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 6, 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 6, 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 6, 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_06Mar18_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.

Gwen R. Pinson

Gwen R. Pinson
Executive Director
Public Service Commission of Kentucky

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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

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 6, 2018. Hearing Log, Witness List, and Exhibit List are included with the recording on March 6, 2018.

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

3. The digital recording accurately and correctly depicts the Hearing of March 6, 2018.

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the Hearing of March 6, 2018, and the time at which each occurred.

Signed this 12th day of March, 2018.

Pamela Hughes

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

Judge: Bob Cicero; Talina Mathews; Michael Schmitt

Witness: Lisa Bellucci; Cynthia S. Lee; David Doss; James Henning; Jeffrey T. Kopp; Tammy Jett; Joseph Miller; Roger Morin Ph.D; Benjamin Pasti; Robert H. Pratt; Donald Schneider; Jeffrey Setser; Thomas Silinski; John Spanos; John Swez; John Verderame; Sasha Weintraub

Clerk: Pam Hughes

Date:	Type:	Location:	Department:
3/6/2018	General Rates	Hearing Room 1	Hearing Room 1 (HR 1)

Event Time	Log Event	
8:18:23 AM	Session Started	
8:18:25 AM	Session Paused	
9:01:08 AM	Session Resumed	
9:01:10 AM	Chairman Schmitt prelimanary remarks	
	Note: Hughes, Pam	Intro of Comm Mathews
9:01:40 AM	Case No. 2017-00321 Duke Energy Kentucky	
9:02:17 AM	Chairman goes over all parties	
	Note: Hughes, Pam	Duke Energy Kentucky, Inc.; Attorney General of Kentucky; Kentucky Industrial Utiltiy Customers, Inc.; Kroger Company; Kentucky School Boards Association; and Northern Kentucky University
9:02:32 AM	Introductions of Counsel	
	Note: Hughes, Pam	PSC - Quang Nguyen, Jenny Sanders, Attorney General - Larry Cook, Kent Chandler and Justin McNiel. KIUC- Mike Kurtz and Jody Cohn. Kroger Co. - Kurt Boehm. NKU - Dennis Howard. KSBA - Matt Malone
9:02:39 AM	Camera Lock PTZ Activated	
9:02:56 AM	Camera Lock Deactivated	
9:02:58 AM	Camera Lock PTZ Activated	
9:03:11 AM	Camera Lock Deactivated	
9:03:13 AM	Camera Lock PTZ Activated	
9:04:01 AM	Camera Lock Deactivated	
9:04:09 AM	Public Notice has been filed	
9:04:18 AM	No Public Comments	
9:04:48 AM	Chairman remarks about public meeting in Florence and some comments in writing in the record.	
9:05:23 AM	Outstanding motions	
	Note: Hughes, Pam	Confidentiality motions by Duke will be ruled on at a later date.
	Note: Hughes, Pam	KSBA to correct direct testimony of Roger Willhite, Duke to correct Rebutttal testimony of William Wathan Jr. Sustained
9:06:37 AM	Chairman remarks that requests be made that several witnesses by allowed to testify on different dates.	
9:08:50 AM	Camera Lock PTZ Activated	
9:09:02 AM	Camera Lock Deactivated	
9:09:28 AM	Camera Lock PTZ Activated	
9:09:40 AM	Camera Lock Deactivated	
9:09:45 AM	Camera Lock PTZ Activated	
9:10:05 AM	Camera Lock Deactivated	
9:10:56 AM	No other outstanding matters	
9:11:50 AM	Atty D'Aszenzo calls James Henning to the stand	
	Note: Hughes, Pam	Sworn in by Chairman

9:13:19 AM	AG-Cook cross exam of Witness Henning	
	Note: Hughes, Pam	Regarding Page 12 of his direct testimony. Line 9; JD Power residential satisfactory study. Regarding what Fast track is and if they are specific to Duke Kentucky. Copies of study, Ky specific data for transactions is on page 3 of 24 of JPH-3, page 4, 5 and on.
9:17:19 AM	AG-Cook cross exam of Witness Henning	
	Note: Hughes, Pam	Direct testimony page 17. Atty Chandler hands out papers for witness to be cross examined about.
	Note: Hughes, Pam	Going to take 10 minute break so that Counsel for Duke can look over material.
9:18:58 AM	Break	
9:19:11 AM	Session Paused	
9:30:08 AM	Session Resumed	
9:30:09 AM	Chairman states that Counsel has reviewed papers	
	Note: Hughes, Pam	This info was not provided before hearing when a total list was asked for.
	Note: Hughes, Pam	Atty Chandler states that these were not to be used until recently.
	Note: Hughes, Pam	Atty Cook remarks about confidential not being in there.
9:31:44 AM	Camera Lock PTZ Activated	
9:33:12 AM	AG-Cook cross exam of Witness Henning	
	Note: Hughes, Pam	Has merger resulted in any synergies or monetary rate savings for rate payers.
	Note: Hughes, Pam	Page 5 of this handout document. Article 5, other provisions. First paragraph, witness reads this into the record.
	Note: Hughes, Pam	Direct testimony page 17. Line 9, Merger with Progress Energy. A handout is document, letter from Frost, Brown, Todd 2011-00124. Dated June 19, 2017.
9:33:20 AM	Camera Lock Deactivated	
9:33:58 AM	Camera Lock PTZ Activated	
9:34:28 AM	Camera Lock Deactivated	
9:35:24 AM	Atty D'Ascenzo objects	
	Note: Hughes, Pam	Overruled
9:37:53 AM	AG-Cook cross exam of Witness Henning	
	Note: Hughes, Pam	Regarding the synergies and rate savings for Duke rate payers. Don Wathan to better address.
9:38:38 AM	AG-Cook cross exam of Witness Henning	
	Note: Hughes, Pam	Page 90 of same document. Change the way Duke KY calculates interest expense for use of excess borrowed short term funds. Defers to Witness Doss.
	Note: Hughes, Pam	Regarding page 70 of same document. Cost allocation manual. Defers to Witness Setser. Page 89 of same document- Money pool transactions. Last paragraph, excess interest charges. Was this charged to rate payers. Defers to Witness Doss.
	Note: Hughes, Pam	Handout stamped by Commisssion of June 20, 2017. 2nd page on bottom. Refers to Affiliate Management audit - page 15. Defers to Witness Wathan
9:44:41 AM	AG-Cook cross exam of Witness Henning	
	Note: Hughes, Pam	Referring to direct testimony. Top of page; page 5 and 6, from lines 5 - 23, and to line 2 on next page. Witness reads this into the record.
	Note: Hughes, Pam	Network transmission service costs and PJM costs. When did Duke KY become PJM member?
	Note: Hughes, Pam	Duke customer system to be updated to a state of the art customer system on all of Duke affiliates. Defers to another witness.

9:53:10 AM	AG cross exam of Witness Henning	
	Note: Hughes, Pam	Referring to expand costs to be recovered - Rider PSM.
	Note: Hughes, Pam	Referring paying PJM costs without having to come in for a rate case since 2005.
9:54:47 AM	Atty Samford asks question to AG	
9:55:06 AM	AG-Cook cross exam of Witness Henning	
	Note: Hughes, Pam	Refers back to costs put in Rider and names them. Specific components deferred to Witness Swez or Verderame. Components of shared costs of new Rider PSM.
	Note: Hughes, Pam	Referring to net costs in Rider PSM. Cost versus profits. 90/10 basis
9:58:19 AM	Atty Howard cross exam of Witness Henning	
	Note: Hughes, Pam	Referring to the costs of PSM mechanism and what percentages go where. The one million dollars going to customers and revenues. Refers to if costs outweigh the savings and the first 1 million dollars going to rate payers. would not be available.
10:01:20 AM	Atty Malone cross exam of Witness Henning	
	Note: Hughes, Pam	3 components of this. Defers to another witness.
	Note: Hughes, Pam	Referring to KSBA statute. Witness not aware.
10:02:30 AM	Atty Kurtz cross exam of Witness Henning	
	Note: Hughes, Pam	Kiuc filed complaint against Duke because of the Tax Reform Act. Non-unaminous agreement with the Commission.
	Note: Hughes, Pam	Referring to Duke's rebuttal that 100% of electric savings would go back to rate payers. Sarah Lawler testimony.
	Note: Hughes, Pam	Referring to Duke Ky not having rate increase in a number of years.
10:03:33 AM	Atty D'Ascenzo objects.	
	Note: Hughes, Pam	Overruled
10:03:51 AM	AG objects to question	
	Note: Hughes, Pam	Overruled
10:06:15 AM	Atty Kurtz cross exam of Witness Henning	
	Note: Hughes, Pam	Refers to this being a future test year case. Does low-growth and customer additions increase Duke's revenue to keep them from seeking rate increase.
	Note: Hughes, Pam	Major base load generation is East Bend in Boone, County. 100% owned. Paid approximately 12 million dollars - 190 MW
	Note: Hughes, Pam	Regarding amazon expansion and they will be customer of Duke.
10:09:33 AM	Atty Nguyen cross exam of Witness Henning	
	Note: Hughes, Pam	Rider PSM - expansion of revenues and costs. Net revenue or net costs. Defers to Verderame or Swez
10:10:30 AM	Atty Nguyen cross exam of Witness Henning	
	Note: Hughes, Pam	Rider DCI - He has overall responsibility to get these approved. Proposal for Rider DCI and framework to get approval. Business justification in order for him to give stamp of approval to include this in this case. Identifying reliability issues and recovering costs.
	Note: Hughes, Pam	Were their reliabilty concerns identified in developing framework for Rider DCI that would trigger the need for this Rider to recover and specific projects.
	Note: Hughes, Pam	Refers to testimony on customer surveys. JD Power survey on page 12. Line 16 - 20. 6 performance areas, witness reads these into the record. Weighted differently. Exhibit JPH-1 shows the breakdown.
	Note: Hughes, Pam	Page 13, lines 2 - 6, direct testimony.
10:18:31 AM	Atty Nguyen cross exam of Witness Henning	
	Note: Hughes, Pam	Page 14, lines 12-16. 4 measures key processes on fast track survey. Independent scores

	Note: Hughes, Pam	Mitigation of costs through the Rider. Capitol investments
	Note: Hughes, Pam	Regarding the Fast track survey. Page 13, line 22 and ending on page 14, line 2.
	Note: Hughes, Pam	Page 15, lines 1-3. 74% of Duke customers are highly satisfied with outages and restoration they experience.
10:24:58 AM	Atty D'Ascenzo re-direct of Witness Henning	
	Note: Hughes, Pam	Refers back to handout from AG. Document 2015 affiliate mangement audit 2011-00124. Merger between Duke And Progress Energy in 2012.
	Note: Hughes, Pam	Test year for this proceding runs though March 2019.
10:26:52 AM	Atty D'Ascenzo re-direct of Witness Henning	
	Note: Hughes, Pam	Regarding larger handout, page 89. Money pool transaction. Reads first sentence under findings 57. When did these transactions occur- calendar year of 2015.
	Note: Hughes, Pam	Refers to document of AG- Joint stipulation agreement. Witness not familiar with this. Regarding settlement of merger between Duke and Progress
10:29:20 AM	Atty D'Ascenzo re-direct of Witness Henning	
	Note: Hughes, Pam	Regarding companies proposal for Rider DCI. Tracking mechanisms in Kentucky riders are in effect. Both have produced benefits for customers.
10:30:48 AM	AG Larry Cook wants to admit some materials into the record	
10:31:31 AM	Atty Samford objects to this one document	
	Note: Hughes, Pam	Sustained.
10:32:20 AM	AG admits exhibit 1 as the audit report dated 6-20-17	
	Note: Hughes, Pam	Cover Ltr dated June 20, 2017 with the 2015Affiliate Management Audit Final Report Of Duke Energy Kentucky. Case No. 2011-00124 Final Report
10:32:56 AM	Witness excused	
10:33:23 AM	break	
10:33:29 AM	Session Paused	
10:46:40 AM	Session Resumed	
10:46:41 AM	Atty D'Ascenzo calls Witness Kopp	
	Note: Hughes, Pam	Sworn in by the Chairman
10:47:11 AM	Atty D'Ascenzo direct of Witness Kopp	
	Note: Hughes, Pam	Jeffrey Kopp, Manager, Business consulting Dev. Burns and McDonald Engineering.
	Note: Hughes, Pam	Adopts testimony
10:48:05 AM	Witness Kopp excused	
10:48:19 AM	Atty D'Ascenzo calls Witness Spanos	
	Note: Hughes, Pam	Jon Spanos- Senior VP of Gannet Fleming Valuation and Rate Consultants llc
	Note: Hughes, Pam	Adopts his testimony
	Note: Hughes, Pam	Sworn in by the Chairman
10:50:01 AM	Witness excused	
10:50:15 AM	Atty D'Ascenzo calls Witness Weintraub	
	Note: Hughes, Pam	Sworn in by the Chairman
	Note: Hughes, Pam	Alexander Sasha Weintruab- Senior VIce President, CUstomer Solutions. Adopts his Direct testimony and Data Requests and also Data Requests submitted by Timothy Duff.
10:51:31 AM	Atty Cook cross of Witness Weintruab	
	Note: Hughes, Pam	Referring to rate making purchase fuel costs are handed down to rate payers
	Note: Hughes, Pam	Variable costs, largest costs and fixed costs

	Note: Hughes, Pam	Referring to greater costs of fuel in summer and winter peak months.
	Note: Hughes, Pam	Regarding usage going up when it is hotter, uses its 12 month fixed bill program for customers so they can mange their bills accordingly. My Home Energy Report is given so customers are aware of the energy they use.
10:55:27 AM	Atty Cook cross of Witness Weintruab	
	Note: Hughes, Pam	Referring to costs of fuel and the accentive to watch their usage (customers). Duke can kick customers off this program if they go way over their usage and customers seem to be aware of their usage
10:56:47 AM	Atty Cook cross of Witness Weintruab	
	Note: Hughes, Pam	Regarding how company determines how much fuel fixed bill customers uses.
	Note: Hughes, Pam	Regarding Company being compensated for all fuel that is used. Higher incremental costs of electricity on the fixed bill will not be passed on to other rate payers. Shareholders bear this additional cost.
	Note: Hughes, Pam	Regarding Residential tariff for customers not on this fixed rate program.
10:59:46 AM	Atty Cook cross of Witness Weintruab	
	Note: Hughes, Pam	Exception of fuel costs anf other riders, the company is at risk for other costs asscociated with the fixed bills.
	Note: Hughes, Pam	Rebuttal testimony- Windfall profits.
11:01:37 AM	Atty Cook cross of Witness Weintruab	
	Note: Hughes, Pam	Page 8, rebuttal testimony. Revenue requirement increased if fixed bill rider is not approved. $ 122,232.00 Witness explains how they come up with this amount.
	Note: Hughes, Pam	Regarding application, testimony or exhibits not showing at how they arrived at this figure. PHDR needed. This info is on Workpapers sponsered by Ms. Lawler (in the record)
11:04:50 AM	AG hands out material that is in the record.	
	Note: Hughes, Pam	AG-DR-02-09
11:06:13 AM	Atty Cook cross of Witness Weintruab	
	Note: Hughes, Pam	AG-DR-02-033 Reads this reponse into the record.
	Note: Hughes, Pam	Dukes responses to AG's DR 2. Subpart D. Budget billing and Fixed Bill projects. Witness reads the response in answer part d.
	Note: Hughes, Pam	Attachment 2 page 2 of 4. Reads first sentence about how fixed bill is determined. No where is there a incentive for customers.
11:10:30 AM	Atty Cook cross of Witness Weintruab	
	Note: Hughes, Pam	If customer is kicked off program if they go over their 15%, who then pays the overage charges. Fuel clause. FAC is kept separate from the fixed bill clause.
	Note: Hughes, Pam	Rebuttal testimony, page 5. Line 3 - Premium charge is designed to recover the cost risk the company is taking on.
	Note: Hughes, Pam	Kentucky Fixed bill progrm to be modeled by the Indiana fixed bill program. Customers can be taken off the fixed bill. Company bears the costs of anything above normal usage.
11:15:00 AM	Atty Nguyen cross of Witness Weintruab	
	Note: Hughes, Pam	No participation in KSBA energy management program since 2014. Why Duke decided not to implement the school program. EE projects. $1 million funds for schools to find rebates or programs that will help them.

