advantages of acquiring existing facilities with documented service histories and avoiding the risks inherent with siting and permitting new facilities. It also cites the advantages of acquiring generation facilities that are already integrated into the Cinergy transmission system and that will continue to be dispatched on a centralized basis along with the rest of the generation in the Cinergy system. Finally,

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[12] T.E., Vol. I, October 29, 2003, at 181-182.

[13] Id. at 182.

[14] ICF Consulting is an international consulting firm whose clients include the United States Environmental Protection Agency, Royal Bank of Canada, JP Morgan Securities, Inc., Moody's Investors Service, other government entities and investment firms, along with utilities and regulatory commissions.

[15] Rose Direct Testimony, Attachments JLR-26 and JLR-26a.

[16] Id.

ULH&P states that the offer from CG&E may not remain available after it goes through the 6- to 9-month RFP process described by the AG. This is due to the potential for other parties to make purchase offers for some or all of the capacity or for wholesale power prices to increase to the point where CG&E decides that selling the output of the units in the market is in its best business interests.

The AG's arguments regarding the affiliate nature of the transaction and whether ULH&P has met its burden under KRS 278.2207(2) are not compelling. It is clear that the cost of the generating units to be transferred reflects CG&E's fully distributed costs. The record evidence is also very clear that the cost of the units is no greater than market. While the AG claims that the absence of an RFP leaves the Commission no alternative but to speculate as to the market price of alternatives to the proposed transaction, he ignores other measures of "market" prices. ICF's market analysis of the facilities being transferred, which the AG neither refuted or contested, is one such measure.

The AG's reliance on the recent CT proposals by East Kentucky and LG&E/KU does not consider any differences between those units and the Woodsdale units that could affect their relative costs. Some of those differences include: (1) Woodsdale's cost includes the cost of the land at that location; (2) Woodsdale's cost includes the cost of the pipelines that will be acquired with the generating units; and (3) the design of the Woodsdale units allows them to operate on either natural gas or propane. Furthermore, the AG has not demonstrated, in arguing as to whether prices are "no greater than market," that the Commission is required to review the components of the proposed transaction separately. Therefore, while the per cost kilowatt ("kw") of capacity of the

Woodsdale units may exceed the cost of the East Kentucky and LG&E/KU CTs, the cost of the total package of generating facilities that ULH&P proposes to acquire is substantially below market value as reflected in ICF's market analysis.

The Commission recognizes the AG's concerns and acknowledges that utilities under its jurisdiction typically conduct an RFP as part of the process of selecting new supply resources. We believe that such a process has benefited Kentucky's utilities and its ratepayers and that it will continue to benefit them in the future. However, in this instance, given the uniqueness of the proposed transaction, we are not persuaded that undertaking an RFP process would benefit ULH&P or its ratepayers. Attempting to acquire an entire generation fleet through a single transaction is unprecedented in the electric utility industry. Given the level of uncertainty that exists in the electric industry today, there are several arguments in favor of relying on factors other than the market or the financial strength of the firms that make up that market. Furthermore, based on ICF's market analysis, the facilities included in the transaction are being offered at an attractive price. As noted in the record, the average depreciated cost of the generating units included in the offer to ULH&P is $332 per kw of capacity.[17] This compares to typical installed costs in today's electric industry of roughly $350 to $400 per kw for CTs and $1,000, or more, per kw for base load coal-fired capacity.[18]

As evident both in Case No. 2001-00058 and Administrative Case No. 387, the Commission is on record as favoring ULH&P owning generation to serve the needs of

[17] Id. at 183.

[18] Response to the Commission Staff's Hearing Data Request of October 29, 2003, Item 1.

its customers and to reduce its reliance on wholesale power purchases. Under the unique circumstances of this case, and given that the evidence demonstrates that a market for baseload capacity comparable to the market for peaking capacity does not exist, we find ULH&P's analysis of supply-side resource options to be reasonable. While CG&E's generation offer may not reflect the mix of facilities that ULH&P would seek under ideal circumstances, this "imperfection" does not persuade the Commission that the proposed transaction should be put on hold while ULH&P undertakes the process of issuing an RFP and evaluating the responses it receives thereto.[19]

Considering all relevant factors, we find that requiring ULH&P to conduct an RFP process is not necessary to determine the reasonableness of the proposed transfer of generating facilities. Based on a thorough review and analysis of the evidence of record, the Commission finds that it has other means of determining whether the proposed transfer is reasonable. We also find that ULH&P's acquisition of the facilities being offered by CG&E is in its best interests and the interests of its ratepayers. Having determined that an RFP is not necessary in this instance, we must still make a determination of whether the various conditions proposed by ULH&P are reasonable before ruling on whether to approve the transfer as proposed.

Transaction Costs

In its amended application, ULH&P requests that it be permitted to defer no more than $2.45 million of transaction costs incurred in conjunction with the proposed acquisition. ULH&P also proposes that the deferred costs be amortized over 5 years,

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[19] The Commission notes that it has no statutory authority to require that CG&E sell any generation to ULH&P or to require CG&E to hold open its current offer until ULH&P has completed an RFP process.

without carrying charges, beginning on the effective date of the Commission's Order in its next general rate case.[20] ULH&P has estimated that the total transaction costs would be $4.9 million, and would include transaction costs associated with filing preparation, financing, and taxes.[21]

The AG recommends that the transaction costs be deferred and recovered, but does not recommend that amortization begin with the next rate case. The AG suggests that, during the period between the transfer of the units and the next rate case, any profits generated by the units in excess of a reasonable rate of return be applied against the recovery of the deferred transaction costs. The AG believes this approach would reduce or possibly eliminate the deferred balance by the time of the next rate case.[22]

The Commission finds that ULH&P's proposal is reasonable and should be approved. Limiting the deferral provides for a sharing of the transaction costs between ULH&P's shareholders and ratepayers. The 5-year amortization period also represents a reasonable balance between the interests of these two groups. The exclusion of carrying charges on the deferred balance is consistent with the Commission's previous

[20] Amendment to Application at 2-3.

[21] Steffen Direct Testimony, Attachment JPS-7. ULH&P explained that as a result of becoming "more comfortable" with certain aspects of Kentucky statutes and regulations, it decided to amend the application. The proposal to defer roughly half of the estimated transaction costs was one of the areas in which ULH&P felt comfortable in shifting the "balance more in customers' favor." See T.E., Volume I, October 29, 2003, at 16.

[22] King Direct Testimony at 10-11. The AG's testimony on this issue related to the original application and request to defer all the transaction costs and amortize those costs over 3 years. The AG did not address the treatment of the transaction costs as included in the amended application in testimony or in his brief.

decisions concerning situations in which the unamortized balance of a deferred cost is excluded from the rate base calculations during a general rate case.

ADITC and Deferred Income Taxes

As a result of Ohio's retail unbundling effective January 1, 2001, ADITC and deferred income tax balances associated with the generating units proposed to be transferred to ULH&P were reclassified as "below the line" and have been amortized "below the line" over the remaining lives of the plants. ULH&P proposes that ADITC and deferred income tax balances associated with the generating units be transferred from CG&E's books to ULH&P's books concurrent with the transfer of the units. ULH&P proposes that the transferred ADITC and deferred income tax balances remain "below the line" items on its books, amortized over the remaining lives of the units, and excluded from retail rate-making in ULH&P's future general rate proceedings. Any deferred income taxes generated after ULH&P owns the units would be "above the line" and included for rate-making purposes.[23] ULH&P acknowledges that the amortization expense associated with the "below the line" ADITC and deferred income tax balances would be recorded "below the line" as well.[24] As of March 31, 2003, the ADITC balance was $7,404,258,[25] and the deferred income tax balance was $83,388,148.[26]

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[23] Application at 9-10 and Steffen Direct Testimony at 12-13.

[24] T.E., Volume I, October 29, 2003, at 216-217.

[25] Response to the Commission Staff's First Data Request dated August 21, 2003, Item 51(a).

[26] Id., Item 52(a).

ULH&P argues that the proposed treatment for the ADITC and deferred income tax balances is reasonable. It states that the units included in the proposal were not subject to retail rate-making in Kentucky during the period when they were owned by CG&E, and concludes that ULH&P's ratepayers should not receive the benefit of the rate base reduction generally made by the Commission for ADITC and deferred income taxes.[27] ULH&P notes that the treatment proposed in this case is identical to that proposed and accepted in a recent plant transfer involving Cinergy affiliates in Indiana.[28] ULH&P also contends that the proposed treatment is consistent with Internal Revenue Service ("IRS") tax normalization requirements, and cites several IRS rulings in support of this conclusion.[29]

The AG opposes ULH&P's proposed treatment of the ADITC and deferred income tax balances. The AG argues that ULH&P's proposal will result in an overstated rate base, a distorted capital structure that will produce an overstated cost of equity, and an overstated income tax expense on a going-forward basis. The AG contends that the proposed treatment is at odds with conventional rate-making and that it does not recognize that the ADITC and deferred income tax balances represent customer-supplied capital that was provided while the plants were under regulation. The AG estimates that the revenue requirement impact of ULH&P's proposed treatment would

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[27] Id., Items 51(d)(1) and 52(c)(1).

[28] T.E., Volume I, October 29, 2003, at 222.

[29] Response to the Commission Staff's Hearing Data Request of October 29, 2003, Item 4. ULH&P cites a 1987 IRS General Counsel Memorandum and references several IRS Private Letter Rulings issued between 1987 and 1996.

be approximately $341.9 million over the next 25 years.[30] The AG recommends that the ADITC balance be either subtracted from ULH&P's rate base or treated as zero-cost capital, with the ADITC balance amortized over the remaining lives of the plant "above the line" in order to recognize the source of the ADITC. The AG further recommends that the deferred income tax balance be accounted for "above the line" in accordance with the FERC Uniform System of Accounts ("FERC USoA").

ULH&P's proposed acquisition of generating facilities from CG&E represents an unprecedented transaction to be considered by the Commission. Not only must the Commission consider that the proposed transaction is between affiliated companies, it must also recognize that the generating assets being sold to the regulated entity have been deregulated. Consequently, the Commission must carefully consider the accounting and rate-making treatments authorized in conjunction with the proposed transaction, including the tax normalization impacts.

After reviewing the arguments and evidence, the Commission finds that the treatment of ADITC and deferred income taxes proposed by ULH&P is reasonable and should be approved. The generating units proposed to be transferred to ULH&P have been deregulated since January 1, 2001. When CG&E's regulated generating fleet became deregulated, the ADITC and deferred income tax balances were moved "below the line" for rate-making purposes. The possibility that some units of the deregulated generating fleet may be returning to regulation does not, in and of itself, support an assumption that the associated ADITC and deferred income tax balances will

[30] AG's Response to Hearing Data Request filed November 7, 2003.

automatically move "above the line" for rate-making purposes. No evidence has been presented in this case that supports such an assumption.

ULH&P has provided the results of its research concerning the treatment of the ADITC and deferred income tax balances from a tax perspective. That research indicates that, upon the sale of public utility assets between two public utilities, ADITC cannot be added to the regulated books of the purchasing utility and that it cannot be flowed-through to the customers of either the buyer or seller. ULH&P's research also indicates that, as the result of an asset sale and purchase transaction, any reduction of the purchaser's cost of service for pre-transfer ADITC or deferred income tax balances would result in a tax normalization violation.

In addition, ULH&P's proposal concerning the transfer of the deferred income taxes is consistent with the FERC USoA. In three separate account descriptions, the FERC USoA provides, "When plant is disposed of by transfer to a wholly owned subsidiary the related balance in this account shall also be transferred."[31] However, the Commission notes that the FERC USoA addresses only the accounting treatment, and does not state for rate-making purposes whether the deferred income taxes are to be recorded "above the line" or "below the line."

Concerning the AG's estimated revenue requirement impact of ULH&P's proposed treatment for ADITC and deferred income taxes, the Commission finds the estimate to be of little persuasive value. The AG has not consistently stated the amount

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[31] See FERC USoA, Account No. 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account No. 282, Accumulated Deferred Income Taxes – Other Property; and Account No. 283, Accumulated Deferred Income Taxes – Other.

of the estimated impact.[32] The Commission has examined the calculation of the $341.9 million estimate and notes that the calculation assumes the rate of return on rate base and federal and state income tax rates to be constant over the approximate 25-year time frame covered by the estimate. The calculations include the determination of an annual return resulting from the AG's contention that there will be an excessive equity ratio. This annual return is also assumed to be constant, and is multiplied by 24.75 years to reflect its impact on the AG's revenue requirement. We note that ULH&P expressed similar concerns about the calculations in its brief.[33] The Commission does not believe that these assumptions produce a reasonable estimate of the revenue requirement impact of ULH&P's proposed rate-making treatment for ADITC and deferred income taxes. The Commission must consider all impacts of the proposal submitted rather than focus solely on the revenue requirement impact, as it appears the AG has done. Given the potential tax normalization issues, the lack of documentation supporting the AG's arguments, and the unrealistic assumptions contained in the AG's estimate of the revenue requirements impact, the Commission cannot consider the AG's position to be a reasonable alternative.

Profits from Off-System Sales

The AG argues that ratepayers should receive 90 percent of the profits from off-system sales and that ULH&P should be allowed to retain 10 percent as an incentive to

[32] The AG did not include an estimate of the revenue requirement impact in his prefiled testimony. At the public hearing, the AG's witness stated the estimated impact was approximately $200.0 million. See T.E., Volume II, October 30, 2003 at 43-44. In the AG's response to the hearing data request, the estimated revenue requirement was determined to be $341.9 million. However, the AG's brief states that the impact on ULH&P's revenue requirement is $317.7 million. See AG's Post Hearing Brief at 10.

[33] ULH&P Brief at 43-44.

make such sales. The AG states that ratepayers receive 100 percent of the profits from off-system sales under standard rate-making treatment, but recognizes that ULH&P should be given an incentive, albeit a small one, to make these sales. The AG also argues against ULH&P's proposed treatment of off-system sales profits on the basis that the proposal is not limited to sales made exclusively from the facilities being transferred. He claims the proposal would also apply to off-system sales derived from other assets that ULH&P could acquire while its proposed treatment of off-system sales profits was in place, which would produce an absurd result.

ULH&P acknowledges that the proposal to share off-system sales profits between customers and shareholders departs from typical rate-making treatment. However, it points out that, since Ohio's electric restructuring went into effect, CG&E has retained 100 percent of the profits from off-system sales from the units. ULH&P argues that this aspect of the proposal is critical to making the transaction acceptable to CG&E from an economic perspective.

The Commission finds ULH&P's proposal that ratepayers retain the first $1 million in profits from off-system sales and 50 percent of profits above $1 million to be acceptable. While it represents a departure from standard rate-making treatment, it represents an improvement for ratepayers compared to the current purchased power contract. As the contract is not cost-based, its pricing is not based on ratepayer retention of any off-system sales profits; hence, under ULH&P's proposal, ratepayers will be receiving a benefit from off-system sales that they had not received previously.

In addition, ULH&P forecasts annual off-system sales profits of $4.5 million in the early years after the transfer, with the amount declining to $1.6 million by 2012. Given the uncertainty attendant to forecasting off-system sales, the guarantee of retaining up to the first $1 million in profits from such sales is a significant benefit to ratepayers.

We recognize that this treatment does not comport with conventional rate-making; however, as stated elsewhere in this Order, this is not a conventional proceeding before this Commission. While ULH&P has referred to the sharing of off-system sales profits that has been approved for American Electric Power ("AEP") in the past, this is largely an issue of first impression.[34] It is also, contrary to the AG's brief, an issue applicable only to sales from the facilities that are the subject of the proposed transfer.[35]

For these reasons, and considering all provisions in the transaction as a whole, we find that the treatment of off-system sales profits proposed in the amendment to ULH&P's application is reasonable. We further find no reason, at this time, that such treatment should not be approved in ULH&P's next general rate proceeding.

FAC Treatment of Energy Transfers Under the PSOA

The AG does not disagree with ULH&P's proposal to include the cost of energy transfers from CG&E to ULH&P for recovery through its future FAC. However, he argues that such treatment is appropriate only if credits that occur when ULH&P makes transfers to CG&E are also passed through the FAC. The amendment to ULH&P's

[34] AEP's sharing of profits from off-system sales has no revenue requirement impact, as does ULH&P's proposal. It involves a monthly comparison of such profits to the level (100%) of profits included in the revenue requirements determination in its prior general rate case.

[35] ULH&P's application and testimony refer to off-system sales from the facilities being transferred and its amended application refers only to its next general rate case. To extend its proposal to include facilities that it might acquire in the future, ULH&P would have to file for and receive Commission approval.

application revised its original proposal, under which it would have retained 100 percent of the profits from off-system sales, such that ratepayers will receive the bulk of the profits from such sales. The proposal in ULH&P's original application would have precluded the AG's proposed treatment of the costs of energy transfers from ULH&P to CG&E. However, recognizing the change to both ULH&P's proposed treatment of off-system sales and its proposed treatment of energy transfers, as set out later in this Order in the section "Other Accounting and Rate-making Treatment Proposals," we conclude that passing through the FAC the credits that occur when ULH&P makes energy transfers to CG&E is entirely consistent with the FAC treatment prescribed in 807 KAR 5:056 and should, therefore, be approved, as proposed by the AG.

OTHER ISSUES

New Agreements and Contracts

ULH&P seeks approval of a form of asset transfer agreement for each of the three generating facilities included in the proposed transfer. A draft of the asset transfer agreement for East Bend was filed with the application.[36] Based on the amendment to ULH&P's application, the final agreements are expected to mirror the draft agreement, except for the deletion of provisions governing a "Regulatory Non-Satisfaction Event" and the "Purchase Option" both of which addressed circumstances that could lead to ULH&P transferring the facilities back to CG&E in the future.

[36] Turner Direct Testimony, Attachment JLT-1.

In conjunction with the proposed transfer, ULH&P and CG&E will enter into the back-up PSA and PSOA described earlier in this Order.[37] The back-up PSA provides a firm supply of power for ULH&P's native load customers to replace capacity from either East Bend or Miami Fort when outages or deratings of those units occur.[38] Pricing terms under the back-up PSA call for energy to be priced at the average variable cost per MWh during the prior calendar month at the plant for which back-up power is required. The capacity charges ULH&P will pay under the back-up PSA are based on a value of power calculated using forward market prices quoted from Megawatt Daily and the North American Power 10x Report.[39] There are separate capacity charges for East Bend and Miami Fort which, on a combined basis, equal $421,595 per month. The overall price for back-up power included in the PSA is less than the price embedded in ULH&P's existing wholesale purchase power contract with CG&E.

ULH&P and CG&E will also enter into the PSOA, which will allow the units being transferred to be jointly dispatched along with other Cinergy generating units. Energy transferred between ULH&P and CG&E under the PSOA will be priced at the market price for the hour in which the energy transfer takes place but will be capped at the receiving entity's incremental cost of available generation. The PSOA also establishes

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[37] Although the Commission can "approve" the back-up PSA and the PSOA as requested by ULH&P, because they both relate to wholesale transactions between ULH&P and CG&E, those agreements are subject to FERC's jurisdiction. Therefore, any approval thereof by the Commission would constitute an official endorsement of the agreements but would not constitute the final approval necessary.

[38] Woodsdale is not covered by the back-up PSA because it is peaking capacity, which will not operate for most hours of the year and will not be relied upon to meet ULH&P's base load requirements.

[39] McCarthy Direct Testimony, as adopted by M. Stephen Harkness, at 4.

the terms under which off-system purchases and sales will be made and how the costs and revenues associated with such transactions will be treated by ULH&P and CG&E.

For its operation of the Woodsdale station, CG&E presently has a contract with CMT to obtain its natural gas supply and contracts with ORVP to obtain propane and to store propane in a cavern partially owned by ORVP. CG&E also has a contract with TEPPCO to store propane in TEPPCO's pipeline system.[40] CG&E owns the pipelines used to transport propane to Woodsdale from both the ORVP cavern and the TEPPCO pipeline. ULH&P will acquire CG&E's pipelines as part of the proposed transaction.

Other than stating his concerns about the price of the facilities and the affiliate aspects of the proposed transaction, the AG did not oppose the form or content of the amended draft asset transfer agreement or ULH&P's proposal to enter into the back-up PSA and PSOA with CG&E. Likewise, the AG did not oppose CG&E's assignment of the "Woodsdale contracts" or its coal supply contracts to ULH&P. The Commission finds that the subject agreements and contracts are required in conjunction with the proposed transfer and, based on information in this record, appear to be reasonable and should therefore be approved, subject to our review and approval of the final documents.[41]

Several of the transaction documents have been and will be drafted to accomplish the proposed transaction. ULH&P commits to submit to the Commission for

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[40] CG&E also has non-affiliate contracts for the coal supply for East Bend and Miami Fort 6, which are to be assigned to ULH&P.

[41] It should be noted, due to their impact on ULH&P's base rates and/or future FAC charges, that both the back-up PSA and the PSOA are subject to periodic audit or review by the Commission.

review and approval the final documents prior to closing. ULH&P refers to 12 transaction documents that will be executed as part of the proposed transaction.[42] The Commission recognizes that the timing of the closing of the proposed transaction will be of significant concern to ULH&P and CG&E. However, the Commission must have adequate time to review the numerous documents related thereto.

Therefore, the Commission finds that a process should be established to address the review and approval of the transaction documents in their final form. ULH&P should submit all the transaction documents in their final form to the Commission no later than 30 days prior to the expected closing date of the transaction. The submitted documents should include all attachments, exhibits, appendices, and schedules that are referenced as part of the particular transaction document. For those documents it has already included in this record, ULH&P should include a detailed explanation for any changes made to the document from the version already existing in the record. For those documents not already included in this record, ULH&P should include a narrative describing the purpose of the document and explaining how the terms and conditions contained in the document are consistent with this Order. ULH&P should file an original and 5 copies of this information with the Commission and a copy with the AG.[43] Upon ULH&P's filing of these documents and explanations, the Commission will complete its review as expeditiously as possible.

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[42] The transaction documents identified in the record are listed in Appendix B of this Order.

[43] This docket will remain open to receive the final documents. The AG, as is his right as an intervenor, will have an opportunity to offer his opinion on those documents.

Request for Deviation Regarding Affiliate Transactions

In 2000, the Kentucky General Assembly enacted guidelines on cost allocations and affiliate transactions, as well as a code of conduct for utilities with nonregulated activities or affiliates. These standards and guidelines are codified in Chapter 278 of the Kentucky Revised Statutes, specifically as KRS 278.2201 through KRS 278.2219. Provided within these statutes is the opportunity for regulated utilities to request from the Commission a waiver or deviation from the requirements thereof.

ULH&P requests permission to deviate from the requirements of KRS 278.2207(1)(b) and requests a waiver from the requirements of KRS 278.2213(6) for its plant acquisition transaction and certain affiliate agreements.[44] These statutes require, respectively, that the services and products provided to the utility by an affiliate be priced at the affiliate's fully distributed cost but in no event greater than market, and that all dealings between a utility and a nonregulated affiliate be conducted at arm's length. The Commission may grant a deviation from KRS 278.2207(1)(b) if it determines that the deviation is in the public interest. It shall grant a waiver or deviation from KRS 278.2207(1)(b) and/or KRS 278.2213 if it finds that compliance with the provisions thereof are impracticable or unreasonable.

The AG argues that ULH&P has failed to demonstrate to the Commission that a waiver or deviation from the provisions of KRS 278.2207 and KRS 278.2213 is

[44] The affiliate agreements for which ULH&P requests deviation and waiver are the contract with CM&T that provides for CG&E to obtain natural gas for Woodsdale (Gas Supply and Management Agreement), the contract with ORVP for propane storage in the Todhunter propane cavern (Commodity Storage Agreement), and the contract CG&E has with ORVP to obtain propane for Woodsdale (Propane Supply and Management Agreement).

appropriate and asserts that ULH&P's request should be denied. The Commission does not agree.

In reviewing ULH&P's arguments justifying the lack of an RFP for the acquisition of the generating facilities and ICF's market analysis of those facilities, the Commission was able to determine that the generating units being transferred from CG&E are priced at CG&E's fully distributed cost and that the cost is below market. Therefore, the Commission finds that no deviation from KRS 278.2207(1)(b) is required for the acquisition of the generating units. The Commission is also satisfied from the evidence presented by ULH&P that the pricing of the products and services provided in the Gas Supply and Management Agreement, Commodity Storage Agreement, and the Propane Supply and Management Agreement is reasonable and that ULH&P's request to deviate from the pricing requirements of KRS 278.2207(1)(b) with regard to these agreements should be granted.

As stated previously, KRS 278.2213(6) requires that all dealings between a utility and its nonregulated affiliate be conducted at arm's length. Thus, a deviation from KRS 278.2213(6) is required for all of the agreements proposed by ULH&P in this proceeding, including the agreements for the generating units that the Commission has determined do not require a deviation from KRS 278.2207(1)(b).

Having reviewed ULH&P's reasons for not issuing an RFP and our previous findings herein that an RFP was not necessary to determine the reasonableness of the transfer of generating units, that the transfer is reasonable and in the public interest, and that the agreements associated with the transfer are in the public interest, the

Commission finds that ULH&P has met its burden under KRS 278.2219. Consequently, ULH&P's request to deviate from KRS 278.2213(6) should be granted.

The Commission finds, however, that the deviations approved herein should apply only to this transaction and the agreements discussed herein. Future transactions or successor agreements will require separate deviation or waiver requests if and when they are proposed by ULH&P.

Other Accounting and Rate-Making Treatment Proposals

In addition to its proposals regarding the value of the facilities being transferred, deferral and recovery of transaction costs, treatment of ADITC and deferred income taxes, and sharing the profits from off-system sales, ULH&P also requested approval of the following provisions related to the back-up PSA and the PSOA, to be effective with its next general rate case:

(1) Inclusion in its future base rates of all monthly capacity charges specified in the back-up PSA; and a commitment to consult with the Commission and the AG prior to filing a successor agreement at FERC;

(2) Inclusion in its future FAC of all energy charges assessed under the back-up PSA in accordance with 807 KAR 5:056 and Commission precedent;

(3) Inclusion in its future FAC of the costs of energy transfers from CG&E under the PSOA in accordance with 807 KAR 5:056 and Commission precedent; and

(4) Inclusion in its future FAC of the cost of the fuel consumed in the facilities in accordance with 807 KAR 5:056 and Commission precedent.

The Commission finds that this request is generally reasonable and should be approved. However, ULH&P did not specify what is meant by "Commission precedent" regarding its requested FAC treatment. Given that application and review of an electric utility's FAC is addressed in its entirety in 807 KAR 5:056, the Commission will limit its decision herein to approving treatment in accordance with that administrative regulation.

Requirement to File a Stand-Alone IRP

In Case No. 2001-00058, the Commission required ULH&P to file a stand-alone IRP by June 30, 2004. Our Order stated that the IRP should include analyses of bids to purchase power from non-affiliated suppliers as well as construction of generation to lock in prices for the long term. In the amendment to its application, ULH&P requests that it be permitted to deviate from the requirement to analyze bids for purchased power. ULH&P states that, should the Commission approve the proposed transfer, such a requirement, which would impose significant costs on ULH&P, would no longer be necessary. Given that ULH&P's load forecast and supply-side analysis show that it will not need additional resources until the 2011-2012 time frame, and that this need is expected to be met with summer season purchases, the Commission finds that the requested deviation is reasonable and should be granted.

ULH&P's Next General Rate Case

Based on the current freeze on ULH&P's retail electric rates, effective through December 31, 2006, many of the accounting or rate-making provisions included in the amendment to its application refer to its next general rate proceeding or contain the phrasing "on or after January 1, 2007." These same references and phrasing were in ULH&P's original application and in numerous of its responses to data requests.

The Commission takes notice of the fact that ULH&P has not filed to increase its retail electric rates since 1991. By the end of the current rate freeze, its customers will have gone 15 years without a base rate increase. The Commission commends ULH&P

for its efficiency and its stewardship of ratepayers' monies, which have contributed to its not requiring a general rate increase for this length of time.

In some of its testimony and exhibits, ULH&P projected the future rate impact of acquiring the facilities that are the subject of the proposed transfer. Its projections show a possible future rate increase going into effect January 1, 2007, concurrent with the end of its current rate freeze. The Commission believes that a general rate proceeding will be necessary for ULH&P within that time frame. Given the numerous changes that have occurred in the electric industry since 1991, we believe that shareholders and ratepayers will both be better served in the long run by ULH&P filing a general rate application to effect a change in rates on January 1, 2007. Such an effective date, of course, would be at the conclusion of the suspension period provided by the statutes and regulations governing changes in rates. Therefore, we find that ULH&P should file a general rate application in 2006 to adjust its retail electric rates, so that, based on the suspension period applicable to ULH&P's choice of test period, the effective date of any eventual rate adjustment ordered by the Commission will be January 1, 2007.

Acceptance of Decision

The decision enunciated herein approves ULH&P's proposal, subject to certain conditions and modifications. Since the proposal was a response to concerns previously expressed by the Commission regarding ULH&P's long-term power supply needs, if any modifications are found to be unacceptable by ULH&P or its affiliates, the Commission wishes to be informed of that finding as soon as is practicable. Therefore, ULH&P should notify the Commission in writing, no later than 30 days from the date of this Order, whether or not it and its affiliates accept this decision, including all modifications.

FINDINGS AND ORDERS

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds that:

1. ULH&P's amendment to its application, which establishes the terms and conditions under which it will acquire CG&E's interests in East Bend Unit No. 2, Miami Fort Unit No. 6, Woodsdale Unit Nos. 1 through 6, and the related property, appurtenances, contracts and agreements, should be approved, subject to Commission review and approval of final drafts of the transaction documents.

2. The termination of ULH&P's current PSA with CG&E, effective on the closing date of the transfer of facilities, is reasonable and should be approved.

3. ULH&P should be granted a waiver, in accordance with KRS 278.2219, from the requirements of KRS 278.2213(6) that its acquisition of the facilities, subject to this transfer, from its affiliate, CG&E, be at arm's length; and ULH&P should be granted a deviation, pursuant to KRS 278.2207, of certain affiliate agreements related to the operation of the facilities being transferred.

4. ULH&P's draft transfer agreements for the three facilities being acquired, with the provisions governing a "Regulatory Non-Satisfaction Event" and the "Purchase Option" deleted, should be approved, subject to Commission review and approval of the agreements in their final form.

5. ULH&P's back-up PSA and its PSOA, which will govern its power transactions with CG&E on a going forward basis subsequent to the consummation of

the proposed transfer of facilities, should be approved, subject to Commission review and approval of the agreements in their final form.

6. The assignment to ULH&P by CG&E of CG&E's interests in the contracts for the supply, delivery, and storage of coal, oil, natural gas and propane used as fuel for electricity generation at East Bend Unit No. 2, Miami Fort Unit No. 6, and Woodsdale Unit Nos. 1 through 6 should be approved, subject to Commission review and approval of the contracts in their final form.

7. The facilities being acquired by ULH&P should be recorded by ULH&P at their original cost less accumulated depreciation. At this time, the Commission knows of no reason why such value should not be used in the future for rate-making purposes.

8. ULH&P should defer no more than $2.45 million of the transaction costs incurred in relation to its acquisition of the subject generating facilities, with the costs to be deferred and amortized over 5 years, without carrying charges, beginning with the effective date of the Commission's Order in ULH&P's next general rate proceeding. At this time, the Commission knows of no reason why the resulting amortization expense should not be recovered through rates beginning with the effective date of the Commission's Order in ULH&P's next general rate proceeding.

9. ULH&P's proposal to record the ADITC and deferred income tax balances associated with the generating facilities being transferred "below the line" is reasonable and should be approved. At this time, the Commission knows of no reason why such treatment should not be reasonable for future rate-making purposes.

10. Based on its approval of the back-up PSA, the monthly capacity charges set out therein are reasonable. The Commission knows of no reason, at this time, why

such charges should not be recovered through rates beginning with the effective date of the our final Order in ULH&P's next general rate proceeding. ULH&P should consult with the Commission and the AG prior to filing any successor agreement with FERC.

11. ULH&P's recovery of energy charges assessed under the Back-Up PSA, from the date that its next FAC goes into effect, on or after January 1, 2007, should be in accordance with 807 KAR 5:056.

12. Treatment of the costs of energy transfers between ULH&P and CG&E under the PSOA, from the date that its next FAC goes into effect, on or after January 1, 2007, should be in accordance with 807 KAR 5:056.

13. ULH&P's proposal to share off-system sales profits with its customers, beginning with the effective date of the Commission's Order in its next general rate proceeding so that customers receive up to $1 million from off-system sales profits annually and 50 percent of such profits above $1 million annually, if any, while ULH&P retains 50 percent of the profits from off-system sales above $1 million annually, if any, is reasonable. The costs attributable to off-system sales should include the incremental costs listed in the PSOA, Paragraph 1.10. ULH&P should implement the necessary processes to allocate appropriately said incremental costs to its off-system sales. The Commission knows of no reason, at this time, why such treatment of off-system sales profits should not be approved in ULH&P's next general rate proceeding.

14. ULH&P should be granted a waiver from the Commission's requirement, imposed in Case No. 2001-00058, that it analyze purchase power alternatives in its stand-alone IRP, which is to be filed by June 30, 2004.

15. ULH&P should file its next general rate application to adjust retail electric rates so that, based on the suspension period applicable to ULH&P's choice of test period, the effective date of any eventual rate adjustment ordered by the Commission will be January 1, 2007.

16. ULH&P should notify the Commission in writing, not later than 30 days from the date of this Order, if this decision, including all conditions and modifications, is acceptable to it and its affiliates.

17. ULH&P should submit the final draft versions of the various transaction documents and accompanying narrative explanations for final Commission review and approval in the manner described herein.

18. Within 10 days of their receipt, ULH&P should file one copy of each of the approval documents issued by the FERC and the SEC.

IT IS THEREFORE ORDERED that:

1. The proposed acquisition of generating facilities by ULH&P, as described in its amended application of October 29, 2003, is approved, subject to the conditions and modifications described in this Order.

2. Findings 2 through 15 shall be implemented as if the same were individually so ordered.

3. ULH&P shall notify the Commission in writing, not later than 30 days from the date of this Order, if this decision, including all conditions and modifications, is acceptable to it and its affiliates.

4. ULH&P shall submit the final draft versions of the various transaction documents and accompanying narrative explanations for final Commission review and approval in the manner described herein.

5. Within 10 days of their receipt, ULH&P shall file with the Commission one copy of each of the approval documents issued by the FERC and the SEC.

Done at Frankfort, Kentucky, this 5th day of December, 2003.

By the Commission

ATTEST:

Thomas M. Dorman

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00252 DATED December 5, 2003

DESCRIPTION OF FACILITIES PROPOSED TO BE TRANSFERRED

East Bend No. 2

A 648 MW (nameplate rating) coal-fired base load plant in Boone County, Kentucky. Commissioned in 1981, it is jointly owned by CG&E and Dayton Power and Light, with CG&E owning a 69% interest. The unit's net rating is 600 MW, after allowing for power used to operate the plant machinery. The net rating of CG&E's 69% share is 414 MW.

East Bend is designed to burn low- to high-sulfur eastern bituminous coal. Its recent achieved heat rates have ranged between 10,400 and 10,900 Btu/kWh. It is equipped with a lime-based flue gas desulfurization system (scrubber) along with a selective catalytic reduction (SCR) control system, which is designed to reduce NO_x emissions by 85%. East Bend No. 2 has a 1.2 lbs./MMBTU SO_2 emission limit. The unit's output is directly connected to Cinergy's 345 kV transmission system.

Burns & McDonnell (B&McD) completed its due diligence review of East Bend in June 2003. Its personnel had visited the East Bend Generating Station on May 23, 2003. Its report concludes that the plant is fully capable of providing long-term, reliable service as a base load power facility if it continues to be properly operated and maintained in accordance with good utility practice. B&McD estimates that the unit's remaining useful operating life is at least 38 years.

Miami Fort No. 6

A 168 MW (nameplate rating) coal-fired base or intermediate load plant in Hamilton County, Ohio. Commissioned in 1960, it is one of four coal-fired units at the Miami Fort Generating Station. CG&E owns 100% of the unit, which has a net rating of 163 MW.

Miami Fort 6 is designed to burn low- to medium- sulfur eastern bituminous coal. Its recent heat rates have ranged between 9,900 and 10,200 Btu/kWh. It is equipped with a high efficiency electrostatic precipitator and with a temporary selective non-catalytic reduction (SNCR) system for NO_x reductions. Miami Fort 6 has a 5.0 lbs./MMBTU SO_2 emission limit. The SNCR has not performed as well as expected and will be replaced with second generation low NO_x burners in the future. It is directly connected to Cinergy's 138 kV transmission system.

B&McD visited the Miami Fort Generating Station on May 26, 2003. It shares a 600-foot tall exhaust stack and continuous emissions monitoring system with its sister unit, Miami Fort No. 5 as well as crushed coal conveyors. Miami Fort 6 also shares coal handling and fuel oil storage facilities with the three other units at the site. B&McD's report concludes that the plant is fully capable of providing long-term, reliable service as a base load/intermediate power facility if it continues to be properly operated and maintained in accordance with good utility practice. B&McD estimates that the unit's remaining useful operating life is at least 17 years.

Woodsdale

A 490 MW (nameplate rating) six-unit combustion turbine station located in Butler County, Ohio. Its net summer capacity, including inlet cooling, is 500 MW. It is owned 100% by CG&E. The Woodsdale Generating Station was originally planned for twelve units, but only six units were constructed. It has dual fuel capability (natural gas and propane) and black start capability. Five units were commissioned in 1992 with the sixth unit commissioned in 1993.

Woodsdale is connected to two interstate natural gas transmission pipelines, Texas Eastern Transmission Company and Texas Gas Transmission Company. Its contracts with Ohio River Valley Propane LLC, an affiliate, provide for its propane supply and its propane storage. NO_x emissions are controlled by water injection. Woodsdale's output is directly connected to Cinergy's 345 kV transmission system.

B&McD visited the Woodsdale Station on May 28, 2003. Its report noted that Units 5 and 6 had undergone major overhauls in 2001 and that Units 1-4 will have major overhauls in 2004-2005. B&McD's report concludes that the plant is fully capable of providing long-term, reliable service as a peaking power facility if it continues to be properly operated and maintained in accordance with good utility practice. B&McD indicated that the units' remaining useful operating lives will be dependent on the number of times the units are started and that, based on the number of starts that have occurred since the units were commissioned, they should be able to operate for several more years.

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00252 DATED December 5, 2003

TRANSACTION DOCUMENTS

Documents Filed with the Commission as of July 21, 2003:

- Asset Transfer Agreement for Unit 2 of the East Bend Generating Station (See Turner Direct Testimony, Attachment JLT-1)

- Back-up Power Sale Agreement (See McCarthy Direct Testimony, Attachment RCM-1)

- Purchase, Sales and Operation Agreement (See McCarthy Direct Testimony, Attachment RCM-2)

Documents Referenced But Not Flied with the Commission:

- Schedules referenced in Section 7.09 of the Asset Transfer Agreement for Unit 2 of the East Bend Generating Station

- Asset Transfer Agreement for Miami Fort 6

- Asset Transfer Agreement for Woodsdale

- Assignment Document for the Gas Supply and Management Agreement (See Roebel Direct Testimony, Attachment JJR-1 for copy of the current Gas Supply and Management Agreement)

- Assignment of the Commodity Storage Agreement (See Roebel Direct Testimony, Attachment JJR-2 for copy of the current Commodity Storage Agreement)

- Assignment of the Storage and Service Agreement (See Roebel Direct Testimony, Attachment JJR-3 for copy of the current Storage and Service Agreement)

- Assignment of the Propane Supply and Management Agreement (See Roebel Direct Testimony, Attachment JJR-4 for copy of the current Propane Supply and Management Agreement)

- Amendment/Assignment of current Coal Contracts
- Ownership transfer and lease back of shared stack at Miami Fort 5 and 6
- Use of shared coal handling and fuel oil storage facilities associated with Miami Fort 6

DEK
Exhibit 12

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 532

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Virginia Electric & Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	ORDER APPROVING RATE INCREASE AND COST DEFERRALS AND REVISING PJM REGULATORY CONDITIONS

HEARD: Wednesday, August 17, 2016, at 7:00 p.m., Halifax County Historic Courthouse, 10 N. King Street, Halifax, North Carolina

Tuesday, September 13, 2016, at 7:00 p.m., Pasquotank County Courthouse, 206 E. Main Street, Courtroom C, Elizabeth City, North Carolina

Wednesday, September 14, 2016, at 7:00 p.m., Commissioner's Meeting Room, Dare County Administration Building, 954 Marshall Collins Drive, Manteo, North Carolina

Wednesday, September 21, 2016, at 7:00 p.m., Martin County Courthouse, 305 E. Main Street, Williamston, North Carolina

Tuesday and Wednesday, October 4 and 5, 2016, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

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BY THE COMMISSION: On March 1, 2016, pursuant to Commission Rule R1-17(a), Virginia Electric and Power Company (VEPCO), d/b/a in North Carolina as Dominion North Carolina Power (DNCP or the Company), filed notice of its intent to file a general rate case application. On the same date, DNCP filed a letter informing the Commission of the Company's intention to propose accounting adjustments to include an appropriate level of amortization of deferred post-in-service costs associated with the Company's Warren County Power Station (Warren County CC) in its rate case revenue requirement.

On March 4, 2016, DNCP filed a Response in Opposition to a motion filed on February 25, 2016, by Nucor in Docket No. E-22, Sub 479, to impose on DNCP additional jurisdictional allocation study filing requirements. On March 7, 2016, CIGFUR I filed a letter stating its position on Nucor's February 25, 2016 motion. On March 17, 2016, the Commission issued an Order denying Nucor's motion and granting alternative relief. In compliance with Paragraph 4 of the Commission's March 17, 2016 Order, DNCP filed a Single CP Cost of Service Study on May 31, 2016.

On March 31, 2016, the Company filed its Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina (Application), along with a Rate Case Information Report Commission Form E-1 (Form E-1),[1] and the direct testimony and exhibits of J. Kevin Curtis, Vice President - Technical Solutions; Mark D. Mitchell, Vice President – Generation Construction; James R. Chapman, Senior Vice President - Mergers & Acquisitions and Treasurer; Robert B. Hevert, Managing Partner of Sussex Economic Advisors, LLC; Paul M. McLeod, Regulatory Advisor - Regulatory Accounting Group; Bruce E. Petrie, Manager - Generation System Planning; Michael S. Hupp, Jr., Director - Power Generation Regulated Operations; Glenn A. Pierce,[2] Manager – Regulation; and Paul B. Haynes, Director - Regulation. The Company also filed requests for authority to use certain deferred accounts to implement a levelization methodology for its nuclear unit and refueling

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[1] An erratum to DNCP's Form E-1 was filed on July 13, 2016, redacting confidential information from the original.

[2] Witness Pierce's direct testimony was subsequently adopted by witness Haynes.

maintenance outage expenses, as well as relief from the conditions imposed by the Commission in its April 19, 2005 Order approving DNCP's integration into PJM Interconnection, Inc. (PJM), in Docket No. E-22, Sub 418 (PJM Order).

Petitions to intervene were filed by CIGFUR I on March 7, 2016, Nucor on April 4, 2016, NCSEA on April 5, 2016, and CUCA on August 1, 2016. Notice of intervention was filed by the Attorney General on June 13, 2016.

The Commission subsequently entered Orders granting the petitions to intervene of CIGFUR I, NCSEA, Nucor, and CUCA. The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19. The Attorney General's intervention is recognized pursuant to G.S. 62-20.

On April 20, 2016, Nucor filed a motion requesting *pro hac vice* admission before the Commission for Damon E. Xenopoulos. On June 3, 2016, DNCP filed a motion requesting *pro hac vice* admission before the Commission for Joseph K. Reid, III. Orders allowing these motions for limited practice before the Commission were issued on April 26, 2016, and June 7, 2016, respectively.

On April 26, 2016, the Commission issued an Order Establishing General Rate Case and Suspending Rates. On May 10, 2016, the Commission issued an Order Scheduling Hearings and Requiring Public Notice.

On May 2, 2016, DNCP filed an Application for an Accounting Order to Defer Certain Capital and Operating Costs Associated with Brunswick County Power Station Addition in Docket No. E-22, Sub 533. On May 3, 2016, the Company filed a Motion for Reconsideration of the Commission's March 29, 2016 Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility in Docket No. E-22, Sub 519.

On May 17, 2016, the Commission issued an Order Consolidating Dockets, which consolidated this general rate case with DNCP's pending petition for deferral accounting authority to defer post-in-service costs associated with commercial operation of the Brunswick County Power Station (Brunswick County CC) in Docket No. E-22, Sub 533, and the Company's motion for reconsideration in Docket No. E-22, Sub 519, of the Commission's Order denying the Company's request to defer post-in-service costs associated with commercial operation of the Warren County CC.

On July 8, 2016, DNCP submitted a supplemental filing pertaining to the Company's request for relief from the conditions imposed by the PJM Order, supported by the supplemental direct testimony of Michael S. Hupp, Jr. and James R. Bailey, Manager – Planning and Strategic Initiatives – Electric Transmission Department.

On August 12, 2016, DNCP filed the supplemental direct testimony and exhibits of James R. Chapman, Deanna R. Kesler, Regulatory Consultant in Demand Side Planning – Integrated Resource Planning, Bruce E. Petrie, Paul M. McLeod, and Paul B. Haynes, as well as applicable updated NCUC Form E-1 information report items.