11:20:45 AM	Atty Nguyen cross of Witness Weintruab	
	Note: Hughes, Pam	Staff's DR 4 - excel formatted-tab 3; fixed bill. Consumption and risk adder. Provide detail of differences and purpose of these Riders
	Note: Hughes, Pam	Referring to Average and non-average customers in the hot summer usage. Weather normilization.
	Note: Hughes, Pam	Risk adder and what it is and means. Value assigned to this Risk adder. 7 to 8% premium applied to fixed bill.
11:26:12 AM	Comm Mathews cross of Witness Weintruab	
	Note: Hughes, Pam	Regarding the differnce in Fixed billing and budget billing.
11:27:49 AM	Atty Malone cross of Witness Weintruab	
	Note: Hughes, Pam	Who did Duke interact with in the Counties about the 1 million set aside for the school districts. The School system has to come in and engage Duke Energy about the project.
	Note: Hughes, Pam	!2 years since last rate case, any knowledge with the LGE/KU school projects.
	Note: Hughes, Pam	Limited amount of funds that schools have. Lack of a school energy manager for these programs can cause big problems and make things difficult. Facility managers.
	Note: Hughes, Pam	Referring to the 1 million dollars for the KSBA district breakdown.
11:31:24 AM	Atty Kurtz cross of Witness Weintruab	
	Note: Hughes, Pam	Under consumption and over consumption in these programs. Under is credit in next year.
11:32:06 AM	Witness Excused	
11:32:14 AM	Atty D'Asenzo calls Witness Morin	
	Note: Hughes, Pam	Sworn in by the Chairman.
11:33:00 AM	Atty D'Ascenzo direct of Witness Morin	
	Note: Hughes, Pam	Adopts his testimony's and DR's. One correction on rebuttal , page 6. Line 9- vertically integrated electric utility. Line 11 - 9.8 % Page 9, line 17 - insert vertically integrated electric utility. 9.8%
	Note: Hughes, Pam	Roger A. Morin Ph.D Principal Utility Research International.
11:35:20 AM	AG hands out papers not in the record.	
	Note: Hughes, Pam	4 handouts (green folder and other pages)
11:37:39 AM	Atty Chandler cross of Witness Morin	
	Note: Hughes, Pam	Rebutall testimony, cited the Order in the KY Power Case. lines 16 - 18. Page 28 of the Ky Power Order in Case No. 2017-00179. Witness reads first full sentence on the page.
	Note: Hughes, Pam	Cap in was 4.8% interest rate. What is current rate on treasury bond- 3%. 9.7 ROE in the Ky Power case 2017-00179. Thinks Commisson makes up its own mind in this case.
11:38:28 AM	Camera Lock PTZ Activated	
11:38:37 AM	Camera Lock Deactivated	
11:42:34 AM	Atty Chandler cross of Witness Morin	
	Note: Hughes, Pam	Page 10 of rebuttal. Dominion Resources was included, and has highest ROE on list. Line 8 shows 10.9%
	Note: Hughes, Pam	Dominion Energy handout page. Dominion Energy 10k, page 20. Electric regulation of Virginia. 2015 kept Virginia rate base the same into 2022.
	Note: Hughes, Pam	Page 12 in rebuttal testimony. Dividend average used. 3.1% subject to check.
11:47:02 AM	Atty Nguyen cross of Witness Morin	
	Note: Hughes, Pam	Rebuttal testimony pages 27-28. Trends in interest rates.

11:48:48 AM	Atty Nguyen cross of Witness Morin	
	Note: Hughes, Pam	Referring to risks and returns. Rebutall testimony, ROE 9.8%. Proxy group average allowed. Is the ROE of 10.3% comparably inflated. Risk factors. Mitigation processes that Duke has planned or implemented.
	Note: Hughes, Pam	Any current market changes that may affect current ROE analysis.
11:53:17 AM	Atty D'Ascenzo re-direct of Witness Morin	
	Note: Hughes, Pam	KY Power Order on page 28. Interest rates are increasing but historically slow. Federal reserve indicated that interest rates will be rising. In his rebuttal testimony he has a graph,
11:54:53 AM	AG cross of Witness Morin	
	Note: Hughes, Pam	Ky Power Order came out in January 2018. His graph was mid-2017.
11:55:45 AM	AG cross of Witness Morin	
	Note: Hughes, Pam	Midpoint of ROE was 9.9%. Regarding when he recommended bottom half of ROE since 2006.
11:56:45 AM	Atty Kurtz cross of Witness Morin	
	Note: Hughes, Pam	Referring being a part of PJM. Risks
11:57:27 AM	Witness excused	
11:57:35 AM	Atty D'Ascenzo calls Witness Silinski	
	Note: Hughes, Pam	Sworn in by the Chairman.
11:58:52 AM	Atty Honaker direct Witness Silinski	
	Note: Hughes, Pam	Thomas Silinski, VP Total Rewards and Human Resource Operations. Adopts his testimony
11:59:34 AM	AG moves to introduces exhibits 2, 3 and 4	
	Note: Hughes, Pam	Chairman admits these into the record
12:00:43 PM	Atty McNeil cross Witness Silinski	
	Note: Hughes, Pam	Craft technicians and line technicians can take 5 years to train. Positions differ on how long it takes to train. Hiring experienced workers. Craft positions are maybe a third.
	Note: Hughes, Pam	Regarding the Career advancement to employees by Duke Energy. Importance of compensation and benefits.
12:03:02 PM	Atty McNeil cross Witness Silinski	
	Note: Hughes, Pam	Testimony. Strategies of the road ahead. Compensation and benefits are part of what it takes to advance this strategy.
12:03:45 PM	Atty McNeil cross Witness Silinski	
	Note: Hughes, Pam	Page 11 of testimony - "recognition awards" and what they are and what for. Estimate on how often they are given, maybe less than 5 % of employees get these.
	Note: Hughes, Pam	Page 11, incentive pay to get employees to perform to a high level. Attachment TS-2 . Titles "Pay for Performance". 3rd bullet point, witness reads this. Regarding Dukes short-term incentive program. Short term and long term incentives programs and what they are tied into.
	Note: Hughes, Pam	Regarding other companies Duke compares itself to.
	Note: Hughes, Pam	Page 14 of testimony-chart. Overall wage increase budget from years of 2013 - 2017.
12:11:42 PM	Atty McNeil cross Witness Silinski	
	Note: Hughes, Pam	Page 24 of direct testimony. Results are available. PHDR needed.
12:12:09 PM	Atty McNeil cross Witness Silinski	
	Note: Hughes, Pam	Non union employees benefits are frozen
	Note: Hughes, Pam	Regarding the pension plan of the company.
	Note: Hughes, Pam	Enhanced company match employees and 401k match at the 6% match.

12:16:03 PM	Atty Nguyen cross Witness Silinski	
	Note: Hughes, Pam	Response to Staff's DR2 - item 5.a. 21% cost of employee medical coverage to single coverage. The attachment 1 of 1 provides calculation. 20% in column under Kentucky, must have been an error.
	Note: Hughes, Pam	PHDR to confirm this % and calculation.
12:18:55 PM	Atty Nguyen cross Witness Silinski	
	Note: Hughes, Pam	Duke Kentucky's original test year on medical expense and impact on reveune requirement. PHDR needed
12:19:48 PM	Atty Nguyen cross Witness Silinski	
	Note: Hughes, Pam	Regarding the Retirement plans offered by Duke Kentucky. 2014 or 2015 when change came into affect.
	Note: Hughes, Pam	Legacy employees, defined benefits were frozen and moved into the 401k program going forward.
	Note: Hughes, Pam	PHDR- population of employees eligible for defined benefit plan and also the other benefit plan.
12:22:55 PM	Atty Honaker re direct of Witness Silinski	
	Note: Hughes, Pam	Regarding Compensation for employees and the total rewards
	Note: Hughes, Pam	Dukes retention of employees. More attrition
12:24:09 PM	Witness excused	
12:24:17 PM	Break	
12:24:23 PM	Session Paused	
1:30:19 PM	Session Resumed	
1:30:26 PM	Witness David Doss called to the stand	
	Note: Hughes, Pam	Sworn in by Chairman
1:30:55 PM	Atty Honaker direct of Witness Doss	
	Note: Hughes, Pam	David Doss - Duke Energy, Director of Electric Utilities and Infrastructure
	Note: Hughes, Pam	Sworn in by the Chairman
	Note: Hughes, Pam	Adopts testimony
1:31:38 PM	Atty Chandler cross of Witness Doss	
	Note: Hughes, Pam	AG exhibit 1. Audit report, page 89. Findings V-7. Parts of the findings was in error. Explains why he thinks it is in error. $ 25 million pool catergorized as long term debt. This is not in test year
	Note: Hughes, Pam	Page 90. V-1 Disagrees wiith the premise
1:37:31 PM	Atty Honaker re direct of Witness Doss	
	Note: Hughes, Pam	Witness not aware of this report or concerns.
1:38:02 PM	Witness excused	
1:38:11 PM	Witness Robert Pratt called to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman
1:38:44 PM	Atty Honaker direct of Witness Pratt	
	Note: Hughes, Pam	Duke energy, Director, Regional Fianacial Forecasting
	Note: Hughes, Pam	adopts his testimony and Patty Mullins responses
1:39:37 PM	Atty Chandler cross of Witness Pratt	
	Note: Hughes, Pam	Direct testimony on page 10, line 19. He reads this into the record. O&M expenses, related to advanced metering.
1:40:49 PM	Witness excused	
1:40:59 PM	Witness Schnieder called to the stand	
	Note: Hughes, Pam	Donald Schneider Jr.
	Note: Hughes, Pam	Sworn in by Chairman
1:41:56 PM	Atty D'Ascenzo direct of Witness Schneider	
	Note: Hughes, Pam	Adopts all testimony and DR's.
1:42:28 PM	Atty Chandler of Witness Schneider	
	Note: Hughes, Pam	DR; AG-01-073 .

	Note: Hughes, Pam	Data Requests regarding AMI deploynment. Test year adjustment for AMI. AG-1-40; costs anticipated in DLS-4 exhibits in Case No 2016-00152
1:46:41 PM	Atty Chandler cross of Witness Schneider	
	Note: Hughes, Pam	AG-DR-01-074 Public Other costs for AMI project.
1:49:09 PM	Atty Chandler cross of Witness Schneider	
	Note: Hughes, Pam	Handed out an Order in Case No. 2016-00152. Settlement agreement in this order. Regarding Mr. Wathan's rebuttal testimony about test year adjustment
1:50:17 PM	Atty D'Ascenzo objection	
1:50:28 PM	Atty Chandler states he will let him read.	
	Note: Hughes, Pam	Overruled
1:51:10 PM	Atty Chandler cross of Witness Schneider	
	Note: Hughes, Pam	Mr. Wathan's rebuttal testimony about savings. Witness drafted the original cost benefit analysis in the original CPCN case. Regarding incremental costs. Section 4 in the settlement attached to the Order- onoing costs of operations.
	Note: Hughes, Pam	DR 1-74 b.1. 490,000.00 ongoing costs in the test year. Anywhere that staes incremental costs. Witness appeared in the hearing in case no 2016-00152.
1:54:35 PM	Witness excused	
1:55:07 PM	AG exhibit 5	
	Note: Hughes, Pam	Order in PSC Case No. 2016-00152
1:55:16 PM	Witness Miller called to the stand.	
	Note: Hughes, Pam	Sworn in by the CHairman
1:55:49 PM	Atty Samford direct of Witness Miller	
	Note: Hughes, Pam	Joseph Miller VP, Central Services. Adopts testimony
1:56:21 PM	Witness excused	
1:56:44 PM	Witness Lee called to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman
1:56:57 PM	Atty Samford direct Witness Lee	
	Note: Hughes, Pam	Cynthia Lee, Director Asset Accounting
	Note: Hughes, Pam	Adopts her testimony and DR's.
1:57:34 PM	Atty Chandler cross of Witness Lee	
	Note: Hughes, Pam	Ash ponds closure and costs. ESM is 17 million dollars. Asset retirement costs. Amoritized once accepted by the Commission. Legal requirements to treat all costs the same
2:00:18 PM	Atty Nguyen cross of Witness Lee	
	Note: Hughes, Pam	Ash pond estimated to close in 2022 East bend remaining life.
2:01:51 PM	Atty Nguyen cross of Witness Lee	
	Note: Hughes, Pam	Any studies of costs of ash pond closure costing higher cost to rate payers if over a 23 year period. No analysis provided. PHDR need for 10 year v. 23 years.
2:02:56 PM	Atty Chandler re cross of Witness Lee	
	Note: Hughes, Pam	Regarding 17 million amount over the estimated amount and the portion that has not yet been spent.
2:04:14 PM	Atty Kurtz cross of Witness Lee	
	Note: Hughes, Pam	What is carrying charge and how much? States 6%, subject to check.
2:04:43 PM	Witness excused	
2:05:06 PM	John Swez called to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman

2:05:24 PM	Atty Samford direct of Witness Swez	
	Note: Hughes, Pam	Sponsering DR's of Scott Burnside. Direct testimony, page 24 line 17 charge code 2111 should be 2211.
	Note: Hughes, Pam	Director, Generator Dispatch and Operations.
2:06:54 PM	Atty Chandler cross of Witness Swez	
	Note: Hughes, Pam	Regarding if company proposes to change the way Black start is credited to customers. .
	Note: Hughes, Pam	Black start capability in direct testimony page 12. Where does this show up in a customers bill? Charge code 1380 and 2380.; Cost and Credit. Flows through the Rider PSM.
	Note: Hughes, Pam	Capitol that had to be invested to start the black start unit. Duke spent the money to do this.
2:13:02 PM	Atty Kurtz cross of Witness Swez	
	Note: Hughes, Pam	Regarding the black start in Woodsdale units costs and role it plays in this case. Defines black start. Regarding the money spent to make the black start. PJM pays them.
2:15:52 PM	Atty Nguyen cross of Witness Swez	
	Note: Hughes, Pam	Page 24 of direct testimony. Proposed PJM billing line items flowed through Rider PSM. Broken down into 2 groups. Page 25, lines 12 -13.
	Note: Hughes, Pam	Regarding the netting out process and categories and costs that are netted for the proposed billing line items to be included in Rider PSM.
2:19:51 PM	Atty Samford re direct of Witness Swez	
	Note: Hughes, Pam	Two units that have black start capabilities and original construction. Cincinatti was original owner. Duke got them in 2006
2:20:46 PM	Atty Kurtz re cross of Witness Swez	
	Note: Hughes, Pam	Regarding 6 units at Woodsdale.
	Note: Hughes, Pam	Regarding directing the ions to Woodsdale to the coal unit.
2:22:51 PM	Atty Howard cross of Witness Swez	
	Note: Hughes, Pam	Regarding Firm Contracts for natural gas.
	Note: Hughes, Pam	Secondary fuel, onsite storage. Has the onsite storage facilities been built?
	Note: Hughes, Pam	Deisel as a secondary fuel.
	Note: Hughes, Pam	Regarding Woodsdale units originally designed to run on natural gas with propane as a back up.
2:26:23 PM	Witness excused	
2:26:35 PM	Call John Verderame to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman.
2:27:07 PM	Atty Samford direct of Witness Verderame	
	Note: Hughes, Pam	John Verderame. Managing Director Power Trading and Dispatch
	Note: Hughes, Pam	Adopts his testimony
2:27:46 PM	Atty Chandler cross of Witness Verderame	
	Note: Hughes, Pam	Has Duke Kentucky made Investments to ensure it doesn't recieve capacity performance each year.
	Note: Hughes, Pam	Regarding spending capitol to ensure it complies with the black start projects at Woodsdale
	Note: Hughes, Pam	Regarding Capacity performance. Bonuses
	Note: Hughes, Pam	Proposed Rider PSM provides for multiple costs or credits, it is proposed to be split 90/10.
2:33:56 PM	Atty Chandler cross of Witness Verderame	
	Note: Hughes, Pam	Regarding capacity performance bonuses assesment.