On September 7, 2016, the Public Staff filed the direct testimony and exhibits of Jack L. Floyd, Engineer, Electric Division; John R. Hinton, Director, Economic Research Division; Michael C. Maness, Assistant Director, Accounting Division; James S. McLawhorn, Director, Electric Division; Jay B. Lucas, Engineer, Electric Division; Dustin R. Metz, Engineer, Electric Division; Katherine A. Fernald, Assistant Director, Accounting Division; and Darlene P. Peedin, Supervisor, Electric Section, Accounting Division. On the same day, Nucor filed the direct testimony of J. Randall Woolridge, Professor of Finance and University Fellow at Pennsylvania State University; Lane Kollen, Vice President and Principal, Kennedy and Associates; Jacob M. Thomas, Senior Project Manager, GDS Associates, Inc.; and witness Dennis W. Goins, Economic Consultant, Potomac Management Group.

On September 7, 2016, CUCA filed a motion requesting a one-day extension of time for it and the other intervenors to file their testimony and exhibits. The Commission issued an Order allowing CUCA's motion on September 8, 2016.

On September 8, 2016, CUCA filed the direct testimony of Kevin O'Donnell, President of Nova Energy Consultants, Inc.; CIGFUR I filed the direct testimony of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; and Nucor filed the supplemental direct testimony of witness Goins.

On September 26, 2016, DNCP filed the rebuttal testimony and exhibits of J. Kevin Curtis, Mark D. Mitchell, James R. Chapman, Robert B. Hevert, Paul M. McLeod, Mark C. Stevens, Director of Regulatory Accounting, James I. Warren, member of the law firm of Miller & Chevalier Chartered, Michael S. Hupp, Jr., and Paul B. Haynes.

On September 28, 2016, DNCP filed a list of witnesses, the order of witnesses, and estimated time for cross-examination of the witnesses.

On October 3, 2016, the Public Staff filed a notice of settlement in principle. In addition, the Public Staff filed a motion to delay the hearing of expert testimony. The Public Staff requested that the Commission convene the hearing as scheduled on October 4, 2016, at 9:30 a.m., to receive public witness testimony, but delay the start of the testimony by expert witnesses until 1:30 p.m. that afternoon.

Also, on October 3, 2016, DNCP, the Public Staff, and CIGFUR I (Stipulating Parties) entered into and filed an Agreement and Stipulation of Settlement (Stipulation). In addition, DNCP and the Public Staff filed a joint motion to excuse witnesses.

In support of the Stipulation, on October 3, 2016, DNCP filed the testimony and exhibits of J. Kevin Curtis, Robert B. Hevert, and Paul B. Haynes, and the joint testimony of Mark C. Stevens and Paul M. McLeod; and the Public Staff filed the testimony and exhibits of Katherine A. Fernald and John R. Hinton.

On October 4, 2016, Nucor filed a motion to postpone the hearing of expert testimony for 14 calendar days following the filing of the final version of the Stipulation and the additional expert witness testimony, if any. In summary, Nucor asserted that it needed additional time to prepare for the hearing due to the Stipulation recently filed by DNCP, the Public Staff and CIGFUR I.

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

Halifax:	Belinda Joyner, Tony Burnette, Larry Abram, Dean Knight, Janice Bellamy, Regina Moffett, and Betty Bennett
Elizabeth City:	Peter Bishop
Manteo:	Robert Woodard, Walter L. Overman, Dwight Wheless, Robert C. Edwards, Manny Medeiros, and Judy Williams
Williamston:	Martha McDonald, John McDonald, Tawilda Bryant, Rhett B. White, Ronnie Smith, John Liddick, Linda Gibson, Samantha Komar, Louise Simmons, Jerry McCrary, Glenda Barnes, and Reginald Williams, Jr.
Raleigh:	No public witnesses appeared.

On October 3, 2016, DNCP filed a Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund, pursuant to G.S. 62-135.

The matter came on for hearing on October 4, 2016, at 9:30 a.m. After determining that there were no public witnesses who desired to testify, the Chairman heard the parties' arguments on the Public Staff's motion to delay the start of the expert witness testimony until 1:30 p.m. that afternoon, and Nucor's motion to postpone the hearing for 14 calendar days. The Chairman ruled that the hearing of expert testimony would commence at 1:30 p.m., on October 4, 2016. Further, the Chairman ruled that the concerns of Nucor and other parties about needing more time to prepare direct testimony and cross-examination regarding the Stipulation would be addressed by rearranging the order of witnesses and other accommodations, if such accommodations became reasonably necessary during the hearing. Thus, the Public Staff's motion was granted, and Nucor's motion was denied, but Nucor's and the other parties' concerns about needing additional time to prepare were resolved.

The expert witness hearing began at 1:30 p.m., on October 4, 2016, and was concluded on October 5, 2016. DNCP presented the testimony of witnesses Curtis, Chapman, Mitchell, Hevert, McLeod, Stevens, Warren, Hupp, and Haynes. The testimony and exhibits of DNCP witnesses Kesler, Bailey, and Petrie were stipulated into the record. Nucor presented the testimony of witness Woolridge. The testimony and exhibits of Nucor witnesses Kollen, Thomas, and Goins were stipulated into the record. CUCA presented the testimony of witness O'Donnell. The testimony of witness Phillips was withdrawn by CIGFUR I.

The Public Staff presented the testimony of witnesses Maness, Fernald, Floyd, and McLawhorn. The testimony and exhibits of Public Staff witnesses Lucas, Peedin, Metz, and Hinton were stipulated into the record.

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

On October 11, 2016, the Commission issued a notice of mailing of transcript and ordered that the parties submit briefs and/or proposed orders by November 10, 2016. On November 4, 2016, the Attorney General moved that the date by which briefs and proposed orders must be filed be extended until November 15, 2016. The motion was granted by Order issued November 8, 2016. On November 15, 2016, the Attorney General requested a second extension to November 16, 2016. The motion was granted on November 15, 2016.

On October 12, 2016, the Commission issued an Order Approving Financial Undertaking and an Order Approving Public Notice of Temporary Rates in response to DNCP's Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund.

On October 18, 2016, in response to a request by the Commission during the hearing, DNCP filed additional information regarding its weatherization and other energy assistance programs.

On November 15, 2016, DNCP and the Public Staff filed a late-filed exhibit, as requested by the Commission, comparing the regulatory conditions in the PJM Order with the commitments made by DNCP in the present docket.

Also on November 15, 2016, NCSEA filed a post-hearing Brief.

On November 16, 2016, CUCA filed its Proposed Findings and Brief, and Nucor and the Attorney General's Office filed post-hearing Briefs. In addition, DNCP, the Public Staff and CIGFUR I filed a Joint Proposed Order.

On December 2, 2016, the Public Staff filed a letter on behalf of the Stipulating Parties requesting that the Commission accept revisions to two paragraphs of their Joint Proposed Order regarding Nucor's motion to postpone the expert witness hearing for 14 calendar days.

On December 9, 2016, DNCP filed for informational purposes a letter of December 8, 2016, from DNCP to Nucor regarding the continuation of services to Nucor under the parties' existing contract and Schedule NS.

On December 13, 2016, DNCP and NCSEA filed a letter informing the Commission of an agreement reached between them regarding DNCP's time-of-use rate offerings.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence at the hearings, the Stipulation, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

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

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

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

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2015, adjusted for certain known changes in revenue, expenses, and rate base through June 30, 2016.

The Application

5. In summary, by its general rate case Application, supporting testimony and exhibits filed on March 31, 2016, in this docket, DNCP sought an increase in its non-fuel base rates and charges to its North Carolina retail customers of $51,073,000, along with other relief, including cost deferrals and changes to its rate design and regulatory conditions. The Application was based upon a requested rate of return on common equity (ROE) of 10.50%, an embedded long-term debt cost of 4.889%, and DNCP's actual capital structure of 53.36% common equity and 46.64% long-term debt, as of December 31, 2015.

The Stipulation

6. On October 3, 2016, the Public Staff filed a Notice of Settlement in Principle with DNCP and CIGFUR I. On October 3, 2016, the Stipulating Parties entered into and filed the Stipulation resolving all of the issues in this proceeding among the Stipulating Parties.

7. After carefully reviewing the Stipulation, the Commission finds that the Stipulation is the product of give-and-take in settlement negotiations among the Stipulating Parties, and is material evidence entitled to be given appropriate weight by the Commission.

Revenue Requirement and Adjustments to Cost of Service

8. The Stipulation, as reflected on Settlement Exhibits I and II, provides for a stipulated increase in the revenue requirement of $25,790,000, consisting of an increase of $34,732,000 in non-fuel revenues and a decrease of $8,942,000 in base fuel revenues. The Stipulation provides for $375,722,000 of operating revenues, $299,084,000 of operating revenue deductions, and $1,040,035,000 of original cost rate base for use in establishing base rates in this proceeding.

9. The costs of rate base and operating revenue deductions reflected in and underlying the Stipulation, as well as the level of operating revenues under present rates, were prudently and reasonably incurred. These rate base costs and operating expenses are necessary for DNCP to meet its obligation to provide safe, adequate, and reliable electric service.

10. The Stipulation provides for certain accounting adjustments, which are set forth in detail at Settlement Exhibit II. The Stipulating Parties agree that settlement regarding those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The accounting adjustments outlined in Settlement Exhibit II are just and reasonable to all parties in light of all the evidence presented.

11. For purposes of this proceeding, the Stipulation removes certain site separation costs associated with development of the proposed North Anna Nuclear Station Unit 3 from the stipulated revenue requirement, and additionally provides that consideration of the recovery of such costs is reserved for a future proceeding. The Stipulation's treatment of the North Anna Unit 3 site separation costs is appropriate, just and reasonable to all parties in this case.

EDIT Refund

12. The Stipulation provides that the appropriate level of excess deferred income taxes (EDIT) to be refunded to customers in this case is $15,708,000 (on a pre-income-tax basis), which includes EDIT associated with the January 1, 2017, reduction in the North Carolina corporate state income tax rate from 4% to 3%.

13. DNCP shall implement a decrement rider, Rider EDIT, to refund EDIT to customers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit IV, the appropriate amount to be credited to customers is a total of $16,816,000, which should be credited to customers via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11. The ratemaking treatment of the EDIT regulatory liability set forth in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Implementation of Session Law 2015-6 (House Bill 41)

14. Pursuant to Section 2.4.(a) of House Bill 41 (HB 41), the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all tax changes enacted in Session Law 2013-316 (HB 998). Under G.S. 105-130.3C, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016. The base non-fuel rate revenue requirement in the Stipulation reflects the 3% North Carolina state income tax (SIT) rate effective for the taxable year beginning on or after January 1, 2017.

Nuclear Refueling and Outage Expense Levelization Accounting

15. Section VII of the Stipulation provides that the Company may use levelization accounting for nuclear refueling costs, as described in the testimony of Public Staff witness Fernald and Fernald Exhibit 3. The levelization accounting treatment of the nuclear refueling costs set forth in the Stipulation is just, reasonable and appropriate.

Coal Combustion Residuals (CCR) Costs

16. DNCP's actions through June 30, 2016, in addressing CCR remediation have been prudent, and its CCR costs incurred through June 30, 2016, are reasonable.

17. Section VIII of the Stipulation provides for the Company's deferral and recovery of CCR expenditures incurred through June 30, 2016, and that such costs be amortized over a five-year period. Section VIII of the Stipulation also provides that by virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR expenditures incurred through June 30, 2016, DNCP has continuing authority pursuant to the Commission's August 6, 2004 Order in Docket No. E-22, Sub 420, to implement asset retirement obligation (ARO) accounting and to defer additional CCR expenditures for consideration for recovery in a future rate case, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a future rate case or other appropriate proceeding.

18. The ratemaking treatment of the CCR costs set forth in the Stipulation, as well as the other provisions of the Stipulation regarding CCR costs, are just and reasonable to all parties in light of all the evidence presented.

Regulatory Assets

19. Section XI of the Stipulation provides for deferral accounting treatment and recovery over a three-year period on a levelized basis of deferred post-in-service costs for the Warren County CC and Brunswick County CC.

20. Section XI of the Stipulation also provides for deferral accounting treatment and recovery of the Chesapeake Energy Center (CEC) impairment and closure cost regulatory assets, as proposed by DNCP witness McLeod and further modified by Public Staff witness Fernald.

21. The Stipulation also provides for deferral accounting treatment and recovery of certain regulatory assets and liabilities expiring in 2017 as proposed by Public Staff witness Fernald, which is set forth in Section XI of the Stipulation.

22. The Stipulating Parties agreed to, and by the Stipulation requested Commission approval of, deferral accounting treatment as proposed by Company witness McLeod of costs associated with the beyond design basis studies mandated by the Nuclear Regulatory Commission (NRC) for North Carolina jurisdictional purposes. Through the Stipulation, the Company committed to comply with Commission Rule R8-27(a)(2) prior to establishing any regulatory assets and liabilities for North Carolina jurisdictional purposes in the future.

23. For the present case, the deferral and recovery of the deferred costs presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Accounting for Deferred Costs

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

Accounting and Reporting Recommendations

25. Section XIII of the Stipulation provides for certain accounting and reporting commitments by the Company, as recommended by the Public Staff and agreed to by the Company. As a result of the Stipulation, the Company will notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure. Additionally, the Public Staff's accounting recommendations concerning the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) and the service company charges will be addressed by DNCP and the Public Staff in Docket Nos. E-22,

Subs 476 and 477. Further, the Company agreed in the Stipulation to provide the Public Staff, within 90 days of the date of the Stipulation, with a presentation regarding its accounting practices for non-nuclear asset retirement obligation costs.

Base Fuel Factor

26. The Stipulation provides for a total decrease in DNCP's annual base fuel revenues of $8.942 million from its North Carolina retail electric operations, based on a base fuel factor of 2.073 cents per kilowatt-hour (kWh) (including regulatory fee), which is just and reasonable to all parties in light of all the evidence presented.

27. The base fuel factor should be differentiated between customer classes as provided on Company Rebuttal Exhibit PBH-1, Schedule 9, Page 2.

28. The Stipulation also provides for an adjustment to the Company's base fuel and non-fuel expenses to reflect 78% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage), with the remaining 22% of the cost of energy purchases being recovered by DNCP in base rates. This represents a reduction from the Company's current Marketer Percentage of 85%. The 78% Marketer Percentage agreed to in the Stipulation is reasonable and appropriate for use in this proceeding. The 78% Marketer Percentage shall remain in effect until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

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

29. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the 51.75% common equity and 48.25% long-term debt, as set forth at Section II.B of the Stipulation, is a just, reasonable, and appropriate capital structure for DNCP in this general rate case.

30. DNCP's June 30, 2016, actual long-term debt cost of 4.650% is appropriate for use in this proceeding.

31. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the rate of return on common equity that the Company should be allowed the opportunity to earn is 9.90% as set forth at Section II.B of the Stipulation. This rate of return on common equity is just, reasonable, and appropriate for DNCP in this general rate case.

32. Based on the expert witness evidence, the public witness evidence and the Stipulation, the overall rate of return that the Company should be allowed the opportunity to earn on the Company's invested capital, including its costs of equity and long-term debt, is 7.367%, as set forth at Section II.B of the Stipulation. This overall rate of return is just, reasonable, and appropriate for use in this general rate case.

33. The authorized levels of overall rate of return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of G.S. 62-133, and are fair to DNCP's customers generally and in light of the impact of changing economic conditions.

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

a. DNCP's currently authorized overall rate of return on rate base and allowed rate of return on common equity are 7.80% and 10.20% respectively.[3]

b. DNCP's current base rates became effective on November 1, 2012, and have been in effect since that date.

c. In its Application, DNCP sought approval for rates based on an overall rate of return on rate base of 7.88% and an allowed rate of return on common equity of 10.50%.

d. In the Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.367% and an allowed rate of return on common equity of 9.90%.

e. From January 2013 through September 2016, the average authorized ROE for vertically integrated electric utilities was 9.87%. Of the 77 cases decided during that period, 35 included authorized returns of 9.90% or higher. The Commission is not specifically relying on past rate of return on equity determinations authorized for other utilities in determining DNCP's cost of equity and ROE in this case; however, it is appropriate to note such past determinations as a check or as corroboration of the Commission's decision regarding the cost of equity demonstrated by the evidence in the present proceeding.

f. The stipulated overall rate of return on rate base of 7.367% and allowed rate of return on common equity of 9.90% are supported by credible, competent, material, and substantial evidence.

g. The 9.90% rate of return on equity falls between the 10.5% ROE initially requested by the Company and the ROEs recommended by ROE witnesses for Nucor and CUCA (9.0% and 8.6%) and the Public Staff (9.3% before supporting the settlement ROE of 9.90%) in this case.

h. It is appropriate to give substantial weight to the high end of the range of results from Public Staff witness Hinton's updated comparable earnings analysis, where the three highest ROE results - 10.0%, 9.9% and 9.7% - average 9.867%.

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[3] Virginia Electric & Power Co., Docket No. E-22, Sub 479, Order Granting General Rate Increase, (Dec. 21, 2012) (2012 Rate Order), Order on Remand (July 23, 2015) (2015 Remand Order).

i. It is also appropriate to give substantial weight to an average of a combination of the updated analytical results of DNCP witness Hevert. The average of his high growth rate multi-stage Discounted Cash Flow (DCF) results, his Capital Asset Pricing Model (CAPM) Value Line market risk premium results, and his bond yield plus risk premium results, is 9.86%.

j. It is not appropriate to approve the single number recommendation of any of the ROE witnesses in this case, nor any one analytical method. Rather, a 9.90% ROE represents a reasonable middle ground, avoiding the extremes reflected in the recommendation of the Company witness on the one end and the recommendations of intervenor witnesses on the other end. A 9.90% ROE is supported by witness Hinton's comparable earnings results. It is also supported by the averaging of witness Hevert's high growth rate multi-stage DCF results, CAPM Value Line market risk premium results, and bond yield plus risk premium results.

k. Substantial expert evidence presented in this matter, uncontroverted by other expert testimony on the subject, indicates that the overall economic climate in North Carolina (as well as nationally) continues to improve. This evidence includes data and projections from reliable sources indicating that in the few months before the hearing in this matter: (1) unemployment rates were declining; (2) real gross domestic product growth was continuing; (3) median household income was growing; and (4) residential electricity costs remain well below the national average. In DNCP's service territory specifically, such data show that: (1) economic conditions remain difficult for many people; (2) but recent changes in economic conditions have been positive, as unemployment has fallen considerably in the last several years and per capita income has been growing.

l. During four public hearings held in Halifax, Manteo, Elizabeth City, and Williamston, the Commission heard testimony regarding economic conditions and the potential impact of DNCP's proposed rate increase on the Company's customers. No public witnesses appeared at the hearing held in Raleigh. Of the 120,000 DNCP retail customers in North Carolina, 26 public witnesses testified at the hearings, many of whom testified that the rate increase was not affordable to many customers, including senior citizens, persons on fixed incomes, persons with disabilities, the unemployed and underemployed, and the poor. The Commission has considered this public witness testimony in its deliberations in setting just and reasonable rates for DNCP, including its determination that a 9.90% ROE and a 51.75% equity component of the stipulated capital structure are reasonable.

m. The rate increase approved in this case, which includes the approved ROE and capital structure, will be difficult for some of DNCP's customers to pay, in particular the Company's low-income customers.

n. The 9.90% rate of return on equity takes into account the impact of changing economic conditions on consumers. The authorized revenue amount available to pay a return on equity is lower for DNCP because the Stipulation reduced downward DNCP's requested revenue requirement, and this reduction is intertwined with the decision on rate of return on equity in that it affects the earnings available to investors and the rates customers will pay.

o. No party submitted evidence showing that any regulatory commission applies increments or decrements to the return on equity to account for economic conditions or customer ability to pay.

p. DNCP has made significant capital investments since its last rate case in 2012, much of which relates to its efforts to add new baseload combined cycle generating capacity to its fleet and to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina and throughout its system. All of these investments further the mission of ensuring reliability, operational excellence, and efficient electric service for DNCP's customers. The Company plans to make additional significant capital investments in the future.

q. Continuous safe, adequate, and reliable electric service by DNCP is essential to the well-being of the people, businesses, institutions, and economy of North Carolina, and access to capital at reasonable rates is critical to DNCP's ability to fund its ongoing capital investment requirements and DNCP's provision of safe, reliable, and cost effective electric service.

r. The 9.90% ROE and the ratemaking capital structure consisting of 51.75% common equity approved by the Commission in this case result in a cost of capital that will enable DNCP by sound management to produce a fair return for its shareholders, and is just, reasonable, and fair to DNCP's customers considering the impact of changing economic conditions on those customers. The resulting cost of capital is as low as reasonably possible and appropriately balances DNCP's need to obtain financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

s. The potential difficulties that DNCP's low-income customers will experience in paying DNCP's increased rates will be somewhat mitigated by the $400,000 of shareholder funds that the Company will contribute to assist low-income customers.

Revenue Increase

35. The Stipulation provides for an increase in DNCP's annual electric sales revenues from its North Carolina retail electric operations of $34.732 million. With the stipulated decrease in annual base fuel revenues of $8.942 million, there is a net overall revenue increase of $25.790 million from its North Carolina retail electric operations. The increase in annual non-fuel base rates to be paid by DNCP's North Carolina retail customers is just and reasonable to all parties in light of all the evidence presented.

EnergyShare Contribution

36. Section XV of the Stipulation provides that the Company will make a one-time $400,000 shareholder contribution to the North Carolina EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina

service territory. This $400,000 will be an additional contribution in 2017 on top of the Company's usual annual contribution of about $360,000. This shareholder contribution represents an additional rate mitigation measure that could not have been ordered by the Commission without agreement by the Company. This provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Cost of Service Allocation Methodology

37. The Stipulation provides for the use of the Summer-Winter Peak and Average (SWPA) methodology to allocate the Company's cost of service to the North Carolina jurisdiction and among the customer classes in this case. The Stipulating Parties agreed that use of the SWPA methodology for allocation between jurisdictions and among customer classes shall not be a precedent for, and may be contested in, future general rate case proceedings. The Stipulating Parties further agree that the Company's proposed adjustment to DNCP's recorded summer and winter peaks to recognize the peak demand contributions of non-utility generators (NUGs) interconnected to the Company's distribution system is appropriate and reasonable. The SWPA cost of service methodology, as adjusted by DNCP to account for the peak demand contribution of distribution-connected NUGs, is appropriate for determining the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility for purposes of this case.

38. DNCP's adjustment to the peak component of SWPA appropriately recognizes the impact non-utility generators have on DNCP's utility system and is appropriate for use in this proceeding.

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

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

41. It is not reasonable nor necessary at this time to require the Company to re-evaluate the issues addressed in the 1994 fuel study filed in Docket No. E-22, Sub 333, as raised by Nucor.

Rate Design

42. For purposes of apportioning and assigning the approved increase in base non-fuel and base fuel revenues between the North Carolina customer classes in this proceeding, the apportionment and rate design principles presented by Company witness Haynes in his direct and rebuttal testimony, as modified in Section V of the Stipulation, are reasonable, appropriate, and nondiscriminatory. The Stipulation further provides that in developing rates based upon the foregoing class apportionment, the Company agrees

to recover 100% of the stipulated revenue increase through the energy and demand components of rates and not to increase the basic customer charge component of rates.

Schedule 6L

43. The new Rate Schedule 6L, as amended in Company Rebuttal Exhibit PBH-1, Schedule 12 to eliminate the NAICS "Manufacturing" classification as part of the qualification for this rate schedule, is reasonable, nondiscriminatory, and should be approved.

Utilities International Model (UI Model)

44. The Stipulation provides that DNCP will work with its cost of service model vendor to determine whether an application can be produced that would enable an intervenor or the Public Staff to perform certain cost of service model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings. DNCP should work with its vendor, Utilities International, to assess reasonable additional cost of service model functionalities that can be produced in an Excel spreadsheet-based format. DNCP should be prepared prior to filing its next general rate case to release the Excel product to intervenors as requested.

LED Schedule

45. The Stipulation provides that the Company shall develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of the Commission's final order in this proceeding. This provision of the Stipulation is reasonable and appropriate.

Time-Differentiated Rates

46. DNCP currently does not offer a Real Time Pricing (RTP) rate for its service territory in North Carolina. It is reasonable to expect the Company to propose a pilot or experimental RTP rate offering no later than July 1, 2017.

47. The number of DNCP residential customers receiving service on either of the time-of-use rates offered by DNCP in North Carolina is approximately 0.3%. In 2008, the Commission encouraged utilities to increase the utilization of time-differentiated rates. However, the percentage of DNCP's residential customers participating is smaller now than it was in 2007. Therefore, DNCP should be required to provide a written summary of its time-of-use rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter. Further, the Commission approves the terms of the agreement filed herein by DNCP and NCSEA on December 13, 2016.

Terms and Conditions

48. The Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Item 39 of the Company's Form E-1 filed with its supplemental direct testimony on August 12, 2016. The rate designs, rate schedules, and service regulations proposed by the Company are reasonable, as filed, except as specifically addressed in the Stipulation and this Order.

Quality of Service

49. The overall quality of electric service provided by DNCP is good.

PJM Conditions

50. It is appropriate to relieve the Company from compliance with most, but not all, of the conditions that were imposed by the Commission's April 19, 2005 Order Approving Transfer Subject to Conditions issued in Docket No. E-22, Sub 418. The Company shall continue to file with its annual fuel clause adjustment filing the information required by Paragraph 5 of the November 10, 2004 Joint Offer of Settlement between DNCP and PJM. The Independent Market Monitor (IMM) for PJM shall continue to annually file the information required by Paragraph 6 of that same Joint Offer of Settlement. DNCP committed in the Stipulation to comply with the representations and commitments made in its July 8, 2016 Supplemental Filing with respect to certain obligations, and that provision of the Stipulation is just and reasonable. Further, it is appropriate to require the Company to file as a compliance filing in this case a comprehensive document entitled "Code of Conduct" that shall include all representations and commitments to which the Company will be bound, consistent with this Order.

Acceptance of the Stipulation

51. Based upon all of the evidence in the record, including consideration of the public witness testimony and the record evidence from parties who have not agreed with the Stipulation, the provisions of the Stipulation are just and reasonable to the customers of DNCP and to all parties to this proceeding, and serve the public interest. Therefore, the Stipulation should be approved in its entirety. In addition, the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

Just and Reasonable Rates

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

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

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Form E-1 of DNCP, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party. In addition, the Commission finds and concludes that the Company's use of a test period of the 12 months ended December 31, 2015, with appropriate adjustments through June 30, 2016, comports with the requirements of G.S. 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

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

On March 1, 2016, pursuant to Commission Rule R1-17(a), DNCP filed notice of its intent to file a general rate case application. On the same date, DNCP filed a letter informing the Commission of the Company's intention to propose accounting adjustments to include an appropriate level of amortization of deferred post-in-service costs associated with the Company's Warren County Power Station (Warren County CC) in its rate case revenue requirement.

On March 31, 2016, DNCP filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $ 51,073,000 in its annual electric sales revenues from its North Carolina retail electric operations. The Application is based on a requested rate of return on common equity (ROE) of 10.50%, an overall rate of return of 7.88%, an embedded long-term debt cost of 4.889%, and DNCP's actual capital structure of 53.36% common equity and 46.64% long-term debt, as of December 31, 2015. Further, the Application states that DNCP's 2015 ROE was 5.06%, and its overall rate of return was 4.98%.

The Company's last general rate case was in 2012 in Docket No. E-22, Sub 479. By Order issued on December 21, 2012, the Commission approved an increase in DNCP's base non-fuel revenues of $36,438,000, and a decrease of $14,484,000 in its base fuel revenues. DNCP's current authorized ROE is 10.2%, its authorized overall rate of return is 7.8%, and its authorized capital structure for ratemaking purposes is 51% common equity, 1.5% preferred stock and 47.5% long-term debt.

In its present Application, the Company proposed to implement the non-fuel base rate increase on a temporary basis subject to refund effective on November 1, 2016, along with an accelerated implementation of its new lower base fuel rate – to be filed in August 2016 – as part of any temporary rates (subject to refund) proposed to become effective November 1, 2016. The Company also proposed a methodology for returning certain excess accumulated deferred income taxes (EDIT) to customers through a decrement rider, Rider EDIT, over a two–year period; sought authority to use certain deferred accounts to implement a levelization methodology on its books for its nuclear unit refueling and maintenance outage expenses; and requested an adjustment of the Marketer Percentage to 100%. Further, DNCP requested the deferral of several costs that it had incurred. Finally, DNCP requested relief from the regulatory conditions imposed in the PJM Order.

In its supplemental testimony filed on August 12, 2016, DNCP updated the increase sought in its non-fuel base rates and charges to its North Carolina retail customers to $47.8 million. Upon making certain adjustments, DNCP updated the increase sought to $46.8 million in rebuttal testimony filed on September 26, 2016.

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

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

The evidence supporting these findings of fact and conclusions is contained in the testimony of DNCP's witnesses Curtis, Haynes, Hevert, McLeod and Stevens, Public Staff witness Hinton, the provisions of the Stipulation, and the entire record in this proceeding.

On October 3, 2016, DNCP, the Public Staff and CIGFUR I (Stipulating Parties) filed a Stipulation resolving all of the issues among the Stipulating Parties. The Stipulation is based on the same test period as the Company's Application. In summary, the Stipulation provides:

- A $34.7 million increase in DNCP's annual non-fuel base revenues;
- A $8.9 million decrease in DNCP's annual fuel base revenues;
- A 2-year Excess Deferred Income Taxes decrement rider (Rider EDIT) returning to ratepayers excess deferred income taxes in the amount of approximately $15.7 million beginning November 1, 2016;
- An overall base rate increase for all customer classes of approximately 7.47%, excluding the effect of any 2017 Fuel Factor Riders and the Rider EDIT decrement;
- An increase to residential customers' bills for 2017 limited to 0.08%, taking into account the effect of the base rate increase, overall fuel decrease, the Company's proposed 2017 Fuel Factor Riders, and the Rider EDIT decrement;
- A rate of return on equity of 9.90% and an overall rate of return on rate base of 7.367%;

- A capital structure for ratemaking purposes consisting of 51.75% equity and 48.25% long-term debt;
- An embedded cost of debt of 4.650%;
- A 5-year amortization of costs associated with coal combustion residual expenditures incurred through June 30, 2016;
- Withdrawal from this case of DNCP's request to recover site separation costs associated with the proposed North Anna 3 nuclear plant. Consideration of the recovery of any such costs would be reserved for a future proceeding;
- Allocation of the Company's cost of service based on the Summer/Winter Peak and Average (SWPA) method;
- A one-time $400,000 shareholder contribution by DNCP to the EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina service territory;
- Deferral of the post-in-service costs of the Warren County CC and Brunswick County CC generating facilities;
- Deferral of the Chesapeake Energy Center (CEC) impairment and closure costs; and
- Subject to certain clarifications and conditions, release of DNCP from further compliance with the regulatory conditions imposed by the Commission in its Order Approving Transfer Subject to Conditions, Docket No. E-22, Sub 418 (April 19, 2005), approving DNCP's participation in PJM.

In his testimony in support of the Stipulation, filed on October 3, 2016, DNCP witness Curtis stated that the Company was able to reach a settlement with the Public Staff after extensive discovery conducted by the Public Staff and other intervenors. Witness Curtis further testified that the Stipulation is the product of give-and-take negotiations between the Company and the Public Staff. He testified that through extensive discussions and negotiations with the Public Staff, the Company and Public Staff were able to strike the balance between reasonable rates for customers and the Company's need to attract capital in order to continue providing safe and reliable service. In addition, witness Curtis testified that the Company understands that the Commission must set just and reasonable rates, including the authorized ROE, in a way that balances the economic conditions facing DNCP's customers with the Company's need to attract capital in order to continue providing safe and reliable service. He testified that the Stipulation mitigates the impact on DNCP's customers of the rate relief provided to the Company through, for example, the agreed-upon cost of service adjustments, the reduced overall revenue requirement, the decreased base fuel factor, and the refund of excess deferred income taxes through decrement Rider EDIT. Witness Curtis also noted that the Stipulation provides significant benefits that could not otherwise be ordered by the Commission, including the accelerated refund of the current fuel over-recovery through decrement Rider A1, and the Company's agreement to make a $400,000 contribution of shareholder funds to the North Carolina EnergyShare program, to provide energy assistance to customers in need in DNCP's North Carolina service area.

Company witness Hevert filed testimony on October 3, 2016, in support of the Stipulation. He testified that although the ROE agreed upon in the Stipulation is below the lower end of his recommended range (i.e. 10.25%), he recognizes that the Stipulation represents the give-and-take regarding multiple issues that would otherwise be contested.

Company witnesses Stevens and McLeod filed joint testimony on October 3, 2016, in support of the Stipulation. They testified that subsequent to the filing of the Company's Application, DNCP, the Public Staff and other intervenors engaged in substantial discovery, and that the parties filed testimony asserting their positions, with DNCP also filing rebuttal testimony responding to the other parties' positions. Witnesses Stevens and McLeod further testified that after lengthy negotiations the Company and Public Staff arrived at a settlement of all of the issues between them. Witnesses Stevens and McLeod also noted that DNCP negotiated in good faith with other parties, and was able to reach a settlement with CIGFUR I. In addition, witnesses Stevens and McLeod stated that the Stipulation is the result of give-and-take negotiations in which each party made substantial compromises on certain issues in order to gain compromises from the other party on other issues, and that the Stipulating Parties believe the results reached are fair to the Company and its customers. Finally, they noted that the Stipulation resolves all issues among the Stipulating Parties without the necessity of contentious litigation.

DNCP witness Haynes also filed testimony on October 3, 2016, in support of the Stipulation. Witness Haynes testified that he believes the Stipulation constitutes a just and reasonable approach to establishing DNCP's cost of service, apportioning the costs among the customer classes, and designing the Company's rates and charges. Moreover, he testified that the Stipulation represents a compromise between differing interests in a number of respects, including CIGFUR I's support of the Company's proposed SWPA cost allocation methodology, and CIGFUR I's withdrawal of its request that an additional portion of the rate increase be allocated to the NS Class.

Public Staff witness Hinton also filed testimony in support of the Stipulation on October 3, 2016. Witness Hinton testified that the Public Staff and DNCP have fundamentally different views of the current market conditions and cost of capital, and that neither party persuaded the other to change its views. He testified that the Public Staff and DNCP nonetheless found a way to bridge their differences and to reach agreement on a proposed ROE and capital structure. Witness Hinton further stated that the stipulated ROE of 9.90% and equity ratio of 51.75% came about as a result of various compromises on other issues by both DNCP and the Public Staff. In addition, Public Staff witness Fernald testified to her belief that the Stipulation is in the public interest.

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

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding.
>
> The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

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

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

The Commission gives substantial weight to the testimony of DNCP witnesses Curtis, Haynes, McLeod and Stevens describing the Stipulating Parties' efforts in negotiating the Stipulation. Further, the Commission gives significant weight to the settlement testimony of Public Staff witnesses Fernald and Hinton, which in their discussion of the benefits that the Stipulation will provide to customers and their testimony describing the compromise reflected in the Stipulation's terms indicate the Public Staff's commitment to fully represent the using and consuming public. In addition, the Commission gives some weight to the fact that the settlement was not reached until October 3, 2016, the day before the expert witness hearing began. Prior to that date, DNCP, the Public Staff and CIGFUR I pre-filed the testimony of their experts setting forth their litigation positions on the issues. That indicates to the Commission that the Stipulating Parties were fully prepared to litigate the contested issues in the event that a settlement was not reached.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-11

The evidence supporting these findings of fact and conclusions is contained in DNCP's verified Application, the direct, supplemental and rebuttal testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Rate Base

Per Settlement Exhibit I of the Stipulation, the amount of original cost rate base is $1,040,035,000. A breakdown of the components of the original cost rate base is as follows (000's omitted):

Line No.	Item	After Rate Increase
1	Electric plant in service	$1,947,252
2	Accumulated depreciation and amortization	(716,858)
3	Net electric plant in service (L1 + L2)	1,230,394
4	Materials and supplies	44,916
5	Cash working capital	18,476
6	Other additions	19,607
7	Other deductions	(17,434)
8	Customer deposits	(5,126)
9	Accumulated deferred income taxes	(250,799)
10	Rounding	1
11	Total original cost rate base (Sum of L3 thru L10)	$1,040,035

Discussion of Certain items included in Rate Base

North Anna 3 Site Separation Costs

The Company's Application included certain North Anna Power Station "site separation" plant investments in DNCP's rate base for ratemaking purposes.

Public Staff witness Metz testified that the North Anna Power Station consists of two nuclear reactors, North Anna Units 1 and 2, that are in-service, as well as a potential site for a third nuclear reactor, known as North Anna 3, for which DNCP has not sought a certificate of public convenience and necessity from the Virginia State Corporation Commission (SCC), a determination of need from this Commission pursuant to G.S. 62-110.6, or approval from this Commission of its decision to incur project development costs pursuant to G.S. 62-110.7. In the Company's most recent integrated resource plan (IRP) in Docket No. E-100, Sub 147, DNCP indicates that it is engaged in development efforts in regard to North Anna 3 and is currently pursuing a Combined Operating License from the NRC, which is expected next year.

Witness Metz testified that the Company has included in its cost of service certain capital investment and related expenses associated with site preparation activities for North Anna 3. Site activities for North Anna 3 have involved removing existing structures/buildings that support North Anna Units 1 and 2, and then relocating them outside of the proposed construction zone of North Anna 3.

Witness Metz cited Company witness Mitchell's testimony in SCC Case No. PUE-2015-00027 that stated, "[t]he services supported by each of these assets will be used by the operating Units 1 and 2 as well as Unit 3 if the Company proceeds with construction. However, but for the development of North Anna 3, the development of these assets would not have been needed." Further, in rebuttal in that same case, witness Mitchell stated: "I highlight that but for the development of North Anna 3, these preconstruction site separation activities would not have been needed." Public Staff witness Metz asserted that these costs should be assigned to North Anna 3 and thus removed from DNCP's cost of service in this proceeding.

Similarly, Nucor witness Kollen testified that the site separation costs are solely related to North Anna 3, and not North Anna 1 and 2; therefore, these costs should be removed from rate base and depreciation expense in this proceeding. Witness Kollen additionally testified that in the Company's most recent biennial review, the Virginia SCC removed the North Anna 3 costs from rate base and operating expense that it was not required to include pursuant to Virginia state law (70% of new nuclear construction costs incurred between July 1, 2007, and December 31, 2013).

In rebuttal, Company witness Mitchell provided a brief history of North Anna Units 1 and 2 and explained the decision making process to move forward with North Anna 3 development as part of the Company's resource planning strategy. Witness Mitchell explained that North Anna Units 1 and 2 are benefiting from the new buildings and how these common facilities would eventually support a third nuclear unit at the site. The new facilities, including warehouses, paint shops, welding areas, and vehicle repair shops, are now in service supporting the operating North Anna station, including Units 1 and 2. Witness Mitchell disputed Public Staff witness Metz's characterization of the activities in question as "site preparation activities for North Anna 3" rather than "site separation activities" needed for North Anna, testifying that the new support buildings and infrastructure are needed today in order to continue the safe and reliable operations of North Anna Units 1 and 2. Witness Mitchell testified that this limited universe of costs are site "separation" investments that are now in service and being used to support operations at North Anna Units 1 and 2.

Company witness Stevens disagreed with Public Staff witness Metz's and Nucor witness Kollen's claim that the North Anna site separation costs are solely related to North Anna 3, not to North Anna Units 1 and 2. While the future development of an additional nuclear unit was the driver of the overall project, witness Stevens explained that the site separation assets are common assets that are used and useful assets today at North Anna. Witness Stevens asserted that the Company's accounting for the site separation assets is also consistent with the FERC USOA. As such, he insisted that the site separation assets – which are now in-service and are used and useful today – should not be recorded in construction work in progress (CWIP), but appropriately recorded in plant-in-service.

In his rebuttal testimony, witness Stevens testified that the Virginia SCC did not remove North Anna 3 rate base and operating expenses in the Company's most recent biennial review in Virginia – it included the recovery of 70% of "all costs" related to North Anna 3 as a period expense in the Company's earnings test results for fiscal year 2014. Specifically, he testified that the Virginia legislature has provided explicit direction to the Virginia SCC through Va. Code § 56-585.1 regarding the manner in which VEPCO, operating in Virginia as Dominion Virginia Power, shall be authorized to recover the costs of new generating facilities (including recovery of CWIP) and other utility plant. DNCP witness Stevens asserted that the Virginia cost recovery statute should have no bearing on DNCP's recovery of the North Carolina portion of site separation costs under the North Carolina Public Utilities Act. According to witness Stevens, prudently incurred investments in plant-in-service that are used and useful today to serve the Company's North Carolina customers are recoverable under the North Carolina Public Utilities Act.

Witness Stevens asserted in his rebuttal testimony that Nucor witness Kollen's calculation of its adjustment to remove the site separation costs was overstated. According to DNCP witness Stevens, witness Kollen imputed depreciation expense for the assets rather than evaluating the actual depreciation expense reflected in the cost of service. Witness Stevens further testified that Nucor witness Kollen also failed to adjust for accumulated deferred income taxes associated with the site separation assets, thereby incorrectly reducing rate base.

For purposes of this proceeding, the Stipulation provides that certain site separation costs associated with development of the proposed North Anna Nuclear

Station Unit 3 be removed from the stipulated revenue requirement, and that consideration of the recovery of such costs shall be reserved for a future proceeding. Based on this proceeding and the entire record as a whole, the Commission finds and concludes that the Stipulation's treatment of the North Anna Unit 3 site separation costs is appropriate, just and reasonable in this case.

Cash Working Capital (CWC)

In his direct testimony, Company witness McLeod testified that the CWC requirement is based on a lead/lag study prepared based on calendar year 2013 data. According to witness McLeod, the CWC calculation for regulatory purposes is consistent with DNCP's lead/lag study methodology described in the Company's Reply Comments filed in Docket No. M-100, Sub 137, and meets the requirements identified in the Commission's March 21, 2016 Order Clarifying Order on Lead-Lag Study Procedure.

Public Staff witness Fernald identified and proposed a number of adjustments and corrections to the Company's calculation of CWC in her testimony. Additionally, the Public Staff adjusted CWC under present rates to reflect all of the Public Staff's adjustments, in accordance with the Commission's Order in Docket No. M-100, Sub 137.

Nucor witness Kollen testified that the Company's CWC calculation includes the following non-cash expenses: depreciation and amortization expense; deferred federal and state income tax expense, and income available for common. Witness Kollen argued that these non-cash expenses are typically excluded in the lead-lag calculation for that reason, and recommended that the Commission exclude these non-cash expenses from the lead/lag calculation.

As reflected in the rebuttal testimony of Company witness McLeod, DNCP reviewed Public Staff witness Fernald's testimony and exhibits and accepted each of the revisions to the Company's lead-lag study and allowance for CWC, as adjusted by witness Fernald, with the exception of the current state income tax expense lead days. Company witness McLeod testified that the Company disagreed with the Public Staff's correction to the current income tax expense lead days because the Company's expense lead days are based on all current tax payments during the year. Witness McLeod explained that the Company does not necessarily agree with the Public Staff's other revisions to the expense lead and revenue lag days, but has accepted the changes for purposes of this proceeding due to their minor impact on the overall base non-fuel rate revenue requirement.

In his rebuttal testimony, Company witness Stevens disputed Nucor witness Kollen's recommendation to exclude certain non-cash items from the determination of CWC. Witness Stevens explained that the Company's treatment of these items is consistent with the Company's prior practices and this Commission's prior treatment of lead-lag studies and CWC. According to witness Stevens, the Commission had previously addressed the same issue also raised by Nucor in Docket No. M-100, Sub 137, and the Commission overruled Nucor's position. Witness Stevens recommended that the

Commission reject Nucor's adjustment to exclude these expenses from the lead-lag calculation.

The Commission notes that the allowance for CWC in the Stipulation includes an expense lead for current income taxes based on the statutory filing deadlines as proposed by Public Staff witness Fernald. The Commission finds and concludes that for the present case the CWC allowance presented in the Stipulation and agreed to by DNCP and the Public Staff is just and reasonable to all parties in light of all the evidence presented. With respect to Nucor witness Kollen's recommendation regarding certain non-cash items, Nucor has not presented any new evidence to dissuade the Commission from its findings and conclusions addressing inclusion of non-cash items in CWC, as set forth in its May 15, 2015, Order Ruling on Lead-Lag Study Procedure, in Docket M-100, Sub 137. Therefore, the Commission rejects Nucor's position regarding the exclusion of certain non-cash items in the calculation of CWC.

Accumulated Deferred Income Taxes Due to Bonus Depreciation on Brunswick County CC

In its supplemental filing, DNCP updated its rate base as of June 30, 2016. DNCP witnesses testified that this calculation also incorporated both the investment and the accumulated deferred income taxes (ADIT) associated with the recently completed Brunswick County CC. Embedded in the ADIT calculation is the impact of bonus depreciation as recorded on the Company's books and records as of June 30, 2016.

Nucor witness Kollen testified that the Company calculated ADIT due to first year bonus depreciation for the Brunswick County CC and included only six months as a subtraction from rate base. According to witness Kollen, bonus depreciation is taken when the asset is placed in service for tax purposes and the entirety of the ADIT is available at June 30, 2016, not just half (or six months) as reflected in the Company's filing. Witness Kollen contended that the Company chose to allocate the bonus depreciation equally over the months in calendar year 2016 in the filing; however, this understates the ADIT available from bonus depreciation at June 30, 2016. Witness Kollen recommended that the Commission reflect the full federal ADIT from bonus depreciation at June 30, 2016.