2:35:12 PM	Atty Kurtz cross of Witness Verderame	
	Note: Hughes, Pam	Regarding capacity performance and how it works for RPM entities and FRR, and it only happens in an emergency situation. 640 MW's for East Bend station.
	Note: Hughes, Pam	East bend always committed fully. Woodsdale not always. Wants East Bend to be online all the time.
2:39:34 PM	Atty Nguyen cross of Witness Verderame	
	Note: Hughes, Pam	Phase in for non FRR entities
	Note: Hughes, Pam	2017-2018 capacity for the delivery year. 600mw's east bend
	Note: Hughes, Pam	Decision in waiting until now to get Woodsdale and Eastbend compliant. 2016-2017 offering mw's in excess.
2:42:56 PM	Atty Nguyen cross of Witness Verderame	
	Note: Hughes, Pam	Regarding available capacity that Duke would have. Duke is a summer peak.
	Note: Hughes, Pam	Page 8, direct testimony. Table at top of page. 2017 was 31% to 2021 was 30%. Reserves for each of the 5 years as well. Page 7, number is target reserve number used for planning purposes.
	Note: Hughes, Pam	Did PJM perform calculations for load requirements and capacity for 17-18 delivery year. What was reserve margin? 15% PHDR needed confirmation if has been provided or provide if not. Do a 3 year
2:49:45 PM	Atty Nguyen cross of Witness Verderame	
	Note: Hughes, Pam	Page 13 of direct testimony. Regarding base residual option for the 2020-2021 year. What is LDA?
	Note: Hughes, Pam	Has the Duke KY/Ohio zone historically had an adder zone.
	Note: Hughes, Pam	Regarding occurences in past where Duke needed to purchase short term capacity. Unplanned
2:55:22 PM	Comm Mathews cross of Witness Verderame	
	Note: Hughes, Pam	Subject to the capacity performance even though they are FRR.
	Note: Hughes, Pam	Regarding Woodsdale factoring into the Ucap.
	Note: Hughes, Pam	Ucap close to predicted load. How is it calculated?
	Note: Hughes, Pam	Regarding Duke being an FRR.
2:58:46 PM	Atty Samford re direct of Witness Verderame	
	Note: Hughes, Pam	Minimum offers rule explanation..
	Note: Hughes, Pam	Rider PSM. Capacity sales would flow through the PSM.
	Note: Hughes, Pam	FRR status and recent changes by PJM to have impact on company to move from a FRR to an RPM. Length of time to make this transition. 3 year delay after Commission approval
	Note: Hughes, Pam	Capacity performance in effect since June 2016. No capacity performance hours to date
3:02:44 PM	Atty Kurtz re cross of Witness Verderame	
	Note: Hughes, Pam	Ferc rule on which proposal they want.
	Note: Hughes, Pam	Mandated capacity factor is 30% 5 CP in PJM for thier responsibility. Witness can't speak to that. Regarding market monitor and requiring subsidization.
3:07:13 PM	Atty Chandler re cross of Witness Verderame	
	Note: Hughes, Pam	Regarding capacity performance having insurance policy. Back up fuel at Woodsdale is an insurance policy and requirement for fuel availability to be compliant.
3:08:35 PM	Atty Chandler re cross of Witness Verderame	
	Note: Hughes, Pam	Regarding cost or credits from qualified facilities. Can't answer.
	Note: Hughes, Pam	Regarding capacity purchases for QF
3:09:50 PM	Witness excused	
3:10:02 PM	Break	
3:10:10 PM	Session Paused	

3:23:33 PM	Session Resumed	
3:23:40 PM	Jeff Setser called to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman
3:23:59 PM	Atty Honaker direct of Witness Setser	
	Note: Hughes, Pam	Jeff Setser, Director of Allocation and Reporting. Adopts his testimony
3:24:45 PM	Atty Chandler cross of Witness Setser	
	Note: Hughes, Pam	Page 70 of exhibit. Finding IV -1 Cost allocation manuel. Has Duke made the necessary changes that are included there.
3:26:49 PM	Witness excused	
3:26:57 PM	Witness Benjamin Pasti called to the stand	
	Note: Hughes, Pam	William Benjamin Pasti
	Note: Hughes, Pam	adopts testimony and DR's.
	Note: Hughes, Pam	Sworn in by the Chairman
3:28:17 PM	Witness excused	
3:28:30 PM	Witness Jett called to the stand	
	Note: Hughes, Pam	Sworn in by the CHairman
3:29:10 PM	Atty Samford direct of Witness Jett	
	Note: Hughes, Pam	Change to Page 17 direct testimony, 1st paragraph, 2nd line- agents should be struck.
	Note: Hughes, Pam	Tammy Jett-Principal Environmental Specialist
3:30:00 PM	Atty Chandler cross of Witness Jett	
	Note: Hughes, Pam	AG DR -192. Any change to the CCR or ELG rules and how would they effect Duke Kentucky.
3:31:02 PM	Witness excused	
3:31:21 PM	Witness Lisa Bellucci called to the stand	
	Note: Hughes, Pam	Sworn in by the Chairman
3:31:40 PM	Atty D'Ascenzo direct of Witness Bellucci	
	Note: Hughes, Pam	Lisa Bellucci. Director Tax operations. adopts testimony and adopts Cooper Monroe's DR.
3:33:32 PM	Atty Chandler hands out Order in Case No. 2017-00477-AG exhibit 6	
	Note: Hughes, Pam	Reads Last sentence of next full paragraph.
	Note: Hughes, Pam	Regarding the use of 20 years was an estimate.
	Note: Hughes, Pam	Last sentence in 2nd paragraph, deferred as if they should be returned. Aware if Commission knew the ARAM when they determined this.
	Note: Hughes, Pam	Regarding if she has read this Order. Reads final sentence on first page.
3:36:23 PM	Objection	
	Note: Hughes, Pam	Sustained
3:36:34 PM	Atty Chandler cross of Witness Bellucci	
	Note: Hughes, Pam	Order filed in December 27, 2017. Date Mr. Kollens testimony filed 12/28/17 subject to check.
	Note: Hughes, Pam	Regarding the commissions beliefs of rate of Unprotected and protected ADIT's would be.
3:38:14 PM	AG hands out Mr. Kollens response to DR number 70	
	Note: Hughes, Pam	Previous page b.i ; and b.iv. She reads Mr. Kollens response to b..iv.
	Note: Hughes, Pam	Questions 70 and 70.b. She reads his answer to b.
3:41:18 PM	Atty Chandler cross of Witness Bellucci	
	Note: Hughes, Pam	Page 5 of rebuttal testimony. Book values of excess ADITS, amoritized according to the ARAMS. Figures are book figures.

3:42:54 PM	Atty Kurtz cross of Witness Bellucci	
	Note: Hughes, Pam	Rebuttal testimony exhibit 1. 2.820 non grossed up revenue effect. Protected excess ADIT. Unprotected excess Commission requires they can be given back at any time. 20 year period or 15 year period. Unprotected is a base rate offset.
	Note: Hughes, Pam	Regarding the benefits of the Tax Act. Amortization of excess ADIT 3.78 million. Subject to check
3:47:04 PM	Atty Nguyen cross of Witness Bellucci	
	Note: Hughes, Pam	Settlement filed Friday in the Gas case, agreed to 15 % amorization rate for the protected piece. 15 year amorization in unprotected property. Protected is calculated by the ARAM method.
3:48:58 PM	Atty Chandler cross of Witness Bellucci	
	Note: Hughes, Pam	Offset for capitalization.
3:49:29 PM	Atty Nguyen cross of Witness Bellucci	
	Note: Hughes, Pam	Unprotected assets is 15 year life in Gas case, Duke is still proposing 20 year life in unprotected assets. Would Duke be willing to do a 15 year life. PHDR to reflect the 15 years
3:50:35 PM	Witness excused	
3:50:50 PM	Chairman remarks about plan for rest of day.	
	Note: Hughes, Pam	Atty Samford talks about his witnesses and availability.
3:51:50 PM	Atty Kurtz asks for order of witnesses	
	Note: Hughes, Pam	Atty Samford names witnesses for tomorrow.
3:52:52 PM	Chairman asks for any other witnesses for the day.	
	Note: Hughes, Pam	No more witnesses to testify today.
3:53:23 PM	Adjourned for the day	
	Note: Hughes, Pam	Hearing will continue on March 7, 2018.
3:53:36 PM	Session Paused	
4:05:25 PM	Session Ended	

Judge: Bob Cicero; Talina Mathews; Michael Schmitt

Witness: Lisa Bellucci; Cynthia S. Lee; David Doss; James Henning; Jeffrey T. Kopp; Tammy Jett; Joseph Miller; Roger Morin Ph.D; Benjamin Pasti; Robert H. Pratt; Donald Schneider; Jeffrey Setser; Thomas Silinski; John Spanos; John Swez; John Verderame; Sasha Weintraub

Clerk: Pam Hughes

Name:	Description:
AG Exhibit 01	Cover Ltr stamped June 20, 2017 from Duke Energy. WIth 2015 Affiliate Management Audit of Duke Energy Kentucky
AG Exhibit 02	PSC Order in Case No. 2017-00179
AG Exhibit 03	Dominion Energy paper
AG Exhibit 04	United States Securities and Exchange Commission - Form 10-K
AG Exhibit 05	PSC Order in Case No. 2016-00152
AG Exhibit 06	PSC Order in Case No. 2017-00477

AG
Exhibit 1

DUKE ENERGY.

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Rocco O. D'Ascenzo
Associate General Counsel

RECEIVED

JUN 20 2017

PUBLIC SERVICE
COMMISSION

VIA OVERNIGHT DELIVERY

June 19, 2017

Talina Rose Mathews
Executive Director
Kentucky Public Service Commission
211 Sower Blvd
Frankfort, KY 40602-0615

Re: Case No. 2011-00124
In the Matter of the Joint Application of Duke Energy Corporation, Cinergy Corp., Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., Diamond Acquisition Corporation, and Progress Energy, Inc. for Approval of the Indirect Transfer of Control of Duke Energy Kentucky, Inc.

Dear Dr. Mathews:

In the Settlement Agreement in the above-referenced case, Duke Energy Kentucky, Inc. (Duke Energy Kentucky) made several merger commitments. In response to Merger Commitment No. 12, which states:

> *"Joint Applicants commit to periodic comprehensive third-party independent audits of the affiliate transactions under the affiliate agreements approved as part of the merger transaction. Such audits will be conducted no less often than every two years, and the reports will be filed with the Commission and the Attorney General. Duke Energy Kentucky shall file the audit report, if possible, when Duke Energy Kentucky files its annual report. The audits will continue for six years or until three service company audits are performed, in the event more than six years are needed to perform three audits."*

Enclosed herein is an original and six copies of the 2015 Affiliate Management Audit Final Report of Duke Energy Kentucky. As Duke Energy Kentucky has now submitted three service company audits, it has fulfilled this merger commitment.

Please file stamp the two copies of this letter and the Final Report enclosed herein and return in the enclosed return-addressed envelope.

Respectfully submitted,

Rocco D'Ascenzo (92796)
Associate General Counsel
Duke Energy Kentucky, Inc.
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(513) 287-4320
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Rocco.D'ascenzo@duke-energy.com
Counsel for Duke Energy Kentucky, Inc.

cc: Rebecca Goodman (w/ enclosure)

Schumaker & Company

2015 Affiliate Management Audit
of
Duke Energy Kentucky

Case Number: 2011-00124
Final Report

May 8, 2017

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2015 Affiliate Management Audit
of
Duke Energy Kentucky

Case Number: 2011-00124
Final Report

May 8, 2017

Schumaker & Company

I. Executive Summary

A. Background & Perspective

In 2011, Duke Energy Corp. (Duke Energy), the ultimate corporate parent company of Duke Energy Kentucky (DEK), merged with Progress Energy, Inc. (Progress). As part of its approval of the merger in Case No. 2011-00124, Duke Energy Kentucky was ordered to adhere to 46 merger commitments the Kentucky Public Service Commission (KPSC) established in Case No. 2005-00228, of which four (4), specifically Commitments 10, 11, 12, and 13 specifically relate directly to this audit. They apply as follows:

- DEK is in compliance with its Commitment 10, which requires proper accounting of costs (accounting and reporting system used by Duke Energy Kentucky will be adequate to provide assurance that directly assignable utility and non-utility costs are accounted for properly and that reports on the utility and non-utility operations are accurately presented).
- DEK is in compliance with its Commitment 11, which requires that it implement and maintain appropriate cost allocation procedures that will accomplish the objective of preventing cross-subsidization, and be prepared to fully disclose all allocated costs, the portion allocated to Duke Energy Kentucky, complete details of the allocations methods, and justification for the amount and the method, plus giving the Commission 30 days' advance notice of any changes in cost allocation methods set forth in agreements approved as part of the merger transactions.
- DEK is in compliance with its Commitment 12, which requires that it commit to third-party independent audits of the affiliate transactions under the affiliate agreements approved as part of the merger transaction.
- DEK is in compliance with its Commitment 13, which requires that it protect against cross-subsidization in transactions with affiliates.

Also within the scope of this audit is DEK's compliance with KPSC regulations, including:

- 807 KAR 5:080 SECTION 2 — Annual reports
- 807 KAR 5:080 SECTION 3 — Filing of cost allocation manual and amendments
- 807 KAR 5:080 SECTION 4 — Notice of establishment of new non-regulated activity

With the approval of the merger of Duke Energy with Progress Energy Corporation (Progress Energy), the KPSC imposed three additional conditions on its approval of the merger, specifically:

- DEK must continue to offer a full range of cost-effective energy conservation and efficiency programs.
- The Board of Directors of the combined company must include at least one non-employee member who resides in the company's service territory in Kentucky, Indiana, or Ohio.
- No merger costs may be passed on to DEK ratepayers.

Refer to *Chapter II – Merger Order Requirements* for a discussion of Duke Energy's responses.

DEK is part of the Duke Energy organization, in which its summary organization structure, as of December 31, 2015 is depicted on *Exhibit I-1*.