In response to Nucor witness Kollen, in his rebuttal testimony Company witness Warren discussed the history of bonus depreciation, and explained that bonus depreciation is conceptually no different from other forms of accelerated depreciation; it represents an incentive provided by the government for stimulating capital investment. Witness Warren testified that by allowing businesses to claim accelerated depreciation, Congress essentially causes the government to extend interest-free loans to those enterprises. These loans, according to witness Warren, produce incremental cash (*i.e.*, a reduction in the amount of tax otherwise payable), which are presently available to the utility, but will have to be paid back to the government over time. He further testified that the repayment of such loans is effected by filing future tax returns. Witness Warren explained that the outstanding loan balance is reflected as an ADIT credit, which is properly reflected as a reduction to rate base. In this way, ratepayers receive the entire benefit of the interest-free feature of the loan.

DNCP witness Warren testified that the nature of the disagreement between the Company and witness Kollen is over how much of the ADIT benefit of the Company's 2016 bonus depreciation should be recognized when computing its rate base as of June 30, 2016. The Company contends that it should recognize a half year's worth of the benefit. Witness Kollen contends that it should recognize 100% of the benefit. Witness Warren explained that on DNCP's accounting records, it spreads the benefits of accelerated tax depreciation ratably over the entire year in which the accelerated depreciation is claimed. He stated that this methodology is not one that it applied only to the Brunswick County CC facility or used only for purposes of calculating ADIT in this proceeding. In fact, as of June 30, 2016, the Company's accounting records reflect 50% of the benefit of the bonus depreciation (as well as of the "regular" accelerated tax depreciation on the non-deducted cost) it will claim on its 2016 tax return relating to Brunswick County CC facility. Thus, the ADIT the Company has recognized for purposes of this proceeding conforms to the ADIT it has recognized for all other purposes. Witness Warren further testified that witness Kollen's proposal recognizes an ADIT amount for purposes of the Company's rate base calculation that does not appear on its books and records.

Witness Warren testified that witness Kollen's assertion that the bonus depreciation deduction is taken when the asset is placed in service is both inaccurate and irrelevant. The Brunswick County CC bonus depreciation deduction will not be taken until DNCP files its 2016 federal income tax return in the second half of 2017. According to witness Warren, the critical issue is when the cost-free capital produced by the Company's ability to claim bonus depreciation with respect to the Brunswick County CC facility becomes available to the Company. According to witness Warren, witness Kollen incorrectly presumes that this occurs when the facility is placed in service.

Witness Warren explained that the Company acquires the cost-free capital produced by accelerated depreciation on the facility by reducing its estimated tax payments. As a tax year progresses, corporations are required to make four estimated tax payments so that they pay their tax liability during the year – not when they file their tax return. The amount of the quarterly estimated tax payments, according to Witness Warren, is equal to the lesser of: (1) one-fourth of the tax liability for the year; or (2) an amount calculated by annualizing the taxable income generated during the period. In terms of alternative (1) above, one-fourth of the impact of any bonus depreciation claimed during the year will reduce each of the four estimated tax payments. Thus, the effect of bonus depreciation is spread ratably throughout the year. Therefore, under alternative (1), the ADIT recorded on the Company's books and records as of June 30, 2016, accurately reflects the cost-free capital in its possession. Witness Warren contended that witness Kollen's proposed adjustment imputes a quantity of cost-free capital that, in fact, did not exist as of June 30, 2016.

Witness Warren explained that under alternative (2) above, the applicable tax regulation, Treasury Regulation §1.6655-2(f)(3)(iv), dictates how depreciation must be handled when a taxpayer annualizes its taxable income. It provides that, in determining taxable income for any annualization period, a proportionate amount of the taxpayer's estimated annual depreciation is taken into account. Thus, the benefit of the bonus depreciation actually claimed during the first period is spread over all four periods. Therefore, under alternative (2), the ADIT recorded on the Company's books and records as of June 30, 2016, accurately reflects the cost-free capital in its possession. Witness Warren contended that witness Kollen's proposed adjustment would again impute a quantity of cost-free capital that did not exist as of June 30, 2016.

Further, witness Warren testified that witness Kollen's proposal also creates a conflict with the tax depreciation normalization rules (Normalization Rules). The Normalization Rules are established by §168(i)(9) of the Internal Revenue Code of 1986, as amended, and Treas. Reg. §1.167(l)-1. They are quite complex, but prescribe: (1) how to implement the required tax benefit deferral (*i.e.*, normalization); (2) what can be done with the deferred tax benefit once it is deferred; and (3) under what circumstances the deferred tax benefit can be reversed. Witness Warren explained that accelerated depreciation was enacted by Congress to promote investment by businesses (including utilities) in plant and equipment. However, Congress was concerned that, in the case of a regulated utility whose rates are set by reference to its costs (one of which is tax expense), these incentives could be extracted from the utility and flowed directly to its customers through the rate-setting process, and the benefits would be stripped from the utilities and converted into consumption subsidies for utility customers who did not necessarily use the money to make plant investments. According to witness Warren, this was not Congress' intent, and it included in the tax law a set of rules to prevent this from happening – the Normalization Rules.

Witness Warren further explained that because the Normalization Rules permit rate base to be reduced by the cost-free capital produced by claiming accelerated depreciation, the benefits of accelerated depreciation that those rules intend to preserve can be passed through to ratepayers by ratemaking that presumes the existence of an excessive quantity of cost-free capital. DNCP witness Warren testified that the Normalization Rules therefore impose a limit on the amount of depreciation-related ADIT by which rate base can be reduced. Witness Warren contended that the limitation that is relevant to witness Kollen's proposed adjustment is the one contained in Treasury Regulations §1.167(l)-1(h)(6) entitled "Exclusion of normalization reserve from rate base." Treasury Regulations Section §1.167(l)-1(h)(6)(i) states, in pertinent part:

> [A] taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied...exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

This regulation requires that rate base not be reduced by an ADIT balance unless that balance has been included in the utility's cost of service. Witness Warren testified that the additional six months of ADIT that witness Kollen proposes to factor into the Company's rate base computation has not been included in the Company's cost of service. Witness Warren asserted that only the amount that has been reflected on the Company's accounting records – the amount that it has used in its rate base computation – has been included in cost of service.

Witness Warren testified that as a condition for claiming accelerated tax depreciation (including bonus depreciation) on any of its depreciable assets, a utility must use a normalization method of accounting. Thus, the penalty for a violation in this proceeding would not be confined to the Brunswick County CC facility, but would extend to all of the Company's North Carolina depreciable assets. Witness Warren explained that the penalty for violating the Normalization Rules is draconian. By no longer being able to claim accelerated depreciation, a non-compliant utility would not generate any additional interest-free, governmental loans. Moreover, witness Warren stated that all governmental loans outstanding as of the date of the violation would have to be paid back a good deal more rapidly than would otherwise have been the case. The inability to claim accelerated tax depreciation would result in a significant reduction in the quantity of cost-free loans such depreciation deductions produce. Company witness Warren attested that this would manifest itself in the form of a dramatically reduced ADIT balance. Since the Company's ADIT balance offsets the rate base upon which a return must be allowed, diminished ADIT balances will produce a higher rate base and, consequently, higher rates than had the normalization violation not occurred.

The Stipulation reflects ADIT from bonus depreciation for the Brunswick County CC as of June 30, 2016, as a reduction to rate base as proposed by the Company.

Based upon the evidence presented by Company witness Warren, the Commission concludes that witness Kollen's proposal to reflect the full federal ADIT from bonus depreciation for the Brunswick County CC as a reduction to rate base as of June 30, 2016, is unreasonable and inappropriate. The Commission agrees with Company witness Warren that DNCP acquires the cost-free capital produced by accelerated depreciation on the facility by reducing its estimated tax payments made over the course of the tax year. As of June 30, 2016, the Company had only acquired half of this benefit, which DNCP has appropriately reflected as a reduction to rate base. The Commission, therefore, finds and concludes that the ADIT reflected in the Stipulation associated with the Brunswick County CC bonus depreciation is just and reasonable to all parties in light of all the evidence presented.

Operating Expenses

Operating Expenses per the Stipulation are $299,084,000. A breakdown of the operating expenses allowed in this proceeding is as follows:[4]

Line No.	Item	Amount (000's omitted)
1	Electric operating expenses:	
2	Operations and maintenance:	
3	Fuel clause expenses	$90,686
4	Other operations and maintenance expenses	98,989
5	Depreciation and amortization	60,047
6	Gain / loss on disposition of property	309
7	Taxes other than income taxes	15,233
8	Income taxes	33,820
9	Total electric operating expenses (Sum of L3 thru L8)	$299,084

Discussion of Certain items included in Operating Expenses

Uncollectible Expense

In its Application, DNCP proposed a normalization adjustment to uncollectible expense based on an historical average uncollectible expense rate for the five-year period of 2011-2015. Public Staff witness Fernald presented testimony stating that in 2014, the Company changed its write-off and collection policies for customers with medical certifications. According to witness Fernald, prior to that time, although these customers existed, the Company did not include them in its determination of the reserve for uncollectibles. She further testified that in 2014, DNCP began including customers with medical certifications in its calculation of the reserve, and to implement this policy change the Company recorded a $12.1 million credit accounting adjustment, on a total system level, to its reserve for uncollectibles account, with a charge to uncollectible expense, in order to establish an initial reserve for these customers. Witness Fernald testified that data from 2014 and prior years should not be used to determine an ongoing level of uncollectibles, since data from those years cannot validly be compared with 2015 data. Accordingly, witness Fernald stated that she calculated uncollectibles based on 2015 data, reflecting the Company's current policy of establishing a reserve for customers with

[4] Chart omits 000's.

medical certificates. Witness Fernald noted that the uncollectibles rate utilized by the Public Staff was 0.4814% as compared to the Company's 0.5549% rate.

Company witness McLeod testified that the Company's adjustment based on a five-year historical average expense rate methodology was consistent with the methodology approved by the Commission in the 2012 rate case, Docket No. E-22, Sub 479 (2012 Rate Case), as well as the Company's prior 2010 rate case, Docket No. E-22, Sub 459 (2010 Rate Case). Witness McLeod noted that the methodology approved in the 2012 Rate Case, which the Company followed in its Application, was first proposed by Public Staff witness Fernald in that proceeding. Witness McLeod argued that a change in accounting policy should not negate the use of an historical average since the purpose of using a historic average is to recognize the volatile nature of the expense - capturing both the highs and lows – and include a "normal" level that the Company will incur over a reasonable period of time. He asserted that normalization adjustments are designed to smooth out volatility in interim years including changes in accounting policy.

The Stipulation provides for an adjustment to uncollectible expenses based on 2015 data as proposed by witness Fernald. The Commission finds and concludes that for the present case the accounting adjustment is just and reasonable to all parties in light of the agreement between the Company and the Public Staff in the Stipulation and all the evidence presented.

Major Storm Restoration Expense

The Company proposed a normalization adjustment to non-labor and overtime major storm restoration expenses based on an historical average of costs during the five-year period of 2011-2015. Company witness McLeod testified that this adjustment is appropriate for ratemaking purposes given the unpredictable nature of storm activity, which can cause a material level of expense in a short period of time.

Public Staff witness Fernald proposed to normalize major storm expense based on the average storm costs for the last 10 years, instead of the last five years as proposed by the Company. Witness Fernald testified that the use of a 10-year average is consistent with the normalization of storm costs in the recent rate cases for Duke Energy Carolinas in Docket No. E-7, Subs 909, 989, and 1026, and for Duke Energy Progress in Docket No. E-2, Sub 1023. In addition, due to the unpredictability of both the frequency and cost of major storms, she contended that a 10-year average is more appropriate for use in determining a normalized level. Witness Fernald further recommended that since the Company has a normalized level of storm costs included in rates in this case, costs for future storms should not be deferred nor amortized.

Nucor witness Kollen testified that the data indicates that there is no "normal" storm damage expense and that a "normalized" expense is highly dependent on the number of years used for that purpose, as there are significant differences from year to year. Witness Kollen recommended that the Commission implement storm damage reserve accounting for ratemaking purposes and calculate the storm damage expense using the three most recent years of expense. According to Witness Kollen, this proposal would allow for the tracking of storm damage costs and the recovery of storm damage expenses on a dollar-for-dollar basis with the net over/under recovery position as a component of rate base. Witness Kollen further testified that any storm costs more or less than the expense accrual, under this scenario, would be tracked in the reserve and he suggested that the Commission could periodically adjust the storm damage expense to target a zero reserve balance over time.

In rebuttal testimony, witness McLeod testified that the Public Staff's reliance on a 10-year average understates the normal level of storm expenses that can be expected to occur going-forward. Witness McLeod asserted that the Public Staff's reliance on 10 years of data also fails to take into account operational changes that have occurred over that period of time.

In rebuttal testimony, Company witness Stevens recommended that the Commission reject Nucor witness Kollen's proposal to establish a ratemaking mechanism for tracking DNCP's storm costs. Witness Stevens contended that the methodology presented by Company witness McLeod is reasonable, and that witness Kollen's storm damage tracker goes beyond any known Commission precedent.

The Stipulation provides for an adjustment to major storm restoration expenses based on data during the period January 1, 2010 to June 30, 2016, in effect, including a levelized storm restoration expense level less than the five-year average recommended by the Company and greater than the level proposed by Public Staff. The Commission finds and concludes that for the present case this stipulated level of storm expense is reasonable and appropriate and is just and reasonable to all parties in light of all the evidence presented. The Commission also finds that Nucor witness Kollen's recommendation for the Commission to order a storm cost tracker should not be implemented in light of the Commission's preceding determination to include storm restoration expense in the cost of service.

Annual Incentive Plan Expense

In the Company's Application, Company witness McLeod explained that the annual incentive plan (AIP) represents at-risk compensation paid out to Company employees only upon meeting certain operational and financial goals during the plan year. During 2015, not all of the operational and financial goals of the Company were achieved, and, as a result, less than 100% of at-risk compensation was paid to employees. Witness McLeod proposed in his direct testimony an accounting adjustment that provides for 100% of the plan target based on employees meeting all operational and financial goals during the year.

Public Staff witness Fernald testified that she agreed that incentive pay, such as DNCP's AIP, represents a part of employees' overall compensation. However, witness Fernald explained that the actual amounts paid to employees under the AIP could vary widely. AIP payout percentages in the last five years have ranged from a 20% payout during the test year to 100% payouts in 2013 and 2014. Witness Fernald recommended that the three-year average of the payout percentage, amounting to 73.33%, be used to determine the amount of AIP expense for this proceeding.

Nucor witness Kollen recommended that the ratemaking level of AIP expense should be limited to the lesser of: (a) the expense incurred in the test year, if the Company's actual payout was less than 100% of target; or (b) 100% of target, if its payout exceeded 100% of target. Witness Kollen contended that the concept underlying the AIP is that employees are paid for performance and that a portion of their payroll is at risk and the Commission should not require customers to pay for performance that the Company did not achieve. Witness Kollen proposed to reduce the Company's adjustment from 100%, as proposed, down to 20% to reflect the actual test year payout.

Company witness McLeod testified in rebuttal that the methodology used by the Company in this case is consistent with the methodology approved by the Commission in 2012 Rate Case. Witness McLeod requested that the Commission again allow the Company to incorporate AIP expense at the 100% target payout percentage and to continue to incentivize high employee performance for the benefit of DNCP's customers. Witness McLeod asserted that Nucor witness Kollen's ratemaking adjustment for AIP expense was asymmetric. Witness McLeod testified that the AIP payout percentage during the test year was the single lowest payout in at least the past eight years.

The Stipulation provides for a normalized level of AIP expense based on the three-year average of the payout percentage of 73.33% as proposed by witness Fernald. The record shows that the Company's AIP payout percentage is, on average, well above the 20% payout percentage recommended by witness Kollen. Therefore, the Commission finds and concludes that for the present case the level of AIP expense presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Employee Severance Program Costs

In the Company's supplemental filing, witness McLeod proposed to include a normalized level of employee severance program costs for ratemaking purposes based on the average severance program costs during the years 1994 through 2016. The normalized annual level of severance costs was determined by dividing the average severance program costs by 4.4 years, the average frequency of severance programs as determined by the Company.

Public Staff witness Fernald explained that in the 2012 Rate Case, an ongoing level of severance program costs was included in rates based on the actual costs of the Company's 2010 employee severance program, which at that time was its latest corporate-wide severance program. Witness Fernald discussed DNCP's most recent employee severance program, the Organizational Design Initiative (ODI), which was announced during the first quarter of 2016. Witness Fernald recommended that the level of employee severance program costs for ratemaking purposes in this proceeding be based upon the actual cost of the most recent corporate-wide severance program, amortized over five years. These costs are lower than the employee severance costs allowed in the 2012 rate case, according to witness Fernald, but this reflects the fact that the costs of ODI, and the savings it generated for ratepayers, were lower than those of the Company's previous programs.

Nucor witness Kollen testified that the scope and frequency of prior employee severance has varied considerably, and thus there is no "normal" employee severance program cost. According to witness Kollen, the Company's change in methodology from its initial filing to its update filing demonstrates how the "normalized" expense can be affected by the selection of the programs to be included, the scope and cost of the programs, and the frequency of the programs. It also demonstrates, according to witness Kollen, that one event can significantly affect the average cost, amortization period, and amortization expense.

Witness Kollen recommended that the Commission reject the approach proposed by the Company. Instead, he recommended that the Commission establish a policy that allows the Company to defer the costs of major severance programs, subject to a reasonableness test showing savings in excess of costs, and then amortize and recover those costs over a reasonable period coincident with reflecting the savings in rates, including a return on the unamortized costs. In this case, witness Kollen proposed that the Commission authorize the Company to defer the costs of the ODI, include the costs in rate base, and amortize the costs over a 10-year period, which is equivalent to the longest interval without a severance program in the last 27 years.

In rebuttal testimony, Company witness McLeod explained that in the 2012 Rate Case, the Commission concluded the normalized level of employee severance program costs should reflect "actual historical operating experience" and "should be recovered at a level consistent with DNCP's historical practice...." According to witness McLeod, the Public Staff and Nucor are calculating the going level of severance program costs based solely on ODI, which is by far the least cost program in the past 22 years.

DNCP witness Stevens, in his rebuttal testimony, disputed Nucor witness Kollen's recommendation for the Commission to establish a deferral accounting approach to employee severance program costs. Stevens contended that the deferral mechanism approach suggested by Nucor does not meet the standard or threshold the Commission sets for establishing regulatory assets. According to witness Stevens, the matter is really a debate about the appropriate level of expense to reflect in the cost of service for ratemaking purposes.

The Stipulation provides for a normalized level of employee severance program costs based on the cost of ODI over a five-year period, as recommended by the Public Staff. The Commission finds and concludes that for the present case the accounting adjustment presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented. This approach is consistent with the methodology approved by the Commission in the Company's most recent rate case, which provided for an ongoing level of employee severance program costs and is consistent with DNCP's historical practice of instituting such programs. The Commission in not persuaded by witness Kollen's recommendation to establish a deferral accounting practice for severance costs to be amortized over a protracted period of time. Therefore, the Commission concludes that Nucor witness Kollen's recommendation should be rejected.

Section 199 – Domestic Production Activities Deduction

In supplemental testimony, Company witness McLeod defined the Section 199 – Domestic Production Activities Deduction (Section 199 Deduction or DPAD) as a federal incentive pursuant to Internal Revenue Code §199, which is a permanent benefit available for the generation of electricity – *i.e.*, a federal incentive to manufacture certain goods in the United States. The deduction is equal to 9% of the Company's taxable income attributable to the generation of electricity. Witness McLeod proposed a ratemaking Section 199 Deduction based on a five-year average for the years 2011-2015, on a stand-alone basis for DNCP.

Public Staff witness Fernald explained that the Section 199 Deduction is a tax credit that can be taken by DNCP on the taxable income associated with generation of electricity. A major factor in the computation of taxable income, according to witness Fernald, is the amount of tax depreciation, including bonus depreciation, taken by the Company. Witness Fernald stated that the more bonus depreciation taken, the greater the tax deduction for depreciation expense, and the lower the taxable income. Witness Fernald further explained that the amount of bonus depreciation that could be taken was different in 2011 than what could be taken in 2012 through 2015. In 2011, under the then-current tax laws 100% of the cost of newly acquired property could be deducted as bonus depreciation; however, beginning January 1, 2012, the bonus depreciation deduction decreased to 50% of the cost of the property, where it is set to remain until December 31, 2017. After that it is set to decrease to 40% for 2018, and then to 30% for 2019. Public Staff witness Fernald additionally testified that due to the 100% bonus depreciation deduction in 2011, the Company experienced a net operating loss for that year and was thus unable to utilize the Section 199 Deduction for that tax year. Based on all the above information, witness Fernald concluded that 2011 should not be included in calculating the average Section 199 Deduction, and instead recommended that the Section 199 Deduction be calculated based on the average of the four years from 2012 through 2015, the years for which bonus depreciation was at the current rate of 50%.

Nucor witness Kollen discussed the calculation of the retention factor and claimed the Company failed to include the DPAD in the retention factor (applicable to the increase in taxable income resulting from the rate increase). Witness Kollen testified that the Section 199 Deduction was calculated as 9% of the utility's production taxable income subject to various potential limitations. In the ratemaking process, according to witness Kollen, the test year income tax expense included in the revenue requirement was calculated in two steps. The first step calculates the income tax expense included in operating income and in the operating income deficiency before the rate increase. This calculation includes the Section 199 Deduction on production taxable income, including the effects of any limitations. The second step calculates the income tax expense on the rate increase resulting from the claimed operating income deficiency. The operating income deficiency was grossed up for income taxes and other revenue related expenses through the retention factor to calculate the revenue deficiency or rate increase. Witness Kollen testified that in this second step, the income tax expense on the rate increase was included in the rate increase itself. According to witness Kollen, the calculation assumes that the entirety of the rate increase is subject to income taxes and should reflect all related deductions, including the Section 199 Deduction, and the Section 199 Deduction is fully available without any limitation because the limitations are already embedded into the calculation of the operating income deficiency. Witness Kollen proposed to revise the Section 199 Deduction stating that the federal income tax rate should be reduced by the 9% Section 199 Deduction times the ratio of the production rate base to the sum of the production, transmission, and distribution rate base before it is reflected in the calculation of the retention factor.

In rebuttal testimony, Company witness McLeod explained that Public Staff witness Fernald changed the allocation factor used by the Company for the SIT expense Section 199 Deduction from the Net Book Income factor to the production allocation factor (Factor 1). According to witness McLeod, this is inconsistent with witness Fernald's recommendation to allocate all income tax expense based on the Net Book Income factor.

Witness McLeod concluded that the five-year average Section 199 Deduction produces a reasonable result that should be utilized for ratemaking purposes.

Company witness Warren testified in rebuttal that tax law permits a business to claim a Section 199 Deduction equal to 9% of the lesser of: (1) certain qualified net income (referred to as QPAI); (2) the taxpayer's taxable income; or (3) 50% of the W-2 wages associated with the production of the QPAI. To qualify as QPAI, according to witness Warren, the net income has to be derived from specified activities associated with manufacturing, and the generation of electricity is an eligible activity. Witness Warren asserted that Nucor witness Kollen's proposal was inappropriate because it assumes the DPAD is fully available without any limitation. Witness Warren explained that the DPAD is limited; it is only available for QPAI. Moreover, witness Warren testified that it is limited by taxable income and by 50% of W-2 wages and, therefore, cannot be presumed to be "fully available." Witness Warren contended that witness Kollen's approach implicitly presumes that additional revenue will produce additional QPAI in the same amount and that there will be no taxable income or W-2 wage limitation on the DPAD computation. Unlike other tax deductions, witness Warren explained that the amount of the DPAD is a function of the interaction of a number of variables, and presuming that additional revenues will necessarily produce additional DPAD is overly simplistic.

Witness Warren explained that the Financial Accounting Standards Board (FASB) analyzed and characterized the DPAD in 2004, soon after the enactment of the tax law provision that established the DPAD, and considered how to properly reflect the DPAD for financial reporting purposes. Witness Warren testified that the FASB made a determination that the Section 199 Deduction should not be treated as an adjustment to the income tax rate, but instead, it should be treated as a "special deduction," which is recognized only in the year in which it is deductible on the tax return. The reason for this conclusion was that the DPAD is contingent upon the future performance of specific activities, including the level of wages. Witness Warren contended that the FASB's conclusion is consistent with his recommendation to exclude the DPAD from the retention factor.

Company witness Stevens contended that Nucor witness Kollen double counted the Section 199 Deduction by incorporating his own adjustment, while also leaving in the Company's standalone regulatory accounting adjustment for the Section 199 Deduction in the revenue requirement. According to witness Stevens, witness Kollen also misapplied his own methodology by applying the change in the retention factor to the Company's entire North Carolina jurisdictional rate base. The proper ratemaking exercise, according to witness Stevens, is to derive a Section 199 Deduction effect only for the additional revenue required to produce the targeted return on equity. Stevens testified that Nucor witness Kollen overstated the impact of the proposed retention factor by $1.5 million. Witness Stevens also testified that other electric utilities under the jurisdiction of the Commission do not utilize a retention factor that is comprised of a Section 199 Deduction, and witness Kollen's proposal represents a significant deviation from past regulatory practice for electric utilities in North Carolina and would lead to inaccurate results. Witness Stevens recommended that the Commission reject witness Kollen's proposal.

The Stipulation provides for a normalized level Section 199 Deduction based on an historical average for the four years 2012-2015 as recommended by Public Staff witness Fernald.

Based on the foregoing, the Commission finds and concludes that Nucor witness Kollen's proposal to include the Section 199 Deduction as a component of the retention factor is inappropriate. The Commission does not find the evidence presented by Nucor witness Kollen convincing, nor does it agree that the incremental revenue increase approved in this case would produce an additional Section 199 Deduction tax benefit. The Commission agrees with the testimony of Company witness Warren that the Section 199 Deduction is more appropriately characterized in the current proceeding as a special deduction, subject to taxable income and wage limitations. Thus, the Commission finds and concludes that it is inappropriate to include the Section 199 Deduction as a component of the retention factor for purposes of determining revenue requirement. Further, the Commission finds and concludes that for the present case the accounting adjustment presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Income Tax Expense Allocation

Public Staff witness Fernald testified that the Company allocated income tax expense as follows:

> (1) The Company allocated current and deferred SIT expense to North Carolina retail based on the net book income.
>
> (2) The Company allocated the deferred federal income tax (FIT) expense (i.e., the federal income tax expense associated with revenues and expense items that are recognized in different periods for tax purposes due to timing differences) based on the nature of the timing differences.
>
> (3) The Company allocated the current federal income tax expense based on federal taxable income.

Witness Fernald contended that the income tax expense included in the cost of service for ratemaking should be the amount of income tax expense based on book taxable income, regardless of whether for tax purposes the Company will pay that tax now or later due to timing differences. Therefore, witness Fernald stated, the more appropriate allocation factor for income tax expense is the net book income factor. As such, Public Staff witness Fernald proposed an adjustment to allocate all income tax expense based on net book income.

In rebuttal testimony, Company witness McLeod testified that Schedule 6 (Current Income Tax) and Schedule 7 (Deferred Income Tax) of the Company's cost of service study (COSS) in NCUC Form E-1, Item 45a include detailed calculations of current and deferred FIT expense on both a system level and North Carolina jurisdictional basis. Witness McLeod explained that Schedule 6 contains computations of taxable income for the test period based on the level of operating revenue and expense as determined in the Company's other COSS schedules and an allocation of the various book/tax timing differences, and deferred taxes are allocated among the Company's four jurisdictions in COSS Schedule 7 based on the underlying book/tax timing difference, which corresponds with Schedule 6. Witness McLeod noted that this methodology is consistent with the methodology approved in both of DNCP's most recent rate cases - the 2010 Rate Case and the 2012 Rate Case. Witness McLeod noted that although the Public Staff's audit did not reveal any inherent flaws in the Company's methodology, the Public Staff recommended a complete departure from the methodology proposed by the Company.

Witness McLeod explained that the Company allocates SIT expense to the North Carolina jurisdiction based on the Net Book Income factor because the Company does not have the same level of detail for SIT expense during the test year as it did for FIT expense. Witness McLeod asserted that under these circumstances, it is appropriate to make simplifying assumptions in order to produce a reasonable result for ratemaking purposes. Witness McLeod explained that the Company does, however, have detailed information regarding the book/tax timing differences for FIT expense, and as a result, the methodology in the COSS produces a more accurate and precise allocation of FIT expense than the Public Staff's approach.

According to Company witness McLeod, there are two primary reasons why the methodology in COSS produces a more precise allocation of FIT expense than the Net Book Income factor. First, witness McLeod testified that the Net Book Income factor does not account for all of the permanent differences between book income and taxable income, which causes the Company's effective tax rate to deviate from the statutory rate and will cause the effective tax rate to be different between the Company's jurisdictions. The second item that will cause the Net Book Income factor to not properly reflect North Carolina's appropriate allocable portion of FIT expense, according to witness McLeod, is income tax credits. Witness McLeod argued that since income tax credits are not included in the calculation of the Net Book Income factor, the Public Staff's proposed methodology overrides the allocator designated in the COSS and replaces it with the Net Book Income factor resulting in an inappropriate shift of tax benefits between the jurisdictions. In concluding his testimony, witness McLeod recommended that the Commission allocate FIT expense based on the methodology in the Company's cost of service study since this provides a more precise determination of North Carolina jurisdictional FIT expense.

The Stipulation allocates FIT expense based on the methodology in the Company's cost of service study, as recommended by Company witness McLeod. The Commission finds and concludes that for the present case, the accounting adjustment is just and reasonable to all parties in light of all the evidence presented.

Non-Fuel Variable O&M Expense Displacement

Public Staff witness Maness testified that DNCP made pro forma adjustments to include in the cost of service the full costs of the Brunswick County CC, which began commercial operation on April 25, 2016, including adding incremental non-fuel variable operating and maintenance (O&M) expenses to reflect a full year of operation. With the addition of the Brunswick County CC, witness Maness testified that other plants in DNCP's fleet will operate less frequently, and thus incur fewer non-fuel variable O&M expenses. Therefore, witness Maness asserted, the Public Staff proposed to adjust non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses. Otherwise, operating revenue deductions would include both (1) a general annualized and normalized level of variable expenses and (2) the incremental variable expenses related to specific new generation facilities.

In his rebuttal testimony, Company witness McLeod testified that the Company agrees with certain aspects of witness Maness' adjustment for purposes of this case. Specifically, the Company agrees that the addition of the Brunswick County CC will result in some level of purchased power energy savings recovered through base non-fuel rates, and thus proposed in its rebuttal testimony a purchased energy savings adjustment to reduce purchased energy costs proportionate to a pro forma level of the Brunswick County CC generation. However, witness McLeod testified that the Company disagrees with the portion of the adjustment pertaining to energy-related expenses not adjusted elsewhere for growth. Witness McLeod explained that the adjustment is premised on the fact that the Company has included a fully annualized level of Brunswick County CC operating expenses, which was the Company's intent. However, upon further evaluation, the Company determined that its initial adjustment to annualize the Brunswick County CC O&M expense did not include a provision for maintenance outage expenses, which will result in a significant level of cost when incurred. Furthermore, witness McLeod testified that witness Maness' displacement adjustment also does not account for these maintenance outages as the adjustment assumes that the Brunswick County CC will operate for 12 full months. According to witness McLeod, the Public Staff's displacement adjustment, if accepted in full, would understate the level of energy-related expenses necessary to serve the end-of-period customers at the normalized level of generation.

In rebuttal testimony, witness McLeod proposed a new accounting adjustment that reflects an annualized level of purchased energy savings in base non-fuel rates as a result of the Brunswick County CC commencing commercial operation. Witness McLeod recommended that the Commission reject Public Staff witness Maness' displacement adjustment, and incorporate witness McLeod's adjustment that reflects an annualized level of purchased power energy savings for the Brunswick County CC.

The Stipulation reflects an annualized level of purchased power energy savings for the Brunswick County CC as proposed by Company witness McLeod. At the hearing, Public Staff witness Maness testified that while not necessarily agreeing with all aspects of the calculation of this adjustment, the Public Staff accepted it in the Stipulation for purposes of this proceeding only.

Based on the testimony of Public Staff witness Maness and DNCP witness McLeod, and the Stipulation, the Commission finds and concludes that the O&M displacement adjustment, as agreed to in the Stipulation, is just and reasonable to all parties in light of all the evidence presented and should be accepted for purposes of this proceeding.

<u>Depreciation Rates for Warren County CC and Brunswick County CC</u>

Nucor witness Kollen testified that for depreciation expense and rates reflected in the revenue requirement for Warren County CC and Brunswick County CC, the Company used the per books depreciation expense for June 2016, after several adjustments detailed in its workpapers, and annualized the adjusted depreciation expense. According to witness Kollen, the depreciation rates for the per books depreciation expense were provided to the Company by witness John Spanos, a consultant with Gannett Fleming, in a single page letter. The letter included no additional support, analyses, or workpapers, all of which typically are provided in conjunction with an actual depreciation study performed by an expert. The letter states that the depreciation rates "are based on a 36-year life span, interim survivor curves and future interim net salvage percents where applicable. Each of these parameters is established with the general understanding of the new facility and the estimates of comparable Dominion facilities." Witness Kollen stated that the letter provides the proposed interim survivor curve, net salvage rates, and annual depreciation accrual rates for each plant account.

Witness Kollen testified that the Commission should not simply accept the Company's proposed depreciation expense and rates for these units. Witness Kollen contended that there is no support for the parameters used by witness Spanos other than general references to other units owned and operated by the Company. Witness Kollen asserted that he had reviewed the relevant pages from the Company's most recent depreciation studies, and found that the survivor curves and net salvage parameters proposed by witness Spanos did not match any of the Company's other units. He also found that there was a range of life spans for the Company's other CC units from 34 years to 45 years.

In support of his position, witness Kollen testified that one of witness Spanos' colleagues, Ned W. Allis, recommended a 40-year life span for new combined cycle units in a pending Florida Power & Light Company (FPL) proceeding, a change from the 35-year life span that witness Allis recommended in the prior FPL proceeding for new combined cycle units. With that evidence, witness Kollen recommended a 40-year life span for the Warren County CC and Brunswick County CC. Nucor witness Kollen testified that this is the midpoint of the range for the Company's other combined cycle units and is the same life span recommended by witness Allis. Witness Kollen further recommended that the Commission ignore projected interim retirements and net salvage in this proceeding since these units are new and have almost no history of interim retirements or net salvage. Witness Kollen argued that these parameters should be introduced and supported by competent evidence in the Company's next depreciation study.

In response to Nucor witness Kollen's proposal, Company witness Stevens explained in rebuttal that the Company's depreciation consultant provided specific guidance on appropriate depreciation accruals based on informed judgment for Warren County CC and Brunswick County CC. Witness Stevens stated that expert opinion directs that a 36-year useful life for Warren County CC and Brunswick County CC is appropriate given the operating characteristics of these combined cycle units, reviews of Company practice and outlook as they relate to Company operation and retirement, experience of similar existing units within DNCP's generation fleet, and current practice in the electric industry.

DNCP witness Stevens further testified that electric utilities do not experience the exact same performance of a generation facility across the U.S. The expected useful life of a given unit is specific to each utility based on the operating performance of similar units within its owned fleet, the maintenance performance of those units, as well as the expected dispatch characteristics of those units. Witness Stevens contended that a Florida utility's natural gas combined-cycle facility would likely have a different set of operating parameters and conditions and impact on equipment than a natural gas combined-cycle facility constructed by the Company in Virginia.

Witness Stevens also explained that DNCP owns no other combined cycle units with a useful life greater than 36 years. The natural gas combined cycle facilities at Bellemeade, Rosemary, Gordonsville, Chesterfield Unit 7, Chesterfield Unit 8, Possum Point Unit 6, and Bear Garden all have a useful life of 36 years as determined by the Company's depreciation consultant. Witness Stevens noted that this depreciation study was filed with the Commission on April 1, 2013, in Docket No. E-22, Sub 493. Therefore, based on the facts presented, he rejected witness Kollen's testimony that a 40-year life span is the midpoint of the range for the Company's other combined cycle units as inaccurate.

With respect to Nucor witness Kollen's recommendation that the Commission ignore interim cost of removal and net salvage into its depreciation accrual rates for Warren County CC and Brunswick County CC in this proceeding, witness Stevens testified that this practice would be contrary to Generally Accepted Accounting Principles and the FERC USOA.

Witness Stevens further recommended that the Commission reject Nucor's proposed adjustment to the depreciation accruals for Warren County CC and Brunswick County CC.

The Stipulation reflects depreciation expense for the Warren County CC and Brunswick County CC based on the depreciation accrual rates proposed by DNCP.

Based upon the evidence presented in this proceeding, the Commission finds and concludes that the depreciation accrual rates proposed by DNCP for the Warren County CC and Brunswick County CC are appropriate and should be utilized for ratemaking purposes in this case. The Commission concludes that the evidence presented by DNCP supports a useful life of 36 years for these facilities as reasonable for ratemaking purposes until the Company performs another depreciation study. The Commission concludes that Nucor witness Kollen's recommendation to ignore interim cost of removal and net salvage is unsubstantiated and witness Stevens' testimony that witness Kollen's proposal would be contrary to Generally Accepted Accounting Principles and the FERC USOA has not been challenged. Accordingly, the Commission finds and concludes that this recommendation should not be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

The evidence supporting these findings of fact and conclusions is contained in the verified Application, the testimony and exhibits of Company witnesses McLeod, Haynes, and Stevens and Public Staff witnesses Fernald and Floyd, and the Stipulation.

In the Company's Application, Company witness McLeod testified that HB 998 was signed into law on July 23, 2013. According to witness McLeod, prior to the passage of HB 998, the North Carolina SIT rate was 6.9%, and HB 998 made the following changes to the NC SIT Rate:

- Reduced to 6% effective January 1, 2014;
- Reduced to 5% effective January 1, 2015; and
- Reduced to 4% effective January 1, 2016, assuming certain triggering events occurred, as set forth in the legislation.

Witness McLeod explained that after the passage of HB 998, the accumulated deferred North Carolina SIT balance was overstated based on the legislative changes to the statutory corporate tax rate, or in other words, contained "excess" deferred income taxes (EDIT). In its Order Establishing Procedure for Implementation of Session Law 2015-6 in Docket No. M-100, Sub 138 issued on September 11, 2015, the Commission ordered DNCP to hold the EDIT in a regulatory liability account to be refunded to ratepayers in the context of DNCP's next general rate case proceeding. Witness McLeod testified that the Company is proposing a methodology in this case for crediting the North Carolina jurisdictional portion of the EDIT to customers as this is the first general rate case since the Company established the EDIT regulatory liability.

Company witness McLeod proposed to refund the EDIT to customers through a decrement rider over a two-year period (Rider EDIT). This mechanism, according to witness McLeod, provides transparency as the credit is differentiated from the base rate cost of service. Additionally, excluding the credit from the base rate cost of service will defer the need for a subsequent base rate case after the credit is fully amortized. Witness McLeod testified that this approach returns the credit to customers in an efficient and timely manner, and is equitable to both the Company and customers.

Witness McLeod proposed to include capital savings associated with the regulatory liability until the liability is fully returned to customers. According to witness McLeod, the capital savings decline as the regulatory liability is credited to customers over the two-year period; therefore, the revenue requirement during the first year is greater than the revenue requirement in the second year. Witness McLeod discussed the Company's methodology for determining the North Carolina jurisdictional EDIT to be refunded to customers based on a retrospective analysis of the methodologies approved by the Commission for allocating deferred North Carolina SIT expense in DNCP's previous base rate cases.

With respect to the level of SIT expense included the base non-fuel revenue requirement, witness McLeod proposed an accounting adjustment to reduce NC SIT expense for ratemaking purposes based on an apportioned NC SIT rate that includes a 4% statutory rate.

In direct testimony, Company witness Haynes proposed to allocate the Rider EDIT credits to customer classes based upon North Carolina rate revenue for 2015. Witness Haynes developed a decrement rate based upon actual 2015 kWh sales to be applied to each customer's 2015 sales. The total credit amount for each customer will be amortized over 12 months and provided through a monthly bill credit.

Public Staff witness Fernald testified regarding the history of HB 998, noting that it also added a new section, G.S. 105-130.3C, to the General Statutes concerning possible future rate reduction triggers. On August 4, 2016, the North Carolina Department of Revenue announced that pursuant to G.S. 105-130.3C, the corporate tax rate for tax years beginning on or after January 1, 2017, will be reduced from 4% to 3%. Witness Fernald testified that there are no restrictions on how EDIT should be refunded to ratepayers, and explained that the Public Staff believes that the manner in which EDIT should be refunded to ratepayers, including the period over which the EDIT is amortized, should be determined on a case-by-case basis in each utility's next general rate case. In this particular case, witness Fernald explained, in addition to the need for EDIT collected from past ratepayers to be returned to future ratepayers, there are several deferrals, which represent costs incurred to provide service to past ratepayers that will now be recovered from future ratepayers.

In this case, Public Staff witness Fernald proposed an EDIT regulatory liability of $15,708,000, which included the additional EDIT related to the decrease in the tax rate from 4% to 3% that was announced on August 4, 2016. She identified several regulatory assets and liabilities whose amortizations end in 2017, and proposed re-amortizing the unamortized balances for these assets and liabilities, since these amortizations will end in 2017 and will not continue on an ongoing basis. The total deferred costs and unamortized balances for regulatory assets and liabilities with amortizations ending in 2017 to be recovered from North Carolina ratepayers in this proceeding, as recommended by Public Staff witness Fernald in her testimony, are as follows:

Deferred Costs	Total Cost to be Recovered from NC Ratepayers
Warren County CC Deferral	$10,204,000
Brunswick County CC Deferral	2,957,000
Chesapeak Closure Costs	1,504,000
North Branch Net Proceeds/Costs	175,000
Unamortized Balances	
Unamortized Desighn Basic Costs - Surry	39,000
NUG Buyout Costs - Atlantic	104,000
NUG Buyout Costs - Mecklenburg	481,000
Bear Garden Deferral	593,000
DOE Settlement	(565,000)
Total per Public Staff	$15,492,000

Public Staff witness Fernald testified that both the EDIT liability and the deferred costs and unamortized balances listed above represent revenues collected or costs incurred in providing service to past ratepayers that will now be returned to or recovered from future ratepayers. Consequently, witness Fernald recommended that, instead of a decrement rider as proposed by the Company, the refund of the EDIT liability should be treated in the same manner as the recovery of these deferred costs and unamortized balances based on the circumstances in this proceeding. Therefore, witness Fernald recommended that both the EDIT liability and the deferred costs and unamortized balances listed above be included in the cost of service through a levelized amortization. Since the difference between the impact on rates of amortizing the EDIT liability and the deferrals and unamortized balances over three years and the impact of amortizing them over five years is not substantial, witness Fernald recommended that the levelized amortization of the EDIT liability and deferred costs and unamortized balances listed above be amortized over a three-year period using the after-tax rate of return recommended by the Public Staff in this proceeding.

With respect to the level of SIT expense included the base non-fuel revenue requirement, Public Staff witness Fernald proposed accounting adjustments to reflect the reduction in the North Carolina corporate tax rate from 4% to 3% effective for taxable income on or after January 1, 2017.

Public Staff witness Floyd testified that he recommended the Commission reject DNCP's proposed Rider EDIT. Witness Floyd stated that the Public Staff is concerned that although the EDIT was collected from customers over many years, that it will only be repaid to those who were customers during 2015. Witness Floyd testified that he believed witness Fernald's approach to the EDIT credit to be best as it returns the EDIT to all customers and removes the need for a Rider.

In rebuttal testimony, Company witness Stevens testified that a decrement rider provides greater precision in order to demonstrate to multiple constituents – the Commission, North Carolina customers, and the North Carolina General Assembly – that the amount to be refunded did in fact get refunded. Witness Stevens testified that a decrement rider provides greater transparency on the EDIT refund to North Carolina customers. DNCP's decrement rider approach, according to witness Stevens, is preferable because it credits the EDIT back to North Carolina customers more quickly in two years compared to the Public Staff's recommended three years.

Company witness McLeod accepted the total EDIT regulatory liability of $15,708,000 presented by Public Staff witness Fernald. Witness McLeod also accepted the Public Staff's recommendation to calculate the EDIT regulatory liability amortization on a levelized basis using an annuity factor. These changes were reflected in the Rider EDIT credit amounts presented in witness McLeod's rebuttal schedules and exhibits. Witness McLeod also accepted witness Fernald's accounting adjustments to reduce the level of NC SIT expense in the base non-fuel revenue requirement to reflect the reduction in the NC corporate tax rate from 4% to 3% effective for taxable income on or after January 1, 2017.

With respect to Rider EDIT, Company witness Haynes proposed that after Year 1, any over or under-recovery of the credit amount should be deferred and added (or subtracted) as appropriate from the Year 2 credit amount. Such amount should be allocated based upon the annualized revenue in witness Haynes' rebuttal exhibits. Witness Haynes proposed that prior to the tenth month from the effective date of the Year 2 rider, DNCP will provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of Year 2. For any deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff will work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

The Stipulation provides that the appropriate level of EDIT to be refunded to customers in this case is $15,708,000 (on a pre-tax basis), which includes EDIT associated with the January 1, 2017, reduction in the North Carolina corporate state income tax rate from 4% to 3%. DNCP shall implement a decrement rider, Rider EDIT, as described in the rebuttal testimony of Company witnesses McLeod and Haynes, to refund EDIT to customers over a two-year period on a levelized basis, with a return. As shown on Settlement Exhibit IV, the appropriate amount to be credited to customers is

$16,816,000, which should be credited to customers via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11.[5]

Further, pursuant to Section 2.4.(a) of Session Law 2015-6, the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all of the tax changes as enacted in HB 998. Under G.S. 105-130.3C, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016. The base non-fuel rate revenue requirement in the Stipulation appropriately reflects the 3% NC SIT rate effective for the taxable year beginning on or after January 1, 2017.

The Commission finds and concludes that for the present case the ratemaking treatment of the EDIT regulatory liability presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented. The Commission also finds and concludes that the base non-fuel rate revenue requirement in the Stipulation reflects the 3% NC SIT rate effective for the taxable year beginning on or after January 1, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact and these conclusions is contained in the verified Application, the Stipulation, the testimony and exhibits of the DNCP and Public Staff witnesses, and the entire record in this proceeding.

In the Company's Application, Company witness McLeod requested Commission approval of a levelization methodology on its books and records for its nuclear refueling and maintenance outage expenses. Witness McLeod testified that DNCP operates four nuclear units: two units at Surry and two units at North Anna. The Company utilizes a "3/3/2" planning practice for scheduling nuclear outages, meaning the Company performs three outages in two successive years, then two outages every third year.

According to witness McLeod, the Company incurs substantial outage costs during the refueling outages, and absent the levelization accounting treatment on its books and records, DNCP experiences and will continue to experience significant variability in its annual operating costs which causes the cost of service for one year to appear inconsistent with a previous year. DNCP requested approval of a levelization methodology in order to minimize this variability and to better match the refueling outage expenses with the period over which the benefit is realized. Witness McLeod stated that this request for accounting authority is not intended to modify the Company's existing approach to levelizing nuclear outage expenses for ratemaking purposes. Witness McLeod noted that the Commission approved similar accounting treatment in the most

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[5] On October 19, 2016, the Company filed proposed Rider EDIT to be implemented on November 1, 2016. The Rider EDIT rates for each customer class are identified on pages 129 and 260 of the Company's October 19 filing, and the supporting workpapers are included on page 291.

recent general rate case proceedings for Progress Energy Carolinas, now Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC).[6]

Witness McLeod testified that under this accounting methodology, costs incurred during the three months leading up to an outage, costs incurred during the typical two-month outage period, and trailing costs incurred during the three months after an outage are deferred to a regulatory asset account. The deferrals are amortized over the period of the operating cycle between scheduled refueling for the unit, not to exceed 18 months. Amortization begins the month following completion of the outage and adjustments are made for trailing costs.

Public Staff witness Fernald testified that the Company implemented deferral and amortization of nuclear refueling outage costs on its books in April 2014 pursuant to Virginia legislation. Prior to this change, the Company expensed nuclear refueling outage costs in the month that the costs were incurred. According to witness Fernald, the Company has accounted for nuclear refueling outage costs since April 2014 as follows:

> (1) The costs related to nuclear refueling outages are recorded to the appropriate O&M expense account as incurred, as was done in the past.
>
> (2) A credit is recorded to FERC Account 407.4 – Regulatory Asset Deferral O&M for the costs being deferred. When this credit is netted against the amount charged to O&M expense, the costs being deferred are in effect removed from the cost of service. The Company decided that costs eligible for deferral include incremental costs incurred three months prior to the outage, during the outage, and three months after the outage. Specific details regarding the types of incremental costs eligible for deferral are provided in Fernald Exhibit 3.
>
> (3) The deferred costs are then amortized over the refueling cycle, not to exceed 18 months, and the amortization expense for the costs is recorded to FERC Account 407.3.

Witness Fernald explained that in prior rate cases, pro forma adjustments have been made to normalize nuclear refueling outage costs for DNCP. With levelized accounting, the costs reflected in the Company's financial statements will be consistent with the ratemaking treatment of the costs, according to witness Fernald. In future rate proceedings, the test period amounts produced by this levelized accounting method will be the starting point in determining normal nuclear refueling outage expenses, subject to appropriate ratemaking adjustments.

Witness Fernald testified that DNCP's nuclear refueling outage deferral window for nuclear refueling outage costs is a longer period of time than that used by DEC and DEP.

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[6] Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013), Finding of Fact No. 31, and Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sept. 24, 2013), Finding of Fact No. 36.

Witness Fernald testified that the accounting procedures established by DNCP are used for regulatory purposes in Virginia, and the Public Staff does not believe that the difference in the nuclear refueling outage deferral window necessitates the time and effort required to maintain a different accounting treatment for North Carolina. Public Staff witness Fernald emphasized that the amounts to be recovered for nuclear refueling outage costs are always subject to review in North Carolina rate cases.

Witness Fernald recommended approval of the Company's levelized accounting treatment with the following conditions:

> (1) The regulatory asset associated with the nuclear refueling outage deferral accounting will not be included in rate base in rate cases. The Company has made an adjustment in this proceeding to remove the nuclear refueling outage deferral balance in regulatory assets from rate base.
>
> (2) Under the Virginia legislation, the amortization period is to be no more than 18 months. The amortization period should be consistent with the refueling cycle of the nuclear units, which currently is 18 months. If DNCP changes the frequency of the refueling cycle for any of its nuclear units in the future, the amortization period for the deferral accounting should be changed to reflect the change in the refueling cycle.

Nucor witness Kollen testified that the change in accounting would result in a one-time reduction in maintenance expense. The Company's proposal will delay the nuclear outage expense for accounting purposes by approximately 18 months to reflect the fact that the costs will be deferred when incurred and then amortized to expense over the period between outages instead of being expensed when incurred. According to witness Kollen, if this accounting is authorized by the Commission, the Company's nuclear outage expense will be reduced when each of the next four outages occur, in other words, there will be a one-time savings in O&M expense. Witness Kollen contended that the Company would retain the one-time savings if the Commission does not direct the Company to defer and amortize the savings as a reduction to expense for ratemaking purposes.

Witness Kollen proposed that the Commission adopt the change in accounting for ratemaking purposes, subject to a deferral and amortization of the one-time savings in expense.

In rebuttal testimony, Company witness Stevens testified that Nucor witness Kollen mischaracterized the financial impacts of implementing the nuclear outage levelization accounting methodology on DNCP's books and records. Witness Stevens argued that the new accounting methodology did not change the cost of nuclear outages. Operating expense in the period was reduced when this accounting methodology was first implemented. However, this was not a "one-time savings," but instead a timing difference resulting from implementation of a new accounting methodology.

Witness Stevens argued that witness Kollen's proposal to establish a regulatory liability for nuclear outage expenses is inappropriate as nuclear outage costs are a component of the base non-fuel rate cost of service, and the Company is not recovering these costs dollar for dollar. According to witness Stevens, an analysis demonstrates that the incurred costs in the past few years are greater than the normalized level of nuclear outage costs approved by the Commission in its 2012 Rate Case. The Company incurred system level average costs for this period of $83.680 million compared to the system level costs included in base rates of $78.163 million. Therefore, witness Stevens concluded that there are no one-time savings or windfalls as suggested by witness Kollen.

The Stipulation provides that the Company may use levelized accounting for nuclear refueling costs, as described in the testimony of Public Staff witness Fernald.

The Commission concurs with DNCP and the Public Staff that implementing this nuclear levelization accounting methodology should have no ratemaking implications, contrary to the proposal set forth by witness Kollen. Accordingly, the Commission finds and concludes that Nucor witness Kollen's proposal to establish a regulatory liability for purported one-time savings associated with establishment of the nuclear outage levelization accounting methodology is inappropriate. The implementation of a new accounting methodology for nuclear outage costs does not change the underlying nature and amount of nuclear outage costs incurred by the Company. The Commission further finds and concludes that DNCP's request to implement levelization accounting for nuclear outage and refueling expenses, as set forth in the Stipulation, is hereby granted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

The evidence supporting these findings of fact and conclusions is contained in the verified Application, the testimony and exhibits of Company witnesses Curtis, Hevert, Mitchell and McLeod, Nucor witness Kollen, and Public Staff witness Maness, the Stipulation, and the entire record in this proceeding.

DNCP witness Curtis testified that DNCP's coal combustion residual (CCR) expenditures are the result of efforts by DNCP to comply with the United States Environmental Protection Agency's (EPA's) Standards for Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments (CCR Final Rule), which became effective for DNCP on April 7, 2015.

DNCP witness Mitchell testified that the Virginia Department of Environmental Quality incorporated the CCR Final Rule into its solid waste management regulations in December 2015. He stated that DNCP is developing comprehensive closure and storage plans for the CCR impoundments located at DNCP's operating and non-operating coal plants. Witness Mitchell discussed the Company's plans to close or retrofit the ash ponds and landfills at Chesapeake, Yorktown, Chesterfield, Clover, Mt. Storm, Bremo, and Possum Point Power coal-fired generating stations. He testified that the pond and landfill closures or retrofits are in response to the CCR Final Rule regulating the management of CCR stored in ash ponds and landfills. Witness Mitchell explained that the CCR Final

Rule establishes environmental compliance requirements for the disposal of CCR, and provides specifications for construction and closure of CCR ponds and landfills. In addition, witness Mitchell testified that these new regulations also impose higher requirements in the areas of structural integrity standards, public disclosure, location restrictions, inspection, groundwater monitoring and cleanup for existing and new CCR ponds and landfills.

In direct testimony, Company witness McLeod testified that the enactment of the CCR Final Rule created a legal obligation to retrofit or close all inactive and existing ash ponds over a certain period, as well as to perform required monitoring, corrective action, and post-closure care activities as necessary. Witness McLeod explained that the Company recognized ARO liabilities of $385.7 million on a total system basis during the test year for financial reporting purposes in accordance with Accounting Standard Codification (ASC) 410-20 (formerly Statement of Financial Accounting Standard No. 143) related to future ash pond and landfill closure costs. Witness McLeod testified that the Company eliminates all the effects of ARO accounting pursuant to ASC 410-20 from the cost of service, including the AROs associated with the CCR Rule, in accordance with the Commission's directives in Docket No. E-22, Sub 420. Witness McLeod proposed to defer the actual North Carolina jurisdictional CCR-related cash expenditures incurred through the update period in this case (June 30, 2016) to be amortized over a three-year period commencing with rates approved in this case effective November 1, 2016.

DNCP witness McLeod further testified that the CCR Final Rule requires DNCP to close or retrofit all of its active and inactive coal ash ponds and landfills. He stated that DNCP has eight generating facilities where coal ash remediation must be performed. In his direct testimony, witness McLeod testified that DNCP spent $37.5 million during the test period and anticipated spending an additional $63.8 million through June 2016. He testified that DNCP proposes to defer its portion of the expenditures over a three-year period.

In his supplemental testimony, witness McLeod adjusted the updated January 2015 through June 2016 CCR costs to a total of $84.4 million. He testified that DNCP proposes to establish a regulatory asset in the amount of $4.3 million, North Carolina's allocable share of the CCR costs to date, and to amortize this amount over a three-year period beginning with the effective date of the rates set in this proceeding.

Public Staff witness Maness testified that the Public Staff generally agrees with the concept proposed by the Company of deferring and amortizing the costs incurred through June 30, 2016, over a multi-year period, but does not necessarily agree that this treatment is automatically mandated by the August 6, 2004, Order Allowing Utilization of Certain Accounts in Docket No. E-22, Sub 420 (2004 ARO Order). Witness Maness also disagreed with the Company's proposed three-year amortization period and instead proposed a 10-year amortization. According to witness Maness, the majority of the costs underlying the ARO liability, and thus current and future expenditures, are related to generating assets that have already been retired or are financially impaired and are soon to be retired. He testified that for costs of significant size related to retired or abandoned plants, the Public Staff in recent years has consistently recommended an amortization or levelization period of 10 years, and this period has been approved by the Commission.

In addition, Public Staff witness Maness testified regarding some of the specific CCR work being performed by DNCP, as described by DNCP in response to data requests. Witness Maness stated that four of the DNCP coal-fired facilities are closed, or have been converted to natural gas-fired facilities. At the closed facilities, remediation is taking three different forms: (1) cap and close method; (2) a clean and close method in which the coal ash is moved to an on-site pond that is being capped and closed, and the original impoundment is closed; or (3) the clean and close method, except the original impoundment is used for a new purpose. With regard to operating coal facilities, witness Maness stated that DNCP's work at this point is mainly project planning and engineering.

Witness Maness testified that the Public Staff investigated DNCP's CCR remediation efforts and found that the efforts and costs were prudent and reasonable. He stated that DNCP incurred $84.4 million in cash expenditures for CCR remediation from January 2015 through June 2016. He also provided DNCP's projected CCR costs during the next several years. That amount was filed by DNCP under seal as a confidential trade secret. Witness Maness testified that DNCP has recorded this amount, adjusted to its current fair value, as an ARO. The present amount of the ARO recorded on DNCP's financial statements is $326 million. As these costs are incurred and deferred into a regulatory asset account, that amount will be deducted from the ARO.

With respect to the ongoing deferral of CCR expenditures, witness Maness indicated that the Company plans to defer North Carolina jurisdictional CCR cash expenditures for review by the Commission in future base rate proceedings, and subsequent recovery through base non-fuel rates approved in such proceedings. Witness Maness contended, however, that it was clear from the language of the 2004 ARO Order that the Commission intended that the authorization granted by the Order would have no impact on the ratemaking treatment to be determined by the Commission. He stated that although the 2004 ARO Order could be read as applying to all AROs, it should be noted that at the time of its issuance, the only significant ARO in existence was the one established for nuclear decommissioning. At that time, the Commission already had in place a long-standing, comprehensive mechanism to provide for the tracking and recovery of nuclear decommissioning costs. Witness Maness testified that the purpose of the 2004 ARO Order was to maintain Company accounting to match the Commission's longstanding accounting and ratemaking treatment of those costs, consistent with the statement in the ARO Order that "the intent and outcome of the deferral process shall be to continue the Commission's currently existing accounting and ratemaking practices." However, in the case of CCR expenditures, witness Maness testified that the Commission has not yet decided what the long-standing accounting and regulatory treatment of those costs should be. Therefore, in the absence of any action by the Commission in this case, witness Maness stated that continuing "the Commission's currently existing accounting and ratemaking practices," as the 2004 ARO Order requires, would most likely mean that the CCR expenditures through June 30, 2016, and afterwards, would simply be written off to expense in the year incurred. Witness Maness testified that because no prior

Commission treatment of CCR costs has been determined, the Company could not simply unilaterally presume that its proposed ratemaking deferral is authorized. Nonetheless, witness Maness testified that in this proceeding the Public Staff has investigated the CCR expenditures that the Company has proposed to defer and amortize, and has determined that the costs were reasonable and prudently incurred. Therefore, the Public Staff recommended the establishment of a regulatory asset for those expenditures.

Given the above, witness Maness made several recommendations regarding ongoing CCR deferrals:

> (1) That the Company be allowed to defer additional CCR expenditures through calendar year 2018, without prejudice to the right of any party to take issue with the special accounting treatment in a regulatory proceeding.
>
> (2) That the Commission note in its order in this proceeding that it is not making any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones it has approved for recovery in this case.
>
> (3) That the annual amortization expense approved for recovery in this proceeding continue to be credited as an offset to any future deferrals recorded by the Company, up until the time rates approved in the Company's next general rate case go into effect. Additionally, any other appropriate credits related to CCR expenditures, such as recoveries from third parties or governmental authorities, should be recorded as an offset to any future deferrals.
>
> (4) That the Company be required to file an annual report with the Commission, on the same date it files its annual FERC Form 1 report, detailing the CCR deferrals recorded in the previous calendar year as well as the annual amortization offset and any other offsets recorded.
>
> (5) That because CCR costs are being incurred due to the nature of the coal burned to produce energy over the years, the energy allocation factor be used to determine the North Carolina retail revenue requirement.

Moreover, Public Staff witness Maness testified that, during its investigation in this proceeding the Public Staff became aware that the Company has been or is involved in several legal disputes with various parties regarding its CCR compliance activities or the state of its CCR facilities. Additionally, witness Maness explained that the Company remains subject to possible state and federal findings of non-compliance with applicable statutes and regulations. Witness Maness indicated that the Public Staff has not become aware of any significant costs that have been incurred to date as a result of these disputes. Nevertheless, the Public Staff recommended that the Commission include in its order in this proceeding, in association with any approval of future deferral, a finding that any costs resulting from fines, penalties, other imprudent or unreasonable activities, or corrective actions to address those activities, are not allowable for deferral or recoverable for ratemaking purposes, and that legal costs incurred or settlements reached in resolution of disputes will be subject to close scrutiny to make sure that they are reasonable and appropriate for recovery from ratepayers.

Nucor witness Kollen testified that a three-year amortization period is unduly and unnecessarily short. Witness Kollen explained that a reasonable amortization period for the inactive and retired plants is 10 years, and a reasonable amortization period for the operating plants is the remaining life of each plant. The remaining service lives for the operating plants, according to witness Kollen, range from six to 35 years. Witness Kollen estimated an approximate amortization period based on the remaining service lives of 20 years. For the combined CCR costs of DNCP's retired and operating plants, witness Kollen proposed a 15-year amortization period for all CCR deferrals. Nucor reiterated this position in its post-hearing Brief.

In rebuttal testimony, Company witness Stevens argued that a lengthy recovery period for regulatory assets does not serve the best interests of DNCP's North Carolina customers or the Company. Since the Company is afforded a return on the unamortized balance for ratemaking purposes, witness Stevens argued that a longer amortization period costs customers more in the long run, while delaying the Company's recovery of actually incurred costs in the short run. Witness Stevens contended that delaying recovery of these actually incurred costs produces greater rate instability, and the Company's position strikes a reasonable balance of establishing rates that send accurate price signals to North Carolina customers, while recognizing the appropriate level of cost of service. The Company's proposed non-fuel base revenue increase in this proceeding, according to Stevens, is almost completely offset by a 2017 fuel factor reduction and decrement rider to refund EDIT with the total overall change in North Carolina retail rates approximating 0.2%. Witness Stevens noted that for many customer classes, their bills would reflect an overall decrease in rates on January 1, 2017.

With respect to Nucor witness Kollen's proposal to amortize CCR expenditures over 15 years, witness Stevens explained that the Company anticipates significant additional CCR expenditures subsequent to June 30, 2016, and a short duration for the amortization of this first wave of CCR expenditures is more appropriate. Witness Stevens contended that the Company's position aligns well with the fuel factor reduction and the significant EDIT refund, and setting an appropriate amortization level for this first wave of CCR expenditures allows for greater rate stability when addressing the need to recover additional phases of ongoing CCR compliance in future rate filings.

With respect to Public Staff witness Maness' proposal to amortize CCR expenditures over 10 years, witness Stevens argued that the comparison of the CCR expenditures to the abandonment or impairment and early retirement of a generating facility is neither reasonable nor accurate. Witness Stevens testified that the abandonment or impairment and retirement of a generating facility is a one-time, non-recurring event, while CCR expenditures are recurring and are environmental compliance and remediation costs, not abandoned plant, that will need to be recognized in future rate filings. According to witness Stevens, the Public Staff's proposal will likely result in overlapping vintages of CCR expenditure regulatory asset amortizations in future rate cases. To the contrary, witness Stevens explained that under the Company's proposal, the regulatory asset from the instant proceeding will conclude and be replaced by the next regulatory asset in the next general rate case, allowing for a more smooth transition from one case to the next, and more importantly, achieving greater rate stability for customers.

With respect to witness Maness' discussion regarding the Company's proposed ratemaking treatment of CCR expenditures, Company witness McLeod explained in his rebuttal testimony that the Company has set forth a ratemaking methodology for CCR expenditures in this case, and the Public Staff and other parties have the opportunity to respond. Witness McLeod testified that no one is disputing that the Commission will ultimately rule on the Company's proposed ratemaking methodology for CCR expenditures.

In addition, witness McLeod testified that the Company already requested and the Commission has already granted deferral authority for CCR expenditures in the 2004 ARO Order, and it is not necessary for the Company to request deferral authority from the Commission again for ARO costs beyond 2018 as recommended by Public Staff witness Maness. With respect to witness Maness' recommendation for the Commission to note in its order in this proceeding that it is not making any conclusions regarding the prudence or reasonableness of the Company's overall CCR plan, or regarding specific expenditures other than the ones it has approved for recovery in this case, witness McLeod argued that it is not necessary for the Commission to address future CCR expenditures in this proceeding. Further, witness McLeod disagreed with witness Maness' recommendation for the annual amortization expense approved for recovery in this proceeding continue to be credited as an offset to any future deferral recorded by the Company, up until the time rates approved in the Company's next general rate case go into effect, stating that the Company is not recovering these costs dollar for dollar, they are simply part of the total base non-fuel rate cost of service. Witness McLeod stated that it would be no more appropriate to grant witness Maness' proposal for these costs than it would for any other cost in the base non-fuel cost of service. Witness McLeod also contended that it is not necessary or appropriate for the Commission to address the future ratemaking treatment of fines, penalties, or other litigation costs in this case.

Finally, witness McLeod indicated that the Company accepted the Public Staff's adjustment to calculate the CCR expenditures regulatory asset by the energy factor.

The Stipulation includes the following provisions with respect to CCR costs:

(1) Amortization periods – CCR expenditures incurred through June 30, 2016, should be amortized over a five-year period. Notwithstanding this agreement, the Stipulating Parties further agree that the appropriate amortization period for future CCR expenditures shall be determined on a case-by-case basis.

(2) Deferral of future CCR expenditures – By virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR

expenditures incurred through June 30, 2016, the Company has authority pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, to defer additional CCR expenditures, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a rate case or other appropriate proceeding.

(3) Continuing amortization and deferral of CCR expenditures – The Company and the Public Staff reserve their rights in the Company's next general rate case to argue to the Commission (a) how the unamortized balance of deferred CCR expenditures incurred by the Company prior to June 30, 2016, and the related amortization expense should be addressed; and (b) how reasonable and prudent CCR expenditures incurred by the Company after June 30, 2016, should be recovered in rates.

(4) Overall prudence of CCR Plan – The Public Staff's agreement in this proceeding to the deferral and amortization of CCR expenditures incurred through June 30, 2016, shall not be construed as a recommendation that the Commission reach any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones to be recovered in this case.

(5) Reporting - The Company shall file with the Commission, on the same date it files its quarterly ES-1 report, a report detailing 1) the CCR deferrals recorded in the reporting period, and 2) regulatory accounting entries pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, with regard to any costs other than nuclear decommissioning costs or CCR costs, recorded in the reporting period.

(6) That DNCP agrees to provide the Public Staff, within 90 days of the date of the Stipulation, with a presentation regarding its accounting practices for non-nuclear asset retirement obligation costs.

At the hearing, witness Maness testified that the Stipulating Parties had reached agreement as to the CCR issues set forth in his testimony. He also stated that the Company and Public Staff agreed that it was not necessary for the Commission to make any findings regarding the possible future treatment of fines, penalties, or other litigation costs in this proceeding.

Further, witness Maness testified that the Public Staff's general impression is that DNCP's CCR repository facilities "were constructed and operated in a similar manner to facilities in various areas in the country." (T Vol. 8, at p. 361) In addition, witness Maness elaborated on the Public Staff's investigation of DNCP's CCR remediation efforts. He testified that the effort thus far has been engineering studies for work to be performed at the various sites, and beginning the closure of existing impoundments, such as dewatering of CCRs and water treatment. Witness Maness further testified that the Public Staff's Engineering Division reviewed invoices for the CCR work performed by DNCP and did not find any of the costs to be unreasonable.

On November 16, 2016, the Attorney General's Office (AGO) filed a post-hearing Brief. The AGO takes the position that the proposed recovery of coal ash expenditures unfairly burdens consumers and should be rejected by the Commission. The AGO notes that the Commission must set rates that are fair to the ratepayers and utility, pursuant to G.S. 62-133(a), and that the burden of proof is on the utility, under G.S. 62-75. The AGO further states that the Commission should consider, among other things, whether the CCR costs incurred are reasonable and prudent, and that this determination is detailed and fact specific, especially in the context of complicated cost recovery for environment-related clean-up costs. In addition, the AGO states that DNCP's CCR costs are projected to increase significantly over the next two or three years.

Moreover, the AGO contends that DNCP's CCR expenditures do not relate to operations that are used and useful for DNCP's current customers because they are for the disposal of CCRs that were produced over decades at plants that no longer generate electricity. Further, the AGO maintains that DNCP's proposal to include the unamortized balance of CCR costs in DNCP's rate base and earn a return on the unamortized balance is not a fair or lawful burden to impose on ratepayers, and is contrary to the holding in State ex rel. Utilities Comm'n. v. Carolina Water Service, 335 N.C. 493, 439 S.E.2d 127 (1994).

In addition, the AGO asserts that DNCP failed to provide detailed evidence about whether the CCR remediation costs it seeks to recover are reasonable and prudent, and that the Public Staff's analysis was insufficient. According to the AGO, DNCP appears to simply rely on compliance with the CCR Final Rule to justify its recovery of costs. The AGO also points out that DNCP has been sued for alleged violations of CCR environmental regulations.

Discussion and Decision

Prudence and Reasonableness

In the Coal Ash Management Act of 2014, the General Assembly included a moratorium prohibiting the Commission from allowing CCR clean-up costs in a utility's base rates. The moratorium was in effect until January 15, 2015. However, that section also states that "Nothing in this section prohibits the utility from seeking, nor prohibits the Commission from authorizing under its existing authority, a deferral for costs related to coal ash combustion residual surface impoundments." G.S. 62-133.13.

DNCP, like many electric utilities in the United States, has for decades generated electricity by burning coal. During those decades, the widely accepted reasonable and prudent method for handling CCRs has been to place them in coal ash landfills or ponds (repositories). At the hearing in this docket, in response to questions by the Commission, DNCP witness Stevens testified that when the EPA issued its draft CCR Rule in December 2014, DNCP first began addressing the fact that its CCRs could not remain stored in their existing repositories in perpetuity. Further, as discussed above, in his direct testimony, DNCP witness McLeod testified that the CCR Final Rule requires DNCP to close or retrofit all of its active and inactive CCR repositories. He further testified that

DNCP spent $37.5 million during the test year and anticipated spending an additional $63.8 million through June 2016. He later filed supplemental testimony adjusting the updated January 2015 through June 2016 CCR costs to a total of $84.4 million.

Public Staff witness Maness testified that the Public Staff's general impression is that DNCP constructed and operated its CCR repositories in a manner that is similar to CCR facilities in various areas of the United States. He stated that four of the eight DNCP coal-fired facilities are closed, or have been converted to natural gas-fired facilities. At the closed facilities, DNCP is using three methods in its effort to comply with the CCR Final Rule: (1) cap and close method; (2) a clean and close method in which the coal ash is moved to an on-site pond that is being capped and closed, and the original repository is closed; or (3) the clean and close method, except the original repository is used for a new purpose. He described the efforts as engineering work at various facilities, and the beginning of closure work at some facilities, including dewatering of the ash ponds and water treatment. Witness Maness also testified that the Public Staff Engineering Division reviewed the invoices for the CCR work that has been performed by DNCP thus far, and that the Public Staff did not find that any of DNCP's CCR costs were unreasonable. Witness Maness testified that the Public Staff found that DNCP's efforts and costs expended were prudent and reasonable.

Based on the allocation methodology agreed upon in the Stipulation, DNCP's allocable share of the CCR costs is $4,417,000. The Stipulating Parties agreed to DNCP's requested deferral of these costs and an amortization period of five years.

The Commission finds the CCR testimony of DNCP witnesses Stevens and McLeod and Public Staff witness Maness to be credible and to constitute substantial evidence that DNCP's actions in planning and beginning the work for permanent CCR repositories have been prudent, and that the CCR remediation costs incurred thus far by DNCP are reasonable. In particular, the Commission gives substantial weight to Public Staff witness Maness's testimony describing the Public Staff's investigation of DNCP's CCR remediation efforts. Witness Maness testified in some detail regarding the three CCR remediation options being employed by DNCP. He also testified that the Public Staff found that DNCP's CCR remediation efforts and costs were prudent and reasonable.

The AGO takes issue with the probative value of the DNCP and Public Staff evidence in support of CCR remediation costs recovery, not with the absence of such evidence. As outlined in detail above, the record contains substantial, unrebutted evidence from DNCP and Public Staff witnesses that DNCP's CCR remediation expenditures at issue were reasonable and prudent. The AGO has offered no witness or other probative evidence that DNCP's incurrence of CCR remediation costs were imprudent or unreasonable. No witness offered evidence that the costs should not be recovered. The only material dispute among the witnesses was over the appropriate amortization period for deferred remediation costs.

The AGO contends that DNCP's CCR activities have not produced property that is used and useful for DNCP's ratepayers. The Commission does not agree and determines that the used and useful argument misses the point. The AGO's argument is based on the fact that some of the coal-fired generating plants producing CCRs were no longer in service or were converted to gas-fired generation or some of the coal ash repositories had been closed before the test year. The Commission finds the AGO's logic misplaced. Due to federal and state environmental regulations, and in an attempt to remediate potential environmental degradation, DNCP incurred expense in the test year as extended. The fact that some of the coal-fired plants from which the CCRs had been removed were no longer in service or that the repositories in which the CCRS were stored had been closed and no longer receiving CCRs is beside the point. The issue is not recovery of costs of closed plants or costs of storing CCRs in repositories over past periods. The issue is recovery of remediation costs incurred in the test year as extended. In addition, a number of the electric generating plants from which CCRs are being and have been produced and the repositories are still in operation and have not been taken off line or closed.

Moreover, the current CCR repositories are and have served their purpose of storing CCRs for many years. In that respect, they have been used and useful for DNCP's ratepayers. However, pursuant to the CCR Final Rule, DNCP must incur expenses to the existing repositories for environmental remediation. As a result, the required solution for the CCR remediation serves the public policy of encouraging and promoting harmony between public utilities, their users and the environment. See G.S. 62-2(a)(5). Based on the testimony of witnesses Stevens, McLeod, and Maness, DNCP is responding to the CCR Final Rule requirements in a responsible and prudent manner. The result of DNCP's efforts should be the expenditure of funds to establish permanent CCR storage repositories. Like the existing CCR repositories, these permanent storage repositories will be used and useful for DNCP's ratepayers.

Further, the Supreme Court's decision in Carolina Water Service, cited by the AGO, does not support a denial of rate base treatment for the deferred and unamortized test year costs of CCR remediation. In Carolina Water Service, the Commission allowed the utility to include in the utility's rate base the unamortized portion of net costs still on the books at time of retirement not charged off in the test year for its Mt. Carmel wastewater treatment plant, even though the plant was not operating at the end of the test year and would never again be in service. The Commission's rationale was that the Mt. Carmel wastewater treatment plant unrecovered net costs should be treated as an extraordinary property retirement, with the deferred and unamortized costs included in the utility's rate base. The Supreme Court reversed that portion of the Commission's Order. The Court stated:

> [C]osts for abandoned property may be recovered as operating expenses through amortization, but a return on the investment may not be recovered by including the unamortized portion of the property in rate base.

Carolina Water Service, 335 N.C., at 508, 439 S.E.2d, at 142.

The issue in Carolina Water Service was whether to include in rate base the unamortized, unrecovered costs of a wastewater treatment plant that had been placed in service many years ago at which time the costs of the plant were incurred but with respect to plant that had been permanently retired. As addressed above, the costs at issue in this case are test year remediation costs, not unamortized costs of abandoned plants. Whatever costs DNCP incurred in past years in coal-fired generating plants already removed from service or costs incurred in the past to store CCRs in repositories now closed are not costs DNCP seeks to recover as DNCP's CCR remediation costs.

If, hypothetically, the Court had determined that costs Carolina Water Service had incurred in the test year to remediate potential environmental degradation from a discontinued wastewater treatment plant could be amortized but that the unamortized costs could not be included in rate base, perhaps such precedent would support the AGO's position; however, such costs are not those the Court addressed.

Although four of the coal-fired generating plants that are the sites of DNCP's CCR remediation efforts are no longer generating electricity, DNCP is not seeking to defer undepreciated costs of these plants or inclusion of unamortized costs in rate base as part of its CCR cost recovery request. Also, the existing CCR repositories at these sites cannot be abandoned by DNCP. Unlike the abandoned Mt. Carmel wastewater treatment plant in Carolina Water Service, the existing CCR repositories continue to be used and useful for storing CCRs, and will continue to be used and useful until DNCP moves the CCRs to a permanent repository, or takes the necessary steps to cap and close the existing repository.

The Commission's determination for allowing a portion of test year CCR costs to be recovered in this case is beneficial to DNCP, and the decision to amortize a large percentage of these test year CCR costs over a five-year period is a benefit to the ratepayer. The Commission likewise finds reasonable the provisions of the Stipulation allowing a return on the unamortized balance over the five-year period to be fair to the Company. Further, the Commission deems appropriate the establishment of a regulatory asset through which future CCR costs are accounted for, and thereby potentially departing from the general rule of matching future annual costs with revenues in the same period. In this fashion, the Company will have the opportunity to seek cost recovery for this unexpected and extraordinary cost expended in response to the CCR Final Rule which has required DNCP to store CCRs in a manner different from that in which the CCRs were being stored prior to 2015. The cost of complying with federal and state CCR remediation requirements was a risk that was unknown to the Company prior to 2015. Absent deferral, failure to recover those future costs could materially impact the Company's earnings. The Company's actions and testimony, and the testimony of Public Staff witness Maness, provide justification for the Commission's decisions. No witness testified against the effort to treat future CCR remediation costs as a regulatory asset for deferral and consideration in a future rate case. Based upon the entire evidence of record, the present Stipulation to allow the test year CCR costs to be recovered in this case by amortization over a five-year period with the unamortized balance to earn a return and the authorization to treat future CCR costs incurred through 2018 as a regulatory asset (which is the mechanism to facilitate the deferral of future CCR costs) is proper and in the public interest under the facts and circumstances of this case.

Conclusions on CCR Cost Deferral

Based on the foregoing and the record, the Commission finds and concludes that DNCP shall be allowed to defer the costs of its remediation of coal combustion residuals through June 30, 2016, and shall be allowed to amortize those deferred costs over a period of five years. The Company submitted substantial evidence that its costs incurred to comply with federal and state law regarding disposal of CCRs were prudently and reasonably incurred. No other party presented conflicting direct evidence on prudence or reasonableness of these costs. However, the Commission's approval of DNCP's CCR cost deferral is based on the particular facts and circumstances presented in this docket and, therefore, is not precedent for the treatment of CCR costs in any future proceedings.

In addition, the Commission finds and concludes that the treatment of CCR costs incurred by DNCP after June 30, 2016, shall be reviewed in a future rate case, subject to the provisions of the Stipulation regarding future amortization periods, deferral of future CCR expenditures, continuing amortization and deferral of CCR expenditures, and any other arguments or positions presented by the Company, the Public Staff, or another party at that time. Further, the Commission's determination in this case shall not be construed as determining the prudence and reasonableness of the Company's overall CCR plan, or the prudence and reasonableness of any specific CCR expenditures other than the ones deferred and authorized to be recovered in this case.

Finally, the Commission finds reasonable the provisions of the Stipulation regarding the agreement of DNCP to make a presentation to the Public Staff regarding its accounting practices for non-nuclear asset retirement obligation costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-23

The evidence supporting these findings of fact and conclusions is contained in the filings and Orders in Docket Nos. E-22, Sub 519, and Sub 533, the Company's verified Application, the direct and rebuttal testimony and exhibits of Company witnesses McLeod and Stevens, the testimony of Public Staff witness Fernald and Nucor witness Kollen, the Stipulation, and the entire record in this proceeding.

Warren County CC and Brunswick County CC Deferrals

The Company's initial Application proposed to amortize the deferred costs, including a return on investment, associated with the Warren County CC requested in the Company's petition in Docket No. E-22, Sub 519. [7] As explained by Company witness

[7] The Commission previously addressed the deferral costs related to the Warren County CC. On January 30, 2015, DNCP filed an application for an accounting order in Docket No. E-22, Sub 519 (Sub 519 docket) requesting that it be allowed to defer certain costs associated with its Warren County CC generating facility that was placed in service in December 2014. After comments by the parties and an oral argument held on June 15, 2015, the Commission issued an Order Denying Deferral Accounting for Warren County CC on March 29, 2016. DNCP filed for reconsideration regarding the deferral of the Warren County CC on March 3, 2016 (Motion for Reconsideration). On May 17, 2016, the Commission issued an Order

McLeod, DNCP requested to defer the incremental costs incurred from the time the assets were placed into service (December 2014) until the time they are reflected in the base non-fuel rates, and that these cost be amortized over a three-year period, with the unamortized balance, net of ADIT, included in rate base.

The initial Application also proposed to amortize the deferred costs, including a return on investment, associated with the Brunswick County CC requested in the Sub 533 docket, from the time the assets were placed into service (April 2016) until the time they are reflected in base non-fuel rates, and that these costs be amortized over a three-year period.

Public Staff witness Fernald testified that DNCP filed additional evidence concerning the Sub 519 docket. She stated that had DNCP filed this additional evidence concerning its December 2014 ES-1 information as part of its original deferral application, the Public Staff's position on the original deferral request would have changed. Witness Fernald further testified that while the Public Staff does not agree with all of the Company's additional adjustments to the December 2014 ES-1 included in its Motion for Reconsideration, the Public Staff would have agreed with the Company's proposed adjustment to apply the 2014 cost of service study factors to the December 2014 ES-1. Witness Fernald stated that with this adjustment, the ROE would have been materially below the Company's authorized ROE, and the Public Staff would not have opposed the Company's deferral request based on earnings. Therefore, Public Staff witness Fernald recommended that the Warren County CC deferral costs of $10,204,000 for North Carolina retail be recovered from ratepayers in this proceeding through a levelized amortization over a three-year period.

Nucor witness Kollen recommended that the Commission deny DNCP's proposed regulatory deferrals associated with the Warren County CC and Brunswick County CC. With respect to the Warren County CC deferral, witness Kollen discussed the Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility issued on March 29, 2016, in Docket No. E-22, Sub 519, in which the Commission denied the Company's deferral request. Witness Kollen noted the Commission subsequently agreed to rehearing on the issue in the instant proceeding.

According to witness Kollen, the Company's requests sought deferral of costs only through June 30, 2016. He argued that since that date now has passed, an accounting order issued after June 30, 2016, necessarily would authorize retroactive ratemaking.

Nucor witness Kollen noted that the Company did not seek to return to customers savings from the ODI implemented earlier in 2016. The Company proposes to recover increases in its costs (i.e. the Warren County CC deferral request), while at the same time

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consolidating the Motion for reconsideration for the Warren County CC deferral with the general rate case application filed in this docket. The Order also consolidated the Deferral Request for the Brunswick County CC, which was filed in Docket No. E-22 Sub 533 (Sub 533 docket) into the general rate case docket as well.

retain reductions in its costs. These proposals, according to witness Kollen, are inconsistent and inequitable.

Additionally, witness Kollen testified that any deferrals authorized for 2015 cannot and will not be recorded in 2015 and will not affect the Company's earnings in 2015, as the Company's accounting books now are closed and final for 2015. He stated that the ROE effect of the Brunswick County CC costs is approximately 0.08%, all else being equal, or approximately two months of the effect of Warren County CC. This is not material, according to witness Kollen, even if the Company is not earning its authorized return and does not meet this basic test applied by the Commission in the Warren County CC and other deferral proceedings. Nucor witness Kollen, therefore, recommended that the Commission reject the Company's request to defer and amortize these post-commercial operation costs.

In the event that the Commission authorizes deferral of these costs, witness Kollen recommended that the Commission levelize or annuitize the revenue requirement effect over a 10-year amortization period to include a return on and recovery of the regulatory asset. He testified that the post-commercial operation costs are analogous to "start-up costs" that could be amortized over the life of the unit. Witness Kollen argued that the Company's proposed three-year amortization period is unduly short and unnecessarily increases the revenue requirement compared to a longer amortization period.

In rebuttal testimony, Company witness Stevens testified that it is important for the Commission to fully assess a utility's request for deferral accounting with the evidence on the financial condition and earned return of the utility in question, as well as the impact that an extraordinary event has on that earned return and financial condition. In response to witness Kollen's testimony regarding the Commission's prior denial of the Warren County CC deferral request, witness Stevens contended that the extensive and detailed evidence presented in the Company's May 3, 2016, Motion for Reconsideration, filed in Docket No. E-22, Sub 519, demonstrates that DNCP's earned return for the 2015 test year was 5.99%. Witness Stevens testified that the financial impact of placing the Warren County CC in service is also significant and meets the Commission's well-established standard for deferral authorization, especially given the substantial fuel savings derived from the operation of the generation asset for the benefit of North Carolina customers, including Nucor, on a timely and current basis. With respect to witness Kollen's assertion that the effect of the Brunswick County CC deferral request only amounts to eight basis (.08%) points ROE, witness Stevens referenced the evidence in the Company's Application for Dominion North Carolina Power for an Accounting Order for the Brunswick County CC (Docket No. E-22, Sub 533), asserting that there was a 31 basis points net detrimental impact to the Company's annualized earned return under existing tariffs. This was benchmarked against the Company's fully adjusted test period North Carolina jurisdictional ROE of 5.06%, when all components for regulatory accounting purposes are properly taken into account.

With respect to Nucor witness Kollen's comparison of the Warren County CC and Brunswick County CC deferrals with a proposed deferral associated with the savings from

ODI, witness Stevens testified that the Company has reflected a full going-level of ODI savings in the base non-fuel revenue requirement in this proceeding. Witness Stevens explained that it has been this Commission's practice to approve accounting deferrals sparingly based on its well-established standard of whether a significant and unusual or extraordinary event has occurred that has materially impacted a utility's earnings and overall financial condition. The ODI program was a narrow severance program targeted at certain management layers in the organization – it would not qualify as an issue ripe for deferral given its relatively small impact. Witness Stevens stated that in the Commission's recent denial of the Public Staff's request for deferral accounting associated with a modest increase in annualized revenues resulting from the Company's January 1, 2015, extension of the agreement for electric service with Nucor (Docket No. E-22, Sub 517), the Commission noted that deferral is only warranted where an event affecting the utility's costs or revenues is unusual or extraordinary because changes in revenues, expenses, and investments happen routinely between the time a utility's rates are fixed by the Commission and the time of the next rate case and routine changes alone do not result in a change in the balance of revenues, expenses, and investments struck by the Commission's last rate Order. According to witness Stevens, the ODI program savings are not extraordinary and of such material financial significance to warrant deferral accounting consideration.

With respect to Nucor witness Kollen's proposed 10-year recovery period for the Warren County CC and Brunswick County CC deferrals, witness Stevens argued against such an extended period for the same reasons he generally disagrees with extended recovery periods for other regulatory assets in this proceeding. According to witness Stevens, North Carolina customers have also been receiving substantial fuel expense savings on a timely and current basis through the fuel factor as a direct result of the Warren County CC and Brunswick County CC investments, and it is not appropriate to substantially delay the recovery of the costs incurred that resulted in the fuel savings. Witness Stevens contended that the Commission has generally authorized a shorter time period for the amortization of deferrals associated with new major generation facilities placed into service by North Carolina electric utilities, and DNCP is not aware of the Commission using a 10-year recovery period in recent cases. Witness Stevens added that the Public Staff has agreed with the Company's proposed three-year amortization period in this case.

The Stipulation provides for deferral accounting treatment and recovery of deferred post-in-service costs for both the Warren County CC and the Brunswick County CC. The Stipulation provides that the deferred costs will be recovered over a three-year period on a levelized basis.

The issue before the Commission in this case is one of cost deferral, a recognized practice allowing recovery of unusual expenses arising from extraordinary circumstances or events; and its use, which the Commission has historically employed sparingly, does not constitute impermissible retroactive ratemaking. The Commission has established relatively clear guideposts and standards over the years for determining when a petition for deferral is appropriate. This is especially the case in the context of major new generating facilities that also create material fuel cost savings that are flowed through to ratepayers through lower fuel rates. Based upon the evidence now before the Commission, the Commission finds that DNCP has made the requisite showing that the Warren County CC and Brunswick County CC costs in question had a material impact on the Company's financial condition. As shown in the Company's Motion for Reconsideration in Docket No. E-22, Sub 519, the Company's verified Application in this case, and the testimony of Public Staff witness Fernald, the Commission also recognizes that DNCP's earnings were well below its authorized cost of equity of 10.2% when both the Warren County CC and Brunswick County CC were placed in service. Much of the evidence presented by the Company in this case, relating to its earnings at the time the Warren County CC went into service, was not presented as evidence before the Commission at the time the Commission issued its initial order of March 29, 2016, in Docket No. E-22, Sub 519, denying the Company's request for deferral of the post-in-service costs of the Warren County CC.

In consideration of the foregoing, the Commission finds and concludes that DNCP's requests to defer post-in-service costs of the Warren County CC and the Brunswick County CC should be and are hereby granted. The Commission further finds that the evidence in the record does not support Nucor witness Kollen's view that the ODI program savings are sufficiently extraordinary and of such material financial significance to warrant deferral accounting consideration. The Commission finds and concludes that for the present case deferral and recovery of the Warren County CC and Brunswick County CC deferred post-in-service costs presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

<u>Regulatory Assets and Liabilities with Amortization Ending in 2017</u>

Public Staff witness Fernald identified the following regulatory assets and liabilities that will be fully amortized in 2017:

Regulatory Asset or Liability	Amortization Ends On
Unrecovered design basis costs – Surry	May 31, 2017
NUG buyout costs – Atlantic	May 31, 2017
DOE settlement	June 30, 2017
Bear Garden deferral	October 31, 2017
NUG buyout costs – Mecklenburg	October 31, 2017

Witness Fernald recommended that the unamortized balances of these regulatory assets and liabilities as of October 31, 2016 (the date the Company proposed to implement the provisional rates in this proceeding), be re-amortized over three years using a levelized amortization, consistent with her recommended treatment of the EDIT liability and deferred costs.