Exhibit I-1
Summary Duke Energy Corporation Organization
as of December 31, 2015

- Duke Energy Corporation (DE 05.03.2005)
  - Bison Insurance Company Limited (100%)(SC 06.15.2012)
    - NorthSouth Insurance Company Limited (100%)(SC 06.15.2012)
  - Cinergy Corp. (100%)(DE 06.30.1993)
    - (see Appendix A for subsidiaries)
  - Duke Energy Renewables NC Solar, LLC (100%)(DE 02.25.2010)
    - (see Appendix B for subsidiaries)
  - Duke Energy Pipeline Holding Company, LLC (100%)(DE 08.27.2014)
    - Duke Energy ACP, LLC (100%)(DE 08.27.2014)
      - Atlantic Coast Pipeline, LLC (40%)(DE 08.27.2014)
    - Duke Energy Sabal Trail, LLC (100%)(DE 02.06.2015)
      - Sabal Trail Transmission, LLC(7.5%)(DE 06.10.2013)
  - Duke Energy Carolinas, LLC (100%)(NC 11.27.1963)
    - APOG, LLC (20%)(DE 06.22.2007)
    - Advance SC LLC (100%)(SC 07.09.2004)
    - Caldwell Power Company (100%)(NC 07.28.1921)
    - Carolinas Virginia Nuclear Power Associates, Inc. (25%)(NC 10.04.1956)
    - Catawba Manufacturing and Electric Power Company (100%)(NC 10.15.1901)
    - Claiborne Energy Services, Inc. (100%)(LA 03.01.1990)
    - Duke Energy Receivables Finance Company, LLC (100%)(DE 07.16.2003)
    - Eastover Land Company (100%)(KY 06.30.1970)
    - Eastover Mining Company (100%)(KY 07.15.1970)
    - Greenville Gas and Electric Light and Power Company (100%)(SC 01.28.1881)
    - MCP, LLC (100%)(SC 08.18.2000)
    - Piedmont Venture Partners Limited Partnership (10.64%)(NC 10.03.1996)
    - Sandy River Timber, LLC (100%)(SC. 10.26.2007)
    - Southern Power Company (100%)(NC 12.30.1927)
    - TBP Properties, LLC (100%)(SC 12.11.2006)
    - TRES Timber, LLC (100%)(SC 12.11.2006)
    - Wateree Power Company (100%)(SC 02.26.1909)
    - Western Carolina Power Company (100%)(NC 09.10.1907)
  - Duke Energy Corporate Services, Inc. (100%)(DE 05.26.2008)
    - Duke Energy Business Services LLC (100%)(DE 11.18.1998)
  - Duke Energy Registration Services, Inc. (100%)(DE 11.18.1998)
    - (see Appendix C for subsidiaries)
  - Progress Energy, Inc. (100%)(NC 08.19.1999)
    - (see Appendix D for subsidiaries)

Source: Information Response 1 (SCH-DR-01-001 Supplemental Attachment)
The service company is Duke Energy Business Services, LLC (DEBS).
The regulated utilities are Duke Energy Carolinas, LLC (DEC), plus Duke Energy Indiana, Inc. (DEI), Duke Energy Ohio, Inc. (DEO), Duke Energy Kentucky, Inc. (DEK), Miami Power Corporation, and Ohio Valley Electric Corporation, which are part of the Cinergy Corporation. See *Exhibit III-1* for additional detail in organization.

B. Audit Methodology & Work Plan

Schumaker & Company followed a three-step process designed to sustain vital, interactive working relationships our project team and DEK. Our approach for achieving the audit objectives was as follows:

- Step I – Diagnostic Review
- Step II – Detailed Review and Analysis
- Step III – Draft and Final Report Preparation

Each task area in our work plan was designed to allow our team to efficiently gather and analyze information necessary to develop an opinion whether DEK adequately complied with Kentucky's affiliate standards in 2015. The tables on the following pages illustrate a general discussion of the type of work steps typically performed for each task area, as well as the preliminary information that would be required and the key indicators that we would use to assess that specific task area.

Affiliate Relationships		
Typical Work Steps	**Information Required**	**Key Indicators**
Review governing regulations, orders, and decisions from the Commission regarding affiliate transactions and determine if these affiliate relations rules have been fully complied with by DEK; identify any situations of non-compliance and determine the actual or potential impact of this non-compliance. Obtain DEK organization charts showing the relationships of DEK with its affiliates. Identify all affiliates that had transactions with DEK during the last three years. Identify all products and services provided from/to regulated and unregulated affiliates of DEK during the last three years. Document the frequency and dollar magnitude of all affiliate goods and services by year and by affiliate for all items received by or provided by DEK. Develop diagrams, graphs, and/or tabulations identifying affiliates, services, dollar magnitude, and other useful information and data. Explain any significant trends or changes. Analyze trends of these allocated amounts compared to the trends of these costs in the parent/affiliate. Separately identify affiliate transactions involving the transfer of employees, property, and/or technology. Identify, by plant category, any capital expenditures made by affiliates but allocated to DEK's operations. Evaluate any transactions that have had a significant effect on depreciation expense. Identify shared facilities, systems, and programs among affiliates including employee training, joint purchasing, information technology, advertising and promotion, and corporate support services. Review internal systems for providing assurance that goals and objectives are accomplished at the lowest possible cost and maximum benefit to ratepayers. Identify internal controls in place to protect against irregular, illegal, and/or improper transactions. Review filings, reports, and communications involving affiliate relationships.	Copies of all governing regulations, orders, and decisions from the Commission regarding affiliate transactions Duke Energy and DEK organization charts showing all affiliate relationships, including regulatory status of affiliates Description of all products and services provided from/to regulated and unregulated affiliates of DEK during the last three years Level and nature of affiliated transactions (actual and budget dollars) from/to DEK's operations and affiliates during the last three years, including a breakdown by: ♦ From/to affiliate ♦ Type of transaction ♦ Time period Actual dollars and personnel equivalents, by functional category, for each associated regulated and/or non-regulated DEK affiliate The level and nature of affiliated transactions (actual and budgeted capital expenditure dollars, by plant category) allocated to DEK's operations by affiliates during the last three years – as compared to its parent/affiliates Any cost allocation manual documentation, including formulas and basis	All affiliate transactions of DEK should be in complete compliance with all of the governing regulations, orders, and decisions from the Commission regarding affiliate transactions. The relationships with affiliates are clearly documented. The costs are fairly representative of the value of goods and services provided and of the benefits derived by Kentucky ratepayers. DEK should be able to easily furnish information regarding the products and services provided to/from its affiliates and the corresponding financial transactions that result. DEK should not be negatively impacted by its relationships in the overall corporate organization. Any affiliate costs charged to DEK are reasonable and competitive in the market.

Cost Allocation Methodologies – Affiliate Transactions and Cost Accumulation and Assignment		
Typical Work Steps	**Information Required**	**Key Indicators**
Determine procedures specified for identifying, tracking, and posting direct, indirect, and general overhead costs to specific projects or cost pools. Determine how these assignment policies, procedures, and practices have changed over time; assess the rationale for these changes. Assess methodologies (e.g., accounting systems) used to accumulate and assign costs. Examine criteria used to assign costs. Evaluate Duke Energy's hierarchy for placing emphasis on direct billing versus cost allocation, and for developing causal relationships in formulating allocation methodologies. Evaluate whether direct billing is used whenever possible. Assess whether cost accumulation/assignment bases are reasonable and appropriate (e.g., based on cost causative factors) and whether they have been consistently developed. Review documentation involving policies and guidelines in place to establish the appropriation of resources and costs, including (but not limited to): ◆ Finance manuals ◆ Assignment policies ◆ Cost allocation manuals Identify generic direct billing and/or cost allocation methodologies in place within DEK and its affiliates used to calculate the costs for services or products provided. Assess whether cost allocation methodologies, and their associated bases and factors, are reasonable and appropriate, and whether they have been consistently applied. Assess whether these methodologies are regularly reviewed and revised. Determine whether the policies, procedures, and practices governing these transfer pricing methodologies and accounting standards are adequately documented and understood by the personnel involved. Identify the data sources and special studies required to develop allocations factors (if they are used), and evaluate their appropriateness. Determine how allocation policies, procedures, and practices have changed over time; assess the rationale for these changes.	Any cost accounting documentation involving cost accumulation and assignment Copies of DEK's general ledger and pertinent subsidiary ledgers Any accounting manuals and other documentation describing methodologies, bases, and factors used for direct billing and/or cost allocation, and/or segregating regulated and unregulated costs, including (but not limited to): ◆ Finance manuals ◆ Assignment policies ◆ Cost allocation manuals Description of daily accounting standards and recordkeeping methods and procedures that support the daily operations between DEK and its affiliates	DEK and its affiliates should have in place well-defined and consistently applied procedures for accumulating and assigning costs, and should be able to provide timely, current, and accurate information regarding the level, nature, and magnitude of costs incurred. Direct billing and allocation methodologies used by DEK and its affiliates should be founded on reasonable and fair factors and bases that properly reflect the value of products and services received, and should be supported by automated systems and contracts that provide management with the information and data it needs for recording and managing these activities. DEK should not be negatively impacted by its relationships in the overall corporate organization. Any affiliate costs charged to DEK are reasonable and competitive in the market.

Cost Allocation Methodologies – Affiliate Transactions and Cost Accumulation and Assignment		
Typical Work Steps	**Information Required**	**Key Indicators**
Determine if contracts are in place and current where appropriate. Determine if the formal contracts define the nature of affiliate services rendered, set forth clearly defined bases for associated charges, and stipulate terms and conditions favorable to DEK's regulated operations in Kentucky. Determine if any contracts with third parties involving more than one affiliate provide DEK's operations with full consideration for performance, taking into account risk premiums or time value of money implicit in the payment or collection terms of such contracts. Assess whether the direct billing and cost allocation processes are adequately automated. Evaluate those mechanisms and procedures in the direct charges/cost allocation guidelines intended to guard against the cross-subsidization of unregulated entities, either through intentional or unintentional means. Identify the extent to which DEK's financial strength is impacted by or insulated from its affiliated (regulated or unregulated) companies.		
Identify the decision-making process used in the determination of services required, and for identifying the most optimum means of providing these services. Identify how DEK determines whether internal or external resources are used; identify instances of comparisons between outside vendors and internal resources for products and services provided to DEK.	Any analyses regarding use of external vendors for the development and delivery of services to DEK and its operations Any cost/benefit analyses performed during the last three years regarding provision of services by DEK or its affiliates	Decisions pertaining to the use of external vendors should be based on analysis that considers cost-benefit, financial, and other factors. These decisions should consider comparisons to provision directly by DEK or its affiliates, as well as the benefits that customers of regulated operations will receive.

C. Summary of Recommendations

The recommendations contained in the audit report are shown in Exhibit I-2, including recommendation number, page number in the report, priority, and estimated time-frame to initiate implementation efforts.

Exhibit I-2
Summary of Recommendations

			Implementation	
	Description	**Page**	**Priority**	**Initiation Time Frame**
II-1	Provide sufficient documentation during DEK's next rate case to ensure that Duke Energy/Progress Energy merger costs were not passed on to DEK ratepayers.	15	High	0-24 Months
III-1	Provide the KPSC in early 2017 a copy of the results from the market study assessments performed in 2016.	58	High	0-6 Months
IV-1	Continue to develop an improved formal comprehensive cost allocation manual that brings together all required elements of such documentation.	75	Medium	0-12 Months
IV-2	Develop service level agreements for key functions providing affiliate services to DEK.	76	Medium	0-12 Months
IV-3	Develop a formal policy and associated documentation regarding process for handling asset loans, so that they exist going forward in situations where asset loans are actually done.	76	Low	0-24 Months
V-1	Change the way DEK calculates interest expense for the use of excess borrowed short-term funds.	90	High	0-6 Months

Actions taken by Duke Energy regarding prior Schumaker & Company 2013 report recommendations are summarized in *Exhibit I-3*.[1]

Exhibit I-3
Duke Energy Actions to Prior Schumaker & Company 2013 Audit

Recommendation	Action Taken
Recommendation II-1 Provide sufficient documentation during Duke Energy Kentucky's next rate case to ensure that Duke Energy/Progress Energy merger costs are not being passed on to DEK ratepayers.	Kentucky has not had a rate case since the last audit period.
Recommendation III-1 Aggressively send notifications to employees who have not passed affiliate rules training even before the Day 30 currently used. **Recommendation III-2** Continue to enhance Affiliate Standards training, plus make sure all Duke Energy employees taking such training using *MyTraining* by the end of 2014.	For regulatory training deployed by the Ethics & Compliance Department, Duke Energy has revised its standard deployment period from 60 days to 90 days and made significant changes to the reminder and past due escalation schedules. Employees receive a total of five (5) reminders prior to the due date, including the initial notice. Duke Energy has also increased the escalation and automated system reminders (from *MyTraining*), which are also sent to immediate managers earlier in the process, prior to the due date. Previously Duke Energy began escalation two (2) weeks after the due date with management and escalated weekly thereafter, until it notified senior management. Below is the current deployment reminder and escalation process now being used: ♦ **DAY 1** – *MyTraining* > initial notice to individual ♦ **DAY 45** – *MyTraining* > reminder to individual ♦ **DAY 60** – *MyTraining* > reminder to individual and copy to manager ♦ **DAY 70** – Manual reminder and incomplete report to management ♦ **DAY 80** – *MyTraining* > reminder to individual, copying manager, and manual > incomplete report to management ♦ **DAY 89** – *MyTraining* > reminder to individual ♦ **DAY 91** – *MyTraining* > overdue to individual, copy to manager, and manual > incomplete report to senior management ♦ **DAY 98** (and weekly thereafter) – *MyTraining* > overdue to individual, copy to manager, and manual > incomplete report senior management until 100% complete
Recommendation IV-1 Develop a formal comprehensive cost allocation manual that brings together all required elements of such documentation.	The Ohio/Kentucky Rates & Regulatory Group has updated the Kentucky cost allocation manual to include similar information that is presented in the North Carolina cost allocation manual.
Recommendation IV-2 Develop a formal policy and associated documentation regarding asset loans.	Each asset loan is considered unique; therefore, a company-wide policy does not exist and Duke Energy does not believe it would be beneficial. Each asset loan requires significant discussions between legal, asset accounting, and supply chain to determine the best strategy and ensure all affiliate requirements are met. As Duke Energy has affiliate transfer training, this training program includes information about asset loans. Given the rarity of an asset loan, Duke Energy believes this information is sufficient to ensure all affiliate guidelines are followed when there is an asset loan. Supply Chain is not aware of any loans in 2015 for any jurisdiction.

Source: Information Response 48

II. Merger Order Requirements

A. Background & Perspective

This chapter addresses Duke Energy Kentucky's (DEK's) response to merger order requirements previously discussed in *Chapter II – Executive Summary*.

B. Findings & Conclusions

Finding II-1 Duke Energy has essentially addressed Commitments 10, 11, 12, and 13 of Case No. 2005-00228 that KPSC established and other KPSC regulations.

As detailed in *Chapter I Section A – Background & Perspective* section of, in 2011, Duke Energy Corporation (Duke Energy) merged with Progress Energy, Inc. (Progress). As part of its approval of the merger in Case No. 2011-00124, Duke Energy Kentucky was ordered to adhere to 46 merger commitments the Kentucky Public Service Commission (KPSC) established in Case No. 2005-00228, of which four (4), specifically Commitments 10, 11, 12, and 13, specifically related directly to this audit. Also, the three KPSC regulations involve annual reports, filing of cost allocation manual and amendments, and notice of establishment of new non-regulated activity. DEK has generally been in compliance with these items.

Finding II-2 DEK continued to offer a full range of cost-effective energy conservation and efficiency programs.