Company witness McLeod discussed several concerns with Public Staff witness Fernald's proposal. First, witness McLeod testified that the amortization periods for these regulatory deferrals were established by the Commission in prior cases based on the specific facts and circumstances in those cases. Second, the Public Staff's adjustment, according to witness McLeod, would result in an adjustment to rates in this case based on events scheduled beyond the close of the hearing date in this proceeding. Witness McLeod also contended that it is not appropriate to convert to a levelization approach for the treatment of regulatory assets and liabilities midstream, as this will result in either an over- or under-recovery of carrying costs on the deferral balance over the life of the asset.

The Stipulation amortizes the unamortized balances of these regulatory assets and liabilities as of October 31, 2016, based on the date the provisional rates were expected to be implemented in this proceeding, over three years using a levelized amortization, as proposed by Public Staff witness Fernald. The Commission finds and concludes that for the present case the stipulated treatment of these unamortized balances is just and reasonable to all parties in light of all the evidence presented.

Beyond Design Basis Study Regulatory Assets

Public Staff witness Fernald testified that the Company has included in other additions in this proceeding two regulatory assets related to costs incurred to perform studies at the Surry and North Anna nuclear plants as required by the Nuclear Regulatory Commission (NRC) as a result of the disaster at the Fukushima nuclear plant following an earthquake and tsunami in Japan. Witness Fernald proposed to exclude these two regulatory assets from rate base and instead include the expenses related to these NRC studies incurred in 2015 in O&M expenses in this proceeding. Witness Fernald noted that the Company did not file a request with the Commission to defer the cost of these studies. Public Staff witness Fernald commented that the Commission previously stated in prior DNCP rate case orders that it does not consider a deferral period, an amortization period, or a window for filing a deferral request to be open-ended.

In rebuttal testimony, Company witness McLeod argued that DNCP's accounting methodology for the beyond design basis study costs is consistent with the treatment of design basis documentation costs incurred in the late 1980s and early 1990s. Witness McLeod explained that at that time, the Company requested and received guidance from the FERC for design basis documentation costs incurred, and that the FERC instructed the Company to record the costs to FERC Account 182.2 (regulatory asset account), and that these costs have been included in the Company's cost of service studies in North Carolina for over two decades.

Witness McLeod testified that since these costs were mandated by the NRC, and the Company deferred them to FERC Account 182.2 in accordance with FERC's instructions, it would be improper to account for them as other O&M expenses as recommended by the Public Staff. Witness McLeod represented that the Company will make diligent efforts to seek the Commission's approval on a timelier basis in the future.

The Stipulation provides for deferral accounting treatment of the beyond design basis study costs mandated by the NRC as proposed by Company witness McLeod. The Stipulation also provides that the Company will comply with Commission Rule R8-27(a)(2) prior to establishing any regulatory assets and liabilities for North Carolina jurisdictional purposes in the future. The Commission hereby approves deferral accounting treatment for the beyond design basis study costs *nunc pro tunc* as of July 2012, which is the date the Company began deferring these costs. The Commission finds and concludes that recovery of the beyond design documentation study costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Chesapeake Decommissioning and Closure Costs Regulatory Asset

In its Application, DNCP proposed to include any decommissioning and closure costs incurred at Chesapeake and to amortize such deferred costs as of June 30, 2016, across a three-year recovery period.

Nucor witness Kollen testified that the Company deferred the costs for dismantling and other site costs for Chesapeake, but did not offset those costs by the savings in O&M expense, other operating expenses, and depreciation expense. According to witness Kollen, these expenses were included in the revenue requirement in the 2012 Rate Case, and the Company will continue to collect these expenses through the revenue requirement until rates are reset at the conclusion of this proceeding, even though they no longer are incurred. Witness Kollen asserted that Nucor had requested that the Company quantify the savings since the retirement of the plant, and the Company did not do so and simply responded that the proposed regulatory asset does not include any offsets for avoided operating expenses after the facility was retired.

Witness Kollen recommended that the Commission deny the Company's request for recovery of the deferral unless DNCP can demonstrate that the costs exceed the savings until rates are reset in this proceeding. Alternatively, if the Company provides an appropriate quantification of the savings from the avoided operating expenses (realized since closure of the plant in late 2014), then the Commission should calculate the revenue requirement on the deferred cost net of the savings on a levelized basis using a 10-year amortization period.

In response to Nucor witness Kollen, Company witness Stevens noted there were no operating O&M or depreciation expenses associated with Chesapeake in the Company's 2015 test year cost of service study. The only O&M expenses are those related to closure costs incurred in the 2015 test year. Witness Stevens contended that the cost avoidance of retiring Chesapeake Units 1-4 should also be reflected in Nucor's evaluation. In the 2012 Rate Case, the Company presented information that demonstrated that to comply with the Mercury Air Toxics Standard rules it was expected that Chesapeake Units 1-4 would all require Dry Flue-Gas Desulfurization equipment by 2015. In addition, witness Stevens testified that these units would require other new environmental equipment to comply with other expected environmental rules such as CSAPR, Ozone Standard Review, NAAQS, and 316(b). Witness Stevens presented an analysis showing the net present value cost increase in lieu of retirement totaled over $190 million for these four coal units.

Witness Stevens additionally testified that the purported savings on O&M and depreciation expenses previously incurred at Chesapeake did not create a windfall for the Company that can now retroactively be captured, as Nucor witness Kollen contends. Witness Stevens contended that no further adjustments are necessary because the environmental cost avoidance well exceeded the assumed savings and certainly caused no over-recovery of DNCP's cost of service during this period.

With respect to Nucor witness Kollen's proposed 10-year recovery period for the Chesapeake decommissioning and closure cost deferral, witness Stevens argued against such an extended period for the same reasons he generally disagreed with extended recovery periods for regulatory assets. Witness Stevens noted that the Public Staff agreed with the Company's proposed three-year amortization period and that this is also consistent with prior Commission treatment of regulatory assets.

The Stipulation provides for deferral accounting treatment of the Chesapeake closure costs regulatory asset and recovery over a three-year period on a levelized basis. The Commission does not findNucor's reasoning persuasive and, therefore it declines to adopt Nucor's recommendations in this matter. Rather, the Commission agrees with the deferral treatment as specified in the Stipulation. The Commission finds and concludes that recovery of the Chesapeake closure costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact and these conclusions is contained in the testimony of Public Staff witness Maness and DNCP witness McLeod.

Public Staff witness Maness addressed the question of how revenues received by DNCP for CCR cost deferrals after the approved amortization period should be treated. Witness Maness testified that DNCP appears to interpret prior Commission orders to allow CCR cost deferral to continue automatically after the approved amortization period and for an indefinite period into the future. He stated that the Public Staff disagrees with DNCP's interpretation and recommends that the Commission allow deferral to continue through 2018, subject to prudency and reasonableness reviews, and subject to a credit of the approved CCR expense to future deferrals until DNCP's next general rate case.

In his rebuttal testimony, DNCP witness McLeod disagreed with the Public Staff's recommendation that the annual amortization cost should continue to be credited to DNCP's deferred CCR costs until the Company's next general rate case. Witness McLeod opined that the deferred CCR costs should be treated as any other cost of service expense being recovered in the Company's non-fuel base rates.

The Commission does not agree with DNCP's position on this issue. A deferred cost is not the same as the other cost of service expenses recovered in the Company's non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DNCP continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission, that does not mean that DNCP is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact and these conclusions is contained in the testimony of Public Staff witness Fernald, the rebuttal testimony of Company witness Stevens, the Stipulation, and the entire record of this proceeding.

In her testimony, Public Staff witness Fernald made three accounting recommendations. The first recommendation related to the Yorktown Plant. Witness Fernald urged that upon the closure of the Yorktown plant, should DNCP plan to amortize Yorktown's net book value and closure costs (other than those relating to the closure of coal ash ponds, for North Carolina ratemaking purposes), that DNCP should notify the Commission of the closure and also provide the Commission with an estimate of the net book value and closure costs.

Witness Fernald's second recommendation related to the FERC USOA. She stated that under Commission Rule R8-27, the FERC USOA is prescribed for all electric utilities under the jurisdiction of the Commission. Witness Fernald noted that DNCP does not maintain its accounting system based on the FERC USOA, but instead uses a different system of accounts, which it refers to as natural accounts. Public Staff witness Fernald explained that in order to comply with the Commission's requirements and produce its financials and reports based on the FERC USOA, DNCP maintains a module to convert its natural account postings to FERC accounts.

Witness Fernald testified that the FERC USOA identifies and categorizes costs in a manner that is consistent with ratemaking and identifies costs that are of particular interest to regulators. If a company does not maintain its accounting system based on the FERC USOA, it must still be able to produce records based on the FERC USOA, to a level such that an audit trail is maintained. Witness Fernald noted that during the Public Staff's investigation, there were several instances where costs could not be audited based on the FERC USOA. Based on that, Public Staff witness Fernald recommended that the Company maintain its accounting records in a manner such that it is able to produce records based on the FERC USOA – including allocations from its affiliates such as the service company charges discussed below – so that an audit trail is maintained and fluctuations based on the FERC USOA can be explained. Witness Fernald further recommended that the Company file the procedures and processes that it will implement to improve the transparency between the FERC accounts and the natural accounts with the Commission within 90 days after issuance of the Order in this proceeding.

Witness Fernald's third recommendation related to service company charges. Each month, when DNCP is billed by its affiliated service company, Dominion Resources Services, Inc. (DRS), for (1) services performed by DRS personnel and (2) third-party bills paid by DRS and allocated to DNCP, the expenses allocated to DNCP are initially mapped to FERC Account 923 - Outside Services Employed. Witness Fernald explained that the Company has an automated program that then takes the amounts billed by DRS to DNCP each month and reclassifies items to different accounts as may be appropriate.

Witness Fernald testified that during the Public Staff's investigation, DNCP was unable to provide the specific transactions billed by DRS to DNCP by FERC account. The Company's accounting records should be maintained such that the details of the transactions billed by DRS to DNCP, including the amounts allocated for third-party bills by vendor and the FERC account to which they are charged, is available. Finally, witness Fernald recommended that the Company file the procedures and processes that it will implement to comply with this recommendation with the Commission within 90 days after the date of the Order in this proceeding.

With respect to the Public Staff's accounting recommendation regarding the Yorktown Plant, Company witness Stevens avowed that the Company would notify the Commission when the Yorktown closure occurs and provide an estimate of the undepreciated value of Yorktown at the time of closure and the estimated level of costs to be incurred for closure.

With respect to the Public Staff's second recommendation pertaining to the FERC USOA, Company witness Stevens indicated that the Public Staff applied no materiality threshold when making such statements and that the Company views its accounting practices as reasonable and appropriate.

In response to the Public Staff's generalized comment about improving transparency between FERC accounts and natural accounts, Company witness Stevens attested that the Company filed its Application for a revised Services Agreement between DRS and DNCP with the Commission on September 23, 2016. Witness Stevens reiterated the Company's commitment to provide the Public Staff with information in Docket Nos. E-22, Subs 476, 477, and 482, which will help to address the Public Staff's issues and concerns.

The Stipulation includes the following provisions addressing Public Staff witness Fernald's accounting recommendations:

(1) The Company will notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure.

(2) The Public Staff's accounting recommendations concerning the FERC USOA and the service company charges will be addressed in Docket Nos. E-22, Subs 476, 477, and 482.

The Commission finds and concludes that the three accounting recommendations as detailed by Public Staff witness Fernald and agreed to by the Company in the Stipulation are appropriate and should be accepted. The Commission further finds and concludes that provisions set forth in the Stipulation as agreed to between the Company, the Public Staff and CIGFUR I are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-28

The evidence supporting these findings of fact and conclusions is contained in the Application, the direct testimony and exhibits of Company witnesses Petrie, Haynes and Hupp, the supplemental testimony and exhibits of Company witnesses Petrie and Haynes, the testimony and exhibits of Public Staff witnesses Peedin and Lucas, the Stipulation, and the entire record in this proceeding.

In his direct testimony, witness Petrie presented an estimate of DNCP's adjusted system fuel expense for the period July 1, 2015 – June 30, 2016, of $1.689 billion, which was used by witness Haynes to estimate the anticipated reduction in the fuel factor rate. He also estimated the deferred fuel balance as of June 30, 2016, and described DNCP's forecasted fuel expense recoveries for the second half of 2016. In his supplemental testimony, witness Petrie presented an updated adjusted total system fuel expense for the 12-month period ending June 30, 2016, of $1.74 billion, as shown in the Company's August 5, 2016 fuel factor adjustment filing in Docket No. E-22, Sub 534. He noted that this total adjusted amount was calculated based on the 100% Marketer Percentage proposed by witness Hupp in his direct testimony. Witness Petrie also testified that the Company's projected fuel over-recovery at the end of December 2016, assuming an interim rate change on November 1, 2016, was approximately $3.9 million.

In his direct testimony, Company witness Haynes used a placeholder base fuel rate based on the fuel factor approved in the Company's 2015 fuel adjustment case, Docket No. E-22, Sub 526. In his supplemental testimony, witness Haynes used the updated adjusted total system fuel expense presented by witness Petrie to calculate an average base fuel factor of $0.02116/kWh, a reduction from the current base fuel factor of $0.02427/kWh. He also used the revised Rider A rate of zero consistent with the Company's 2016 fuel adjustment filing. He further testified to the Company's reintroduction of Rider A1 on November 1, 2016, for the purpose of accelerating the return of DNCP's fuel over-recovery to its customers in conjunction with placing the proposed updated non-fuel and base fuel rates into effect on a temporary basis on that date. He explained that implementation of Rider A1 will lower the estimated over-recovery balance as of December 31, 2016, and reduce further the impact of the proposed base rate increase.

In his direct testimony, Company witness Hupp presented the Company's recommendation that the Marketer Percentage applicable to DNCP be increased from 85%, as it was established in the Company's 2012 Rate Case and used in DNCP's 2015 fuel factor case, Docket No. E-22, Sub 526, to 100%. He testified that this increase would result in a more appropriate treatment of purchased power costs, because it would permit DNCP to recover all of its prudently incurred purchased power costs through fuel rates. He explained that, when DNCP purchases rather than self-generates power, it does so in order to minimize the cost incurred to meet its customers' energy requirements. As a result, the resulting cost of DNCP's market energy purchases will likely be less than the variable marginal cost of running one of the Company's own generators to meet the energy need. Witness Hupp also testified that the Company believes that any prudently incurred power purchases made to serve customers' energy requirements should be fully allowable through fuel. He stated that the variable costs of running one of the Company's generators largely represent allowable fuel costs deemed recoverable by the Commission in the Company's fuel factor cases. Therefore, witness Hupp stated, purchases of energy deemed to be less expensive than this marginal and allowable cost of fuel for fleet operations should – when shown to be prudently incurred – also be fully allowable through fuel with no impacts to base rates. He testified that this would better align the Company's recoverable fuel-related expenses with its actual costs.

Witness Hupp noted that the Company's request for relief of the PJM Order conditions, addressed below with regard to Finding of Fact No. 50, removes the barrier that the Commission identified in its order in DNCP's 2014 fuel clause adjustment proceeding as preventing the Commission from using the discretion provided at subsection (f) to permit DNCP to recover 100% of its purchased power costs through fuel, including deemed congestion related costs.

Public Staff witness Peedin testified that with respect to purchased power, DNCP is entitled under G.S. 62-133.2(a3) to recover only "the fuel cost component, as may be modified by the Commission, of electric power purchases identified in subdivision (4) of subsection (a1)," and the fuel cost component of other purchased power, through the prospective fuel factor and the EMF. She testified that the Public Staff interprets the phrase "fuel cost component, as modified by the Commission" to mean that, in DNCP's case, the fuel cost component of purchases subject to economic dispatch must be determined by the Commission when the actual cost is not known, and that the Commission may modify the method for making that determination as appropriate. She stated that allowing DNCP to recover all of the energy costs of purchased power through a Marketer Percentage of 100% appears to read this phrase out of the statute and implies that the energy costs consist solely of fuel costs. She opined that is not the case, stating that a significant portion of energy costs consist of non-fuel variable operation and maintenance expenses.

Witness Peedin recommended that the Commission adopt a Marketer Percentage of 78% to be used as a proxy for the fuel cost component of purchases for which the actual fuel cost is unknown. She stated that both methods used by the Public Staff to determine this Marketer Percentage were proposed by DNCP in its 2008 fuel proceeding, Docket No. E-22, Sub 451, as an alternative to the off-system sales method then used by DEC and DEP. Witness Peedin described the first methodology as a review of data from the 2014 and 2015 PJM State of the Market reports, which identified each fuel component of the cost of energy used to set the energy market price. She stated that according to these reports, the fuel components of energy cost for years 2014 and 2015 were both 73.90%. She described the second methodology as a review of data provided by DNCP that blended the Company's internal data with PJM State of the Market report data for the DOM Zone. She stated that the average of the 2014 and 2015 values under the two methods was 78%. Based on her recommended Marketer Percentage of 78%, witness Peedin further recommended an adjustment to DNCP's non-fuel purchased power energy expense so that 22% of that expense would flow through base rates as purchased energy costs. This resulted in an adjustment to increase the base non-fuel rates by $2.261 million and decrease fuel rates by the same amount.

The Stipulation provides for a base fuel factor of $ 0.02073/kWh, as differentiated between customer classes, as shown on Company Rebuttal Exhibit PBH-1, Schedule 9. The Stipulation also provides that the appropriate EMF to be included in DNCP's updated annual fuel factor for the 2017 rate year shall be determined by Commission order in the Company's 2016 fuel case, Docket No. E-22, Sub 534.

The Stipulation also provides for a Marketer Percentage of 78%, to remain in place until the Company's next base rate application or its 2018 fuel factor application, whichever occurs first.

No party opposed the stipulated base fuel factor or the stipulated Marketer Percentage or conducted cross-examination on these issues at the hearing.

Based on all of the evidence in this proceeding, the Commission finds and concludes that the stipulated base fuel factor of $0.02073/kWh is just and reasonable for DNCP in this case. The Commission also concludes that a marketer percentage of 78%, to be applied to appropriately determine the fuel cost component of energy purchased for which the fuel cost is unknown, should continue to be used until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and these conclusions is contained in the Application, the direct, supplemental, and rebuttal testimony and exhibits of Company witness Chapman, the direct and settlement testimony and exhibits of Public Staff witness Hinton, the direct testimony and exhibits of Nucor witness Woolridge and CUCA witness O'Donnell, the Stipulation and the hearing testimony of witness Chapman.

In the Application, and as explained by DNCP witness Chapman in his direct testimony, the Company proposed a capital structure reflecting long-term debt of 46.641% and common equity of 53.359%. Witness Chapman, who is Senior Vice President – Mergers and Acquisitions and Treasurer for the Company, testified that the appropriate capital structure for use in this case was the Company's actual capital structure as of December 31, 2015. He discussed the Company's significant capital needs going forward, and explained how the Company plans to finance those capital needs, based on a balance of debt and common equity that DNCP believes will support the Company's credit ratings going forward, and continue to enable the Company to access a number of markets, under a wide range of economic environments, on reasonable terms and conditions. He stated that this market access is critical to fund the ongoing infrastructure capital expenditure program that will be necessary to meet the Company's public service obligations in North Carolina and throughout its system. In his supplemental testimony, witness Chapman updated the Company's proposed capital structure to its actual structure as of June 30, 2016, which reflected a long-term debt component of 46.080% and an equity component of 53.920%. Based on the Company's proposed cost rates for long-term debt and common equity, witness Chapman's proposed capital structure produced an overall weighted-average cost of capital of 7.803%.

Public Staff witness Hinton initially filed testimony stating that the Company's proposed common equity ratio produces an overall return on rate base greater than necessary to maintain credit quality and continue to attract capital. Witness Hinton noted that DRI's announced acquisition of Questar Corporation (Questar) led to an S&P credit downgrade for DRI and its subsidiaries, including VEPCO, from A- to BBB+. He noted that the credit rating reports indicate that VEPCO's regulated operations have lower business risk than DRI's unregulated businesses. He opined that the Questar acquisition may contribute to an already high debt ratio for DRI. He also noted that it is too early to tell whether recent actions, in particular the Questar acquisition, pose a risk that will increase the cost of capital.

Witness Hinton referred to DRI's confidential target capital structure for the Company as support for his position on capital structure. In addition, he noted that although the Company's average equity ratio from November 2009 to March 2016 was 54.01%, in contrast the common equity ratio averaged 49.97% for the six-year period prior to November 2009. He referenced testimony submitted in a Virginia State Corporation Commission proceeding regarding the Company operating with an equity ratio at the upper end of its target range, and opined that the increase in the equity ratio in recent years is not necessary for reasonable financing or justified in terms of its impact on Company customers. He also stated that DRI has a much higher debt ratio and lower equity ratio than the Company, and asserted that the Company's ratepayers were being asked to pay a high equity ratio to help offset DRI's high debt ratio. Finally, he stated his concern about the effect of added earnings from Virginia's return on equity incentives on the Company's capital structure. Witness Hinton concluded by recommending a capital structure consisting of 50.96% common equity and 49.04% long-term debt. Witness Hinton based his recommended capital structure on data from Regulatory Research and Associates, Inc., on recently commission approved equity ratios for other vertically integrated electric utilities with comparable Standard & Poor (S&P) bond ratings between BBB+ and A-. He accepted the Company's proposed long-term debt cost rate of 4.645%.

Nucor witness Woolridge testified that DNCP's proposed capital structure includes more equity and less debt than other electric utilities, does not include short-term debt, which amounts to almost 10% of its capitalization as of December 31, 2015, and includes much less equity than the capitalization of DNCP's parent DRI. He testified that the median common equity ratios of his and witness Hevert's proxy groups are 47.1% and 48.2%, respectively, and that DNCP's proposed capitalization includes more equity and less financial risk than these averages. Witness Woolridge, like Public Staff witness Hinton, noted concerns with the use of double leverage where the regulated utility subsidiary finances equity with the use of debt raised through the parent company. Witness Woolridge also compared DNCP's capitalization as of December 31, 2015, comprised of 9.81% short term debt, 41.20% long term debt, and 48.99% common equity, to that of DRI, comprised of 13.03% short term debt, 56.61% long-term debt, and 30.36% common equity. He noted that he used utility holding companies in his proxy group because their common stock is traded in the markets, and their financial risk and equity ratios are thus relevant for comparison rather than those of operating utilities. He testified that a high equity ratio will have a downward impact on a utility's financial risk, and that the ROE should be adjusted to account for that. He stated that based on these factors he proposed a capital structure consisting of 50% long-term debt and 50% common equity. He asserted that this capital structure is more in line with the average common equity ratios approved by state regulatory commissions in electric utility rate cases in 2015 and 2016 than the Company's proposed structure. Witness Woodridge adopted the Company's proposed long-term debt cost rate of 4.65%.

CUCA witness O'Donnell testified that DNCP's proposed capital structure is not comparable to the average common equity ratio of companies in witness Hevert's comparable group nor similar to the average equity ratio granted by state regulators for electric utilities in 2015 and to-date in 2016. He stated that the average common equity ratio for witness Hevert's comparable group is 50.1%. He stated further that the average common equity ratio granted to electric utilities by regulators across the United States in 2015 was 48.86% and to-date in 2016 is 43.67%. He noted that, in 2016, excluding limited issue rider cases, there have been only five rate case decisions and two of those were made in states that use non-investor sources of capital in the regulatory capital structures. Witness O'Donnell's calculation of the common equity ratio for those two companies was 49.47%. He noted further that DRI's common equity ratio as of December 31, 2015 was 34.9%. He concluded that DNCP's requested capital structure is not representative of capital structures of utility holding companies or of operating companies. He recommended a capital structure consisting of 50% common equity and 50% long-term debt, with a weighted debt cost rate of 4.89%. He justified this recommendation as being well above the DRI equity ratio, approximately equal to the equity ratio of witness Hevert's comparable group, and slightly above the average equity ratio granted to electric utilities by state regulators across the country in 2016.

In his rebuttal testimony, witness Chapman testified that the capital structures recommended by witness Hinton (50.96% common equity, 49.04% long-term debt), Witness Woolridge and witness O'Donnell (both 50% common equity, 50% long-term debt) were not reasonable, as they ignored the Company's actual capital structure as of June 30, 2016, as well as DNCP's actual capital structure at year-end of the each of the previous three years. He stated that the actual capital structure is the relevant structure for this case because it is the structure that supports DNCP's target credit ratings, which in turn allows DNCP to attract debt investment at an attractive cost basis. He noted that the equity component of DNCP's actual capital structure as of June 30, 2016 is in line with the equity component of the Company's year-end capital structure for the previous three years as well as to the forecasted capital structure as of December 31, 2016. He disagreed with these witnesses' reliance, without further justification, on proxy groups for their capital structure recommendations, due to the difficulty of determining a truly comparable capital structure within a proxy group of peer utilities that operate in different regulatory jurisdictions.

With regard to these witnesses' comparison of the Company's proposed capital structure to that of DRI, witness Chapman stated that development of the Company's financing plan is done with the objective of maintaining the current credit ratings of the Company, not those of DRI. He stated that a similar but separate analysis is undertaken at the DRI level, which accounts for financing needs of other, non-VEPCO subsidiaries in addition to the Company. He testified that claims that the DRI capital structure is relevant for purposes of this case are unfounded, and that VEPCO ratepayers are not being singled out and asked to pay more to offset DRI's higher debt ratio. He explained that all of DRI's subsidiaries support the parent company's debt capital structure.

Witness Chapman also addressed the impact of DRI's acquisition of Questar on VEPCO's cost of capital, stating that S&P's downgrade of the entire Dominion family due to the acquisition announcement had no discernible impact on VEPCO's cost of debt. He also stated that this one "consolidated" or "family" credit rating change should not adversely impact VEPCO's cost of debt, noting the unchanged "indicator" rating for VEPCO that S&P published along with its downgraded consolidated rating. Finally, in response to arguments concerning the increase in DNCP's common equity ratio in recent years, he stated that the higher equity component that the Company has experienced since 2009 supports using the capital structure that the Company proposed in this proceeding. He stated that the actual equity ratio is appropriate as it offsets the construction risk that an equity investor would experience during a period of heavy capital spending such as the one the Company is currently undertaking. Finally, he explained that witness Hinton's concern regarding Virginia's return on equity incentives is overstated, because it has a negligible impact on DNCP's retained earnings account, and because witness Hinton did not recognize other recent events that had a significant downward impact on the Company's retained earnings.

Following settlement negotiations between DNCP, the Public Staff, and CIGFUR I, as reflected in Section II.B of the Stipulation, the Stipulating Parties proposed a capital structure of 51.75% common equity and 48.25% long-term debt. The Stipulating Parties agreed to use 4.650% for the cost of long-term debt, based on a correction that was presented in witness Chapman's rebuttal testimony and that was not challenged by any party.

In his stipulation testimony, witness Hinton testified that the capital structure reflected in the Stipulation represents a compromise by both parties in an effort to reach agreement. He accepted the change in the long-term debt cost rate from the originally proposed debt cost rate. He noted that the stipulated 51.75% equity ratio is 217 basis points lower than the Company's request, 125 basis points lower than currently authorized for DEC and DEP, 79 basis points higher than his earlier recommendation, and 75 basis points higher than the Commission-authorized equity ratio in the last two DNCP rate cases. He stated that he believes the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by over $12 million. He also noted the $400,000 to be paid by DNCP shareholders to assist low-income customers.

At the hearing in this case, witness Chapman noted as part of his summary of his testimony that, while the equity component of the stipulated capital structure is below that reflected in the Company's actual capital structure as of June 30, 2016, his opinion is that the stipulated capital structure and overall weighted average return will still allow the Company to access capital markets on reasonable terms in order to secure the capital required to make the significant investments DNCP is planning and will, therefore, benefit the Company's North Carolina customers. No party cross-examined witness Chapman at the hearing.

In its post-hearing Brief, CUCA contends that the Commission should adopt witness O'Donnell's recommendation of a 50% equity and 50% debt capital structure. Similarly, the Attorney General's Office (AGO) states that the evidence supports a capital structure that uses an equity ratio of 50% or less. To support its argument, the AGO largely relies on the testimony of witness Woolridge concerning the median equity ratio of his proxy risk group, the median equity of witness Hevert's proxy group, and the lower equity ratio of DNCP's parent company, DRI, including short-term debt. Nucor's post-hearing Brief, likewise, proposes a capital structure consisting of 50% common equity and 50% long-term debt, relying on the testimonies of witnesses Hinton, Woolridge, and O'Donnell concerning the average equity ratios of various proxy groups and the average of equity ratios approved in electric rate cases by state commissions over various periods of time. The Commission concludes that such comparisons may be relevant and of some interest, but are entitled to minimal weight in determining the appropriate capital structure for DNCP for ratemaking purposes. Instead, the Commission gives substantial weight to the rebuttal testimony of DNCP witness Chapman. He testified that it is difficult to determine a truly comparable capital structure for a proxy group of utilities that operate in different regulatory jurisdictions because not all regulatory jurisdictions define capital structure in the same manner. Some jurisdictions include and/or exclude different balance sheet items, such as short-term debt, income tax items, customer deposits, etc. For example, he contended that the average equity ratio of witness Hinton's peer group is 51.89% when calculated in a manner consistent with DNCP's proposed capital structure in this case. In addition, as noted above, witness Woolridge's proxy group used utility holding companies while DNCP is a subsidiary operating company. Finally, also important is that the mean, median, and range of equity ratios vary for different proxy groups and, therefore, the witnesses use their own discretion in arriving at their recommended capital structures after considering such comparisons.

With regard to comparisons to DRI's capital structure, witness Chapman testified that DNCPs financing plan is developed with the objective of maintaining the current credit ratings of DNCP, not those of DRI. He stated that a similar but separate analysis is undertaken at the DRI level, which accounts for financing needs of DRI's other subsidiaries, in addition to DNCP. Witness Chapman stated that all of DRI's subsidiaries support the parent company's debt capital structure.

The Commission must consider all of the evidence and exercise its independent judgment in determining the appropriate capital structure for DNCP in the context of setting DNCP's rates. The Commission gives substantial weight to Company witness Chapman's testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. As witness Chapman noted, witness Woolridge and witness O'Donnell rely primarily on the averages of their respective proxy groups without providing any further rationale in support of their recommended capitalization ratios.

The Commission is also persuaded by the fact, as noted in the stipulation testimony of Public Staff witness Hinton, that the stipulated 51.75% equity ratio is 217 basis points lower than the Company's request, 125 basis points lower than currently authorized for DEC and DEP, 79 basis points higher than his earlier recommendation, and 75 basis points higher than the Commission-authorized equity ratio in the last two DNCP rate cases. The Commission places substantial weight as well on witness Hinton's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by over $12 million.

The Commission accords substantial weight to the stipulation testimony of witness Hinton, and finds that an equity ratio of 51.75% represents an appropriate reduction from the Company's actual ratio, for purposes of reducing the amount of higher cost equity financing to be borne by ratepayers in this case. Based upon the evidence described above and the record in this docket as a whole, the Commission finds and concludes that the stipulated capital structure and costs of long-term are fair and reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-34

The evidence supporting these findings of fact and conclusions is contained in the Application, the direct, rebuttal, and stipulation testimony and exhibits of Company witnesses Curtis and Hevert, the pre-filed direct and settlement testimony and exhibits of Public Staff witness Hinton, the pre-filed direct testimony and exhibits of Nucor witness Woolridge and CUCA witness O'Donnell, the Stipulation, and the hearing testimony.

Based upon the evidence and legal analysis set forth below, the Commission concludes, based on its own independent analysis, that the stipulated rate of return on common equity of 9.90% proposed in the Stipulation in this proceeding and the resulting stipulated overall rate of return on rate base of 7.367% are just, reasonable, and fair to the Company, its shareholders and its customers and that such rates of return are fully consistent with the requirements of North Carolina law governing the establishment of public utility rates of overall return and returns on common equity.

Summary of the Evidence on Return

DNCP's existing allowed rate of return on common equity, established by the Commission in 2012 in Docket No. E-22, Sub 479, is 10.2%.[8] Its existing approved overall rate of return on rate base is 7.80%.[9] In its Application, DNCP proposed that the allowed rate of return on common equity in this proceeding be established at 10.5%. This proposed rate of return on common equity, in conjunction with the other elements of the Company's proposed capital structure, resulted in a proposed overall rate of return on rate base for the Company of 7.88%. Based on the capital structure updated to June 30, 2016, the 10.5% ROE recommended by witness Hevert, and a cost of long-term debt revised to 4.650% in witness Chapman's rebuttal testimony, the Company's final proposal for the overall rate of return was 7.805% prior to the Stipulation.

DNCP's original rate of return request was supported by the direct testimony and exhibits of DNCP witnesses Curtis and Hevert. Witness Curtis, who is Vice President – Technical Solutions for Virginia Electric and Power Company, testified to the significant capital investment needs facing the Company. He stated that in order to attract the capital needed to meet these substantial future capital needs, the Company must achieve an adequate authorized ROE in this proceeding, and that the 10.5% ROE proposed by DNCP will allow the Company to attract capital on reasonable terms in the still-volatile and highly competitive capital markets. He explained that the ability to attract capital on favorable terms is important to DNCP's ability to maintain its current credit ratings and, ultimately, minimize the cost of capital for customers. An adequate return also ensures DNCP's ability to commit capital to future construction projects to provide safe, reliable, and cost-effective electric service to North Carolina customers without eroding the Company's shareholders' interests. In witness Curtis' supplemental testimony, he stated that as of June 30, 2016, the

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[8] See 2012 Rate Order; 2015 Remand Order.

[9] Id.

Company's fully-adjusted earned rate of return on equity capital for the update period was only 5.50%, far below the Company's currently-authorized 10.2%.

Witness Hevert served as DNCP's primary cost of equity witness. Witness Hevert filed direct testimony and nine exhibits in support of DNCP's request for a 10.5% return on equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the subject company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation.

Witness Hevert's direct testimony and exhibits document the specific analyses he conducted in support of DNCP's rate filing and provide a detailed description of the results of his analyses and resulting cost of equity recommendations. He applied the Constant Growth and Multi-Stage forms of the DCF model, the CAPM, and the Bond Yield Plus Risk Premium approach to develop his ROE recommendation.

Witness Hevert testified that a return that is adequate to attract capital on reasonable terms enables the utility to provide service while maintaining its financial integrity, and that the utility's return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. He stated that the Commission's decision should result in providing DNCP with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a range of 8.33% to 10.01% ROE, the results of his Multi-Stage DCF analysis were a range of 9.40% to 10.09%, and the results of his Multi-Stage DCF analysis that used the current proxy group P/E ratio to calculate the terminal value was a range of 9.34% to 10.91%. The results of witness Hevert's CAPM analysis showed a range of 8.69% to 11.64%. The results of his Bond Yield Risk Premium analysis indicated an ROE range from 10.04% to 10.47%. In his rebuttal testimony, witness Hevert updated his results to show an ROE range of 8.14% to 9.32% for his Constant Growth DCF analysis, a range of 8.85% to 9.97% for his Multi-Stage DCF analysis, a range of 8.87% to 11.22% for his CAPM analysis, and a range of 10.02% to 10.38% for his Bond Yield Risk Premium analysis. Based on his analyses, witness Hevert concluded that a rate of return on common equity in the range of 10.25% to 10.75% represents the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets. Within that range, he recommended an ROE for DNCP of 10.5% in both his direct and rebuttal testimony.

Witness Hevert explained that his ROE recommendation also took into consideration several additional factors, including (1) DNCP's planned investment program, (2) the risks associated with environmental regulations, (3) the regulatory environment in which DNCP operates, (4) flotation costs, and (5) the increased uncertainty in the capital markets. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized ROEs tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his ROE estimates for the effect of these factors.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his ROE recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and the U.S. generally since late 2009 and early 2010, with December 2015 rates of 5.60% in the State. He noted that since the Company's last general rate filing in March 2012, unemployment in the counties served by DNCP has fallen by over 4 percentage points. He explained further that while at its peak in 2009 into early 2010, the unemployment rate in those counties reached 13.41% (1.41 percentage points higher than the statewide average), by December 2015 it had fallen to approximately 7.30% (1.80 percentage points higher than the statewide average). He summarized that although it remains higher than the national and State averages, it has fallen considerably since its peak in early 2010. Witness Hevert also noted that since 2013, the State has consistently exceeded the national rate for real gross domestic product growth, and that since 2009, median household income in North Carolina has grown at a somewhat faster annual rate than the national median income. In addition, total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Finally, he noted that since 2005, residential electricity costs in North Carolina remain approximately 13% below the national average. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within DNCP's service area continue to steadily emerge from the economic downturn that prevailed during the Company's previous rate case, and have experienced significant economic improvement during the last several years that is projected to continue. In his opinion, DNCP's proposed ROE is fair and reasonable to DNCP, its shareholders and its customers, in light of the impact of changing economic conditions on DNCP's customers.

Witness Hevert also addressed the capital market environment, and testified that the current market is one in which it is important to consider a broad range of data and models when determining the cost of equity.

Witness Chapman stated that granting the Company an authorized return of 10.5% on common equity will allow DNCP to compete in the capital markets and to raise equity and debt at reasonable rates. He testified that authorizing the Company's requested return on common equity will allow DNCP to carry out its responsibility to provide reliable services at affordable cost and is fundamental to the Company's ability to maintain a strong credit profile, and that the ability to access capital markets on reasonable terms will reduce DNCP's borrowing cost for the benefit of the customers.

Public Staff witness Hinton testified that current economic conditions are characterized by continued low inflation rates and the reduction in long-term interest rates, particularly the decrease in treasury yields since December 2012 (the time of the DNCP's last general rate case). He further opined that continued low inflation rates have led to lower expected returns in the equity markets, which he supported by recent articles denoting that investors should expect lower rates of return. Witness Hinton used the DCF model, the Regression Analysis of Allowed Returns on Equity for electric utilities, and the Comparable Earnings method as his primary methods for determining the appropriate cost of common equity. He also used the CAPM as a check on those primary methods. For his DCF and comparable earnings analyses, witness Hinton estimated DNCP's cost of equity capital by reference to a group of proxy companies. The results of his analyses were a range of 8.30% to 9.30% for the DCF method, a single estimate of 9.49% for the Regression Analysis, and a range of 9.00% to 9.80% for the Comparable Earnings method. Corrections submitted in his settlement testimony changed his DCF range to 8.40% to 9.40%, and his Comparable Earnings range to 9.03% to 9.87%, but did not change his recommended ROE for DNCP. The result of his CAPM analysis was an estimated ROE of 8.00%, which witness Hinton used as a secondary check on his other results. Witness Hinton also performed tests for the reasonableness of his recommendation: (1) his recommended capital structure and cost rates for debt and equity yielded a pre-tax interest coverage ratio of 4.3 times, and (2) for other electric utilities he identified the average approved rate of return on equity as 9.52% in the first six months of 2016 and 9.60% for all of 2015, excluding Virginia cases that added incentive points to the cost of capital in certain cases. He concluded that a reasonable range of DNCP's cost of equity is between 8.80% and 9.80%, and recommended an ROE for this case of 9.30%. Witness Hinton also recommended an overall cost of capital of 7.02%.

Witness Hinton also testified with regard to changing economic conditions noting that North Carolina Department of Commerce and Bureau of Economic Analysis data show relatively faster growth in per capita income for DNCP's service area compared to the State as a whole, for the 2000 through 2015 period. He noted that the unemployment rate for counties in the Company's service area has fallen from 10.4% in April 2013 to 6.7% as of April 2016. He concluded that while this part of the State has a relatively poor economy, these data indicate that economic conditions facing DNCP ratepayers as a whole have been improving since DNCP's last rate case.

Witness Hinton also critiqued witness Hevert's exclusive use of earnings per share forecasts to estimate the growth component of the DCF. He questioned as unrealistic the use of a 13.65% expected investment return on the S&P 500 in witness Hevert's CAPM analysis. He also questioned witness Hevert's argument that the Company's business risks deserve special consideration. Witness Hinton testified against any risk adjustment due to the Company's projected level of capital expenditures, its level of coal generation, and compliance with the Clean Power Plan, which he believed were risks already factored into return requirements by investors and did not deserve any special recognition or consideration.

Nucor witness Woolridge recommended an ROE of 8.60%, which is near the upper end of the range based on his DCF and CAPM analyses. He applied the constant growth version of the DCF method and the CAPM methods to a proxy group of publicly held electric utilities. He relied primarily on his DCF analysis, as he believes it provides the best measure of public utility equity cost rates. Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness Hevert's proxy groups is in the 7.90% to 8.75% range. He acknowledged that his recommendation is below the average authorized ROEs for electric utility companies.

Witness Woolridge also offered a critique of witness Hevert's ROE recommendation. He asserted with regard to capital market conditions that the forecasts of higher interest rates that witness Hevert used his CAPM and Risk premium analysis are incorrect. He questioned the inputs to witness Hevert's DCF analysis, in particular, his exclusive use of earnings per share forecasts; he disagreed with the low weight that witness Hevert gave his constant-growth DCF results; and he disagreed with witness Hevert's claim that high price-earnings (P/E) ratios can lead to low DCF results. He stated that the projected interest rates and market or equity risk premiums in witness Hevert's CAPM and risk premium approaches are excessive and not reflective of current and prospective market fundamentals. Finally, he disagreed with witness Hevert's inclusion of a flotation cost adjustment to the ROE.

CUCA witness O'Donnell did not conduct his own DCF or other method of determining the appropriate ROE in this case, citing the late entry to the case by CUCA. Rather, he revised the values included in witness Hevert's analyses to correct errors he perceived in those analyses, and, based on those adjustments, recommended an ROE of 9.0% out of a range of 8.50% to 9.50% and, together with his recommended capital structure discussed above, an overall cost of capital of 6.94%. Witness O'Donnell disagreed with the long-term growth rate witness Hevert used for his multi-stage DCF analysis, and with witness Hevert's testimony that, when constant growth DCF results are below the past returns authorized by regulators the validity of the constant growth DCF model is questionable. Witness O'Donnell also disagreed with witness Hevert's explanation of why it is reasonable to focus on different methodologies given the differences in financial markets over time. Witness O'Donnell opined that the expected market return that witness Hevert used for his CAPM and risk premium analyses is not reasonable, and asserted that the Company's requested ROE in this case is related to, but inconsistent with, its pension expense request. He also referenced a September 2, 2015 Order by the Missouri Public Service Commission where that commission found that witness Hevert's CAPM and Risk Premium model resulted in inflated results and his constant growth and multi-stage DCF models are based on excessively high growth rates. Witness O'Donnell presented a graph of allowed ROEs by state regulators across the country over the past 15 years and he noted that in 2016 no electric utility has been granted an ROE in excess of 10%.

In his rebuttal testimony, witness Hevert addressed witness Hinton's analyses with respect primarily to the issues of composition and selection of the proxy group, the growth rates and dividend yields applied in the constant growth DCF model, the application of the Regression Model of Allowed Returns, the reasonableness of the Comparable Earnings method, the application of the CAPM, the relevance of flotation costs in determining the Company's cost of equity, and the business risk of DNCP relative to the proxy group.

Witness Hevert also addressed witness Woolridge's testimony, and explained why the results of witness Woolridge's analyses are not reasonable estimates of the Company's cost of equity. Witness Hevert explained how several aspects of witness Woolridge's DCF analyses and conclusions are not compatible with market conditions and are inconsistent with the practical interpretation of the models' results. Witness Hevert also showed that the growth rates that witness Woolridge asserts are overstated by historical standards represent approximately the 50th to 51st percentile of the actual capital appreciation rates observed from 1926 to 2015. He noted that from January 2014 through September 16, 2016, no utility commission had authorized a return as low as 8.60%, which is Witness Woolridge's recommendation in this case. He also noted Witness Woolridge's recognition that his recommendation is below the average for authorized ROEs for electric utilities, and that the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 70 basis points above witness Woolridge's 8.60%. Witness Hevert also disagreed with witness Woolridge's assertions regarding market/book ratios and the cost of equity and provided updated data in support of that position. Finally, he testified in response to witness Woolridge's proxy group selection and expanded on his position regarding flotation costs.

In his rebuttal to witness O'Donnell's testimony, witness Hevert reiterated that all models are subject to limiting assumptions that may not be valid under certain market conditions, and that it is important to consider the results of multiple methods when estimating the cost of equity. He stated that this position is consistent with the Hope and Bluefield findings that it is the analytical result, as opposed to the methodology, that controls in arriving at ROE determinations. He stated further that a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results in light of the specific case at hand. He explained that capital market conditions influence the application and interpretation of ROE models, because the cost of equity is not directly observable and must be estimated using analytical techniques that rely on market-based data to quantify investor expectations and requirements. Specifically with regard to the constant-growth DCF model, witness Hevert explained that he gave the results of that model less weight in this case for two reasons. First, while one of the limiting assumptions of this model is that the P/E ratio will remain constant over time, the proxy group average P/E ratio had recently been trading at an unusual level relative to the overall market's P/E ratio, and since the date of the analysis he presented in direct testimony had been quite unstable. Second, constant-growth DCF model results recently have been well below the returns authorized for other vertically integrated electric utilities. Witness Hevert also addressed each of witness O'Donnell's contentions regarding the consistency of witness Hevert's ROE analysis as compared to his past analyses, and testified that those contentions are misplaced and should be given little weight.

Witness Hevert also testified that witness O'Donnell provided no testimony as to the reasonableness of the multi-stage DCF model or its application in this proceeding other than with respect to the long-term growth rate, and testified further as to the reasonableness of that rate. Witness Hevert also addressed witness O'Donnell's contentions as to the expected market return and other aspects of his CAPM and risk premium analyses. With respect to witness O'Donnell's contentions regarding the Company's pension fund's expected returns, witness Hevert testified that pension funding expectations should not be viewed as a measure of investors' required return, as the two are developed in separate manners and are used for different purposes.

Finally, in his rebuttal witness Hevert updated his analysis of economic conditions in North Carolina and DNCP's service area and testified that it continues to be his view that on balance, economic data regarding North Carolina and the U.S. do not alter his cost of equity estimates, or his recommendations, one way or the other. He also noted the importance of keeping in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. He stated that, given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in ROE estimates.

As reflected in Section II.B of the Stipulation, the Stipulating Parties agreed to an ROE of 9.90%. In the same Section, the Stipulating Parties also agreed that DNCP should be allowed to earn an overall rate of return on its rate base of 7.367%.

The overall return on rate base and the proposed allowed rate of return on common equity set forth in the Stipulation were supported by the stipulation testimony of DNCP witnesses Curtis and Hevert and Public Staff witness Hinton, and the hearing testimony of witness Hevert.

Witness Curtis testified that the Stipulation, including the stipulated 9.90% ROE, successfully strikes the balance of the Company's need for rate relief with the impact of that rate relief on customers.

Witness Hevert testified that although the stipulated ROE is somewhat below the lower bound of his recommended range (10.25%), he recognizes that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple, otherwise contested issues. He stated his understanding that the Company has determined that the Stipulation terms, taken as a whole, are such that it will be able to raise the external capital required to continue the investments required to provide safe and reliable service when needed at reasonable cost rates, and he appreciates and respects that determination. While his position remains that a range of 10.25% to 10.75% would represent a reasonable and appropriate measure of DNCP's cost of equity in a fully litigated proceeding, he stated that he recognizes the benefits associated with the decision to enter into the Stipulation and as such it is his view that the 9.90% stipulated ROE is a reasonable resolution of an otherwise-contested issue. Witness Hevert also testified that North Carolina falls in the top one-third of jurisdictions in terms of being a constructive regulatory jurisdiction according to RRA, and reiterated the importance of the perception of constructive regulatory environment to ratings agencies. He stated that the stipulated ROE is a reasonable outcome based on its being within three basis points of the average return of 9.87% (and seven basis points of the median) authorized for vertically integrated electric utilities from 2013 through 2016. He also stated that of the 77 cases decided during that period, 35 included authorized returns of 9.90% or higher. He also noted that the stipulated ROE falls 21 basis points below the average (and 30 basis points below the median) authorized ROE during the 2013-2016 time period for jurisdictions that are comparable to North Carolina's constructive regulatory environment and that from that perspective, the stipulated ROE is a somewhat conservative measure of the Company's cost of equity. Finally, witness Hevert testified that on balance, the impact of changing economic conditions data discussed in his direct and rebuttal testimony do not alter his ROE estimates or recommendation, and also do not alter his support of the Company's decision to agree to the stipulated ROE.

Witness Hinton supported the Stipulation as it relates to the cost of equity capital to be used in setting rates in this case, and made several changes and corrections to his direct testimony that did not alter his pre-settlement 9.3% ROE recommendation. He observed that the stipulated 9.90% ROE is higher than his recommended range of 8.80% to 9.80%, and lower than the Company's recommended range of 10.25% to 10.75%. He testified that the 9.90% represents a reasonable middle ground between the Public Staff and DNCP rather than acceptance of a particular analytical model. He also testified that the agreements on ROE and capital structure discussed above could only occur in the context of various compromises by both parties on other issues. Finally, he testified that he believes a 9.90% ROE accounts for the impact on customers when viewed in the context of the overall settlement. He stated that, first, the settlement as a whole is reasonable with regard to the ultimate impact on customers, which is the impact on their monthly bills. Second, he noted that the impact of changing economic conditions in the DNCP service territory is difficult to adequately quantify, as there exist both economic improvement and economic problems. Third, he noted that the one-time payment of $400,000 to assist DNCP's low-income customers in North Carolina, which will come from earnings that would otherwise go to shareholders, will help mitigate the rate increase for the customers who have the greatest need and feel the impact of economic conditions most severely. Witness Hinton concluded that because the contribution could not lawfully be ordered by the Commission in the absence of Company agreement, it therefore provides a response to the impact of economic conditions on customers that could only exist with a settlement agreement, which adds to the reasonableness of the agreed-upon ROE.

At the hearing, witness Hevert testified in response to questions from counsel for CUCA and the Attorney General with regard to the 13.45% Bloomberg estimated market return he used in his CAPM analysis, which as he explained in his rebuttal testimony reflects return expected by analysts covering the companies that compose the S&P 500 Index. It does not represent the return for utilities, but is the expected market return from which the risk-free rate of return is subtracted to find the Market Risk Premium. The Market Risk Premium is then multiplied by the Beta coefficient, which represents a given utility's risk relative to the market. At the hearing, witness Hevert stated that 13.45% is well within that range considering an average historical market return of 12%, and the historical variation in returns of about 20%. In response to questioning from CUCA counsel as to whether his recommended ROE would be higher or lower if he had used the same approaches to his methodologies in this case as in previous cases, witness Hevert explained that it makes sense to apply different weights to the approaches as the markets change, because one model's assumptions no longer become as relevant to the market circumstances as they had been.

In response to questioning by the Attorney General, witness Hevert testified to the recent volatility in the utility sector, as exemplified by the variance in stock prices used as an input to his constant growth DCF analysis. In response to questions from counsel for Nucor, witness Hevert testified that looking at annual averages of returns may indicate a distorted view of trends in returns, since there may be years with fewer cases, or years with cases from jurisdictions that tend to authorize lower returns, rather than looking at individual cases.

On redirect questioning, witness Hevert reiterated that state regulatory commissions generally do not base rate of return decisions on evidence provided by a single witness, and that often state commissions like the Commission have authorized returns lower than his recommendation and higher than intervenor recommendations. He confirmed that the stipulated ROE of 9.90% is slightly below the lower end of his recommended range, and slightly above the higher end of Public Staff witness Hinton's recommended range. He stated the only instance he can recall of a commission authorizing an ROE comparable to the 9.0% and 8.6% ROEs recommended by Nucor and CUCA was in Hawaii, and that that case involved a reduction to the authorized ROE to account for system inefficiencies.

Public Witness Testimony

The public witness testimony heard by the Commission is summarized below.

Belinda Joyner of Garysburg in Northampton County, testifying on behalf of Concerned Citizens of Northampton County, stated that elderly customers on fixed income and retired State employees have to make purchasing decisions based on their limited income whether to buy groceries, medicine, and other items. She testified that without power these customers cannot cook, wash, nor otherwise function, and that a 17% increase in rates is unfair.

Tony Burnette, President of the Northampton County NAACP, is a caregiver for her elderly mother. She testified that a 17% increase would be detrimental to elderly customers and that elderly customers are often at home all day, and would likely use more than the 1000 kilowatts (kW), the monthly usage of an average customer.

Larry Abram of Tillery in Halifax County agreed with other witnesses regarding the difficulty elderly customers would have paying their bills.

Dean Knight of Halifax testified that his cotton gin business has electric bills of about $150,000 per month for three months of the year, and he must pay for improvements to his equipment within his budget, rather than by raising his rates.

Janice Bellamy of Whitakers in Edgecombe and Nash Counties testified to the difficulty she and others on fixed incomes have in paying their bills, such as water and electric bills.

Regina Moffett of Whitakers, advocating for seniors, stated that the proposed rate increase would impact the entire local community and that higher bills would result in decreased church contributions. She also testified that when she became a Dominion customer, she saw a "great decrease" in her electric bill.

Betty Bennett of Garysburg testified that a 17% increase in electricity rates was too high.

Peter Bishop, the Director of Economic Development for Currituck County, testified on behalf of the Currituck County Board of Commissioners. He testified with respect to DNCP witness Hevert's testimony that while North Carolina "and this region" have improved significantly since the recession, the counties within DNCP's service area have not fared well. He stated that the Company could have made a better argument with regard to economic conditions in the area and presented several statistics related to unemployment, poverty rate, median household income, net loss of population, and new businesses showing that the counties within DNCP's service area are worse off than other counties in the State. Mr. Bishop also recommended that the Commission exercise caution when making determinations regarding recovery of coal ash costs, as this is a developing issue, and stated that the best approach may be to wait and see how coal ash cost recovery is handled in the federal courts before setting precedent for this State.

Robert Woodard, Chairman of the Dare County Board of Commissioners, testified in support of the Dare County Board of Commissioners' resolution that was filed on July 19, 2016, in this proceeding. He also testified that the Board's position is that any rate increase would place an undue hardship on Dare County's citizens.

Walter Overman, Vice Chairman of the Dare County Board of Commissioners, testified that Dare County's population has not seen a 17% or even a 6% increase in wages since DNCP's last rate case. He testified that lower-wage residents would be hit especially hard in an area with a high cost of living. He asked that the rate increase be denied.

Dwight Wheless of Columbia in Tyrrell County testified in support of the Columbia Town Board of Aldermen's resolution in opposition to the proposed rate increase. He testified that Tyrrell County has the second lowest per capita income in the State and its citizens would be most hurt by an increase in the cost of electricity. He also testified that Columbia has not experienced any recovery and that its residents are already challenged by constant increases in the cost of food and pharmaceuticals.

Robert Edwards of Nags Head in Dare County testified that the requested rate increase should not be granted. He testified that inflation has remained near zero in recent years and that if the Company made wise and prudent investments, those alone should have improved productivity and reduced costs so that customer rates should actually be lowered. He testified that DNCP should hedge fuel cost fluctuations with long-term purchase agreements and that customers should not be exposed to fuel cost increases. He testified that the proposed increase for residential customers as compared to large users is unfair, and that the requested rate of return on equity is too high.

Manny Madeiros of Kitty Hawk in Dare County testified that DNCP's retail electric rates should not reflect the cost of renewable energy production.

Judy Williams of Manteo in Dare County testified that she and others are living on fixed incomes and even a 7% increase in rates is too high.

Martha MacDonald of Williamston in Martin County testified that the rate increase would have a direct negative impact on seniors, most of whom have Social Security as their sole income, averaging $1300 a month. She testified that Martin County is a Tier 1 County, and that seniors are often forced to choose between paying their electric or water bills or buying food or medicine. She also testified that some residents cannot afford detached homes with insulation and are paying high bills for electricity in mobile homes. She testified that DNCP does a good job restoring power when there are outages.

John MacDonald of Williamston testified that he and many customers in the area are on fixed incomes and cannot afford the proposed rate increase.

Tawilda Bryant of Jamesville in Martin County testified in support of Ms. MacDonald's testimony on the impact of the proposed rate increase on seniors.

Rhett White, the Town Manager of Columbia in Tyrrell County, testified that the Town has struggled in the past to absorb electric rate increases and fuel charge adjustments without increasing local property taxes. He testified that Columbia could not withstand an increase of even 5.9% without an increase of 2 cents per $100 in the Town's tax rate. He testified that many of Columbia's elderly residents are on fixed incomes, sometimes living on the minimum Social Security check of $750 per month. He testified that a typical widowed resident living in a home valued at $75,000 would have to pay another $15 in annual taxes to cover the Town's increased power bills, in addition to the more than $84 that she will pay for her own residential power bill. He also testified that the increase to the County's own power bills would result in increased county taxes for that same resident. He stated that the proposed rate increase would negatively affect the Town's businesses and industry, and that the recent recession is not over in rural Columbia and Tyrrell County. He testified that wages are lower than elsewhere in northeastern North Carolina, unemployment is much higher than throughout the State, poverty rates are high, median household incomes remain the lowest in the region, and out-migration of young residents in search of jobs continues. He testified that the economic climate in Columbia is very different from that described by DNCP witness Hevert, and that the Town is made up mostly of low-income, working residents in a Tier 1 County.

Ronnie Smith, the Chair of the County Commissioners of Martin County, testified that many people in the area cannot afford the proposed increase, and that even small increases impact residents on fixed incomes.

John Liddick of Williamston testified that during the cold winter weather in the past, residents have said they could not afford their electric bills.

Linda Gibson of Williamston testified that most seniors are on fixed incomes of $600 or $700 per month, and that once they pay one or two bills, they have just enough left to buy food. She testified that most jobs in Martin County pay minimum wage or just a bit more and even young people have trouble making ends meet. She also testified in support of DNCP's good service in terms of restoring power after outages.

Samantha Komar of Williamston testified that she is a veteran and on a fixed income. She testified that the median income in the town is $15,000 per year and that residents already often have to choose between paying their electric and water bills or for food and medication.

Louise Simmons of Jamesville testified that she would not be able to pay any more on her electric bill.

Jerry McCrary, the Mayor of Parmele, Martin County, testified that Parmele has about 300 citizens, the majority of whom are seniors. He also testified that the proposed rate increase would harm these residents who already have to choose between buying food, medicine, and paying their bills.

Glenda Barnes of Parmele testified that the proposed 17% increase is too high.

Reginald William Ross, Jr. of Williamston testified that many of the local residents are seniors on fixed income making difficult choices about buying food or medicine.

Legal Standards Applicable to Rate of Return Findings by the Commission

The Commission's analysis of and decision on rate of return on rate base and allowed rate of return on common equity in this case is governed by the United States Supreme Court's Hope and Bluefield decisions,[10] the requirements of G.S. 62-133, and the North Carolina Supreme Court decisions interpreting and applying each of the foregoing to rate of return decisions by the Commission.

[10] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope); Bluefield Waterworks & Improvement Co. v. Public Service Commission, 262 U.S. 679 (1923) (Bluefield).

In Bluefield, the US Supreme Court established the basic framework for rate of return regulation of public utilities. On this subject, the Court held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . . [t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 U.S. at 692-93. In the subsequent Hope decision, the Court expanded on its analysis by stating:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Hope, 320 U.S. at 603.

The Commission has looked to the Hope and Bluefield standards as guidance for setting rates. In Docket No. E-7, Sub 1026, the Commission noted that:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in *Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) (*Bluefield*), and *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*): To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope.

Id., at 7.

The Commission must balance the interests of investors and customers in setting the rate of return on equity. As the Commission has stated, "the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[11] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the Hope and Bluefield comparable risk, capital attraction, and financial integrity standards.

In addition, the Supreme Court has held that "although the Commission must make findings of fact with respect to the impact of changing economic conditions upon consumers," it is not required to "'quantify' the influence of this factor upon the final ROE determination."[12] The Commission echoed this distinction in the 2015 Remand Order as well, stating that it is "not required to isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity."[13]

The Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[14] In Cooper II, which addressed an appeal of the Commission's order on DNCP's previous base rate application, the Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on customers."[15] The Commission made such additional findings of fact in its Order on Remand.[16]

Finally, when a settlement agreement has not been adopted by all of the parties to a case, its acceptance by the Commission is governed by the standards set out by the

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[11] Docket No. E-7, Sub 1026, Order Granting General Rate Increase, (Sept. 24, 2013) at 24; see also Docket No. G-9, Sub 631, Order Approving Partial Rate Increase and Allowing Integrity Management Rider, (Dec. 17, 2013), at 26 (noting North Carolina Supreme Court's determination that the provisions of G.S. 62-133 "effectively require the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States, those of the State Constitution, Art. I, § 19, being the same in this respect"); 2015 Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").

[12] State ex rel. Utilities Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014). In this case the court affirmed the Commission's Order on Remand, issued October 23, 2013, in Docket No. E-7, Sub 989, at pages 34-35, where the Commission pointed out that "adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the 'end result' test of Hope. This the Commission has done." See also State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 745-46, 767 S.E.2d 305, 308 (2015).

[13] DNCP Remand Order at 26.

[14] State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635, 642 (2014) (Cooper II), See also State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) (Cooper I).

[15] Cooper II, 758 S.E.2d at 643.

[16] DNCP Remand Order at 4-10.

North Carolina Supreme Court in State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held that

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

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

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

With these legal principles in mind, the Commission now turns to the analysis of the evidence in this proceeding relating to a determination of the appropriate overall rate of return on rate base and allowed return on common equity for use in this proceeding.

Analysis of the Evidence

In order to reach an appropriate independent conclusion regarding return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. Cooper I, 366 N.C. at 492-493; CUCA I, 348 N.C. at 460-467; CUCA II, 351 N.C. at 229-230.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the approved rate of return on equity for a public utility. Cooper, 366 N.C. at 491, 739 S.E.2d at 548. There is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers. However, the impact on customers of changing economic conditions is embedded in the return on equity expert witnesses' analyses. The Commission noted this at page 38 of its 2012 Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return."

The evidence in this proceeding related to the determination of an overall rate of return on rate base and allowed rate of return on common equity is provided in the testimony of the public witnesses, the testimony and exhibits of DNCP's witness Hevert (and, in support of witness Hevert's recommendations, in the testimony of DNCP witnesses Curtis and Chapman), and the testimony and exhibits of Public Staff witness Hinton, Nucor witness Woolridge, and CUCA witness O'Donnell, and the Stipulation.

Witness Hevert used four different analytical methods, each with multiple variations, to estimate the cost of equity capital for DNCP. He ran a constant growth DCF method with 30-day, 90-day and 180-day low, mean, and high averages for each of his proxy companies, which as updated in his rebuttal testimony resulted in a rate of return on equity range of 8.14% to 9.32%. The range for his updated multi-stage DCF analysis is 8.85% to 9.97%. The range for his updated CAPM analysis is 8.87% to 11.22%, and the range for his updated bond yield plus risk premium analysis is 10.02% to 10.38%. The range between the highest number produced by the four methodologies, 11.22%, and the lowest number, 8.14%, encompasses the stipulated rate of return on equity of 9.90%. Further, the average of witness Hevert's updated analytical results, using the DCF mean growth rate results, is 9.45% (where the CAPM is based on the Bloomberg market risk premium) to 9.58% (where the CAPM is based on the Value Line market risk premium). However, witness Hevert testified that the constant growth DCF results "are difficult to reconcile with observable, prevailing market conditions," and likely reflect increases in utility stock prices that are a temporary overvaluation.

The Commission gives significant weight to witness Hevert's testimony that constant growth DCF results should be viewed with caution in current market conditions. While current stock prices are an observable fact, whether overvalued or not, an underlying assumption of the constant growth DCF is that the price to earnings ratio (P/E) remains constant. However, as noted by witness Hervert, utility sector P/E ratios have increased to the point that they have exceeded both their long-term average and the market P/E. In addition, constant growth DCF results are below authorized returns.

As a result, the Commission finds it reasonable in the current economic circumstances to give no weight to the constant growth DCF results, and to give substantial weight to an averaging of the high growth rate multi-stage DCF, the Value Line-based market risk premium CAPM, and the bond yield plus risk premium results, which indicates a 9.86% ROE. The result of this averaging, being only four basis points below the stipulated 9.90% ROE, is strongly supportive of the stipulated ROE, particularly in light of the Supreme Court's decision in State ex rel. Utils. Comm'n v. General Telephone Co., 285 N.C. 671, 681, 208 S.E.2d 681, 670 (1974) (a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper rate of return on equity).

In addition, the Commission gives substantial weight to witness Hevert's stipulation testimony in support of the stipulated 9.90% ROE. He testified that although the stipulated ROE is somewhat below the lower bound of his recommended range (i.e., 10.25%), he recognized that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple issues that would otherwise be contested by the Stipulating Parties. In addition, he relied on DNCP's determination that the terms of the Stipulation, taken as a whole, are such that DNCP will be able to raise the capital required to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at a reasonable cost rates. The Commission notes that the approved ROE is just one of many factors that affect the earnings available to pay a return to equity investors, and therefore it is essential to assess the reasonableness of the ROE in the context of all the issues that affect earnings.

The Commission agrees with witness Hevert's testimony that although the stipulated ROE falls within the range of analytical results presented in his direct and rebuttal testimony, current capital market conditions are such that the models used to estimate the cost of equity continue to produce a wide range of sometimes conflicting estimates. Indeed, all the cost of capital witnesses used multiple analytical models, with wide-ranging results.

The Commission also gives substantial weight to witness Hevert's testimony that it is important to keep in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. Given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in the analytical estimates of the ROE. The Commission further finds credible witness Hevert's testimony that, on balance, economic data regarding North Carolina and the United States do not alter the cost of equity estimates one way or the other.

The Commission additionally gives substantial weight to the stipulation testimony of Company witness Curtis that the concessions the Company has made through the Stipulation reasonably balance its customers' interest in receiving the lowest rate impact while also meeting DNCP's need to recover the substantial investments that it has made in order to continue to comply with regulatory requirements and safely provide high quality electric service.

Based on the testimony of DNCP witnesses Hevert and Curtis, the 9.90% stipulated ROE, in the context of the settlement as a whole, will be sufficient to meet the requirements of investors in capital markets. The corresponding question is whether a 9.90% ROE imposes no more burden on DNCP customers than is necessary for the Company to provide reliable electric service. In this regard, the Commission gives substantial weight to Public Staff witness Hinton's settlement testimony that the stipulated

9.90% ROE represents a reasonable middle ground between the Public Staff and DNCP, higher than his recommended range of 8.80% to 9.80%, and lower than the Company's recommended range of 10.25% to 10.75%.

The Commission also gives weight to witness Hinton's direct and settlement testimony in its focus on the impact on customers from multiple perspectives. In particular, he testified regarding: (1) data showing improvement in economic conditions, notably unemployment and per capita income, for the population within DNCP's service territory; (2) the benefit customers will receive from lower rates as a result of a negotiated settlement that will reduce the Company's proposed rate increase by over $12 million – a result that eliminates uncertainty regarding the chance that a higher rate increase could have been approved in a fully-contested proceeding; and (3) the $400,000 to be paid by shareholders to assist low-income customers who are the most impacted by a rate increase.

Witness Hinton's direct (pre-settlement) testimony employed three primary analytical methods: a constant growth DCF, a regression analysis of allowed ROEs, and the comparable earnings method. The Commission finds the high end of his comparable earnings results to be probative and compelling in the circumstances of this case. As witness Hinton noted, the comparable earnings method is well-suited to the Hope legal standard of authorizing a utility ROE that allows investors to earn a return comparable to returns available on alternative investments with similar risk. As a result, the Commission gives substantial weight to the high end of the range of results from witness Hinton's updated comparable earnings analysis, where the three highest ROE results – 10.0%, 9.9% and 9.7% - average 9.867%. The Commission considers such substantial weight appropriate in the present circumstances where there is a wide range of analytical results, all with strengths and weaknesses. Thus, it is reasonable to rely more heavily on results that support a middle ground among the analyses of the competing witnesses.

Nucor witness Woolridge acknowledged that his recommendation of an ROE of 8.60% out of a range of 7.90% to 8.75% is below the average authorized ROEs for electric utility companies. The Commission notes witness Hevert's rebuttal testimony that the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 70 basis points above witness Woolridge's 8.60% recommendation. The Commission cannot blindly follow ROE results allowed by other commissions, but must determine the appropriate ROE based upon the evidence and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some weight, as they provide a check or additional perspective on the case-specific circumstances. In addition, DNCP must compete with utilities in other jurisdictions for capital from investors. In this regard, the Commission finds persuasive witness Hevert's testimony at the hearing that North Carolina is generally viewed by the credit ratings agencies to be a supportive jurisdiction, and that an ROE of 9.90% is consistent with the returns recently awarded to utilities in similarly constructive jurisdictions. The Commission has not relied on this evidence to arrive at its ROE decision. Instead, the Commission has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding. That check allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions. In addition, the Commission finds persuasive witness Hevert's responses to witness Woolridge and counsel for Nucor regarding the use of annual averages of the inputs to the DCF analysis and other inputs to his analyses. The Commission gives weight to witness Hevert's rebuttals to witness Woolridge's testimony as discussed above and the check on witness Woolridge's recommended ROE provided by the comparison to other similar jurisdictions. The Commission concludes that witness Woolridge's result of 8.6% ROE is outside the bounds of reasonableness – there is no credible evidence showing that the cost of equity for DNCP has decreased by 160 basis points since the Company's last rate case - and would put the Company at a significant disadvantage in competitive capital markets when attempting to raise capital needed to fund its operations.

The Commission gives little weight to witness O'Donnell's ROE testimony. The Commission find persuasive witness Hevert's responses to witness O'Donnell's' arguments regarding the long-term growth rate and other inputs to his analyses, particularly witness Hevert's discussion regarding the distinction between ROE and pension returns. The Commission agrees with witness Hevert that in light of the Hope case ruling that it is the end result that is the primary consideration in ROE determinations. In this case, witness O'Donnell's end result of a 9.0% ROE, at 120 basis points lower than the last authorized ROE for DNCP, overstates the decline in investors' required return, and therefore is outside the bounds of reasonableness and would put the Company at a significant disadvantage in raising capital needed to fund its operations. Witness O'Donnell provided no testimony as to the reasonableness of the multi-stage DCF model or its application in this proceeding other than with respect to the long-term growth rate.

Counsel for Nucor, CUCA and the Attorney General questioned witness Hevert about various aspects of his analyses; however, their cross-examination did not establish a persuasive basis for an ROE lower than 9.90%. The stipulated 9.90% ROE is itself 60 basis points lower than the 10.5% ROE recommendation resulting from witness Hevert's analysis. The stipulated 9.90% ROE is further corroborated by witness Hevert's hearing testimony that in only one case that he can recall has a commission authorized an ROE comparable to the 9.0% and 8.6% ROEs recommended by Nucor and CUCA, and but for a decrement applied in that case for unrelated reasons, the ROE in that instance would have been 9.5%. Again, while the Commission has not relied on this evidence to arrive at its ROE decision, it has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding that allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions. Overall, the Commission finds the settlement testimony of witness Hevert and witness Hinton to be credible, substantial, and probative evidence that supports approval of a 9.90% rate of return on common equity for DNCP in this proceeding.

As discussed above, numerous customers provided testimony at the public hearings as to the impact that any rate increase would have, especially on those customers in DNCP's service area who are on fixed incomes. The Commission acknowledges and accepts as true the proposition that some percentage of DNCP's customers, particularly those living on fixed incomes, are economically vulnerable and may struggle to pay an increase in DNCP's rates granted in this docket. The Commission gives substantial weight to the public witness testimony as it undertakes to balance the interests of DNCP's customers with the Company's need to obtain financing on reasonable terms for the continuation of reliable electric service.

Conclusions on Return

The Commission has the obligation to reach its own independent conclusion as to whether the Stipulation is just and reasonable, fair to customers, the Company and its shareholders in light of changing economic conditions, and otherwise sufficient to satisfy the requirements of G.S. 62-133. In sum, the Commission finds and concludes for purposes of this case and after thoroughly and independently reviewing all of the evidence that an authorized ROE of 9.90% is just and reasonable based on all of the evidence presented.

The Commission understands that rate increases are not favored by ratepayers and that some portion of any utility's customer base will find it difficult to pay their utility bills from time to time. The Commission further acknowledges that it is the Commission's primary responsibility to protect the interests of utility customers in setting rates for public utilities by complying with the legal principles discussed earlier in this Order. It is also the Commission's responsibility to abide by the constitutional requirements of the Hope and Bluefield cases as reflected in the provisions of G.S. 62-133 and to balance the interests of customers and the regulated utilities.

The Commission finds and concludes, for the reasons set forth herein, that the ROE recommendations of witnesses Woolridge and O'Donnell are to be afforded little weight. The Commission concludes that their analyses would produce a significant risk that the Company could not obtain equity financing on reasonable terms. The Commission further concludes that a 9.90% ROE is reasonable based in part on probative, credible evidence from witness Hevert and witness Hinton. In particular, rather than accept any one approach of any single witness, the Commission has independently determined that the combination of witness Hevert's updated analytical results, as well as witness Hinton's updated comparable earnings results, are supportive of an ROE of 9.90%. The 9.90% ROE is also supported by the Stipulation and the accompanying testimony of DNCP and Public Staff witnesses as to its reasonableness. Finally, as discussed below in more detail, the Commission concludes that a 9.90% ROE is reasonable and appropriate in light of the numerous other adjustments that affect earnings available to investors. Such adjustments include reductions in the Company's requested rate base, reductions in its requested operating expenses, an approved capital structure that imputes a lower equity ratio than the Company's actual capital structure, and a $400,000 shareholder contribution to assist low-income customers. Along with these adjustments, the impact of changing economic conditions on DNCP's customers has been taken into account in determining the approved ROE.

Consumers pay rates, a charge in cents per kilowatt-hour for the electric energy they consume. They do not pay a rate of return on equity. To the extent that the Commission makes downward adjustments to rate base, reduces the approved common equity component of capital structure, disallows test year expenses or increases pro forma test year revenues, the Commission reduces the rates consumers pay during the future period rates will be in effect. However, the utility's investors' compensation for the provision of service to consumers takes the form of return on investment. To the extent the Commission makes adjustments to reduce the overall cost of service, the Commission reduces the rates consumers otherwise must pay irrespective of its determination of rate of return on equity expressed as a percentage, in this case 9.90%. To the extent these adjustments reflect current economic conditions, and consumers' ability to pay, these adjustments reduce not only consumers' rates but also the return on equity, expressed in terms of dollars that investors actually earn. This is also in accord with the end result test of Hope.

In the present case, DNCP's initial Application requested a $51.073 million increase in DNCP's annual North Carolina revenues. That revenue increase would require an overall rate increase of 20.90%. In addition, DNCP requested a 10.5% rate of return on common equity, a 7.88% overall return on a rate base of $1.067 billion, and a capital structure that included 53.359% common equity. In the Company's supplemental and rebuttal cases, it revised its requested revenue increase to $46.8 million and its overall return to 7.805%. These are the "big picture" numbers in the case. However, the crucial details of DNCP's general rate Application, as in all general rate cases, are in the hundreds of line items in the NCUC Form E-1 that detail the Company's cost of service. The details of DNCP's Application, including the cost of service line items, are reviewed by the Public Staff and by other intervenors. The Public Staff typically recommends numerous adjustments to the utility's cost of service items, some adjustments increasing an item and some adjustments decreasing another item. These adjustments are presented by the Public Staff in its testimony, or, as in the present docket, in a settlement agreement with the utility.

In the present docket, the Public Staff's adjustments are shown in Settlement Exhibit II of the Stipulation. There are about 20 adjustments, some up and some down. However, the end result of all the adjustments is a reduction in DNCP's revenue requirement from the $46.752 million requested in the Company's rebuttal case to the stipulated amount of $34.732 million. Thus, the numerous adjustments made by the Public Staff, and approved herein by the Commission, reduce the total annual base revenues to be received by DNCP from ratepayers by $12.020 million, including a reduction of approximately $5.235 million resulting from a decrease in the rate of return to be paid to equity investors.[17] Although the ROE downward adjustment produces a direct reduction in the authorized rate of return on investment financed by equity investors, the numerous other downward adjustments reflected on Settlement Exhibit II further reduce the dollars the investors actually have the opportunity to receive. For example, the authorized 51.75% equity ratio in the capital structure, which is a regulatory

[17] See Settlement Exhibit II.

reduction from the Company's actual equity ratio of 53.92%, reduces revenues available for earnings by another $2.849 million. Thus, while the equity investor's cost was calculated under the terms of the Stipulation by applying a rate of return on equity of 9.90%, instead of the 10.5% requested in the Application, this is only one of many approved adjustments that reduces ratepayer responsibility and equity investor reward.

This is not to say that the Commission accepts the stipulated 9.90% rate of return on equity merely because it is lower than the 10.5% requested by DNCP. Indeed, the Commission has weighed the evidence of the expert ROE witnesses, and in finding some of that evidence to be highly probative and other parts of that evidence as entitled to little weight, has independently found support in the analytical results for a 9.90% ROE. In addition, the Commission concludes that each of the approximately 20 adjustments made by the Public Staff, and accepted herein by the Commission, reflects the fact that ratemaking, and the impact of rates on consumers, must be viewed as an integrated process where the ratemaking end result is what directly affects customers. The Commission's acceptance of the foregoing ratemaking adjustments, including the 9.90% rate of return on equity, reflects the Commission's application of its subjective, expert judgment under the Public Utilities Act that the end result is in compliance with the Commission's responsibility to establish rates as low as reasonably possible without transgressing constitutional constraints.

Solely focusing on the authorized rate of return on equity in assessing the impact of the Commission's decision on consumers' ability to pay in the current economic environment would fail to give a true and accurate picture of the issues presented to the Commission for decision and the totality of the Commission's order. Such an analysis would also be inconsistent with Hope and the CUCA cases. For example, when the Commission approves a reduction in the investment (rate base) against which the authorized 9.90% rate of return on equity is multiplied to produce the dollars in return on equity investment, the financial impact is a reduction in the rates paid by ratepayers and a reduction in the amount received by equity investors, the same result as if the Commission had instead reduced the 9.90% rate of return on equity. In the present case, the Stipulation included a reduction of $4.903 million in authorized rate base, and therefore, a substantial reduction in revenues available to pay earnings to shareholders, compared to the Company's position in its rebuttal testimony.[18]

As previously noted from the Hope decision, it is the "end result" of the Commission's order that must be examined in determining whether the order produces just and reasonable rates. Consistent with that requirement, the Commission has incorporated into its analysis all of the myriad factors that make up DNCP's revenue requirement, including the rate of return on equity and the impact of the Commission's decision regarding the consumers' ability to pay in the current economic environment. With respect to customers' ability to pay, an important adjunct to the 9.90% ROE is the $400,000 shareholder contribution to assist low-income customers, notwithstanding the

[18] See Fernald Exhibit 1, Schedule 2, Revised (filed with the settlement testimony of Public Staff witness Fernald).

significant improvement in economic conditions in DNCP's service territory since the Company's last rate case. Based on the impact on customers, the requirements of investors in capital markets, and the total effect of the Stipulation with its numerous reductions to the Company's proposed revenue requirement, the Commission concludes that a 9.90% rate of return on equity produces just and reasonable rates for DNCP and for its ratepayers. Any further reduction in the authorized rate of return on equity is not justified by any evidence that the Commission has found to be credible and probative in its fact finding role.

In separate post-hearing briefs, the AGO and Nucor emphasized the generally lower results produced by the Constant Growth DCF analyses of all the witnesses. They argue that either the implementation, or interpretation of results, by witnesses Hinton and Hevert in their Mutli-Growth DCF, Comparable Earning, Risk Premium, or CAPM analyses are flawed and excessive. The AGO, which presented no witness, recommends an ROE of less than 9.0%, and Nucor recommends an ROE of 8.6% consistent with the testimony of witness Woolridge.

In its post-hearing Brief, CUCA contends that the stipulated ROE of 9.90% is too high because it represents a "split the baby" approach between the ROE proposed by Public Staff witness Hinton and the ROE proposed by DNCP witness Hevert. Further, CUCA maintains that each of the analytical models used by witness Hevert is seriously flawed, as discussed by CUCA witness O'Donnell in his testimony.

After consideration of the entire record and for the reasons stated herein, the Commission is not persuaded by the AGO or Nucor that the 9.9% ROE in the Stipulation is excessive. The Commission points out that each of the witnesses to this proceeding use considerable judgement or discretion in deciding which ROE estimation method or model to use and present into evidence, or even withhold. In addition, each ROE witness used discretion in deciding what inputs to use within each method, the interpretation of the results of each method, and how the results of each method were weighted in determining the ROE to recommend on behalf of their employer or client. The Commission is uniquely situated and legally charged with using its impartial judgement to determine the ROE using applicable legal standards. The Commission has used its impartial judgment as necessary and appropriate to evaluate and weigh the evidence in reaching its conclusions and findings relevant to the ROE issue as set forth in this Order.

After a careful review of all the evidence in this case, and adhering to the requirements of the above cited legal precedents, the Commission finds that the overall rate of return on rate base and the allowed rate of return on common equity, as well as the resulting customer rates provided for under the Stipulation, are just and reasonable, fair to both DNCP and its customers, appropriate for use in this proceeding, and should be approved. The rate increase approved herein, as well as the rates of return underlying such rates, are just, reasonable and fair to customers considering the impact of changing economic conditions, and are required in order to allow DNCP, by sound management, to produce a fair return for its shareholders, maintain its facilities and provide services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and existing investors.

The Commission notes further that its approval of an ROE at the level of 9.90% - or for that matter, at any level - is not a guarantee to the Company that it will earn a return on its common equity at that level. As noted above, on June 30, 2016, the Company's fully-adjusted earned rate of return on equity capital for the update period was only 5.50%, far below the Company's currently authorized 10.2%. Rather, as North Carolina law requires, setting the ROE at this level merely affords DNCP the opportunity to achieve such a return. See G.S. 62-133(b)(4). The Commission believes, based upon all the evidence presented, that the ROE provided for here will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are fair to its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

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

In the Application and direct testimony and exhibits, DNCP provided evidence supporting an increase of $51.073 million, or approximately 20.90%, in its annual non-fuel revenues from its North Carolina retail electric operations. On August 12, 2016, the Company filed supplemental direct testimony and exhibits updating several cost of service adjustments. These updated adjustments decreased the Company's revenue requirement by $3.3 million, for a revised increase in North Carolina retail revenue of $47.8 million, which was reduced again in the Company's rebuttal case filed on September 26, 2016 to $46.8 million.

On September 7, 2016, the Public Staff filed the direct testimony of witness Fernald, presenting her recommended accounting and ratemaking adjustments to the Company's proposed revenue requirement. Accounting for these adjustments, she recommended an increase in the Company's annual base non-fuel operating revenue of $19,755,000. Nucor filed testimony of witness Kollen, who also made recommendations for accounting adjustments.

On September 26, 2016, the Company filed the rebuttal testimony of witness Stevens, which responded to the various accounting adjustments and recommendations of witness Fernald and witness Kollen.

On October 3, 2016, the Company, the Public Staff and CIGFUR I entered into and filed the Stipulation. Pursuant to the Stipulation, the Company, the Public Staff and CIGFUR I agreed upon an increase to DNCP's annual non-fuel revenue from its North Carolina retail electric operations of $34.732 million or 14.25% and a decrease in annual base fuel revenues of $8.942 million.

Also on October 3, 2016, the Company filed the joint testimony of witness Stevens and witness McLeod in support of the stipulated revenue increase. These witnesses testified in support of the accounting and ratemaking adjustments agreed upon in the Stipulation. They also testified that the Stipulation is the result of negotiations between the Stipulating Parties who, collectively, represent both residential and industrial customer interests impacted by this case. Also on October 3, 2016, the Public Staff filed testimony of witness Fernald recommending and supporting the stipulated adjustments to the Company's requested revenue increase.

Based upon the evidence recited above and the cumulative testimony and evidence supporting the individual components of the stipulated revenue increase discussed throughout this Order, the Commission finds, in the exercise of its independent judgment, that the stipulated net revenue increase of $25.70 million for North Carolina retail electric operations in this case is just, reasonable, and appropriate for use in this proceeding.

The following schedules summarize the gross revenue and the rate of return that the Company should have a reasonable opportunity to achieve based on the determinations made herein. These schedules, illustrating the Company's gross revenue requirement, incorporate the findings and conclusions made by the Commission in this Order. As reflected in Schedule I, and as impacted by the other findings in this Order, DNCP is authorized to increase its annual level of gross revenues by $25.790 million, reflecting an increase of $34.732 million in base non-fuel revenues (including late payment fees and other revenues) and a decrease of $8.942 million in base fuel revenues.

SCHEDULE I
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF OPERATING INCOME
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric sales revenues	$242,718	$34,310	$277,028
Base fuel revenues	99,755	(8,942)	90,813
Late payment fees	1,292	92	1,384
Other revenues	6,167	330	6,497
Total operating revenues	349,932	25,790	375,722
Fuel expenses	90,686	0	90,686
Other O&M expenses	98,829	160	98,989
Depr. and amort. expense	60,047	0	60,047
Gain / loss on disp. of property	309	0	309
Taxes other than income	15,233	0	15,233
Income taxes	23,891	9,929	33,820
Total operating expenses	288,995	10,089	299,084
Net operating income before adj.	60,937	15,701	76,638
Interest on customer deposits	(19)	0	(19)
Interest on tax deficiencies	(1)	0	(1)
Net operating income for return	$ 60,917	$15,701	$ 76,618

SCHEDULE II
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF RATE BASE AND RATE OF RETURN
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric plant in service	$1,947,252	$ 0	$1,947,252
Accumulated depr. and amort.	(716,858)	0	(716,858)
Net electric plant in service	1,230,394	0	1,230,394
Materials and supplies	44,916	0	44,916
Cash working capital	16,406	2,070	18,476
Other additions	19,607	0	19,607
Other deductions	(17,434)	0	(17,434)
Customer deposits	(5,126)	0	(5,126)
Acc. deferred income taxes	(250,799)	0	(250,799)
Rounding	1	0	1
Total original cost rate base	$1,037,965	$ 2,070	$1,040,035
Rate of Return	5.87%		7.37%

SCHEDULE III
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-Term Debt	48.25%	$ 500,818	4.650%	$23,288
Common equity	51.75%	537,147	7.010%	37,629
Total	100.00%	$1,037,965		$60,917
		Approved Rates – Original Cost Rate Base		
Long-Term Debt	48.25%	$ 501,817	4.650%	$23,334
Common equity	51.75%	538,218	9.900%	53,284
Total	100.00%	$1,040,035		$76,618

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence for this finding of fact and these conclusions is contained in the Stipulation, the testimony of DNCP witness Stevens and Public Staff witness Fernald, and the entire record in this proceeding.

Section XV of the Stipulation provides that the Company will make a one-time $400,000 shareholder contribution over and above its usual contribution to its North Carolina EnergyShare program, which provides energy assistance to customers in need in the Company's North Carolina service territory, by March 30, 2017. At the hearing, the Company notified the Commission that it would commit to making this contribution no later than early January, 2017, so that the funds would be available for the winter heating season. Company witness Stevens testified that the Company's usual annual EnergyShare expenditure in North Carolina was approximately $360,000, so the amount agreed upon in the Stipulation would effectively double the amount of shareholder contribution to low-income heating assistance.

The Commission notes that the $400,000 shareholder contribution to low-income energy assistance is a feature of the settlement between the Company, the Public Staff and CIGFUR I that could not have been ordered by the Commission without the agreement of the Company. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37-41

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application and exhibits, the Stipulation, and the testimony of Company witnesses Pierce (as adopted by Haynes), and Haynes, Public Staff witness Floyd, Nucor witness Goins, and CUCA witness O'Donnell, and the entire record before the Commission in this proceeding.

Cost of Service Methodology – The Company's Application, as supported by witness Haynes, used the SWPA cost of service methodology to allocate production and transmission plant costs for both the North Carolina jurisdiction and the North Carolina retail customer classes. The SWPA method recognizes two components of providing service to customers - peak demand and average demand - when determining the responsibility for costs of production and transmission plant and related expenses. The peak demand component takes into account the hour when the load on the system is highest during both the summer months and the winter months. The average demand component recognizes that there is a load incurred by the system over the course of all hours during the year. The average demand is determined based upon the total energy provided to the customers during the year divided by the total number of hours in the year. The average component is then weighted by the system load factor, and the peak component is weighted by one minus the system load factor. The load factor is calculated by taking the Company's actually experienced average demand divided by its actually experienced peak demand during the test year.

Witness Haynes explained that DNCP developed and presented in its Form E-1, Item 45, the "per books," annualized, and "fully-adjusted" jurisdictional and customer class cost of service studies (COSS) based on the SWPA allocation method for the 12-months test year ended December 31, 2015. [19] In developing the SWPA COSS, the Company also made an adjustment to the Company's recorded summer and winter peaks to recognize and add back the kW generated by non-utility generators (NUGs) interconnected to DNCP's distribution system that are not included in those values. This NUG adjustment addresses a "mismatch" between the peak and the average components of the SWPA, as the kWh generated by distribution-interconnected NUGs were included in the average demand component of the SWPA but not in the summer and winter peak component. The NUG adjustment was calculated by determining the actual kW generated by distribution-interconnected NUGs at the time of the summer and winter peaks in both DNCP's Virginia and North Carolina service territories, and then adding these "state" values to each jurisdiction's respective recorded summer and winter peaks to arrive at the adjusted level. DNCP's fully adjusted SWPA COSS produced a North Carolina jurisdictional allocation factor of 5.1166%.

Company witness Haynes testified that the objective of jurisdictional and customer class cost of service studies is to determine the allocation of a share of the system's revenues, expenses, and plant related to providing service across multiple jurisdictions. Certain items can be assigned directly to the jurisdiction and classes based on the utility's records, but other items are not directly assignable and must be allocated. Witness Haynes stated that in this proceeding, the Company allocated its production and transmission plant and expenses using the SWPA cost of service methodology. He noted that the Commission has approved DNCP's use of the SWPA method in five other general rate case proceedings for the Company, dating back to 1983, including the 2012 Rate Case.

Company witness Haynes testified that the SWPA allocation method is consistent with the manner in which DNCP plans and operates its system. Specifically, the "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks while the average component recognizes the type of generation serving customers' energy needs year-round.