The energy efficiency programs that DEK offers include:[2]

- Residential programs
  - Program 1: Low Income Services Program
  - Program 2: Residential Energy Assessments Program
  - Program 3: Energy Efficiency Education for Schools Program
  - Program 4: Residential Smart $aver Efficient Residences Program (The Smart $aver® Residential Energy Efficient Products Program and the Energy Efficient Residences Program are individual measures that are part of a single and larger program referred to and marketed as Residential Smart $aver®. For ease of administration and communication with customers, the two measures have been divided into separate tariffs, even though they are a single program.)
  - Program 5: Residential Smart $aver Energy Efficient Products Program
  - Program 6: Power Manager Program

- Program 7: Low Income Neighborhood
- Program 8: My Home Energy Report

- Non-residential programs
  - Program 1: Smart $aver Prescriptive Program
  - Program 2: Smart $aver Custom Program
  - Program 3: PowerShare®
  - Program 4: Non-Residential Small Business Energy Saver Program

DEK was also granted a limited automatic approval process for cost effective pilot programs that are not greater than $75,000 as well as, automatic approval of cost effective additions to existing programs of measures that do not exceed $75,000 per program. In the 2012 status update filing, Case No. 2012-00495, the Commission ordered that DEK file any Demand Side Management (DSM) program evaluations, proposed program expansion(s), or new programs in a separate filing due each year by August 15th. The amendment filings give an annual update of changes to the portfolio and a refreshed look at costs on an annual basis. Based on these orders, DEK indicates that it has been able to continually update and enhance the DSM portfolio in a cost effective manner, essentially filing an updated portfolio on an annual basis.[3]

For example, DEK made a filing in November 2015 with the KPSC for the fiscal year ending June 30, 2015. As indicated in the filing, the company's offering of DSM programs dates back close to two decades. Throughout the years, the company has offered many enhancements to its portfolio with the purpose of increasing participation and providing customers new and innovative opportunities to control their consumption and impact their utility bill. DEK has been using an August filing process since 2013 to enhance the DSM portfolio and react to market changes.[4] The fiscal year 2015 impacts and participation by program are shown in *Exhibit II-1*.[5]

Exhibit II-1
Impacts and Participation by Program
July 2014-June 2015

	1	Summary of Load Impacts July 2014 Through June 2015*		
Residential Programs		**Incremental Participation**	**kWh**	**kW**
Appliance Recycling Program		779	316,032	35
Energy Efficiency Education Program for Schools		2,213	577,006	166
Low Income Neighborhood		718	557,078	147
Low Income Services		243	351,265	89
My Home Energy Report	2	53,267	10,869,228	3,207
Residential Energy Assessments		577	447,175	88
Residential Smart $aver®		385,099	8,639,278	1,243
Power Manager	3	10,719	-	11,033
Total Residential		453,615	21,757,061	16,007
Non-Residential Programs		**Incremental Participation**	**kWh**	**kW**
Smart $aver® Prescriptive - Energy Star Food Service Products		803	519,321	19
Smart $aver® Prescriptive - HVAC		101,560	910,166	247
Smart $aver® Prescriptive - Lighting		37,112	4,435,230	771
Smart $aver® Prescriptive - Motors/Pumps/VFD		572	364,758	34
Smart $aver® Prescriptive - Process Equipment		125	55,054	13
Smart $aver® Custom		1,793	5,071,530	638
Small Business Energy Saver		592,308	528,145	119
Power Share®	4	22	-	21,787
Total Non-Residential		734,295	11,884,203	23,630
Total		1,187,910	33,641,264	39,637

1 - Impacts are net of freeriders, without losses and reflected at the customer meter point.
2 - Actual participants and impact capability shown as of the June 2015 mailings.
3 - Cumulative number of controlled devices installed. Impacts reflect average capability over the contract period.
4 - Impacts reflect average capability over the contract period.

Source: Information Response 52

Based on the scope of this affiliate audit, the calendar year 2015 impacts and participation by program are shown in *Exhibit II-2*.[6]

Exhibit II-2
Impacts and Participation by Program
2015

	1	Summary of Load Impacts 2015		
Residential Programs		**Incremental Participation**	**kWh**	**kW**
Appliance Recycling Program		689	284,381	31
Energy Efficiency Education Program for Schools		1,036	294,723	78
Low Income Neighborhood		609	365,945	100
Low Income Services		208	282,992	70
My Home Energy Report	2	58,157	11,917,320	3,517
Residential Energy Assessments		507	392,925	77
Residential Smart $aver®		289,024	6,570,484	933
Power Manager	3	10,918	-	11,300
Total Residential		361,158	20,108,770	16,105
Non-Residential Programs		**Incremental Participation**	**kWh**	**kW**
Smart $aver® Prescriptive - Energy Star Food Service Products		33	93,466	10
Smart $aver® Prescriptive - HVAC		6,270	139,134	56
Smart $aver® Prescriptive - IT		1	70	
Smart $aver® Prescriptive - Lighting		32,393	4,920,620	794
Smart $aver® Prescriptive - Motors/Pumps/VFD		647	425,821	40
Smart $aver® Prescriptive - Process Equipment		25	11,011	3
Smart $aver® Custom		384	449,001	54
Small Business Energy Saver		2,444,542	2,179,706	499
Power Share®	4	22	-	23,816
Total Non-Residential		2,484,317	8,218,829	25,272
Total		2,845,475	28,327,598	41,377

1 - Impacts are net of freeriders, without losses and reflected at the customer meter point.
2 - Actual participants and impact capability shown as of the December 2015 mailings.
3 - Cumulative number of controlled devices installed. Impacts reflect average capability over the contract period.
4 - Impacts reflect average capability over the contract period.

Source: Information Response 52

All programs listed in *Exhibit II-2* were in effect during 2015. Included are the number of customers and/or energy efficiency kits added during 2015, plus kWh and KW. For dollars, one must look at the fiscal year filings (July-June) that DEK makes annually in November of each year to the KPSC.[7]

Exhibit II-3 displays the cost effectiveness test results by program for FY2015 (July 2014-June 2015).[8]

Exhibit II-3
Cost Effectiveness Test Results by Program
July 2014-June 2015

	2014-2015			
Program Name	**UCT**	**TRC**	**RIM**	**Participant**
Appliance Recycling Program	0.95	1.15	0.61	
Energy Efficiency Education Program for Schools	1.06	1.22	0.73	
Low Income Neighborhood	1.16	1.50	0.77	
Low Income Services	0.60	0.79	0.48	
My Home Energy Report	1.83	1.83	1.02	
Residential Energy Assessments	3.53	3.55	1.71	
Residential Smart $aver®	2.87	2.98	1.15	6.10
Power Manager	3.31	3.86	3.31	
Smart $aver® Custom	7.56	3.46	1.49	3.98
Smart $aver® Prescriptive - Energy Star Food Service Products	7.96	3.70	1.42	5.51
Smart $aver® Prescriptive - HVAC	3.67	1.01	1.39	1.38
Smart $aver® Prescriptive - Lighting	5.02	1.35	1.49	1.72
Smart $aver® Prescriptive - Motors/Pumps/VFD	6.56	2.35	1.50	3.36
Smart $aver® Prescriptive - Process Equipment	6.64	4.75	1.80	6.19
Smart $aver® Prescriptive - IT*	NA	NA	NA	
Small Business Energy Saver	3.79	2.42	1.49	2.69
Power Share®	3.98	12.61	3.98	

*NA = Not Applicable (There was no participation for this measure for July 2014 - June 2015.)

Source: Information Response 52 and Interview 10
UCT=Utility Cost Test; includes only DEK costs; target > 1;
TRC=Total Resource Test; includes DEK and participant costs; target > 1
RIM=Rate Impact Measure; includes non-participants, target > 1
Participant=includes participant costs only; target > 1; blank indicates that participant charged no costs for program

The Utility Cost Test (UCT) test compares utility benefits (avoided energy, transmission and distribution capacity and generation capacity related costs) to incurred utility costs to implement the program, such as marketing, customer incentives, and implementation costs, and does not consider other benefits such as participant savings or societal impacts.[9] This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.[10] For UCT test results below 1, these figures according to Duke Energy management, occur as follows:[11]

- The Appliance Recycling Program results are below 1, because the program is no longer offered, as the vendor stopped participating; however, Duke Energy is looking to begin the program again with another vendor.
- The Low Income Services results are below 1, but because DEK believes it is an important program, it continues to offer it to low income customers.

For Total Resource Cost (TRC) test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test; however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.[12] For TRC test results below 1, these figures according to Duke Energy management, DEK believes it is an important program; therefore, it continues to offer it to low income customers despite not making the target figure of 1.[13]

The Rate Impact Measure (RIM) test, or non-participants test, indicates if rates are expected to increase or decrease over the long-run as a result of implementing the program.[14] It compares the benefits to the utility, the same benefits as included in the UCT test, to the costs required to implement a program including lost revenues.[15]

The Participant (PCT) test compares the benefits to the participant or customer through bill savings and incentives from the utility, relative to the costs to the participant for implementing the energy efficiency measure. The costs can include incremental equipment and installation costs, as well as increased annual operating cost, if applicable. This test is critical to understanding the market viability of a program or measure.[16] The benefits include reductions in utility bills, incentives paid by the utility and any state, federal or local tax benefits received.[17] None of the participants cost effectiveness test results are below 1, but those showing as blank are because participants do not have any costs associated with such programs.[18]

Finding II-3 The Board of Directors of the combined company includes at least one non-employee member who resides in the company's service territory in Kentucky, Indiana, or Ohio.

The Board of Directors of the combined company must include at least one non-employee member who resides in the company's service territory in Kentucky, Indiana, or Ohio. Of the 12 current Duke Energy directors, Michigan G. Browning resides in Indiana,[19] and is Chair of Browning Investments, LLC.[20] He is an *Independent Lead Director* on Duke Energy's Board whose responsibilities include: Member, Compensation Committee; Chair, Corporate Governance Committee; and Member, Finance and Risk Management Committee. He has been a *Director* of Duke Energy since 2006[21]

Finding II-4 **DEK appears to be responsive to the KPSC's merger order conditions, but it cannot be determined if any merger costs will be passed on to DEK ratepayers until DEK's next rate case.**

According to Duke Energy management, any costs to achieve associated with the merger are charged to the appropriate account pursuant to communicated guidelines provided to Schumaker & Company during our 2013 and 2015 audits. Then, at the time of a rate case, adjustments would be made, if necessary, to remove costs charged to "costs to achieve" from the revenue requirement calculation to be used for establishing new base rates. Duke Energy management believes that such adjustments would ensure that DEK meets it commitment to ensure that "no merger costs are passed on to its retail electric or gas customers."[22]

C. Recommendations

Recommendation II-1 **Provide sufficient documentation during DEK's next rate case to ensure that Duke Energy/Progress Energy merger costs were not passed on to DEK ratepayers. (Refer to Finding II-4)**

According to documentation provided by Duke Energy management in our prior 2013 audit, costs could have been treated as costs to achieve (CTA) the merger if they are incremental, non-recurring, and incurred as a direct result of the merger. Also, for operations & maintenance (O&M) purposes, internal labor was not considered incremental; therefore, it was not included by Duke Energy in CTA, although internal labor could have been charged to capital CTA projects, if employees were involved in the merger activities. External labor (contractors) hired to work on O&M and capital CTA projects were considered incremental and were to be directly charged to CTA projects. Other guidelines, such as those provided for travel/lodging, were included in the documentation. Therefore, we recommended that, during the next DEK rate case, Duke Energy must provide rationalization as to why internal labor costs are not charged to CTA merger costs in selected situations, plus it must provide sufficient documentation to ensure that Duke Energy/Progress Energy merger CTA were not being passed on to Duke Energy Kentucky ratepayers.[23]

As there has not been a rate case since our 2013 audit report, no such documentation has been provided, but should be in DEK's next rate case.[24]

C. Recommendations

None

[1] / Information Response 48
[2] / Information Response 52
[3] / Information Response 52
[4] / Information Response 52
[5] / Information Response 52
[6] / Information Response 52
[7] / Interview 10
[8] / Information Response 52 and Interview 10
[9] / Information Response 52
[10] / Duke Energy Carolinas Integrated Resource Plan (Annual Report) 2011
[11] / Interview 10
[12] / Information Response 52 and Duke Energy Carolinas Integrated Resource Plan (Annual Report) 2011
[13] / Interview 10
[14] / Information Response 52 and Duke Energy Carolinas Integrated Resource Plan (Annual Report) 2011
[15] / Information Response 52
[16] / Information Response 52
[17] / Duke Energy Carolinas Integrated Resource Plan (Annual Report) 2011
[18] / Interview 10
[19] / Information Response 51
[20] / http://www.duke-energy.com/corporate-governance/board-of-directors/board.asp indicates Browning Consolidated, LLC; however, Browning's website http://www.browninginvestments.com/about/company-overview indicates Browning Investments, LLC.
[21] / http://www.duke-energy.com/corporate-governance/board-of-directors/board.asp
[22] / Prior Schumaker & Company audit report, Interview 1, and Information Response 50
[23] / Prior Schumaker & Company audit report
[24] / Information Responses 48 and 50
[25] / Information Response 1
[26] / Interview 1
[27] / Information Response 1
[28] / Information Responses 1 and 2
[29] / Information Response 53 and https://www.duke-energy.com/about-us/leaders-
[30] / Information Response 6
[31] / Information Response 38
[32] / Interview 2
[33] / Prior Schumaker & Company audit report, Information Response 41, and Interviews 2 and 7
[34] / Information Response 41
[35] / Information Response 54
[36] / Information Responses 41 and 65
[37] / Information Response 4
[38] / Information Response 4
[39] / Information Responses 5 and 64 and Interview 3
[40] / Schumaker & Company Prior Audit Report
[41] / Information Response 64
[42] / KRS 278.2213
[43] / Information Response 37 and Interviews 6 and 8
[44] / Interviews 6 and 8

[93] / Interviews 1 and 2
[94] / Interview 1
[95] / Information Response 10
[96] / Information Response 10
[97] / Interview 3
[98] / Interview 3
[99] / Interview 2
[100] / Interview 1
[101] / Information Responses 2 and 8 and Interview 1
[102] / Interview 1
[103] / Interview 1
[104] / Interview 1
[105] / Information Response 55
[106] / Interview 1
[107] / Interview 8
[108] / Interview 3
[109] / Schumaker & Company prior audit report and Interview 3
[110] / Interview 3
[111] / Schumaker & Company prior audit report and Interview 3
[112] / Information Response 43
[113] / Information Response 43
[114] / Information Response 45 and Interview 3
[115] / Schumaker & Company prior audit report and Interview 3
[116] / Schumaker & Company prior audit report and Interview 3
[117] / Schumaker & Company prior audit report and Interview 3
[118] / Schumaker & Company prior audit report and Interview 3
[119] / Schumaker & Company prior audit report and Interview 3
[120] / Information Response 44
[121] / Information Response 42
[122] / Prior Schumaker & Company audit report and Interview 1
[123] / Information Response 2 and Interview 3
[124] / Information Response 10 and Interview 1
[125] / Information Response 9 and Interview 1
[126] / Interview 1
[127] / Prior Schumaker & Company audit report and Interview 1
[128] / Information Responses 2 and 8
[129] / Schumaker & Company prior audit report and Information Responses 2 and 8, and Interview 6
[130] / Information Response 21
[131] / Schumaker & Company prior audit report and Information Responses 2 and 8, and Interview 6
[132] / Information Responses 2 and 8
[133] / Information Responses 2 and 8
[134] / Interview 1, 2, and 8
[135] / Interview 1, 2, and 8
[136] / Schumaker & Company prior audit report
[137] / Schumaker & Company prior audit report
[138] / Information Response 47
[139] / Information Response 48
[140] / Duke Energy Website, Fixed Income Investors, Long-term Debt Details