Company witness Haynes also emphasized that use of a single peak or other peak-only methodology could allow certain customer classes that have zero demand during the peak hour(s) of the year to fully avoid responsibility for production plant costs. Witness Haynes explained that a common example is that streetlights normally do not operate during peak hours. Company witness Haynes also highlighted the NS Class as another example unique to DNCP's North Carolina jurisdictional load. Witness Haynes explained that Nucor, the only customer in the NS Class, has an average annual demand

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[19] At the request of CIGFUR I and Nucor in discovery, and in response to the Commission's March 17, 2016 Order Denying Motion and Granting Alternative Relief, DNCP also developed and filed with the Commission a per books single coincident peak (1CP) COSS on May 31, 2016. The DNCP 1CP COSS is designed using only the single highest system peak during the test year, and produced a per books North Carolina jurisdictional allocation factor of 5.2354%.

throughout the year of approximately 100 megawatts (MW), while Nucor's average of its summer (June 2015) and winter (February 2015) coincident peak demands is approximately 42 MW. Witness Haynes explained that without recognizing an average component in the cost allocation, this customer class would "pay" for only 42 MW and escape cost responsibility for an average of 58 MW for the rest of the year (i.e., the average demand of 100 MW less the allocated demand of 42 MW). Witness Haynes explained that by recognizing both the energy needed to serve load at the peak hour, as well as energy consumed throughout the year, the SWPA method allocates some portion of these system costs to all customers, including those customers that can reduce their peak demand and those that may not place a demand on the system during the respective summer and winter peak hour. Such customers still use and receive the benefit of the Company's investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours.

Public Staff witness Floyd agreed with the Company's use of the SWPA cost of service methodology in this proceeding because it appropriately allocates the Company's production plant costs in a way that most accurately reflects the Company's generation planning and operation. He testified that unlike other methodologies that allocate all of the production plant costs based on a single coincident peak or on a series of monthly peaks, the SWPA methodology recognizes that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements throughout the year and not solely to meet peak demand at a particular time. Witness Floyd also addressed the NUG adjustment to SWPA, stating that the Public Staff agrees with DNCP's adjustment as appropriately recognizing the impact that distribution connected NUGs have on DNCP's system.

Nucor witness Goins recommended that the Commission reject DNCP's use of the SWPA method and, instead, order DNCP to use the Summer-Winter Coincident Peak (S/W CP) method. Witness Goins developed and filed a fully adjusted S/W CP COSS that incorporated the cost-of-capital and ratemaking adjustments proposed by Nucor witnesses Woolridge and Kollen, respectively.

Witness Goins suggested that the use of the SWPA method is unreasonable because the SWPA methodology is used in almost none of the regulatory jurisdictions with which he was familiar. He further argued that the SWPA method is flawed for a number of reasons and ultimately allocates a greater portion of DNCP's cost of service to Nucor and other high load factor customers. Specifically, witness Goins argued that Nucor's load is totally interruptible and, therefore, should be excluded when deriving the SWPA allocation factors. Witness Goins contended that in failing to properly recognize Nucor's interruptible load, the Company overstated the cost to serve Schedule NS and understated the rate of return for Schedule NS. Finally, witness Goins argued that the use of SWPA harms Nucor and other high load factor customers who would be assigned lower levels of fixed production costs under a peak-only methodology.

Nucor witness Goins testified that should the Commission continue to find the SWPA method appropriate for use in this proceeding, the Commission should reject the system load factor weighting methodology used by DNCP and, instead, use a weighting that allocates a greater percentage of production costs based using peak demand and a lesser percentage based upon the average energy-based demand component. Specifically, witness Goins suggested that DNCP's system load factor weighting is heavily biased towards energy and suggested that the Commission could mitigate the bias by establishing weighting for the peak demand component at 75% or greater and the average demand component at 25% or less.

CUCA witness O'Donnell's arguments in support of the 1CP methodology were similar to those of witness Goins in support of S/W CP. Witness O'Donnell suggested that 1 CP best depicts how DNCP dispatches its plant to meet peak load. He further argued that he opposed SWPA because it sends the message to industrial consumers to use less energy and for residential and small consumers to use more energy, which will hurt manufacturing and economic development in Eastern North Carolina and, in time, raise rates to the residential and small commercial consumers when industrial consumers that cannot afford the higher rates move their operations elsewhere or simply close altogether.

In rebuttal, Company witness Haynes extensively addressed and rebutted the cost of service arguments of witness Goins on behalf of Nucor and witness O'Donnell on behalf of CUCA. Witness Haynes explained that the SWPA method reasonably and appropriately recognizes the two components of providing service to customers, peak demand, and average demand, and is consistent with the manner in which the Company's planning department plans for and meets DNCP's system needs, taking into consideration the need to meet both peak demands and the need to provide resources that can be operated to serve customers throughout the year. The "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks, while the average component recognizes the dispatch of different types of generation providing the system with low cost energy year-round. Witness Haynes pointed to the Company's recent additions of the intermediate/baseload gas-fired combined cycle 1,342 MW Warren County CC and the 1,358 MW Brunswick County CC (as well as the Company's historical investments in its baseload nuclear fleet) as production-related plant operated throughout the year to provide baseload energy to the Company's customers.

Witness Haynes responded to Nucor witness Goins' suggestion that SWPA is a rarely used methodology by explaining that there are numerous other jurisdictions, including the Company's Virginia jurisdiction, that include an "average" (energy) component in the development of production allocation factors. The Company operating in Virginia as Dominion Virginia Power has used the Average & Excess (A&E) cost allocation method in every Virginia rate proceeding dating back to 1972. Witness Haynes also testified that the SWPA and A&E methods have the benefit of also being relatively consistent (both include energy components) and, further, that preserving historical continuity in the method used to allocate costs will also avoid significant shifts in allocated costs to a given class between one rate case and the next.

In addressing the peak-only S/W CP and 1CP methods advocated by witnesses Goins and O'Donnell, witness Haynes explained that these methodologies are unreasonable and inappropriate for DNCP because their reliance on the single coincident peak hour or only the two hours of DNCP's summer and winter peaks is inconsistent with the way DNCP plans and operates its system to both meet the system peaks as well as to deliver low cost energy throughout the year. In addition to the new Warren County and Brunswick County Power Station investments, described above, witness Haynes also specifically pointed to the remaining $4.7 billion of nuclear plant in service at the end of 2015, which still represents approximately 30% of DNCP's total production plant investment. Witness Haynes also presented concerns that use of S/W CP would produce unreasonable results in other areas of DNCP's COSS, such as production plant O&M expenses.

Witness Haynes also presented a number of analyses showing that moving from a SWPA methodology to the S/W CP methodology would cause a significant shift of DNCP's cost of service between the classes and would shift recovery of production costs away from Nucor and other high load factor customers and to the residential class. For example, witness Haynes' analysis in his Rebuttal Table 4 showed that the NS Class rate of return increased from approximately 2% under the SWPA method to approximately 18% under Witness Goins' S/W CP method. Witness Haynes' Rebuttal Table 5 presented the shift in class rate of return indices (RORI) between SWPA and S/W CP, with the Schedule NS Class increasing from 0.40 under SWPA to 2.79 under the S/W CP method (an increase of over 597.5 %), while the residential class fell from a RORI 0.97 under the SWPA method to 0.65 under witness Goins' S/W CP method. Witness Haynes also noted that under the fully adjusted cost of service presented by witness Goins, the residential class would receive a $24.8 million increase to achieve the overall jurisdiction S/W CP ROR.

Witness Haynes explained that witness O'Donnell's 1CP method is unreasonable for the same reasons as the peak only S/W CP method. Witness Haynes testified that 1CP also fails to take into consideration both the summer and winter peaks as DNCP is forecasted to remain a summer peaking utility, but recently experienced all-time system peaks during the winter in 2014 as well as during the 2015 test year. Finally, witness Haynes testified that use of the 1CP method would also increase cost responsibility for the North Carolina jurisdiction, while lowering the rate of return for the jurisdiction, and would also significantly shift costs to the residential class compared to the SWPA method.

Witness Haynes also explained that DNCP's continued use of the test year system load factor is a reasonable, reliable, and consistent method for establishing the weighting of the peak and average components of the SWPA COS methodology. Contrary to witness Goins' view, the Company's use of the system load factor is not arbitrary, but is based on DNCP's actual verified usage of the Company's generation capacity throughout the course of the test year relative to installed capacity. Witness Haynes testified that witness Goins' recommendation to weight the peak demand at 75% and the average demand at 25% is both arbitrary and results oriented as it would have the effect of increasing the residential class' percent of system responsibility for production costs by 13.8% and decreasing the cost responsibility allocated to Nucor by 35.2%.

Finally, witness Haynes argued that the Commission's recent decision in Duke Energy Progress' 2013 rate case adopting a 1CP method for that utility, should not have bearing on the Commission's determination of the appropriate allocation methodology for DNCP. Witness Haynes pointed out that the Commission explained in its Order in the Duke Energy Progress 2013 rate case that cost allocation does not lend itself to a "one size fits all approach."[20] Witness Haynes also emphasized that the use of S/W CP or another peak only method is potentially more significant for DNCP than other utilities due to the Company's obligation to serve a "one-customer industrial class" – Schedule NS – which used approximately 19% (863,206,000) of the 4,568,385,000 jurisdictional kWh during the test year but can also significantly reduce its demand on the peak.

Under cross-examination by CUCA, witness Haynes accepted that adopting a peak-only methodology such as S/W CP or 1CP would allocate a significantly lower amount of cost responsibility to large high load factor customers, but argued that these methodologies would also cause a shift in cost responsibility to the residential and other non-industrial rate classes. He testified that using only one or two hours of the year to determine cost responsibility is not consistent with the way DNCP plans and operates its generation plants, nor is it fair from a cost allocation perspective, especially considering smaller general service and residential customers. During cross-examination by Nucor's counsel, witness Haynes disagreed with witness Goins' alternative weighting of the SWPA demand and energy components at 75% demand and 25% energy, explaining that his rebuttal Schedule 1 analysis showed that this modified weighting would make residential cost responsibility go up by 13.8%, while Nucor would receive a minus 35.2% shift in cost responsibility and the 6VP class would have a negative 28.9% shift in responsibility under this weighting. On redirect, witness Haynes identified other jurisdictions that use average components in allocating production costs but stated that the Company had not completed an exhaustive assessment of every jurisdiction and utility in the country. He also testified that while it is up to the Commission to determine the weightings in SWPA, the Commission has previously determined that the use of the system load factor was an appropriate way to weight the average demand component, and one minus that system load factor was an appropriate way to weight the peak demand component.

In its post-hearing Brief, CUCA contends that use of the SWPA methodology, as opposed to the 1CP, results in a rate design that sets higher rates than required for large industrial customers. Further, CUCA notes that the Commission has approved the use of 1CP for Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC.

The Commission finds and concludes that DNCP has carried its burden of proof to show that the SWPA methodology is the most appropriate cost of service methodology to use in this proceeding to assign cost responsibility for production plant to the North Carolina jurisdiction and the Company's customer classes. On this issue, the Commission gives substantial weight to the testimony of Company witness Haynes and Public Staff

[20] Application of Progress Energy Carolinas, Inc., Docket No. E-2, Sub 1023, Order Granting General Rate Increase, at 98 (May 30, 2013).

witness Floyd. The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class's peak demands and overall energy consumption. Company witness Haynes testified extensively that the Company's investment in generating plant, including the recently placed in service Warren County CC and Brunswick County CC, are designed to meet the Company's system peaks and to deliver low cost energy throughout the year. Witness Haynes explained that the SWPA methodology appropriately recognizes that DNCP's system planning is designed to meet both the Company's peak and average system demands and energy needs of customers throughout the year. Both Company witness Haynes and Public Staff witness Floyd testified that the SWPA method appropriately matches allocation of production plant with DNCP's generation planning and operations. The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DNCP plans and operates its generating plants to provide utility service to customers in North Carolina.

The Commission also recognizes and reaffirms its prior determination in the Duke Energy Progress 2013 rate case that cost allocation does not lend itself to a "one size fits all approach."[21] Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service.

The Commission is not persuaded that either the S/W CP methodology or the 1CP methodology is appropriate for the Company in this proceeding. Company witness Haynes and Nucor witness Goins provided calculations to compare the rates of return associated with the cost of service methodologies they advocated. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DNCP's customer classes in this case.

In Nucor's Brief, Nucor reiterated witness Goins' testimony that (1) the Commission should abandon the SWPA methodology, (2) the Commission should adopt the S/W CP methodology, and (3) if the Commission decides to adopt SWPA, it should address two flaws/biases inherent in DNCP's SWPA cost studies. The two flaws alleged by Nucor are (1) energy use is given too much weight, 56%, because peak demand is the primary driver of DNCP's need for additional capacity, and (2) DNCP's use of SWPA creates an asymmetry in DNCP's assignment of fixed production cost responsibility and its average cost recovery of fuel costs.

With regard to increasing the weight assigned to peak demand, Nucor recommends giving a 25% weight to the average demand component and a 75% weight to the peak demand component. In support of this recommendation, Nucor cites the

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[21] Id.

decisions of the Michigan Public Service Commission in two 2015 dockets, one involving DTE Electric Company (Case No. U-17689, Opinion and Order dated June 30, 2015), and the other Consumers Energy Company (Case No. U-17688, Opinion and Order dated June 30, 2015) (collectively, Consumers). Pursuant to Michigan statutory provisions, a 50-25-25 (50% peak demand, 25% on-peak energy use, 25% total energy use) cost allocation method is mandated, unless a party shows that an alternative method would better ensure that rates are equal to cost of service. The purpose of the Consumers proceeding was to determine whether a change in the energy/demand ratios mandated by the statute was warranted. Consumers Energy proposed a 4CP 100-0-0 methodology, whereby costs would be allocated based 100% on peak demand. However, the PSC Staff recommended a 75-0-25 methodology, which the PSC ultimately adopted. The PSC cited extensive evidence on the appropriate allocation formula, stating

> [T]he Commission therefore finds that the Staff's proposal to modify the production cost allocation method from 50-25-25 to 75-0-25 is well supported, better ensures rates are equal to cost of service, and should therefore be approved.

Id., at p. 17.

The Commission is not persuaded on the present record that the Michigan PSC's approach advocated by Nucor should be adopted for DNCP. For reasons perhaps unique to Michigan, the legislature has mandated that the Michigan PSC use a 50-25-25 cost allocation ratio, unless a better methodology is shown. In contrast, DNCP established its 56%-46% ratio based on DNCP's system load factor test-year data. That process is a more direct and accurate approach than the "one size fits all" ratio mandated in Michigan's statute. In addition, Nucor did not support its 25%-75% allocation weighting proposal with sufficient analyses of DNCP's system operating characteristics.

As a result, the Commission is not convinced that Nucor witness Goins' proposal to reject the Company's use of the system load factor and to adopt Nucor's alternative proposal to establish weighting for the peak demand component at 75% or greater and the average demand component at 25% or less is reasonable or appropriate in this proceeding. Nucor's rationale for this modified SWPA method is that reweighting SWPA to shift significantly greater emphasis to the peak demand component would mitigate the "numerous flaws" that Nucor finds in the SWPA method. Because the Commission finds that the SWPA method is not unreasonable or flawed, the Commission does not find Nucor's argument persuasive. Further, based on the evidence of record in this case, the Commission finds that the system load factor is not arbitrary, but is reasonably based on DNCP's actual verified usage of its Company's generation capacity throughout the course of the test year relative to installed capacity. Nucor's request that the Commission select weighting with a peak demand component of 75% or greater and the average demand component at 25% or less would be unreasonable and, indeed, arbitrary as it is not tied to any objective measurement of DNCP's system operations.

Based on the Stipulation and the testimony on the record, the Commission also finds that including the distribution-interconnected NUG generation in the average portion of the SWPA, but not including this NUG generation in the Company's recorded summer and winter peaks creates a mismatch between the peak and average components of the Company's SWPA COSS. The Commission concludes that the Company's adjustment to the summer and winter peaks to recognize the NUG generation at the distribution level appropriately recognizes the impact the NUGs have on DNCP's utility system and should be approved.

Finally, it is also notable that CIGFUR I joined in the Stipulation with DNCP and the Public Staff supporting the SWPA methodology as reasonable and appropriate in this proceeding. Although CIGFUR I has historically opposed the use of a production plant allocation methodology based on jurisdiction and customer class energy usage, it is not unreasonable for the Stipulating Parties to have agreed, as part of their overall settlement of all contested issues, that the allocation of production plant based on the SWPA methodology is reasonable for purposes of this proceeding. As the Commission has noted, that is part of the give-and-take of settlement negotiations. Therefore, based upon consideration of the Stipulation in its entirety, the Commission gives the Stipulation substantial weight in resolving the cost allocation methodology issue.

Based on the evidence in this proceeding, including the Stipulation, the Commission finds and concludes that the greater weight of the evidence shows that the SWPA cost of service methodology provides the most appropriate methodology to assign fixed production costs by incorporating DNCP's seasonal peak demands at the two single hours they occur and by incorporating the total energy consumed by the jurisdiction and customer classes over all the other hours of the year. In addition, the Commission finds good cause to require that the Company should continue to file a cost of service study using the SWPA methodology annually with the Commission.

Further, the Commission emphasizes the importance of properly allocating costs between jurisdictions, and specifically in this case between Virginia and North Carolina, and between customer classes. In that regard, the Commission takes note of Company witness Haynes rebuttal testimony that "The Company has used the A&E cost allocation method in every Virginia rate proceeding dating back to 1972. The 'average' portion of the A&E method is similar to the 'average' portion of the SWPA method." (T Vol. 7, at p. 193) However, even though the "average" portion of the A&E method is similar to the "average" portion of the SWPA method, the Commission finds good cause to require the Company to file an A&E cost allocation methodology in its next North Carolina general rate case, in addition to the methodology proposed by the Company.

Finally, the Commission notes that there is ample opportunity under Commission rules for thorough consideration of all issues related to cost of service in a general rate case. Interested parties may intervene, conduct discovery and present evidence in accordance with the rules of practice and procedure established by the Commission.

Treatment of Nucor in the Company's Cost of Service

The Company's SWPA cost of service study (Form E-1, Item 45) followed the same approach for the Schedule NS customer class (NS Class), as well as all other classes, used in the cost of service studies filed and approved in DNCP's two most recent general rate cases, Docket No. E-22, Sub 479 in 2012 and Docket No. E-22, Sub 459 in 2010. Specifically, as described by Company witness Haynes, the Company used both a summer and winter peak demand for the NS Class that reflected Nucor's measured demand and recognized the interruptible nature of Nucor's arc furnace pursuant to the confidential terms and conditions of the Company's contract with Nucor, the only customer in the NS Class. The 43 MW of peak demand assigned to the NS Class represents the average of the winter and summer peaks of the NS Class at the time of the test year system winter and summer peaks. These peak demands were used to develop the production plant and transmission related demand allocation factors. The Company also used Nucor's actual test year energy consumption of 863,206,000 kWh to develop the average component of SWPA.

In addition to his alternative COSS recommendations, addressed above, Nucor witness Goins argued that Nucor's total load is "non-firm" or interruptible pursuant to the Company's contract with Nucor for electric service and recommended that the Commission reject DNCP's treatment of Nucor's interruptible load in its cost of service study. Witness Goins disagreed with DNCP's characterization that Nucor's load continues to be partially interruptible under the Nucor agreement and argued that rates for service to fully interruptible customers should not recover any fixed production costs.

Witness Goins asserted that because Nucor's load is interruptible, it is not responsible (except by administrative fiat) for DNCP's fixed production costs. He concluded that service to Nucor's interruptible load occurs only when excess capacity used to serve firm load is available. Witness Goins further argued that DNCP's SWPA method allocates fixed production costs to Nucor almost exclusively based on Nucor's energy use. In contrast, about 60% of fixed production costs allocated to North Carolina customers in DNCP's cost studies is allocated on the basis of energy. Witness Goins recommended that if the Commission adopts DNCP's SWPA method, then the Commission should also replace DNCP's system load factor weighting scheme with peak demand component weights equal to or greater than 75% and average demand component weights of 25% or less, and further require DNCP to: (1) investigate the SWPA's asymmetrical allocation problem, including the preparation and filing for review of a detailed analysis of the problem similar to the analysis the Commission ordered in Docket No. E-22 Sub 333 (1994 Fuel Study); and (2) require DNCP in future jurisdictional and class cost studies to exclude Nucor's interruptible load in developing allocation factors for fixed production costs.

In rebuttal, Company witness Haynes explained the Company's reasoning for characterizing the Nucor agreement as partially interruptible as well as for the Company's treatment of Nucor in DNCP's COSS. Witness Haynes stated that Nucor's total load is only subject to interruption during system emergencies, when all other customers' load is also subject to interruption. Witness Haynes testified that the confidential terms of the Nucor agreement only allow for curtailment of Nucor's arc furnace load during very limited hours and, in certain of those hours, allow Nucor to buy through the curtailment at a higher price. Witness Haynes stated that the Company reads and applies the Nucor agreement to require Nucor's non-furnace load to be treated as "firm" and supplied with firm power throughout the year. Company witness Haynes also testified that he reviewed Nucor's actual loads since DNCP's 2012 Rate Case and confirmed that Nucor's non-furnace load has not been interrupted for emergency situations during at least that period.

Based on his understanding of the terms of the Nucor agreement as well as DNCP's implementation of the agreement since at least 2012, witness Haynes stated that DNCP's SWPA method properly takes into account Nucor's interruptibility, while also recognizing the demands Nucor places on the system and the energy consumed by Nucor. Nucor's average Summer/Winter coincident peak demand was approximately 43,192 kW during the test year, which represented the non-furnace load that the Company maintains is load that was actually served during the summer and winter peak hours. With regard to the average demand component, the Company has an obligation to serve Nucor each hour of the year and such a requirement is measured by the energy consumed. If Nucor is interrupted in any hour, then the energy consumption for that hour would reflect the interruption. Nucor actually consumed approximately 19% (863,206,000) of the 4,568,385,000 jurisdictional kWh during the test year. Witness Haynes asserted that the average demand component should reflect Nucor's actual use of the dispatch of the system generation and purchased power – just as is the case for all other customers.

Witness Haynes also performed an analysis detailing how recognizing Nucor's curtailed demand in developing the allocation methodology provides a significant and properly recognized financial benefit to Nucor as well as a lower overall allocation of system costs to the North Carolina jurisdiction. He asserted that the Company's SWPA allocation factors were calculated in a reasonable manner – consistent with the principles approved in DNCP's 2012 Rate Case – that appropriately recognizes the value of Nucor's interruptibility to the system and does not overstate cost nor understate returns for the North Carolina jurisdiction and its customer classes. Cost responsibility has been properly and fairly determined based on requirements placed on the system – by Nucor and all other customer classes – on the summer and winter peak days and throughout the year.

Witness Haynes also explained that the Commission is reviewing the same curtailment provisions that it reviewed in 2012 when it determined that the Company's SWPA method properly recognized Nucor's interruptible load under the Nucor agreement.

In response to Nucor's recommendation that the Commission require DNCP to exclude 100% of Nucor's load as interruptible in developing allocation factors for fixed production costs in future jurisdictional and class COSS, witness Haynes explained that this recommendation is inappropriate and, in effect, would treat the Schedule NS Class as if it did not exist. Witness Haynes explained that such an approach would be inconsistent with the manner in which DNCP has provided service to Nucor since the 2002 amendment to the Nucor agreement, when Nucor requested to transition from marginal cost of fuel and no assigned production plant to average cost of fuel for all system production resources. Haynes explained that if a customer once paid marginal cost and a small margin contributed toward production plant and related costs and now pays a more "certain" average fuel cost, then it should also be responsible for production plant costs – similar to all other customers.

Witness Haynes also reiterated that the provisions of the operative Nucor agreement giving Nucor the benefit of average fuel today are identical to the provisions of the Nucor agreement the Commission reviewed in 2012, when the Commission stated on page 30 of its Order as follows:

> The Commission also notes that the 2002 amendment to the Nucor contract to change the pricing structure was made at the request of Nucor. Nucor sought certainty in its pricing arrangements. Nucor therefore opted for a pricing arrangement that was based on the average fuel costs of the system, rather than the marginal cost pricing structure it had been receiving since the inception of the contract. ***The Commission agrees with the Company that under such an arrangement Nucor elected to receive the benefit of average fuel costs, and in doing so it also should be responsible for a share of the fixed production costs required to produce those same average fuel costs.*** The Commission further notes that the Nucor contract filed in the 2010 general rate case, Docket No. E-22, Sub 459, and in this proceeding no longer contains the language relieving the Company of any responsibility to provide for capacity to serve Nucor. (Emphasis added.)

In opposition to witness Goins' recommendation that Nucor be treated as 100% interruptible in future cost of service studies, witness Haynes concluded that Nucor actually consumes energy produced by DNCP equivalent to the energy needs of 71,000 residential households and because the NS Class is using production plant, it should contribute to fixed costs.

Based on the entire record in this proceeding, including the Stipulation, the Commission is persuaded that the Company has treated the NS Class and Nucor appropriately in its cost of service study and that no additional recognition of the benefits associated with the Nucor contract should be made in this proceeding.[22]

The facts and evidence in this proceeding show that the Company has consistently followed the same approach in this case of recognizing the benefits of Nucor's interruptibility – to both Nucor and the North Carolina jurisdiction – consistent with DNCP's

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[22] In arriving at this conclusion, the Commission takes judicial notice of its most recent general rate case order for DNCP, issued on December 21, 2012 in Docket No. E-22, Sub 479. Specifically, the Commission recognizes its findings and conclusions regarding the interruptibility provisions of the Nucor Agreement and Schedule NS in that proceeding, which were ultimately affirmed on appeal by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635 (2014).

approach in the Company's past two general rate case proceedings. Further, the record in this case is undisputed that the curtailment provisions in the Nucor agreement have not been modified since last reviewed by the Commission in 2012. The Commission again concurs with the Company, Nucor, and Public Staff witnesses that the system, and the NS Class in particular, benefits from only recognizing Nucor's non-arc furnace load in calculating the peak load of the NS Class in the cost of service. Nucor's contract with the Company provides Nucor with flexibility in deciding how and when it consumes energy for the vast majority of hours in the year. Outside of the relatively few hours the Company can contractually request Nucor to curtail its arc furnace load, Nucor is free to buy through all other requests at a fixed price arrangement. The Company's testimony that Nucor's non-furnace load has not been interrupted since at least 2012 is also undisputed. Accordingly, based upon the facts and evidence presented in this case, the Commission does not find Nucor's arguments that the Nucor agreement is totally interruptible to be persuasive nor does the Commission find that Nucor should be treated differently than other customer classes and relieved of paying for its allocated share of DNCP's investment in production plant.

The Commission also again notes that the 2002 amendment to the Nucor contract to change the pricing structure was made at the request of Nucor. Nucor sought certainty in its pricing arrangements. Nucor therefore opted for a pricing arrangement that was based on the average fuel costs of the system, rather than the marginal cost pricing structure it had been receiving prior to 2002. The Commission agrees with the Company that under its current contractual arrangement Nucor has elected to receive the benefit of average fuel costs, and in doing so, it also should be responsible for a share of the fixed production costs required to produce those same average fuel costs. The Commission further notes that the Nucor contract, most recently approved by the Commission in Docket No. E-22, Sub 517, no longer contains the language relieving the Company of any responsibility to provide for capacity to serve Nucor as was the case of the Nucor contract prior to 2010. As the Commission describes below, the Nucor contract provides Nucor the right to continue to receive this partially interruptible service or to work with DNCP to move to another generally available rate schedule.

Based on the same reasons that service to Nucor should not be treated as 100% interruptible in developing the North Carolina cost of service used in setting just and reasonable rates in this case, the Commission finds and concludes that it would similarly be unreasonable and inappropriate to direct DNCP to make this assumption in future cost of service study filings with the Commission, unless the contract with Nucor is significantly altered such that it supports that position.

Fuel Study

In his testimony, Nucor witness Goins asserted that use of the SWPA methodology creates a mismatch in allocating fixed production costs and variable fuel costs. He stated that because high load factor customers are allocated a disproportionate share of DNCP's fixed production costs, they should also be allocated a disproportionate share of cheaper energy costs associated with the higher cost capacity. Instead, DNCP allocated average fuel costs on the basis of class loss-adjusted energy use. In other words, higher load factor classes get the higher baseload plant costs, but not the corresponding savings from lower baseload fuel costs. Witness Goins noted that in the 1994 Fuel Study, DNCP concluded that traditional average fuel cost recovery is not symmetrical with the way the LGS class is allocated production-related cost under the SWPA method. He recommended that the Commission require DNCP to prepare and file a detailed analysis similar to the analysis undertaken in the 1994 Fuel Study.

Witness Haynes testified in opposition to witness Goins' recommendation that DNCP be required to develop a new analysis similar to the 1994 Fuel Study. He explained that all customers, including residential and large industrial, benefit when the utility's system of available generating resources is operated such that the units with the lowest possible variable cost (mostly fuel) are dispatched to serve customer loads not just in the summer and winter peak hours, but in all hours of the year. This lowers fuel expenses recovered through the fuel clause. The capability to lower fuel expenses throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours and not only during the summer and winter peak hours. If all classes of customers are effectively paying "average fuel cost," then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation.

Witness Haynes further testified that the SWPA method produces reasonable results by considering two seasonal peaks and the average demand and appropriately weighting both. DNCP's system load factor is approximately 56%, so the peak demand component is weighted at 44% in calculating the final total allocation factor. Witness Haynes stated that with this 44% weighting of the average of the winter and summer peaks and the ability of high load factor classes in North Carolina to reduce load during peak hours, such customers can reduce, and do reduce, their responsibility for fixed production costs. Witness Haynes testified that this a fair and reasonable approach to determining responsibility for fixed costs while paying average fuel. Witness Haynes therefore testified that there was no reasonable basis for the Commission to require the Company to "re-do" the 1994 Fuel Study.

Witness Haynes also testified during the hearing that DNCP has developed new industrial rate designs since 1994, such as Schedules NS and 6VP that allow high load factor classes in North Carolina to reduce load during peak hours, which has the effect of reducing these customer classes' responsibility for fixed production costs under the Company's SWPA method.

In Nucor's Brief, Nucor reiterated witness Goins' testimony that DNCP's use of SWPA creates an asymmetry in DNCP's assignment of fixed production cost responsibility and its average cost recovery of fuel costs. Witness Goins testified that because higher load factor customers are allocated a disproportionate share of DNCP's fixed production costs (including the higher cost of intermediate and baseload generating plants) under the SWPA methodology, they also should be allocated a disproportionate share of cheaper energy costs associated with the higher cost capacity. According to witness Goins, fixed production costs and variable fuel costs are not allocated symmetrically in DNCP's cost studies.

However, the Commission gives significant weight to the rebuttal testimony of DNCP witness Haynes. He testified that all customers, including residential and large industrial customers, benefit by DNCP's method of dispatching its generating resources such that the units with the lowest possible variable cost (mostly fuel) are dispatched to serve customer loads not just in the summer and winter peak hours but in all hours of the year. This lowers fuel expenses that are recovered through the fuel clause. Witness Haynes stated that the capability to lower fuel expenses throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours of the year, not solely during the summer and winter peak hours. He asserted that when all classes of customers are effectively paying "average fuel cost" determined in fuel clause proceeding, then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation.

Further, in the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that it is unnecessary at this time for the Company to re-evaluate the issues reviewed in the 1994 Fuel Study.

The Commission notes that cost responsibility based on energy (kWh) allocation has been deemed to produce just and reasonable rates in DNCP's past fuel proceedings. Further, the Commission agrees with DNCP and the other Stipulating Parties, including CIGFUR I, that it is unnecessary at this time to require DNCP to develop an analysis similar to the 1994 Fuel Study. The 1994 Fuel Study analysis preceded Nucor's arrival on to DNCP's system in 2000, Nucor's request in 2001 to transition to a more certain average fuel rate (similar to all other customers), and the subsequent 15 years of history, which informs the Commission's current understanding of DNCP's service to Nucor. In addition, with the weighting of the average of the winter and summer peaks and the ability of high load factor classes in North Carolina to reduce load during peak hours, such customers can reduce, and do reduce, their responsibility for fixed production costs. The Commission concludes based upon the record in this case that it is unreasonable and unnecessary to require DNCP to complete an analysis similar to the 1994 Fuel Study.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 42

The evidence for this finding and these conclusions is found in the Application, the testimony of Company witness Haynes, Public Staff witness Floyd, and Nucor witness Goins, and the Stipulation, and all other evidence of record.

The Application and the testimony and exhibits of Company witness Haynes explain how DNCP proposed to apportion the jurisdictional revenue requirement established using the Company's SWPA jurisdictional and class COSS amongst the customer classes. Witness Haynes' testimony and exhibits assigned the revenue requirement to specific rate schedules and then calculated the percent increase that customers on each rate schedule would experience.

In apportioning the revenue requirement among the customer classes, witness Haynes identified general and class-specific principles that the Company used to equitably distribute the base rate revenue increase, including: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional ROR; (2) for classes outside of a reasonable return index range of 0.90 and 1.10 (Parity Index Range), an effort must be made to more reasonably align the rates customers pay with their responsibility for cost, even if the index achieved after apportionment still remains outside of the Parity Index Range; (3) for purposes of apportioning the increase for the LGS and 6VP classes, the two classes are combined to treat large industrial customers within these classes in the same manner and also to recognize certain non-cost factors that support a lesser increase for large industrial customers with high load factors within these classes; and (4) for purposes of apportioning the increase to the NS Class, the Company balanced the need to equitably address certain legacy economic development rate (EDR) subsidy issues with the unique nature of the Company's electric service arrangement with its largest and most energy-intensive customer, Nucor.

Specific to the non-cost considerations that DNCP took into account in apportioning the revenue increase among the industrial customer classes, witness Haynes testified that he considered the quantity and timing of large industrial manufacturing customers' electric usage in their industrial operations, as well as factory utilization and the economic vitality of the Company's North Carolina service territory, as it relates to these industrial customers.

Witness Haynes presented an extensive history of the Company's agreement with Nucor under which DNCP provides electric service to Nucor, beginning with its approval as an EDR in 1999, and then noted DNCP's concern with the legacy rate of return (ROR) index deficiency in Nucor's contribution towards the Company's cost of service. Witness Haynes explained that the Schedule NS rate design has been beneficial to DNCP's operation of its system, as well as to the North Carolina jurisdiction and to Nucor, and stated that recognition of the partially interruptible nature of service to Nucor's arc furnace under Schedule NS and the Nucor agreement is consistent with North Carolina's policy that a utility may design different rates for different customers based upon differences in conditions of service. Witness Haynes testified that the Company is not opposed to continuing Schedule NS and the Nucor agreement in its current form (subject to Nucor electing otherwise, as discussed below), but that continuing the deficiency in the NS Class' rate of return index, and Nucor's deficient contribution to DNCP's cost of service represents an increasingly inequitable legacy benefit of the initial EDR. Witness Haynes explained that this legacy EDR benefit has extended well past the period originally contemplated in 1999, and significantly longer than the four-year term of EDRs offered to other customers. Accordingly, the Company's Application increased the NS Class ROR index from 0.44 to 0.74, which would move the NS Class two-thirds of the way towards the low end of the Parity Index Range (90% of jurisdictional ROR).

Company witness Haynes also testified that while DNCP developed its allocation and rate design proposals based upon the assumption of continued service, inclusive of the requested base rate increase, under current Schedule NS and the existing Nucor agreement, DNCP also provided notice to Nucor of its intent to terminate the existing Nucor agreement as of December 31, 2016, in order to explore whether Nucor is interested in modifying the current Nucor agreement, or alternatively, receiving service under another available DNCP rate schedule.

Public Staff witness Floyd recommended a more generalized approach to apportioning the revenue increase and designing rates, consistent with the approach and considerations that the Public Staff recommended and the Commission adopted in the Company's 2012 Rate Case. Specifically, witness Floyd recommended that the Commission look at changes to base non-fuel and base fuel revenues together and apply the following principles in spreading the impact to base non-fuel and base fuel revenues: (1) employ a +/- 10% "band of reasonableness" relative to the overall jurisdictional ROR such that, to the extent possible, the class ROR stays within this band of reasonableness following revenue assignment after the rate changes; (2) limit the combined base fuel and base non-fuel revenue increase to no more than two percentage points greater than the overall jurisdictional revenue percentage increase; and (3) minimize subsidization of customer classes by other customer classes.

Nucor witness Goins developed a revenue spread premised on the Commission's adoption of his proposed S/W CP methodology that took into account the following principles: 1) set base rates to bring the ROR for each class within plus or minus 10% (±10% constraint) of the system average ROR; 2) allow no base rate decrease for any class; and 3) limit the base rate increase for any class to no more than 1.5 times the system average increase (1.5x constraint) at a 7.80% ROR. According to Goins' analysis, using S/W CP, the proposed increase would be borne by residential and small general service customers, while other classes would receive no non-fuel base rate increase.

In rebuttal, Company witness Haynes critiqued the proposed revenue apportionment presented by Public Staff witness Floyd. He explained that while certain of witness Floyd's rate design considerations are reasonable from a policy perspective, the Company's significantly more detailed fully-adjusted approach to revenue apportionment and rate design is more reasonable and appropriate. In response to Nucor witness Goins' revenue spread proposal, witness Haynes explained that the rates of return based upon witness Goins' fully adjusted cost of service using the S/W CP method differ dramatically from the Company's results using SWPA, resulting in a significant shift in allocated responsibility for production plant, net operating income and the resulting rate of return. Specifically, he explained that allocated rate base responsibility for the residential class would be 17% higher under witness Goins' proposal and that residential rates must go up by $29.37 million in order to bring the residential class to an equal rate of return with the jurisdiction.

Witness Haynes affirmed the Company's support for its initial proposal to increase non-fuel base revenue for the NS Class two-thirds of the way to the bottom of the rate of return index Parity Index Range (0.90 to 1.10). Witness Haynes testified that DNCP's proposed revenue apportionment and rate design strikes a reasonable balance between Nucor and other customers and does not result in an unreasonable increase or "rate shock" to Nucor, as Nucor's overall rates will decrease on January 1, 2017 as a result of this case.

In the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that the stipulated overall $25.790 million increase in base non-fuel and decrease in base fuel revenues should be apportioned consistent with the rate design principles presented by Company witness Haynes in his direct and rebuttal testimony, subject to the Stipulating Parties' further agreement that: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional rate of return; (2) the 6VP class Rate of Return Index will be 1.15; and (3) the NS Class Rate of Return Index will be 0.75, which moves the NS Class two-thirds of the way towards the low end of the Parity Index Range of 0.90 and 1.10.

Based on the Stipulation and the evidence in the record, the Commission concludes that for purposes of this proceeding it is appropriate to apportion the proposed base fuel and non-fuel revenue increase approved in this Order using the methodology recommended by DNCP as modified by the Stipulation. The Commission agrees with the Public Staff, Nucor, CIGFUR I, and the Company that revenue should be distributed so that class rates of return are close to the overall jurisdictional rate of return, whenever possible. Further, the effects of rate shock and other economic and inter-class conditions should also be considered. The Commission believes that the principles employed by Company witness Haynes, as modified by the Stipulation, appropriately balance these objectives.

The Commission also recognizes that DNCP provided notice to Nucor on March 1, 2016, of the Company's intent to terminate the existing Nucor agreement as of December 31, 2016, in order to explore with Nucor whether the customer would be interested in modifying the current Nucor agreement, or alternatively, receiving service under another available DNCP rate schedule, consistent with the terms of the Nucor agreement. Based upon the record in this proceeding, no changes have been proposed to the existing terms and conditions of Schedule NS and the Commission accepts DNCP's position as undisputed that the current Schedule NS rate design and partially-interruptible service to Nucor under the Nucor agreement has been beneficial to DNCP's operation of its system, as well as to the North Carolina jurisdiction and to Nucor. Based on the entire record in this proceeding, the Commission finds and concludes that DNCP should offer Nucor service pursuant to the terms and conditions of Schedule NS and the Nucor agreement approved on March 29, 2016 in Docket No. E-22, Sub 517, as modified to reflect the authorized change in non-fuel base revenues.

Basic Customer Charge

In his testimony, Public Staff witness Floyd discussed the Company's proposed changes to the basic customer charge. He explained that the unit cost data in Item 45e is an approximation of the cost associated with each unit of service for a given utility function and provides an indicative benchmark to use when designing individual rate elements of various rate schedules. Witness Floyd compared the unit cost data in this proceeding to similar data from the 2012 Rate Case and found that those costs designated as "customer" unit costs have decreased since the 2012 Rate Case. This review suggested to him that the basic customer charges currently approved for DNCP rate schedules are greater than the "customer" designated unit costs found in Item 45e. Witness Floyd therefore recommended that none of DNCP's basic customer charges be increased.

In his rebuttal, Company witness Haynes accepted witness Floyd's recommendation with the understanding that any needed revenue apportionment to the rate schedules would be apportioned to the other charges in the rate schedules. The Stipulation provides that in developing rates based upon the class apportionment agreed to in the Stipulation, the Company agrees to recover 100% of the stipulated revenue increase through the energy and demand components of rates and not to increase the basic customer charge component of rates. The Commission finds this provision of the Stipulation to be reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 43

The evidence for this finding of fact and these conclusions is found in the Application, the testimony of DNCP witness Haynes and Public Staff witness Floyd and the Stipulation.

The Company's Application proposed new Large General Service Schedule 6L, which is designed as an additional rate option for DNCP's large industrial customers in addition to existing rate schedules 6C, 6P, 6VP, and 10.

Company witness Haynes explained that the Company developed Schedule 6L in response to recent concerns expressed by DNCP industrial customers that the current industrial Schedule 6P rate is less preferable compared to rate options available in other utilities' service territories. He presented an example showing how the design of rates can impact economic competitiveness and factory utilization and potentially may cause a hypothetical industrial customer in DNCP's North Carolina service territory to consider moving production to a facility located elsewhere in order to lower its electricity bill and thus lower its cost of production. Witness Haynes described the new Schedule 6L as a potentially more advantageous option than existing Schedule 6P for "high load factor" customers that place demands on the Company's system during most if not all hours of the day for seven days per week, and generally maintain annual load factors of approximately 80% and higher. Witness Haynes testified that the new optional Schedule 6L would be applicable to large industrial customers that have achieved a demand of at least 3,000 kW in the three billing months during the most recent 12-month period.

Witness Haynes explained that Schedule 6L is designed to recover more costs through demand charges and less through energy charges when compared to existing Rate Schedule 6P. Witness Haynes also explained that the Company has amended the Company's Rider EDR tariff to include Rate Schedule 6L as an eligible rate schedule. The Company proposed to continue to offer Rate Schedule 6P, as this schedule is appropriate for industrial and commercial customers that do not have an extensive need for electricity around the clock.

Public Staff witness Floyd recommended that the Commission approve proposed Schedule 6L, subject to one change in the tariff language to eliminate the NAICS "Manufacturing" classification as part of the qualification for this rate schedule. Witness Haynes testified in rebuttal that the Company agrees with witness Floyd's proposed change and that the specific NAICS "Manufacturing" classification eligibility limitation had been eliminated in the revised Schedule 6L included as Company Rebuttal Exhibit PBH-1, Schedule 12.

During the hearing, witness Haynes further explained that over the last 10 to 12 years, the Company has developed new rates and structures to address concerns of industrial customers. He testified that about 10 years ago, the Company developed a new Schedule 6VP rate to recognize that some large industrial high usage customers had the ability to curtail in certain hours given a price signal. He explained that proposed Schedule 6L is designed in response to the needs of certain high load factor customers and would recover more costs in the demand component. Under Schedule 6L, the average cost to a high load factor customer under Schedule 6L will be approximately 5.7 cents/kWh. Witness Haynes also testified that DNCP's industrial rates are competitive in North Carolina and significantly lower than industrial customer rates across the EEI South Atlantic region.

The Commission finds and concludes based upon all evidence in the record that Rate Schedule 6L, as presented in Company Rebuttal Exhibit PBH-1, Schedule 12 is reasonable and nondiscriminatory, and should be approved. No party objected to the Schedule 6L design, as amended by DNCP to address the Public Staff's eligibility recommendation. Further, no party disputed witness Haynes testimony during the hearing that certain of the Company's high load factor customers could benefit from the Schedule 6L design.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 44

The evidence supporting this finding of fact and these conclusions is contained in the Application, the testimony of Nucor witness Thomas, the direct and rebuttal testimony of Company witness Haynes, the Stipulation, and the entire record in this proceeding.

As described in the Application and the testimony of Company witness Haynes, DNCP develops its COSS for purposes of allocating and assigning the cost of utility service to the North Carolina jurisdiction and between the North Carolina customer classes. Since DNCP's 2012 Rate Case, the Company has evolved its cost of service model from a basic Microsoft Excel-based model to the Utilities International (UI) Model, a subscription software-supported model developed by UI. The UI Model provides the Company a staged database platform through which business units can directly input cost and other source information into the UI Model. The Company's Cost Allocation group then maintains the UI Model and uses to it perform all cost of service-related regulatory functions, including developing the COSS for North Carolina rate cases. During this proceeding, Nucor as well as other parties requested that DNCP run alternative COSS using alternative allocation methodologies to DNCP's SWPA method.

Nucor witness Thomas developed and supported a fully adjusted S/W CP COSS analysis. Witness Thomas explained that he relied upon information provided in discovery by the Company to develop Nucor's fully-adjusted S/W CP COSS analysis, but commented that the Company's transition to the UI Model has caused difficulty for Nucor and parties other than DNCP to run alternative cost of service (COS) analyses. Witness Thomas testified that DNCP held conference calls with Nucor to explain the UI Model and also made the UI Model available upon reasonable notice at the Company's offices in Richmond for in-person inspection. Witness Thomas testified that DNCP's historic use of spreadsheet-based COS models was more usable by Nucor and other parties who could run various scenarios to evaluate and test the impacts of potential changes in allocator methodologies, allocator selections, changes in recommended ratemaking adjustments, changes in revenue requirements, and other scenarios. He also explained that the UI Model uses its own programming language, and that it could take considerable time for someone unfamiliar with the software to learn how to use the software and subsequently audit the software to validate its functionality. Witness Thomas concluded that although Nucor was able to develop a fully-adjusted S/W CP COS model run, his opinion was that the UI Model presents an undue burden on parties in this proceeding and severely limits their capabilities relative to the spreadsheet-based COS models used by DNCP in prior proceedings.