[45] / Interview 8
[46] / Schumaker & Company prior audit report
[47] / Interview 7
[48] / Interview 7
[49] / Interview 7 and Information Response 26
[50] / Interview 7
[51] / Interview 7
[52] / Interview 7 and Information Response 26
[53] / Information Response 25
[54] / Information Response 18
[55] / Schumaker & Company prior audit report and Interview 8
[56] / Information Responses 18 and 30
[57] / Interview 6
[58] / Information Responses 2 and 8
[59] / Information Response 2
[60] / Interview 8
[61] / Information Response 48
[62] / Information Response 48
[63] / Information Response 48 and Interview 8
[64] / Interview 8
[65] / Interview 8
[66] / Information Responses 18 and 19
[67] / Information Response 61
[68] / Information Response 61
[69] / Information Response 61
[70] / Information Response 61
[71] / Information Response 61
[72] / Information Response 19
[73] / Interview 8
[74] / Schumaker & Company prior audit report and Interview 8
[75] / Interview 6
[76] / Interview 6
[77] / Information Response 16
[78] / Interview 6
[79] / Interview 6
[80] / Information Response 14 and Interview 6
[81] / Information Response 14 and Interview 6
[82] / Information Response 14
[83] / Information Response 14
[84] / Information Response 14
[85] / Duke Energy Website and Information Response 49
[86] / Interview _ and Information Response 49
[87] / Information Response 49 and Interview 7
[88] / Information Response 49
[89] / Information Response 32
[90] / Information Response 2
[91] / Information Response 34
[92] / Information Response 10

[141] / Duke Energy Website, Fixed Income Investors, Recent Issuances & Prospectus
[142] / Information Response 24
[143] / Information Response 24
[144] / Information Response 23, Attachment 2 and Interview 5
[145] / Information Response 23, Attachment 2
[146] / Information Response 23, Attachment 2
[147] / Information Response 23, Attachment 2
[148] / Information Response 23, Attachment 2
[149] / Information Response 23, Attachment 2
[150] / Information Response 23, Attachment 2
[151] / Information Response 23, Attachment 1
[152] / Information Response 23, Attachment 1
[153] / Information Response 23, Attachment 1
[154] / Information Response 23, Attachment 1
[155] / Duke Energy Website, Fixed Income Investors, Credit Facility & Liquidity, Master Credit Facility Agreement
[156] / Duke Energy Website, Fixed Income Investors, Credit Facility & Liquidity, Master Credit Facility Agreement
[157] / Duke Energy Website, Fixed Income Investors, Credit Facility & Liquidity, Master Credit Facility Agreement
[158] / Information Response 12
[159] / Interview 5
[160] / Information Responses 12 and 58
[161] / Information Response 59
[162] / Interview 9
[163] / Information Response 37 and Interview 9
[164] / Information Response 36
[165] / Prior Schumaker & Company Audit Report
[166] / Information Response 36
[167] / Information Response 36
[168] / Information Response 15
[169] / Interview 3
[170] / Interview 3
[171] / Information Response 15
[172] / Information Response 15
[173] / Information Response 15
[174] / Information Response 15
[175] / Information Response 15
[176] / Information Response 15

III. Affiliate Relationships

A. Background & Perspective

Organization Structure

While *Exhibit I-1* displayed in the *Executive Summary* chapter is a summary look at Duke Energy Corporation's (Duke Energy's) organization, *Exhibit III-1* is a detailed look, including changes made September 30, 2015-December 31, 2015.[23]

Exhibit III-1
Detailed Duke Energy Corporation Organization Structure
as of December 31, 2015
(Page 1 of 10)

Summary Level

- Duke Energy Corporation (DE 05.03.2005)
  - Bison Insurance Company Limited (100%)(SC 06.15.2012)
    - NorthSouth Insurance Company Limited (100%)(SC 06.15.2012)
  - Cinergy Corp. (100%)(DE 06.30.1993)
    - (see Appendix A for subsidiaries)
  - Duke Energy Renewables NC Solar, LLC (100%)(DE 02.25.2010)
    - (see Appendix B for subsidiaries)
  - Duke Energy Pipeline Holding Company, LLC (100%)(DE 08.27.2014)
    - Duke Energy ACP, LLC (100%)(DE 08.27.2014)
      - Atlantic Coast Pipeline, LLC (40%)(DE 08.27.2014)
    - Duke Energy Sabal Trail, LLC (100%)(DE 02.06.2015)
      - Sabal Trail Transmission, LLC(7.5%)(DE 05.10.2013)
  - Duke Energy Carolinas, LLC (100%)(NC 11.27.1963)
    - APOG, LLC (20%)(DE 06.22.2007)
    - Advance SC LLC (100%)(SC 07.09.2004)
    - Caldwell Power Company (100%)(NC 07.28.1921)
    - Carolinas Virginia Nuclear Power Associates, Inc. (25%)(NC 10.04.1956)
    - Catawba Manufacturing and Electric Power Company (100%)(NC 10.15.1901)
    - Claiborne Energy Services, Inc. (100%)(LA 03.01.1990)
    - Duke Energy Receivables Finance Company, LLC (100%)(DE 07.16.2003)
    - Eastover Land Company (100%)(KY 06.30.1970)
    - Eastover Mining Company (100%)(KY 07.15.1970)
    - Greenville Gas and Electric Light and Power Company (100%)(SC 01.28.1861)
    - MCP, LLC (100%)(SC 08.18.2000)
    - Piedmont Venture Partners Limited Partnership (10.64%)(NC 10.03.1996)
    - Sandy River Timber, LLC (100%)(SC, 10.26.2007)
    - Southern Power Company (100%)(NC 12.30.1927)
    - TBP Properties, LLC (100%)(SC 12.11.2006)
    - TRES Timber, LLC (100%)(SC 12.11.2006)
    - Wateree Power Company (100%)(SC 02.26.1909)
    - Western Carolina Power Company (100%)(NC 09.10.1907)
  - Duke Energy Corporate Services, Inc. (100%)(DE 05.25.2008)
    - Duke Energy Business Services LLC (100%)(DE 11.18.1998)
  - Duke Energy Registration Services, Inc. (100%)(DE 11.18.1998)
    - (see Appendix C for subsidiaries)
  - Progress Energy, Inc. (100%)(NC 08.19.1999)
    - (see Appendix D for subsidiaries)

Source: Information Response 1 (SCH-DR-01-001 Supplemental Attachment)

Exhibit III-1
Detailed Duke Energy Organization Structure
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Cinergy Corporation
(including Duke Energy Kentucky organization)

Appendix A

```
Duke Energy Corporation
└── Cinergy Corp. (100%)
Cinergy Corp (100%)(DE 06.30.1993)
├── Cinergy Global Resources, Inc. (100%)(DE 05.15.1998)
│   └── (see Appendix E for subsidiaries)
├── Duke Energy Renewables Holding Company, LLC (100%)(DE 10.24.1994)
│   ├── Duke Energy Commercial Enterprises, Inc. (100%)(IN 10.06.1992)
│   │   └── (see Appendix F for subsidiaries)
│   ├── Cinergy-Centrus, Inc. (100%)(DE 04.23.1998)
│   ├── Cinergy-Centrus Communications, Inc. (100%)(DE 07.17.1998)
│   ├── Cinergy Technology, Inc. (100%)(IN 12.12.1991)
│   ├── Duke-Cadence, Inc. (100%)(IN 12.27.1989)
│   ├── Duke Energy Renewables, Inc. (100%)(DE 02.11.1997)
│   │   └── (see Appendix G for subsidiaries)
│   ├── Duke-Reliant Resources, Inc. (100%)(DE 01.14.1998)
│   ├── Frontier Windpower, LLC (100%)(DE 08.21.2015)
│   ├── Frontier Windpower II, LLC (100%)(DE 11.18.2015)
│   ├── Los Vientos Windpower III Holdings, LLC (100%)(DE 07.24.2013)
│   │   └── Los Vientos Windpower III, LLC (100%)(DE 07.24.2013)
│   ├── Los Vientos Windpower IV Holdings, LLC (100%)(DE 07.24.2013)
│   │   └── Los Vientos Windpower IV, LLC (100%)(DE 07.24.2013)
│   ├── Los Vientos Windpower V Holdings, LLC (100%)(DE 07.24.2013)
│   │   └── Los Vientos Windpower V, LLC (100%)(DE 07.24.2013)
│   └── Rio Bravo Windpower, LLC (100%)(DE 07.17.2015)
├── Cinergy Receivables Company, LLC (100%)(DE 01.10.2002)
├── Cinergy Power Generation Services, LLC (100%)(DE 11.22.2000)
├── Duke Energy Indiana, LLC (100%)(IN 09.06.1941)
│   └── South Construction Company, Inc. (100%)(IN 05.31.1934)
├── Duke Energy Ohio, Inc. (100%)(OH 04.03.1837)
│   ├── Duke Energy Beckjord, LLC (100%)(DE 05.31.2012)
│   ├── Duke Energy Kentucky, Inc. (100%)(KY 03.20.1901)
│   ├── KO Transmission Company (100%)(KY 04.11.1994)
│   ├── Miami Power Corporation (100%)(IN 03.25.1930)
│   ├── Ohio Valley Electric Corporation (9%)(OH 10.01.1952)
│   └── Tri-State Improvement Company (100%)(OH 01.14.1964)
├── Duke Energy SAM, LLC (100%)(DE 05.31.2012)
│   └── Duke Energy Vermillion II, LLC (100%)(DE 10.14.2010)
├── Duke Energy Transmission Holding Company, LLC (100%)(DE 07.16.2008)
│   ├── Duke Energy Beckjord Storage LLC (100%)(DE 09.04.2013)
│   ├── Duke-American Transmission Company LLC (50%)(DE 04.11.2011)
│   │   └── (see Appendix L for subsidiaries)
│   └── Pioneer Transmission, LLC (50%)(IN 07.31.2008)
└── Duke Technologies, Inc. (100%)(DE 07.26.2000)
    ├── Duke Energy One, Inc. (100%)(DE 09.05.2000)
    │   └── Cinergy Solutions – Utility, Inc. (100%)(DE 09.27.2004)
    ├── Duke Investments, LLC (100%)(DE 07.25.2000)
    │   └── Current Group, LLC (0.395%)(DE 10.24.2000)
    ├── Duke Supply Network, LLC (100%)(DE 08.10.2000)
    └── Duke Ventures II, LLC (100%)(DE 09.01.2000)
        └── PHX Management Holdings, LLC (100%)(DE 10.15.2015)
            └── Phoenix Energy Technologies, Inc. (70%)(DE 12.20.2008)
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Exhibit III-1
Detailed Duke Energy Organization Structure
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Duke Energy Renewables NC Solar, LLC

Appendix B

- Duke Energy Corporation
  - Duke Energy Renewables NC Solar, LLC (100%)

- Duke Energy Renowables NC Solar, LLC (100%)(DE 02.25.2010)
  - Bethel Price Solar, LLC (100%)(DE 10.11.2013)
  - Clear Skies Solar Holdings, LLC (100%)(DE 11.15.2012)
    - Clear Skies Solar, LLC (100%)(DE 11.15.2012)
      - Black Mountain Solar, LLC (100%)(AZ 05.04.2011)
      - CS Murphy Point, LLC (100%)(NC 01.12.2010)
      - Martins Creek Solar NC, LLC (100%)(NC 04.08.2010)
      - Murphy Farm Power, LLC (100%)(NC 01.27.2010)
      - North Carolina Renewable Properties, LLC (100%)(NC 06.03.2010)
      - RP-Orlando, LLC (100%)(DE 03.05.2010)
      - Solar Star North Carolina I, LLC (100%)(DE 11.07.2006)
      - Solar Star North Carolina II, LLC (100%)(DE 12.15.2009)
      - Taylorsville Solar, LLC (100%)(DE 04.29.2010)
  - Colonial Eagle Solar, LLC (100%)(DE 05.20.2014)
  - Conetoe II Solar, LLC (100%)(NC 04.28.2014)
  - Creswell Alligood Solar, LLC (100%)(DE 06.27.2014)
  - Dogwood Solar, LLC (100%)(DE 09.12.2012)
  - Everetts Wildcat Solar, LLC (100%)(09.25.2014)
  - Fresh Air Energy X, LLC (100%)(NC 04.03.2014)
  - HXOap Solar One, LLC (100%)(04.30.2013)
  - Long Farm 46 Solar, LLC (100%)(NC 09.22.2014)
  - SolNCPower5, LLC (100%)(NC 10.17.2013)
  - SolNCPower6, LLC (100%)(NC 10.17.2013)
  - SolNCPower10, L L C (100%)(NC 08.01.2014)
  - Tarboro Solar LLC (100%)(DE 08.26.2013)
  - Washington Airport Solar, LLC (100%)(DE 10.16.2013)
  - Washington White Post Solar, LLC (100%)(DE 09.10.2012)
  - Washington Millfield Solar, LLC (100%)(DE 05.23.2013)
  - Windsor Cooper Hill Solar, LLC (100%)(DE 10.11.2013)

Exhibit III-1
Detailed Duke Energy Organization Structure
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Duke Energy Registration Services

Appendix C

- Duke Energy Corporation
  - Duke Energy Registration Services, Inc. (100%)

- Duke Energy Registration Services, Inc. (100%)(DE 11 18 1998)
  - PanEnergy Corp. (100%)(DE 01.26.1981)
    - Duke Energy Services, Inc. (100%)(DE 06.08.1959)
      - Duke Energy Marketing Corp. (100%)(NV 11.07.1994)
        - Duke/Louis Dreyfus L.L.C. (50%)(NV 03.01.1995)
      - DETMI Management, Inc. (100%)(CO 06.21.1994)
        - Duke Ventures Real Estate, LLC (100%)(DE 06.09.2009)
          - Century Group Real Estate Holdings, LLC (100%)(SC 02.06.2013)
        - DTMSI Management Ltd. (100%)(British Columbia 12.18.2009)
          - Duke Energy Services Canada ULC (31%)(British Columbia 09.17.2009)
        - Duke Energy Trading and Marketing, L.L.C. (100%)(DE 07.10.1996)
        - Duke Ventures, LLC (100%)(NV 12.19.2000)
      - Dixilyn-Field Drilling Company (100%)(DE 01.31.1977)
        - Dixilyn-Field (Nigeria) Limited (100%)(Nigeria 11.14.1977)
      - Duke Energy Services Canada ULC (69%)(British Columbia 09.17.2009)
      - DukeNet VentureCo, Inc. (100%)(DE 05.18.2010)
    - Eastman Whipstock do Brasil Ltda (100%)(Brazil 05.21.1979)
    - Eastman Whipstock S.A. (100%)(Argentina 10.13.1981)
    - Energy Pipelines International Company (100%)(DE 04.28.1975)
    - Duke Energy China Corp. (100%)(DE 08.13.1976)
    - Seahorse do Brasil Servicos Maritimos Ltda. (100%)(Brazil 03.30.1979)
  - Duke Energy Americas, LLC (100%)(DE 07.02.2004)
    - Duke Energy International, LLC (DE 09.18.1997)
      - *(See separate chart for subsidiaries)*
    - Duke Energy Merchants, LLC (100%)(DE 04.23.1999)
    - Duke Energy North America, LLC (100%)(DE 09.18.1997)
      - Duke Energy Marketing America, LLC (100%)(DE 01.03.2001)
  - Duke Energy Carolinas Plant Operations, LLC (100%)(DE 05.29.2001)
    - DE Nuclear Engineering, Inc. (100%)(NC 03.17.1969)
  - Duke Energy Royal, LLC (100%)(DE 03.13.2002)
  - Duke/Louis Dreyfus L.L.C. (50%)(NV 03.01.1995)
  - Duke Project Services, Inc. (100%)(NC 07.01.1966)
    - D/FD Operating Services LLC (50.0001%)(DE 03.07.1996)
    - Duke/Fluor Daniel (50.0001%)(NC 09.01.1997)
      - D/FD Holdings, LLC (100%)(DE 12.15.2005)
    - Duke/Fluor Daniel El Salvador S.A. de C.V. (50%)(El Salvador)
    - Duke/Fluor Daniel International (50.0001%)(NV 09.01.1994)
      - Duke/Fluor Daniel Caribbean, S.E. (99%)(Puerto Rico 12.08.1996)
    - Duke/Fluor Daniel International Services (50.0001%)(NV 09.01.1994)
      - Duke/Fluor Daniel Caribbean, S.E. (0.50%)(Puerto Rico 12.08.1996)
      - Duke/Fluor Daniel International Services (Trinidad) Ltd. (100%)(Trinidad and Tobago 12.03.1998)

Exhibit III-1
Detailed Duke Energy Organization Structure
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Progress Energy, Inc.

Appendix D

- Duke Energy Corporation
  - Progress Energy, Inc. (100%)

- Progress Energy, Inc. (100%)(NC 08.19 1999)
  - Duke Energy Progress, LLC* (100%)(NC 04.08 1926)
    - APOG, LLC (10%)(DE 06 22.2007)
    - Capitan Corporation (100%)(TN 12 28 1931)
    - Carousel Capital Partners LP (3.07%)(DE 03 27 1996)
    - CaroFund, Inc (100%)(NC 08.15 1995)
      - (see Appendix H for CaroFund, Inc and CaroHome, LLC subsidiaries)
    - CaroHome, LLC (99%)(NC 04 21,1995)
      - (see Appendix H for CaroFund, Inc. and CaroHome, LLC subsidiaries)
    - Duke Energy Progress Receivables LLC (100%)(DE 10 16 2013)
    - Kinetic Ventures I LLC (11 11%)(DE 04.18.1997)
    - Kinetic Ventures II, LLC (14.28%)(DE 12.15.1999)
    - Maxey Flats Site IRP, LLC (3.02%)(VA 05 05 1995)
    - NCEF Liquidating Trust** (4.99%)
    - Powerhouse Square, LLC (99 9%)(NC 01 13 1998)
    - Progress Energy EnviroTree Inc (50%)(NC 12.22 2003)
    - South Atlantic Private Equity Fund IV, LP (14 3294%)(DE 06 26 1997)
    - WNC Institutional Tax Credit Fund LP (99%)(CA 08.12 1994)
  - Florida Progress, LLC (100%)(FL 01 21.1982)
    - Duke Energy Florida, LLC (100%)(FL 07,18 1899)
      - APOG, LLC (10%)(DE 06.22.2007)
      - Inflexion Fund, LP (16.78%)(DE 05 08.2002)
      - Progress Energy EnviroTree, Inc (50%)(NC 12.22.2003)
      - SanGroup, LLC (45.0482%)(FL 04 28 2008)
      - Duke Energy Florida Receivables LLC (100%)(DE 01.27 2014)
      - Duke Energy Florida Solar Solutions, LLC (100%)(DE 02 25.2015)
    - Florida Progress Funding Corporation (100%)(DE 03 18.1999)
    - Progress Capital Holdings, Inc (100%)(FL 05.17.1988)
      - Advantage IQ, Inc (0.034%)(WA 11.06 1995)
      - PIH Inc (100%)(FL 08.12.1997)
        - PIH Tax Credit Fund III Inc. (100%)(FL 04 18.2001)
          - Lehman Housing Tax Credit Fund, LP (11.03%)(NY 03.23.1995)
        - PIH Tax Credit Fund IV, Inc (100%)(FL 04.18 2001)
          - McDonald Corporate Tax Credit Fund, LP (9%)(DE 07.12 1993)
        - PIH Tax Credit Fund V, Inc (100%)(FL 04 18 2001)
          - National Corporate Tax Credit Fund VI, a California Limited Partnership (15 57743%)(CA 04.19 1996)
      - Progress Fuels Corporation (100%)(FL 03.30 1976)
        - Kentucky May Coal Company, LLC (100%)(VA 11.27.1978)
        - Progress Synfuel Holdings, Inc. (100%)(DE 12.07 1999)
      - Progress Telecommunications Corporation (100%)(FL 10 15 1998)
        - Peak Tower, LLC (51%)(DE 02.26.2010)
        - PT Holding Company, LLC (55%)(DE 01 17 2006)
          - PT Attachment Solutions, LLC (100%)(DE 02 16 2006)
  - Strategic Resource Solutions Corp (100%)(NC 01.22 1996)

* Duke Energy Progress, LLC (formerly known as Carolina Power & Light Company) is also the beneficial owner of several entities that were generally acquired through bankruptcy proceedings. These entities are not shown separately due to its minor ownership interest (generally <1%)

As of December 31, 2008, it is believed CP&L owns a beneficial interest in the following entities:
Air Nail Unsecured Creditors Liquid Trust, Creditors Reserve Trust, Heilig-Meyers Liquidating Trust, Estate of Jillian Entertainment, HA2003 Liquidating Trust, CFC Trust, Fleming Post Confirmation Trust, Bombay Liquidation Trust, USOP Liquidating LLC, ZB Company Liquidation Trust and ANC Liquidating Trust

** NCEF Liquidating Trust, a business trust holds the assets of The North Carolina Enterprise Fund Limited Partnership now dissolved

Exhibit III-1
Detailed Duke Energy Organization Structure
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Cinergy Global Resources, Inc.

Appendix E

- Duke Energy Corporation
  - Cinergy Corp (100%)
    - Cinergy Global Resources, Inc (100%)

- Cinergy Global Resources, Inc. (100%)(DE 05 15 1998)
  - Cinergy Global Power, Inc. (100%)(DE 09.04 1997)
    - CGP Global Greece Holdings, SA (99 99%)(Greece 08 10 2001)
    - Cinergy Global (Cayman) Holdings, Inc (100%)(Cayman Islands 09 04 1997)
      - Cinergy Global Tsavo Power (100%)(Cayman Islands 09 04 1997)
        - IPS-Cinergy Power Limited (48.2%)(Kenya 04 28 1999)
          - Tsavo Power Company Limited (49.9%)(Kenya 01 22.1998)
    - Cinergy Global Holdings, Inc (100%)(DE 12 18 1998)
      - CGP Global Greece Holdings, SA (.01%)(Greece 08 10 2001)
    - Cinergy Global Power Africa (Proprietary) Limited (100%)(South Africa 08 03 1999)

Duke Energy Commercial Enterprises, Inc.

Appendix F

- Duke Energy Corporation
  - Cinergy Corp. (100%)
    - Duke Energy Renewables Holding Company, LLC (100%)
      - Duke Energy Commercial Enterprises, Inc (100%)

- Duke Energy Commercial Enterprises, Inc (100%)(IN 10 08 1952)
  - CinCap V, LLC (10%)(DE 07 21 1998)
  - Cinergy Climate Change Investments, LLC (100%)(DE 06 09 2003)

Duke Energy Renewables, Inc.

Appendix G

- Duke Energy Corporation
  - Cinergy Corp (100%)
    - Duke Energy Renewables Holding Company, LLC (100%)
      - Duke Energy Renewables, Inc (100%)

- Duke Energy Renewables, Inc (100%)(DE 02 11 1997)
  - DEGS Biomass, LLC (100%)(DE 09 22 2008)
  - Duke Energy Renewables Commercial, LLC (100%)(DE 12 16 2014)
  - Duke Energy Renewables Solar, LLC (100%)(DE 05 13 2010)
    - Caprock Solar 1 LLC (100%)(DE 10 31 2014)
      - Caprock Solar Holdings 1, LLC (100%)(DE 04 30 2015)
    - Caprock Solar 2 LLC (100%)(DE 10 31 2014)
      - Caprock Solar Holdings 2, LLC (100%)(DE 04 30 2015)
    - ISH Solar Grin, LLC (100%)(DE 08 16 2011)
    - RE AZ Holdings LLC (100%)(DE 10 11 2010)
      - RE Ajo 1 LLC (100%)(DE 10.05 2009)
      - RE Bagdad Solar 1 LLC (100%)(DE 08 13 2009)
    - TX Solar I LLC (100%)(DE 05 27 2009)
    - Gato Montes Solar, LLC (100%)(DE 12 09 2011)
    - West Texas Angelos Holdings LLC (100%)(DE 06 08 2012)
    - RE SFCity1 Holdco, LLC (100%)(DE 06 23 2010) acquired on 08 12 2013
      - RE SFCity1 GP LLC (100%)(DE 05 14 2009) acquired on 08 12 2013
      - RE SFCity1, LP (99% owned by RE SFCity1 Holdco LLC, 1% owned by RE SFCity1 GP LLC) (DE 05 14 2009)
    - Seville Solar Holding Company, LLC (100%)(DE 05 06 2014)
      - Seville Solar Investments One LLC (100%)(DE 04 28 2015)
        - Seville Solar One LLC (100%)(DE 05 06 2014)
        - Tallbear Seville LLC (49%)(CA 11 29 2012)
      - Seville Solar Two, LLC (100%)(DE 05 06 2014)
    - Wild Jack Solar Holdings LLC (100%)(DE 10 06 2015)
      - Wild Jack Solar LLC (100%)(DE 10 06 2015)
        - Pumpjack Solar I, LLC (100%)(DE 02 09 2012)
        - Wildwood Solar I, LLC (100%)(DE 02 09 2012)
  - Duke Energy Renewables Wind, LLC (100%)(DE 05 23 2007)
    - (see Appendix I for subsidiaries)
  - Duke Energy Generation Services, Inc.(DE 06 02 2000)
    - (see Appendix J for subsidiaries)
  - SUEZ-DEGS, LLC (50%)(DE 02 18 1997)
  - Duke Energy Renewable Services, LLC (100%)(DE 10 22 2012)
  - DEGS of Tuscola, Inc (100%)(DE 10 13 1998)
  - REC Solar Commercial Corporation (60%)(DE 11 26 2013)

Exhibit III-1
Detailed Duke Energy Organization Structure
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Duke Energy Carol Fund, Inc.

Appendix H

- Duke Energy Corporation
  - Progress Energy, Inc. (100%)
    - Duke Energy Progress, LLC (100%)
      - CaroFund, Inc
        - CaroHome, LLC

- Duke Energy Progress, LLC (100%)(NC 04.08 1926)
  - CaroFund, Inc. (100%)(NC 08.15.1995)
    - CaroHome, LLC (1%)(NC 04 21 1995)
    - Historic Property Management LLC (100%)(NC 12 09 1999)
  - CaroHome, LLC (99%)(NC 04.21 1995)
    - ARV Partners IV Anaheim LP (19 8%)(CA 03.10 1992)
    - Grove Arcade Restoration LLC (99 99%)(NC 11 29 1999)
    - Baker House Apartments LLC (99.99%)(NC 01.26 1998)
    - HGA Development LLC (99.99%)(NC 12 09 1999)
    - Cedar Tree Properties LP (24.9849%)(WA 07.05 1994)
    - First Partners Corporate LP II (15 84%)(MA 11 26 1996)
    - Wirik Hotel Apartments LLC (99 99%)(NC 03.14.1997)
    - PRAIRIE, LLC (99.99%)(NC 10.29.1998)

Duke Eenrgy Renewables Wind, LLC

Appendix I

- Duke Energy Corporation
  - Cinergy Corp. (100%)
    - Duke Energy Renewables Holding Company, LLC (100%)
      - Duke Energy Renewables, Inc. (100%)
        - Duke Energy Renewables Wind, LLC (100%)

- Duke Energy Renewables Wind, LLC (100%)(DE 05 23 2007)
  - Catamount Energy Corporation (100%)(VT 08 23 1992)
    - (see Appendix K for subsidiaries)
  - DEGS Wind Supply, LLC (100%)(DE, 12.11.2007)
  - DEGS Wind Supply II, LLC (100%)(DE 08 26 2008)