In rebuttal, Company witness Haynes responded that the Company has worked diligently in this case to be supportive of the regulatory process by performing original work to run COSS requested through data requests and motions by CIGFUR I and Nucor, respectively, and also offered to make the UI Model available for inspection at the Company's office in Richmond. Witness Haynes testified that the Company plans to work with Utilities International to determine whether Utilities International can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in spreadsheet-based Excel, generally including manipulating allocation factors to prepare their own COSS in future rate case proceedings.

In the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that the Company will work with Utilities International to determine whether it can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings.

The Commission finds and concludes that the Company has worked in good faith and made reasonable efforts in this case to provide Nucor and other parties with COS-related information through the normal discovery process. The Commission finds that DNCP's commitment in the Stipulation to work with Utilities International regarding assessing reasonable additional COS functionalities that can be produced in an Excel spreadsheet-based format should be completed prior to DNCP filing its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 45

The evidence supporting this finding of fact and these conclusions is contained in the testimony and exhibits of Company witness Haynes and Public Staff witness Floyd and the Stipulation.

Public Staff witness Floyd testified that DNCP does not currently offer customers any lighting services or fixtures that use LED (light emitting diode) technologies. Schedule 26, DNCP's outdoor area and street lighting tariff, only offers mercury vapor and high pressure sodium fixtures. In response to a Public Staff data request, DNCP indicated that it was currently investigating new LED lighting services in conjunction with contract negotiations between the Company's Virginia affiliate and several Virginia municipalities. The Company's response suggested that once these negotiations were completed, and the Company had a better understanding of the LED lighting services that would be covered by those contracts, DNCP could bring new LED lighting services to the Commission for approval. Based on this information, witness Floyd recommended that the Commission require DNCP to either file a request for approval of new LED lighting services and fixtures within one year following the Commission's order in this proceeding or for DNCP to incorporate a new LED lighting services and fixtures rate option in its next general rate case, whichever comes first.

In his rebuttal, Company witness Haynes agreed with witness Floyd's recommendation. The Stipulation provides that the Company agrees to develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of the Commission's final order in this proceeding. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 46

The evidence for this finding of fact and these conclusions is found in the cross-examination of Company witness Haynes by CUCA, and the entire record before the Commission in this proceeding.

During cross-examination by CUCA, Company witness Haynes described Real Time Pricing (RTP) rates. Witness Haynes indicated that a RTP rate is no longer offered to customers in DNCP's service territory in North Carolina. He further stated that if the

Company deemed a RTP rate to be something it wanted to offer its customers, it could bring that forward.

In its post-hearing Brief, CUCA submitted that RTP rates tend to have a significant beneficial impact on high load factor customers. CUCA urged the Commission to require DNCP to propose a pilot RTP rate by July 1, 2017, and to present its RTP proposal for a ruling by the Commission by the end of 2017.

The Commission is of the opinion that an RTP rate, if offered, could provide high load factor customers significant benefits. Therefore, the Commission finds and concludes that it is reasonable to require the Company to propose a pilot or experimental RTP rate offering no later than July 1, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 47

The evidence supporting this finding of fact and these conclusions is found in the testimony and exhibits of Company witness Haynes, the cross-examination by NCSEA and Commissioner Patterson, and the agreement between DNCP and NCSEA.

Company witness Haynes sponsored Company Exhibit PBH-1, which shows DNCP currently has a combined total of 307 residential customers participating in their Time of Use (TOU) rate tariffs (258 customers for Schedule 1P and 49 customers for Schedule 1T). This represents only 0.3% of DNCP's 102,058 residential customers. This is a decrease from 2007, when 366, or 0.4% of DNCP's residential customers received service under a TOU rate tariff.

In its post-hearing Brief, NCSEA requested that the Commission require DNCP to take three actions with regard to TOU rates: (1) offer a rate comparison and potential savings calculation to residential customers who receive a smart meter; (2) in its next general rate case, include a cost of service study that investigates the impacts of making TOU rates the default rate for new residential customers; and (3) file with the Commission the results of certain TOU pilot projects approved by the Virginia SCC.

On December 13, 2016, DNCP and NCSEA filed a letter with the Commission describing the agreement reached by them on the issues raised by NCSEA regarding TOU rate offerings by DNCP. In summary, the agreement provides that DNCP will file with the Commission and serve on all parties to this docket the final annual report to the Virginia SCC regarding DNCP's Dynamic Pricing Pilot Program and Electric Vehicle Pilot Program in the Company's Virginia jurisdiction.[23] Further, DNCP states that it objects to NCSEA's recommendation that the Company perform a rate comparison for every customer who has received a smart meter and is currently served on a non-TOU residential rate, but that the

[23] Virginia Electric and Power Company's Proposed Pilot Program on Dynamic Rates, Virginia SCC Case No. PUE-2010-00135; Application of Virginia Electric and Power Company for Approval to Establish an Electric Vehicle Pilot Program pursuant to § 56-234 of the Code of Virginia, Virginia SCC Case No. PUE-2011-00014.

Company will agree to investigate improving the rate comparison process for residential customers. This investigation will include studying the feasibility of a web-based tool designed to educate customers about TOU rates and providing tools for residential customers to perform their own rate comparison. The Company agrees to discuss the findings of this investigation with NCSEA by the end of 2017.

In addition, the Company states that it objects to NCSEA's recommendation that the Company default residential customers to a TOU rate. The Company also objects to NCSEA's request that the Company develop an alternative cost of service study methodology for inclusion in a future general rate case application, as such an undertaking would be unduly burdensome. However, DNCP agrees to investigate a way to study the impacts of defaulting new residential customers onto TOU rates in a cost of service study and report to the Public Staff and NCSEA the findings of such a study by October 1, 2017. The Company will conduct this investigation using readily available information prepared for the Company's filing in Docket E-22 Sub 532. Moreover, DNCP will provide to NCSEA consolidated hourly profile information for rate schedules 1P and, separately, 1T.

Finally, the agreement states that NCSEA withdraws the recommendations in its post-hearing Brief in consideration of the Company's commitments as set forth above.

The Commission is sensitive to the impact that any residential rate increase has on utility customers in North Carolina, particularly low-income customers. The Commission wants to ensure that DNCP's customers are fully aware of existing rate tariffs that could help them reduce monthly bills. The Company's response (in part) to the NCSEA Data Request Number 2, Question Number 6, states "Customers who received smart meters were not provided with information about DNCP's TOU rate schedules." The Commission finds and concludes that DNCP should be required to provide a written summary of its TOU rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter. In addition, the Commission encourages the Company to investigate opportunities to better educate its customers on the benefits of TOU rates.[24]

In addition, the Commission finds and concludes that the terms of the agreement between DNCP and NCSEA are reasonable, are in the public interest, and should be approved

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[24] Report of the North Carolina Utilities Commission Regarding an Analysis of Rate Structures, Policies, and Measures to Promote Renewable Energy Generation and Demand Reduction in North Carolina, Docket No. E-100, Sub 116 (September 2, 2008).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 48

The evidence supporting this finding of fact and these conclusions is contained in the Application, the testimony and exhibits of Company witness Haynes and Public Staff witness Floyd and the Stipulation.

Item 39 of the Company's Form E-1 filed with the Application and the Company's supplemental direct testimony showed the changes the Company proposed to make to each section of the Terms and Conditions, Rider D-Tax Effect Recovery, Fuel Rider A, and Rider EDR. No party testified in opposition to the adoption of the proposed changes to the Terms and Conditions, and the Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Item 39 of the Company's Form E-1 filed with its supplemental direct testimony. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 49

The evidence supporting this finding of fact and these conclusions is contained in the verified Application and DNCP's Form E-1, the testimony and exhibits of Company witness Curtis and Public Staff witness McLawhorn, and the entire record in this proceeding.

Company witness Curtis provided testimony regarding DNCP's performance with regard to customer service. He testified that the Company's generating fleet has demonstrated excellent performance results. He also stated that DNCP continues to provide excellent customer service, and that the Company has improved its North Carolina System Average Interruption Duration Index (SAIDI), excluding major storms performance, by over 20% since 2007, and maintained consistent performance below 120 minutes since 2012. He noted that because of DNCP's previous infrastructure investments, the Outer Banks area continues to be one of the best performing areas across DNCP's entire service territory.

Witness Curtis also testified that the Company continues to achieve excellence in customer service by offering innovative solutions in response to customer expectations, including leveraging technology to perform quick, seamless customer transactions. He noted that DNCP customers completed more than 13 million online transactions during 2015, and that usage of electronic transactions has increased by 61% since 2012. He described the Company's promotion of social media interactions with customers, including its implementation in 2014 of an interactive map that allows customers to view current outages and see details of current outages, such as status and estimated restoration time. Witness Curtis also testified about recognition for outstanding performance that the Company's parent, Dominion Resources, Inc., had received during the past several years.

Public Staff witness McLawhorn testified that the Public Staff had reviewed service-related complaints received by the Public Staff's Consumer Services Division, the

Company's call center operation reports filed with the Commission, SAIDI and SAIFI statistics, the Company's report on new residential service installations, and complaints directly received by DNCP related to vegetation management. Based on the low number of service-related complaints and the relative level of its service metrics, witness McLawhorn found the overall quality of electric service provided by DNCP to retail customers to be adequate.

Based on the testimony of Company witness Curtis and Public Staff witness McLawhorn, the Commission finds and concludes that the overall quality of electric service provided by DNCP is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 50

The evidence supporting this finding of fact and these conclusions is contained in the Application, the direct, supplemental, and rebuttal testimony and exhibits of DNCP witnesses Hupp and Bailey, the Company's July 8, 2016 Supplemental Filing, the testimony of Public Staff witness McLawhorn, the Stipulation, and the hearing testimony. In addition the Commission relies on its April 19, 2005 Order Approving Transfer Subject to Conditions in Docket No. E-22, Sub 418 (the PJM Order), and the post-hearing exhibit filed by DNCP.

In the Application, the Company requested relief going forward from the regulatory conditions imposed in the PJM Order. The over-arching goal of the conditions in the 2005 PJM Order was stated as follows: "That Dominion's North Carolina retail ratepayers shall be held harmless from all direct and indirect effects and costs, either related to operations, quality of service, reliability, or rates, arising from its integration with PJM ...."

<u>PJM Order Condition (1)a states that:</u>

> Dominion's North Carolina retail customers shall continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law using the same ratemaking methodology as that employed by this Commission as of the time of Dominion's joining PJM notwithstanding Dominion's integration into PJM or decision to participate in any capacity or energy market administrated by PJM; that is, under no circumstances(s) or event(s) shall the costs of generation and transmission, among other things, included in Dominion's N.C. retail rates be greater than the lesser of (1) such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or (2) the marginal costs of generation and transmission supplied into or purchased from PJM;

PJM Order Condition (1)b states that:

> Dominion shall continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources

in order to meet its native load requirements before making power available for off-system sales;

PJM Order Condition (1)c states that:

Dominion shall take all reasonable and prudent actions necessary to continue to provide its NC retail customers with the same (or higher) superior level of bundled electric service as that provided prior to Dominion's integration with PJM, including, for example, reliable generation, transmission, and distribution service; and responsive customer service;

PJM Order Condition (1)d states that:

Dominion shall not include in base rates: (a) PJM administrative fees or any replacement mechanism for such fees approved by FERC[25]; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs) or auction revenue rights (ARRs) or any replacement mechanism for such cost and revenues approved by the FERC; (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service; (d) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement; or (e) any increase in transmission costs to the Company or any revenues resulting from the FERC's orders in Docket Nos. ER04-829 and ER05-6 et al. imposing the Seam Elimination Cost Adjustments (SECAs);

PJM Order Condition (1)e states that:

Dominion shall allocate sufficient FTRs, ARRs, or other revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from Dominion's North Carolina retail ratepayers through the operation of G.S. 62-133.2;

PJM Order Condition (1)f states that:

Neither PJM, Dominion nor any affiliate shall assert in any proceeding in any forum that federal law, including, but not limited to, the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were Dominion not a member of PJM) under

[25] FERC is the Federal Energy Regulatory Commission.

North Carolina law to set the rates, terms and conditions of retail electric service to Dominion's North Carolina retail ratepayers and that Dominion shall bear the full risks of any such preemption;

PJM Order Condition (2) states that:

> Dominion and PJM shall, consistent with, and to the extent not altered by, the above regulatory conditions and this Order, comply with the terms of the Joint Offer of Settlement [JOS] filed December 16, 2004.

The JOS had two signatories: PJM and Dominion. Some of its provisions ended as of December 31, 2014, but others did not. Some of the provisions were reiterated by the Commission in the PJM Order and were put in place "until further Order of the Commission." In its July 8, 2016 Supplemental Filing, Dominion reiterated that it is seeking relief from compliance with the JOS.

PJM Order Condition (3) states that:

> Dominion and PJM shall, consistent with the above additional regulatory conditions, comply with the terms of the Settlement Agreement with Progress filed December 16, 2004. Dominion and PJM shall, with regard to all of the signatories thereof, honor , and discharge Dominion's obligations pursuant to, the various VACAR[26] and other regional agreements referenced in the Settlement Agreement, including, but not limited to the VACAR Reserve Sharing Agreement, as Dominion would have been so obligated to do prior to Dominion's integration with PJM. In fulfilling this condition, Dominion and PJM shall continue to follow the practices and operating procedures around these agreements that have been customarily observed by the participants but do not necessarily exist in written form.

The "Progress Settlement Agreement" among DNCP, PJM and Progress Energy Carolinas, Inc. (now Duke Energy Progress) contained six very detailed provisions intended to ensure that commitments and practices that DNCP had made or instituted in order to assure reliability in the VACAR region during emergencies would survive, with specific tasks being agreed to by PJM.

PJM Order Condition (4) states that Dominion would continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission. The PJM Order further stated that "the conditions imposed by the Commission shall remain in effect for a period of not less than ten (10) years from the date of Dominion's integration into PJM and continuing thereafter indefinitely and until further Order of the Commission."

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[26] VACAR is a sub-region of the SERC Reliability Corporation (SERC), and covers the states of Virginia, North Carolina and South Carolina. In the Southeast, SERC implements and enforces the reliability standards that are developed by NERC and approved by FERC.

In his direct testimony, DNCP witness Hupp noted that the Commission imposed the PJM conditions for a period of not less than 10 years and indefinitely until further Commission order, and that more than 10 years have passed since DNCP integrated with PJM. Witness Hupp testified that to the best of his knowledge, since integration into PJM, DNCP has complied with all of the PJM Order conditions and has held customers harmless via the operational and financial benefits provided by DNCP's membership in PJM. Witness Hupp described the operational benefits as more reliable and efficient operations, improved outage and reserve planning, and participation in the PJM stakeholder process.

Witness Hupp also testified that in Docket No. E-22, Sub 428, the Commission ordered DNCP to perform, beginning with its next fuel case, a study of the fuel costs that would have been incurred had DNCP not joined PJM (the PJM Integration Study). Witness Hupp stated that in each of the ten PJM Integration Studies conducted from 2006 through 2015, DNCP demonstrated significant savings to customers as a result of DNCP's PJM membership. Particularly since 2009 when the Company began using the PJM Integration Study in its current form, witness Hupp testified that the studies demonstrate substantial financial savings that outweigh the costs, including administrative costs, associated with DNCP's integration into PJM.[27]

Witness Hupp testified that based on the consistently demonstrated benefits of DNCP's PJM integration since 2005, the Company should be relieved from further compliance with the PJM conditions. He explained that the Company's integration into PJM is now complete, and concerns about new and unknown aspects of joining a regional transmission organization no longer apply. Witness Hupp noted that in the Company's 2014 fuel factor proceeding the Commission recognized that due to the passage of time since the integration with PJM, one or more of the PJM conditions could be ripe for review.

Witness Hupp testified that several of the PJM conditions prohibit the Company from recovering through rates certain costs associated with PJM participation. These costs include congestion and other fuel-related costs which Condition 1(e) required DNCP to offset with Financial Transmission Rights (FTRs), Auction Revenue Rights (ARRs), and other revenues. Witness Hupp noted that in the Company's 2014 fuel case, due to this condition, the Commission disallowed recovery of $1.5 million of congestion costs that the Company believed were prudently incurred. Condition 1(d) similarly prohibits DNCP from recovering administrative costs associated with PJM membership. Witness Hupp clarified that DNCP is not asking to pass such costs on to customers without a prudence review. Instead, the Company seeks the opportunity to recover these prudently incurred costs.

In its July 8, 2016 Supplemental Filing the Company provided more specific representations regarding its ongoing commitments for its continued retail electric service in North Carolina, notwithstanding its request for relief from the PJM Order conditions.

[27] DNCP is not currently required to perform the PJM Integration Study pursuant to the Commission's final order in the Company's 2015 fuel clause adjustment proceeding, Docket No. E-22, Sub 526.

The Company also presented a detailed cost-benefit analysis of the impact of the PJM integration on customers, supported by the supplemental direct testimonies of witnesses Hupp and Bailey.

DNCP clarified in the Supplemental Filing that, while the Company is seeking relief from all of the PJM Order conditions, certain obligations to which it is subject as a North Carolina regulated electric utility exist separate and apart from the PJM conditions and will continue to apply to the Company even if the Commission grants the Company's request for relief. Furthermore, the Company is subject to some regulatory conditions that were imposed by the Commission before DNCP joined PJM, and DNCP stated that it would remain subject to all such conditions.[28] The Company clarified that it would continue to comply with the following obligations:

(1) DNCP's North Carolina retail customers will continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law notwithstanding DNCP's integration into PJM or decision to participate in any capacity or energy market administered by PJM.

(2) DNCP will continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales.

(3) DNCP will continue to take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with superior bundled retail electric service and customer service.

(4) Neither DNCP nor any of its affiliates will assert in any proceeding in any forum that federal law, including but not limited to the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were DNCP not a member of PJM) under North Carolina law to set the rates, terms, and conditions of retail electric service to DNCP's retail ratepayers, and DNCP shall bear the full risks of any such preemption.

(5) DNCP will continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission.

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[28] Those previously imposed regulatory conditions include Regulatory Conditions 30-42 to the Commission's October 18, 1999 Order Approving Code of Conduct and Amending Conditions of Merger issued in Docket No. E-22, Sub 380, which prohibited the Company from asserting federal preemption of the Commission's authority in any forum.

The Company also provided information in the Supplemental Filing regarding how the other conditions contained in the PJM Order either are moot or are otherwise covered by other agreements.

With regard to Condition (1) of the PJM Order, DNCP clarified that it is requesting relief from the portion of this Condition that requires that the costs of generation and transmission, among other things, included in DNCP's North Carolina retail rates be no greater than the lesser of such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or the marginal costs of generation and transmission supplied into or purchased from PJM. The Company reiterated that it would continue to set rates for service based on its cost of service.

With regard to Condition (2) of the PJM Order, which requires DNCP and PJM to comply with the terms of the Joint Offer of Settlement, DNCP clarified that it is seeking relief from this condition. The Company stated that Paragraphs (1) through (6) of the Joint Offer of Settlement either were subsumed within broader obligations imposed by the conditions contained in the PJM Order or were subject to sunset dates that have since passed.

The Company also explained that Paragraphs (7)(a) through (7)(c) of the Joint Offer of Settlement outline curtailment protocols that have been superseded by current PJM and North American Electric Reliability Corporation (NERC) requirements as provided for in the PJM tariff and NERC reliability standards.

With regard to Paragraph (7)(d) of the Joint Offer of Settlement, which states that "nothing in this approval of this application shall alter the Commission's authority over the application of curtailment practices to Company's retail customers," DNCP stated that any current authority held by the Commission regarding the application of curtailment practices would remain in effect even if the Commission grants the Company's request for relief from these conditions.

DNCP explained that the obligations imposed by Paragraph (8) of the Joint Offer of Settlement, which required a stakeholder process related to locational marginal pricing and settlements, have been fulfilled by PJM's actions to implement Residual Metered Load market rules, which took effect June 1, 2015.

DNCP stated that Paragraphs (9) through (11) of the Joint Offer of Settlement address obligations to which it is already subject as a North Carolina regulated electric utility and that will continue to apply to the Company even if the Commission grants the Company's request for relief from the PJM Order conditions. These obligations include the need to seek permission to build electric generation and transmission facilities in North Carolina, the requirement to comply with the Commission's integrated resource planning requirements, the requirement to promptly address reliability and service quality issues, and the requirement to follow the laws, rules and policies of the Commission for the provision of retail electric service. The Company clarified that it is not seeking authorization to cease compliance with any of these obligations.

DNCP stated that the Commission's jurisdiction over any subsequent transfer of the Company's North Carolina transmission facilities exists independent of Paragraph (12), making that provision unnecessary.

Paragraph (13) provided for the confidentiality of the discussions that resulted in the Joint Offer of Settlement. DNCP stated that due to the passage of time and the application of other agreements, this provision is no longer relevant. Even so, DNCP will continue to treat as confidential any information provided as such.

Paragraph (14) asserted that changes to the Joint Offer of Settlement required the Company's agreement. DNCP stated that, to the extent this requirement is deemed to apply, the Company was submitting a written signed request for relief from the Joint Offer of Settlement.

Paragraph (15) addressed the possibility that the Commission might not accept the Joint Offer of Settlement. DNCP stated that because the Commission had issued its Notice of Decision on March 30, 2005, in Docket No. E-22, Sub 418, Paragraph (15) is moot.

With regard to Condition (3) of the PJM Order, which pertains to the Settlement Agreement between DNCP and DEP that was filed on December 16, 2004, in Docket No. E-22, Sub 418 (Progress Settlement), DNCP clarified that it is seeking relief from this condition. DNCP represented that it had conferred with counsel for DEP, and that DEP and DNCP agreed that the obligations and commitments contained in the VACAR Reserve Sharing Agreement and other regional agreements referenced in the Progress Settlement are being met pursuant to the current, updated versions of those agreements, as well as other agreements entered into subsequent to the Company's PJM integration, including the Joint Operating Agreement between PJM and DEP most recently filed with FERC in Docket No. ER15-29-000. DEP and DNCP therefore agreed that a Commission Order relieving DNCP of the obligation to comply with the terms of the Progress Settlement would not adversely impact the legal effectiveness of the terms and conditions applicable to DNCP, PJM, and DEP under these agreements.

In his supplemental testimony, witness Hupp presented the results of the Company's detailed analysis of the full costs and benefits of PJM integration over the period of 2006-2015. He explained that the analysis compares actual cost and benefit data from the 10-year period during which DNCP has been a PJM member to a theoretical environment in which DNCP did not join PJM and instead continued to operate as a separate control area. He stated that the Company analyzed several categories of cost and benefit data from 2006 through 2015, including market energy, FTRs, ancillary services, administrative costs, market capacity, and transmission costs. Witness Hupp provided detailed descriptions of how the Company derived the data for each category, and testified that the results of the analysis for all of the categories except administrative costs showed there was a substantial economic benefit to the Company's North Carolina retail customers from its integration into PJM. He noted that the Company did not attempt to speculate as to the comparable administrative costs that the Company would have incurred as a separate control area, and that the administrative costs associated with PJM membership were significantly more than offset by the economic benefits realized in each of the other analyzed categories.

In his supplemental testimony, DNCP witness Bailey testified in support of witness Hupp's discussion of the transmission-related costs and benefits associated with DNCP's PJM participation over the 2006-2015 period. Witness Bailey stated that the cost-benefit analysis assumes that the same transmission projects would be developed whether or not the Company was a member of PJM or a separate control area. In support of this assumption, witness Bailey explained that projects developed pursuant to the PJM Regional Transmission Expansion Plan (RTEP) process include "baseline," "supplemental," and "network" projects. He stated that the RTEP process identifies baseline projects for development that are needed to comply with, for example, mandatory NERC reliability standards and, as such, those projects would likely have been developed whether or not the Company was a PJM member. He also stated that the vast majority of supplemental projects, which DNCP develops in response to specific customer needs are based on the need to support load growth or additions that also would be present whether or not DNCP was in PJM. Finally, witness Bailey testified that since network projects are developed in response to specific generation, merchant transmission, or long-term firm transmission service requests and are paid for by the requesting interconnection entity, those projects were not reflected in the cost/benefit analysis.

In his direct testimony, Public Staff witness McLawhorn summarized the PJM Order conditions and the Company's direct and supplemental filings. He stated that based on the Public Staff's review of DNCP's cost benefit analysis and its consultation with an outside consultant, Christensen Associates Energy Consulting, the Public Staff believes that DNCP's study methodology was generally reasonable and that the available data are verifiable. Witness McLawhorn noted that while the Public Staff believes that DNCP's quantification of the net benefits associated with its PJM membership may be overstated, the Public Staff agrees that there has been a net economic benefit to DNCP ratepayers from 2006-2015 as a result of the integration. He also stated that, based on the most current projections of natural gas prices, capacity prices, and other PJM-related costs, the Public Staff expects the net benefits of DNCP's membership in PJM to continue, driven mainly by fuel cost savings. Witness McLawhorn concluded that, based on its review of the cost/benefit analysis and the clarifications made in the Supplemental Filing, the Public Staff believes that the benefits of DNCP's integration into PJM exceed the costs, and that these benefits can be expected to continue under current forecasts, even with inclusion of the costs previously excluded by Conditions 1(d) and (e). He noted further that, as to Conditions 1(a)-(c), (f), 2, 3 and 4, the Public Staff believes that the clarifications made by the Company in the Supplemental Filing are appropriate and sufficient to support relief from those conditions, with the exception of the filing requirements in Paragraphs 5 and 6 of the JOS. These two paragraphs require the filing of information related to congestion costs and transmission constraints, revenues associated with FTRs and ARRs, a summary of DNCP's monthly capacity and energy transactions with the PJM markets, and locational marginal pricing information.

Witness McLawhorn recommended that, to the extent that DNCP does not already file the information required by these Paragraphs in its annual fuel rider application, DNCP should be required to file that information in the same or substantially similar detail as the filing made by the Company on August 31, 2016, with its annual fuel proceeding. Otherwise, he stated that the Public Staff does not oppose the Company's request for relief from the PJM conditions as clarified by DNCP in the Supplemental Filing. Witness McLawhorn recommended that the Commission's order granting the Company's request for relief from these conditions specifically address the subject matter of Conditions 1(a)-(c), (f), 2, 3, and 4 and incorporate the clarifications made by the Company in its Supplemental Filing. Finally, witness McLawhorn testified that the Public Staff believes that the Commission will be able to protect North Carolina ratepayers should DNCP's participation in PJM prove not to be beneficial in the future. He stated that the Commission has full authority to ensure that DNCP complies with the representations and commitments made in the Supplemental Filing with respect to obligations that exist separate and apart from the PJM conditions, including regulatory conditions previously imposed by the Commission. With regard to the additional PJM costs that DNCP may seek to recover from ratepayers upon being relieved of the PJM conditions, that is, costs excluded from rates under Conditions 1(d) and (e), such costs would be recoverable only when they are shown to have been reasonable and prudently incurred.

In his rebuttal testimony, witness Hupp testified that the Company does not oppose witness McLawhorn's recommendation that the Company continue to file the information required by Paragraph 5 of the JOS in conjunction with its annual fuel cases. He also stated the Company's understanding that the independent market monitor for PJM will continue to file the information required by Paragraph 6 of the JOS. [29]

Section XIV of the Stipulation provides that the Company is relieved from further compliance with the PJM Order conditions, subject to: (1) the Company's clarifications regarding its ongoing commitments as contained in its July 8, 2016 Supplemental Filing in this docket; (2) the Company's continuing to file with its annual fuel clause adjustment filing the information required by Paragraph 5 of the JOS; and (3) the IMM for PJM continuing to annually file the information required by Paragraph 6 of the JOS. Section XIV also provides that the Company will comply with the representations and commitments made in the Supplemental Filing with respect to obligations that exist separate and apart from the PJM Conditions.

[29] The Commission notes that on November 16, 2016, counsel for Monitoring Analytics, LLC (PJM's independent market monitor) filed a letter in this docket stating that "should the Commission accept the Stipulation, Monitoring Analytics, LLC, acting as the [IMM] for PJM will continue to annually file ... the information specified in Paragraph 6 of the Joint Offer of Settlement ... filed in ... 2004."

No other party submitted evidence regarding the Company's request for relief from the PJM conditions.

At the hearing, witness Hupp testified in response to Commission questions that the Company would not object to the Commission directing DNCP to continue to comply with the obligations it agreed to continue to meet in the Supplemental Filing notwithstanding the Company's request for relief from the conditions related to those obligations. On redirect, witness Hupp agreed that the Company took the approach of requesting relief from all the conditions while committing to continue compliance with its independent and ongoing obligations as a North Carolina retail electric utility as that would allow for a "clean slate" going forward. Witness Hupp noted that the forward-looking evaluation of costs and benefits that the Public Staff conducted indicated that the benefits and savings of PJM integration would continue. He stated on redirect that it is no longer valid to compare the circumstances before the Company joined PJM to those after integration, given the length of time that DNCP has been a PJM member and the benefits it has shown from integration. He also confirmed that regardless of whether it is a PJM member, the Company always seeks to provide service at least cost and to economically dispatch its fleet.

Witness Hupp confirmed in response to Commission questioning that certain decisions that the Company makes with regard to operating within PJM, such as whether to bid into the markets or buy market energy, would be subject to prudence review. He agreed that, with regard to other costs that PJM controls, such as administrative costs, the Company participates in various committees at PJM and could protest any inappropriate costs, and that either DNCP or the IMM could complain to FERC if there are disagreements with PJM. He also confirmed that in the Company's 2014 fuel case, even though DNCP's fuel costs as a PJM member were lower than they would have been had DNCP operated as a separate control area, FTR and ARR revenues were used to offset congestion costs that the Company incurred in order to gain the benefits of PJM participation. He confirmed that over $1 million from those FTR and ARR revenues were offset against those costs, which he viewed as one way in which the continuance of the conditions would be unfair.

On redirect, witness Hupp confirmed that the cost-benefit analysis included in the Company's Supplemental Filing was conducted at the request of the Public Staff, and that it built on the PJM Integration Studies that DNCP conducted as part of its fuel cases from 2006-2015. He agreed that in addition to the market energy costs addressed in those fuel case studies, the cost-benefit analysis also evaluated FTRs, capacity, transmission costs, ancillary services, and administrative costs, and that the overall result showed a substantial financial benefit to the North Carolina retail jurisdiction from DNCP joining PJM. He clarified that the reporting requirements that witness McLawhorn has asked to be continued were part of the JOS with PJM, and that DNCP is requesting relief from all of the conditions in the other settlement agreement in the PJM case, which was with Progress Energy Carolinas, Inc., now Duke Energy Progress, LLC (DEP). He testified that the Company conferred with DEP on all of the conditions contained in that settlement agreement and that DNCP and DEP agreed that all of them are being addressed now under other agreements. Finally, witness Hupp testified on redirect that the Company has for the past 11 years not been allowed to recover significant costs of doing business due to the PJM Order conditions. He testified that the Company is now seeking to be allowed the chance to recover all of the costs of providing reliable and least cost service to its customers.

In response to Commission questions, witness McLawhorn testified to his recommendation that the Company continue to file the information required by Paragraphs 5 and 6 of the JOS. He agreed that it would be sufficient for the PJM IMM to resume filing the Paragraph 6 information as it had done previously.

The post-hearing exhibit filed by DNCP and the Public Staff shows that, as stated in witness Hupp's testimony, all of the conditions imposed by the PJM Order are now either no longer applicable or are being met under subsequent and currently effective agreements, with the exception of the ongoing reporting requirements agreed to in the Stipulation. The exhibit also noted PJM's confirmation that all of the conditions are now covered elsewhere or no longer apply.

The Commission finds the testimony of Public Staff witness McLawhorn persuasive. He concluded that DNCP's cost-benefit analysis methodology and assumptions were reasonable, and that even if the quantification was overstated, there has been a net economic benefit to DNCP's customers from PJM membership. Witness McLawhorn also stated, based on the most current projections of natural gas prices, capacity prices and other PJM-related costs, the Public Staff expects the net economic benefits of DNCP's membership in PJM to continue. The Commission agrees with witness McLawhorn that it has full authority to ensure DNCP's compliance with the representations the Company made in the Supplemental Filing, and that any additional PJM-related costs that the Company seeks to recover will only be recoverable if the Company shows them to have been reasonable and prudently incurred.

The evidence presented in this case demonstrates that DNCP's integration into PJM has benefited its customers, and that those benefits can be expected to continue even if the Commission relieves the Company from compliance with most of the PJM Order conditions. Going forward and as clarified at the hearing and in witness McLawhorn's testimony, DNCP will be required to show that costs incurred with respect to PJM membership are reasonable and were prudently incurred, just as with any other costs for which the Company seeks recovery. The Commission fully expects Dominion to use its voice in various PJM committees at PJM to protest any inappropriate PJM-related costs, to complain to FERC if there are irreconcilable disagreements with PJM adversely affecting its North Carolina ratepayers, and to communicate any such concerns to the Commission and the Public Staff. Therefore, the Commission concludes that based on all of the evidence presented, it is appropriate to grant the Company's request for relief from most, but not all, of the conditions imposed by the PJM order.

The Company shall continue to comply, or shall compel PJM's independent market monitor to comply, with the reporting obligations established in Paragraphs 5 and 6 of the JOS and as provided at Section XIV of the Stipulation. The Company shall also continue to meet the five commitments that it agreed to be subject to as a North Carolina regulated retail electric utility and as it stated in its Supplemental Filing. Finally, the Company shall make a compliance filing in this docket within 30 days of the issuance of this Order, which filing shall consist of a comprehensive Code of Conduct that shall include all of the ongoing obligations and commitments to which the Company agrees to be bound, consistent with its representations, the Stipulation, and this Order. This filing shall include conditions that predate the PJM Order. The Public Staff is requested to review the filing and provide comments to the Commission within 30 days.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

The evidence supporting this finding of fact and these conclusions is contained in the testimony and exhibits of the Company and Public Staff, and in the Stipulation.

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations among DNCP, the Public Staff, and CIGFUR I. Comparing the Stipulation to DNCP's Application, and considering the direct testimony of the Public Staff witnesses, the Commission observes that there are provisions of the Stipulation that are more important to DNCP, and, likewise, there are provisions that are more important to the Public Staff. For example, DNCP is intent on obtaining deferral of the post-in-service costs of the Brunswick County and Warren County CC generating facilities, as well as deferral of the Chesapeake Energy Center impairment and closure costs. Indeed, the depth of DNCP's commitment to obtain deferral of the Warren County CC costs is evident from the fact that DNCP filed for reconsideration of the Commission's March 29, 2016 Order denying deferral of those costs. On the other hand, the Public Staff is intent on limiting DNCP's Marketing Percentage for the fuel cost of purchase power to 78%, substantially lower than the 100% sought by DNCP. Further, the Public Staff is focused on resisting any increase in the basic facilities charge component of DNCP's rates. Nonetheless, working from different starting points and different perspectives, the Stipulating Parties were able to find common ground and achieve a balanced settlement.

In addition, the Commission notes that the Stipulation provides customer benefits that are beyond what the Commission has the authority to require of DNCP. These include the $400,000 shareholder contribution by DNCP to the EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina service territory; DNCP's withdrawal of its request for recovery of the site separation costs associated with the proposed North Anna 3 nuclear plant; and DNCP's accelerated refund of its fuel cost over-recovery through Rider A1.

The result is that the Stipulation strikes a fair balance between the interests of DNCP and its customers. As discussed above, the Commission has fully evaluated the provisions of the Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. The provisions of the Stipulation strike the appropriate balance between the interests of DNCP's customers in receiving safe, adequate, and reliable electric service at the lowest possible rates, and the interests of DNCP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the provisions of the Stipulation are just and reasonable under the requirements of the Public Utilities Act. Therefore, the Commission approves the Stipulation in its entirety. In addition, the Commission finds and concludes that the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

The evidence for this finding of fact and these conclusions is contained in the Application, the testimony and exhibits of the DNCP witnesses and the Public Staff witnesses, the Stipulation, and the record as a whole.

Pursuant to G.S. 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See G.S. 62-133(b). DNCP's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DNCP's individual customers, as well as to the communities and businesses served by DNCP. DNCP presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

For example, DNCP witness Curtis testified that during the last three years the Company invested $2.3 billion to bring online a total of 2,700 MW of new generation. Witness Curtis stated that this new generation is cleaner and more highly-efficient combined cycle generating capacity that has the potential to create substantial fuel savings due to very favorable current natural gas prices. Witness Curtis cited in particular the operation of the Warren County CC since December 2014, and stated that this facility has created system-wide fuel savings of approximately $65.9 million when compared to wholesale market power purchases. In addition, he stated that the Brunswick County CC is expected to produce similar fuel savings and operational benefits.

Witness Curtis further testified that DNCP has spent approximately $170 million on transmission improvements in North Carolina during the last three years. He stated that these improvements support improved reliability of the transmission system and local economic growth. He also testified that the Company plans to invest an additional $243 million in transmission improvements in North Carolina from 2016 through 2019.

In addition, witness Curtis testified that DNCP has invested over $102 million in its distribution system in North Carolina during the last three years. He stated that these investments balance the need for reliable service with prudent spending.

Witness Curtis also testified regarding the impact of current and proposed environmental regulations on the Company's operations. He stated that during the last decade electric utilities have been required to address compliance with a suite of new environmental standards adopted by the United States Environmental Protection Agency (EPA). He testified that compliance with these standards has had a direct impact on DNCP's operation of its coal-fired generating plants, citing as an example the EPA's Mercury Air Toxics Standards Rule (MATS). Witness Curtis stated that the cost of complying with MATS was a primary driver in the Company's decision to retire over 900 MW of coal-fired generating capacity. He also discussed the impact of the EPA's CCR Final Rule.

Moreover, witness Curtis testified that DNCP has invested approximately $296 million since 2014 to increase security at its transmission substations and at other critical points in its infrastructure. Further, he stated that the Company plans to invest an additional $260 million for such purposes between 2016 and 2018.

In addition, Company witness Mitchell described the 2013 conversion of the Altavista, Hopewell and Southamption Power Stations from coal-burning facilities to renewable biomass-fueled generation facilities.

These are representative examples of the capital investments that have been made and are planned to be made by DNCP in order to continue providing safe, reliable and efficient electric service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DNCP's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DNCP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DNCP, the Public Staff, and CIGFUR I is hereby approved in its entirety.

2. That DNCP shall be allowed to increase its rates and charges effective for service rendered on and after January 1, 2017, so as to produce an increase in gross annual revenue for its North Carolina retail operations of $25,790,000, consisting of an increase of $34,732,000 in base non-fuel revenues, and a decrease of $8,942,000 in base fuel revenues.

3. That the proper aggregate base fuel factor for this proceeding is 2.070¢/kWh, excluding regulatory fee, and 2.073 ¢/kWh, including regulatory fee. The Company shall replace the voltage-differentiated base fuel factors approved in Docket No. E-22, Sub 479, with the following voltage-differentiated base fuel factors, including gross receipts tax, effective January 1, 2017:

Customer Class	Base Fuel Factor
Residential	2.095 ¢/kWh
SGS & PA	2.093 ¢/kWh
LGS	2.079 ¢/kWh
NS	2.014 ¢/kWh
6VP	2.043 ¢/kWh
Outdoor Lighting	2.095 ¢/kWh
Traffic	2.095 ¢/kWh

4. That the jurisdictional and class cost allocation, rate designs, rate schedules, and service regulations proposed by the Company, except as specifically addressed in this Order, are approved and shall be implemented. As discussed in this Order, DNCP shall continue to offer Nucor service pursuant to the terms and conditions of Schedule NS and the Nucor agreement approved on March 29, 2016 in Docket No. E-22, Sub 517, as modified to reflect the authorized change in non-fuel base revenues.

5. That DNCP shall implement Rider EDIT as shown on Settlement Exhibit IV via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11. Prior to the tenth month from the effective date of the Year 2 rider, the Company shall provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of Year 2. If there is a deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff shall work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

6. That as soon as practicable after the date of this Order, DNCP shall file for Commission approval five copies of rate schedules designed to comply with the rate design approved in this Order accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the rate schedules to be approved herein and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.[30]

[30] If necessary, the Commission will address in a subsequent order any refund due based on the any differences in the rates approved in this Order and the Company's temporary rates implemented on November 1, 2016.

7. That as soon as practicable after the issuance of the last Commission Order in DNCP's four pending rate-related proceedings, which are this proceeding, the Sub 534 fuel charge adjustment proceeding, the Sub 535 renewable energy and energy efficiency portfolio standard (REPS) cost recovery proceeding, and the Sub 536 demand-side management proceeding, DNCP shall file a consolidated proposed customer notice addressing the rate changes associated with the non-fuel base and base fuel rate changes approved in this proceeding (Sub 532), the Fuel Rider B in the Sub 534 proceeding, the Rider RP and RPE rate changes in Sub 535, and the demand-side management Rider C and Rider CE rate changes in Sub 536. Such notice shall include the effect of each rate-related proceeding on a residential customer using 1,000 kWh and the combined effect of all four rate-related proceedings on a residential customer using 1,000 kWh. Upon approval by the Commission, DNCP shall notify its North Carolina retail customers of the foregoing rate adjustments by including the approved notice as a bill insert with customer bills rendered during the next regular scheduled billing cycle.

8. That the Company may use levelization accounting for nuclear refueling costs as described in this Order.

9. That the Company shall continue to annually file a cost of service study with the Commission using the Summer/Winter Peak and Average methodology.

10. That the Company shall comply with Commission Rule R8-27(a)(2) regarding future establishments of regulatory assets and liabilities as provided at Section XI.D of the Stipulation.

11. That the Company shall file with the Commission, on the same date it files its quarterly ES-1 report, a report detailing: (1) the CCR deferrals recorded in the reporting period; and (2) regulatory accounting entries pursuant to the August 6, 2004 Order in Docket No. E-22, Sub 420, with regard to any costs other than nuclear decommissioning costs or CCR costs recorded in the reporting period.

12. That the Company shall notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure.

13. That with the exception of the commitments in DNCP's July 8, 2016 Supplemental Filing, the Stipulation, and Commission-imposed conditions that predate DNCP's integration into PJM, DNCP is hereby relieved of the PJM Order conditions. Within 30 days of this Order the Company shall file in this docket a compliance filing which shall consist of a comprehensive Code of Conduct that includes all of these ongoing conditions and obligations, including those that predate the PJM Order. The Public Staff is requested to review the Code of Conduct and provide comments within 30 days of DNCP's compliance filing.

14. That the Company shall continue to file the information referenced in Paragraph 5 of the Joint Offer of Settlement dated December 16, 2004, between DNCP and PJM with its annual fuel clause adjustment filing.

15. That prior to DNCP filing its next general rate case, the Company shall work with Utilities International to determine whether it can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings.

16. That the Company shall develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of this Order.

17. That the Company shall make a one-time shareholder contribution to its EnergyShare program of $400,000, over and above its usual contribution, for the benefit of its North Carolina customers by January 31, 2017.

18. That if DNCP continues to recover any deferred costs for a longer period of time than the amortization period approved by the Commission for those deferred costs, DNCP shall not record those deferred costs in its general revenue accounts, but, rather, shall continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for such deferred costs until the Company's next general rate case.

19. That the Company shall file with the Commission a proposed pilot or experimental Real Time Pricing rate offering no later than July 1, 2017.

20. That DNCP shall provide a written summary of its TOU rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter.

21. That the agreement between DNCP and NCSEA regarding DNCP's TOU rate offerings shall be, and is hereby, approved.

22. That the Company shall file an Average and Excess cost allocation methodology in its next North Carolina general rate case, in addition to the cost allocation methodology proposed by the Company.

ISSUED BY ORDER OF THE COMMISSION.

This the 22nd of December, 2016.

NORTH CAROLINA UTILITIES COMMISSION

Linnetta Threatt

Linnetta Threatt, Acting Deputy Clerk

Public Comment by:
Jeanene Smith

THE UNKNOWN CITIZEN
BY W. H. AUDEN

(To JS/07 M 378
This Marble Monument
Is Erected by the State)

He was found by the Bureau of Statistics to be
One against whom there was no official complaint,
And all the reports on his conduct agree
That, in the modern sense of an old-fashioned word, he was a saint,
For in everything he did he served the Greater Community.
Except for the War till the day he retired
He worked in a factory and never got fired,
But satisfied his employers, Fudge Motors Inc.
Yet he wasn't a scab or odd in his views,
For his Union reports that he paid his dues,
(Our report on his Union shows it was sound)
And our Social Psychology workers found
That he was popular with his mates and liked a drink.
The Press are convinced that he bought a paper every day
And that his reactions to advertisements were normal in every way.
Policies taken out in his name prove that he was fully insured,
And his Health-card shows he was once in a hospital but left it cured.
Both Producers Research and High-Grade Living declare
He was fully sensible to the advantages of the Installment Plan
And had everything necessary to the Modern Man,
A phonograph, a radio, a car and a frigidaire.
Our researchers into Public Opinion are content
That he held the proper opinions for the time of year;
When there was peace, he was for peace: when there was war, he went.
He was married and added five children to the population,
Which our Eugenist says was the right number for a parent of his generation.
And our teachers report that he never interfered with their education.
Was he free? Was he happy? The question is absurd:
Had anything been wrong, we should certainly have heard.

From *Another Time* by W. H. Auden.

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