  - Green Frontier Windpower Holdings, LLC (100%)(DE 02.22.2010)
    - Green Frontier Windpower LLC (100%)(DE 05.13 2010)
      - Three Buttes Windpower, LLC (100%)(DE 08.26 2008)
      - Silver Sage Windpower, LLC (100%)(DE 04.16 2007)
      - Happy Jack Windpower, LLC (100%)(DE 10.27 2006)
      - Kit Carson Windpower, LLC (100%)(DE 06.23.2009)
      - North Allegheny Wind, LLC (100%)(DE 05.31.2006)
  - Ironwood-Cimarron Windpower Holdings, LLC (100%)(DE 12.08 2010)
    - DS Cornerstone, LLC (50%)(DE 04.05 2012)
      - Summit Wind Energy Mesquite Creek, LLC (100%)(DE 08.01 2013)
        - Mesquite Creek Wind LLC (100%)(DE 09.12 2008)
      - Free State Windpower, LLC (100%)(DE 02 01 2012)
        - Ironwood Windpower, LLC (100%)(DE 12.08.2010)
        - Cimarron Windpower II, LLC (100%)(DE 03.07.2011)
  - Kit Carson Windpower II Holdings, LLC (100%)(DE 07.24.2013)
    - Kit Carson Windpower II, LLC (100%)(DE 07.24.2013)
  - Los Vientos Windpower IA Holdings, LLC (100%)(DE 01 27 2011)
    - Los Vientos Windpower IA, LLC (100%)(DE 01.27 2011)
  - Los Vientos Windpower IB Holdings, LLC (100%)(DE 08 02 2012)
    - Los Vientos Windpower IB, LLC (100%)(DE 07 11.2011)
  - Notrees Windpower, LP (99%)(DE 09.30 2005)
  - Ocotillo Windpower, LP (99%)(DE 12.22 2004)
  - TE Notrees, LLC (100%)(DE 09.30 2005)
    - Notrees Windpower, LP (1%)(DE 09 30 2005)
  - TE Ocotillo, LLC (100%)(DE 12 21 2004)
    - Ocotillo Windpower, LP (1%)(DE 12 22 2004)

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Detailed Duke Energy Organization Structure
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Duke Energy Generation Services, Inc.

Appendix J

- Duke Energy Corporation
  - Cinergy Corp (100%)
    - Duke Energy Renewables Holding Company, LLC (100%)
      - Duke Energy Renewables, Inc (100%)
        - Duke Energy Generation Services, Inc (100%)

- Duke Energy Generation Services, Inc. (100%)(DE 06.02.2000)
  - Cinergy Solutions Partners, LLC (100%)(DE 09.12.2000)
  - DEGS O&M, LLC (100%)(DE 08.30.2004)
  - DEGS of Delta Township, LLC (100%)(DE 12.15.2004)
  - DEGS of Lansing, LLC (100%)(DE 06.25.2002)
  - DEGS of Narrows, LLC (100%)(DE 03.17.2003)
  - DEGS of Shreveport, LLC (100%)(DE 06.28.2002)
  - Duke Energy Industrial Sales, LLC (100%)(DE 06.06.2006)
  - Shreveport Red River Utilities, LLC (40.8%)(DE 10.16.2000)

Duke Energy Catamount Energy Corporation

Appendix K

- Duke Energy Corporation
  - Cinergy Corp (100%)
    - Duke Energy Renewables Holding Company, LLC (100%)
      - Duke Energy Renewables, Inc. (100%)
        - Duke Energy Renewables Wind, LLC (100%)
          - Catamount Energy Corporation

- Catamount Energy Corporation (100%)(VT 06.23.1992) [DEGS Wind Vermont, Inc. (VT, 06.20.2008)]
  - Equinox Vermont Corporation (100%)(VT 05.01.1990)
    - Catamount Rumford Corporation (100%)(VT 04.11.1989)
    - Ryegate Associates (33.1126%)(UT 04.30.1990)
  - Catamount Sweetwater Corporation (100%)(VT 06.17.2003)
    - Sweetwater Development LLC (100%)(TX 11.05.2002)
    - Sweetwater Wind 6 LLC (100%)(DE 04.29.2004)
    - Sweetwater Wind Power L.L.C. (100%)(TX 11.05.2002)
  - Catamount Sweetwater Holdings LLC (100%)(VT 06.20.2005)
    - Catamount Sweetwater 1 LLC (100%)(VT 12.12.2003)
      - Sweetwater Wind 1 LLC (13.59%)(DE 06.24.2003)
    - Catamount Sweetwater 2 LLC (100%)(VT 05.05.2004)
      - Sweetwater Wind 2 LLC (13.14%)(DE 04.19.2004)
    - Catamount Sweetwater 3 LLC (100%)(VT 06.03.2004)
      - Sweetwater Wind 3 LLC (13.18%)(DE 04.29.2004)
  - Catamount Sweetwater 4-5 LLC (100%)(VT 03.08.2005)
    - Sweetwater 4-5 Holdings LLC (18.72%)(DE 04.18.2007)
      - Sweetwater Wind 4 LLC (100%)(DE 04.29.2004)
      - Sweetwater Wind 5 LLC (100%)(DE 04.29.2004)
  - CEC Wind Development LLC (100%)(VT 01.12.2007)
  - Top of the World Wind Energy Holdings LLC (100%)(DE 11.15.2010)
    - Top of the World Wind Energy LLC (100%)(DE 03.13.2008)
  - Catamount Sweetwater 6 LLC (100%)(VT 09.07.2005)
  - CEC UK1 Holding Corp. (100%)(VT 09.11.2002)
    - Catamount Energy SC 1 (1%)(Scotland 10.08.2002)
      - Catamount Energy SC 2 (99%)(Scotland 10.08.2002)
    - Catamount Energy SC 2 (1%)(Scotland 10.08.2002)
      - Catamount Energy SC 3 (99%)(Scotland 10.08.2002)
    - Catamount Energy SC 3 (1%)(Scotland 10.08.2002)
  - CEC UK2 Holding Corp. (100%)(VT 09.11.2002)
    - Catamount Energy SC 1 (99%)(Scotland 10.08.2002)
  - Wind Star Holdings LLC (100%)(DE 04.15.2014)
    - Wind Star Renewables, LLC (100%)(DE 04.15.2014)
      - Highlander Solar 1, LLC (100%)(DE 09.03.2010)
      - Highlander Solar 2, LLC (100%)(DE 09.03.2010)
      - Laurel Hill Wind Energy, LLC (100%)(PA 12.14.2004)
      - Shirley Wind LLC (100%)(WI 10.20.2006)

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Duke Energy Transmission Company, LLC

Appendix L

Duke Energy Corporation
└── Cinergy Corp. (100%)
  └── Duke Energy Transmission Holding Company, LLC
    └── Duke-American Transmission Company, LLC

Duke-American Transmission Company, LLC (50%)(DE 04.11.2011)
├── Zephyr Power Transmission LLC (100%)(DE 12.05.2008)
├── DATC Midwest Holdings, LLC (100%)(DE 04.11.2012)
└── DATC Path 15 Transmission, LLC (100%)(DE 08.09.2006)
  ├── Path 15 Funding, LLC (100%)(DE 12.27.2002)
  ├── Path 15 Funding TV, LLC (100%)(DE 11.16.2004)
  │ └── Path 15 Funding KBT, LLC (100%)(DE 09.21.2006)
  └── DATC Holdings Path 15, LLC (47.326% owned by DATC Path 15 Transmission, LLC, 22.574% owned by Path 15 Funding KBT, LLC and 30.099% owned by Path 15 Funding, LLC)(DE 10.16.2002)
    └── DATC Path 15, LLC (100%)(DE 10.16.2002)

Exhibit III-1
Detailed Duke Energy Organization Structure
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Changes to Corporate Structure – September 30, 2015-December 31, 2015

Entities Removed

- On October 21 2015, CST General LLC (100%)(TX 05 22 2001) was dissolved
- On November 24, 2015 Duke Communications Holdings, Inc (100%)(DE 09 20 1996) was dissolved
- On December 17, 2015, SUEZ-DEGS of Orlando LLC (51%)(DE 06 12 1996) was dissolved
- On December 31, 2015, Progress Energy Service Company, LLC (100%)(NC 07 12 2000) was merged into Duke Energy Business Services LLC (100%)(DE 11 18 1998)

Entities Added

- On October 6, 2015, Wild Jack Solar Holdings LLC (100%)(DE 10 06 2015) was formed in Delaware by Duke Energy Renewables Solar LLC
- On October 6, 2015 Wild Jack Solar LLC (100%)(DE 10.06 2015) was formed in Delaware by Wild Jack Solar Holdings LLC.
- On October 15, 2015, PHX Management Holdings, LLC (100%)(DE 10 15 2015) was formed in Delaware by Duke Ventures II, LLC
- On October 22, 2015, Forest Subsidiary, Inc. (100%)(NC 10 22 2015) was formed in North Carolina by Duke Energy Corporation
- On October 29, 2015, 70% of the equity interests of Phoenix Energy Technologies, Inc. (70%)(DE 12 20 2008) were acquired by PHX Management Holdings, LLC (100%)(DE 10 15 2015) through the merger of a newly formed subsidiary of PHX Management Holdings, LLC, Firebird Merger Sub, Inc. (100%)(DE 10,15 2015), with an into Phoenix Energy Technologies, Inc The remaining 30% of the equity interests of Phoenix Energy Technologies, Inc. were retained by its original shareholders.
- On November 18, 2015, Frontier Windpower II, LLC (100%)(DE 11 18 2015) was formed in Delaware by Duke Energy Renewables Wind, LLC
- On December 21, 2015 the following entities were acquired by Duke Energy Renewables Solar, LLC from infigen Energy US Development Corporation
    - Caprock Solar 1 LLC (100%)(DE 10 31 2014)
    - Caprock Solar 2 LLC (100%)(DE 10 31 2014)
    - Caprock Solar Holdings 1, LLC (100%)(DE 04.30 2015)
    - Caprock Solar Holdings 2, LLC (100%)(DE 04 30 2015)

  On December 31, 2015 the following entities were acquired by Duke Energy Renewables NC Solar LLC from NC State Renewables LLC.
    - Long Farm 46 Solar LLC (100%)(NC 09 22 2014)
    - SolNCPower10, L.L.C. (100%)(NC 08 01 2014)
- On December 31, 2015, Tarboro Solar LLC (100%)(DE 08 26 2013) was acquired by Duke Energy Renewables NC Solar, LLC from DERSM, LLC and Community Energy, Inc

Entity Type Changes

- On December 15, 2015, Cinergy Investments Inc (100%)(DE 10.24 1994) converted from a Delaware corporation to a Delaware limited liability company and was renamed Duke Energy Renewables Holding Company, LLC.
- On January 1, 2016, Duke Energy Indiana, Inc (100%)(IN 09 06 1941) converted from an Indiana corporation to a Indiana limited liability company and was renamed Duke Energy Indiana, LLC

Entities Restructured

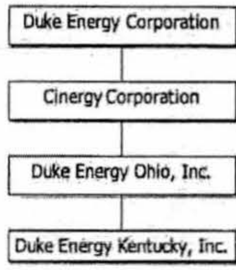
- On October 6, 2015, the equity interests in Pumpjack Solar I LLC (100%)(DE 02.09 2012) and Wildwood Solar I LLC (100%)(DE 02.09 2012) were contributed by Duke Energy Renewables Solar LLC to Wild Jack Solar LLC (100%)(DE 10 06 2015).
- On December 15, 2015, the equity interests in the following companies were distributed by Duke Energy Renewables Wind LLC through the corporate chain to Duke Energy Renewables Holding Company, LLC (f/k/a Cinergy Investments, Inc.) (see Appendix A page 2, for the new structure)
    - Frontier Windpower, LLC (100%)(DE 08 21 2015)
    - Frontier Windpower II, LLC (100%)(DE 11 18 2015)
    - Los Vientos Windpower III Holdings LLC (100%)(DE 07 24 2013) and its subsidiary Los Vientos Windpower III, LLC (100%)(DE 07 24 2013)
    - Los Vientos Windpower IV Holdings, LLC (100%)(DE 07 24 2013) and its subsidiary Los Vientos Windpower IV, LLC (100%)(DE 07 24 2013)
    - Los Vientos Windpower V Holdings, LLC (100%(DE 07 24 2013) and its subsidiary Los Vientos V, LLC (100%)(DE 07 24 2013)

[illegible]

Also Progress Energy Service Company (PESC) employees became Duke Energy Business Services (DEBS) employees in 2014, but the legal entity was kept for existing contract requirements, although no charges were made; then in 2015 PESC was no longer a legal entity.[26]

Exhibit III-2 illustrates Duke Energy Kentucky's (DEK's) parent, Duke Energy Ohio (DEO); DEO's parent, Cinergy Corporation; and Cinergy Corporation's parent, Duke Energy.[27]

Exhibit III-2
Duke Energy Kentucky Parental Structure
as of December 31, 2015



Source: Information Response 1 (Attachment 1)

DEK is responsible for the transmission, distribution, and sale of electricity energy and the sale and transportation of natural gas in northern Kentucky. Its parent company is DEO, which is engaged in the production, transmission, distribution, and sale of electricity and the sale and transportation of natural gas in the southwestern portion of Ohio. Cinergy Corporation is the parent holding company of Duke Energy Indiana, Inc. (DEI), DEO, and Cinergy Investments, Inc.[28]

The DEK Board is comprised of three directors, who have held Duke Energy positions, as follows:[29]

- Lynn J. Good (1/29/2010 to present) – Duke Energy Board Chair; Duke Energy President & Chief Executive Officer; Chief Executive Officer of other Duke Energy entities, including Cinergy Corporation, DEBS, Duke Energy Carolinas (DEC), Duke Energy Florida (DEF), Duke Energy Indiana (DEI), DEK, DEO, Duke Energy Progress (DEP), and Progress Energy; Florida Progress President; Manager at Duke Energy Americas and Duke Ventures; plus Board Director of various Duke Energy entities
- Douglas F. Esamann (6/1/2015 to present) – Duke Energy Executive Vice President, Energy Solutions and President of Midwest and Florida Regions, including DEBS, DEC, DEF, DEI, DEK, DEO, and Duke Energy Progress; Chief Executive Officer of Miami Power Corporation and Tri-State Improvement Company; President of Eastover Land Company and Eastover Mining Company; plus Board Director of various Duke Energy entities
- Dhiaa M. Jamil (6/1/2015 to present) – Duke Energy Executive Vice President and Chief Operating Officer
- Lloyd M. Yates (1/1/2015 to 6/1/2015) – Duke Energy Executive Vice President & Delivery Operations and President – Carolinas Region
- B. Keith Trent (1/1/2015 to 6/1/2015) – Previously DEK Executive VP and DEO Executive VP & Chief Operating Officer, Regulated Utilities

Transactions

Services

Exhibit III-3 and *Exhibit III-4* display affiliate charges (associated with non-power goods and services) to/from DEK for 2013 to 2015.[30]

Exhibit III-3
Affiliate Service Charges
2013 to 2015

From Affiliates to DEK	2013	2014	2015
DE Commercial Enterprises	$8,409,949	$0	$0
DEGS	$0	$0	$0
Duke Energy Business Services	$81,420,226	$86,226,594	$88,331,166
Progress Energy Service Company	$940,382	N/A	N/A
Duke Energy Carolinas	$3,577,970	$6,775,364	$21,167,640
Duke Energy Florida	$0	$139,228	$297,920
Duke Energy Indiana	$162,405	$414,618	$106,666
Duke Energy Ohio	$7,143,367	$16,145,091	$12,067,280
Duke Energy Progress	$536,615	$765,397	$983,478
Non-Utility	$0	$190,054	$1,619,479
Commercial Asset Management	$0	$0	$23,701
Total Affiliate Charges ($)	**$102,190,914**	**$110,656,345**	**$124,597,330**

Breakdown of Charges from Affiliates to DEK

Duke Energy Service Company*	2013	2014	2015
Total Affiliate Charges ($)	**$82,360,608**	**$86,226,594**	**$88,331,166**
Direct %	63.7%	72.4%	75.9%
Allocated %	36.3%	27.6%	24.1%
Total %	**100.0%**	**100.0%**	**100.0%**

Other Affiliates	2013	2014	2015
Total Affiliate Charges ($)	**$19,830,306**	**$24,429,751**	**$36,266,164**
Direct %	39.4%	52.0%	33.7%
Allocated %	23.1%	22.4%	17.0%
Convenience Payments %	16.7%	25.7%	49.4%
*Information Not Made Available%	20.7%		
Total %	**100.0%**	**100.0%**	**100.0%**

Source: Information Responses 3, 6, 65, and 66

*In 2013 Duke Energy Service Company was a combination of DEBS and PESC; however, in 2014 and 2015 it is only DEBS; the figures above do not necessarily agree with our prior 2013 audit report, as previously it was based on FERC Form filings (minimum of $250,000 per item), but above, it is based on raw data.

Also, for 2013, breakdown of DEC and DEP between direct and allocated charges not made available.

In 2014 and 2015 in the Breakdown of Charges from Affiliates to DEK, it excludes accounting transactions, which are included in 2013.

Overall DEBS costs increased from 2013 to 2015. According to Duke Energy management, the direct costs charged to DEK increased mainly due to ancillary transmission costs. This was partially offset by allocated costs decreasing due to incorporation of allocations to Progress entities. The largest change in direct costs are related to DE Carolinas. A large number of capital invoices are being processed through that entity. This is offset somewhat by a decrease in costs related to DEO, specifically related to generation services."[31] According to Duke Energy management, these decreasing costs are primarily due a much larger pool of costs, making very little going to DEK.[32]

Exhibit III-4
Affiliate Service Charges
2013 to 2015

From DEK to Affiliates	2013	2014	2015
Duke Energy Business Services	$43,896	$2,062	$21,596
Duke Energy CAM	$0	$37,720	$95
Duke Energy Carolinas	$0	$75,715	$66,295
Duke Energy Dicks Creek, LLC	$0	$297,233	$6,836
Duke Energy Florida	$0	$108	$35,711
Duke Energy Indiana	$1,240,952	$1,336,873	$1,388,388
Duke Energy Investments	$0	$0	$0
Duke Energy Miami Fort, LLC	$0	$169,910	$3,186
Duke Energy Ohio	$3,220,531	$2,030,593	$2,514,069
Duke Energy One , Inc./Cinergy Solutions-Utility Inc.	$11,590	$6,985	$3,820
Duke Energy Progress	$0	$82,868	$31,506
Duke Energy Zimmer, LLC	$0	$34,844	$668
Duke Energy Power Company	($5,655)	$0	$0
KO Transmission	$18,026	$25,528	$877,200
Duke Energy Beckjord, LLC	$0	$0	$4,086
Total Affiliate Charges ($)	**$4,529,341**	**$4,100,440**	**$4,953,455**

Breakdown of Charges from DEK to Affiliates

Duke Energy Service Company*	2013	2014	2015
Total Affiliate Charges ($)	**$43,896**	**$2,062**	**$21,596**
Direct %	-394.7%	20.7%	76.6%
Allocated %	0.0%	6.3%	23.4%
Convenience Payments %	494.7%	73.0%	0.0%
Total %	**100.0%**	**100.0%**	**100.0%**

Other Affiliates	2013	2014	2015
Total Affiliate Charges ($)	**$4,485,445**	**$4,098,378**	**$4,931,859**
Direct %	46.6%	-42.8%	42.5%
Allocated %	33.6%	36.6%	29.4%
Convenience Payments %	19.8%	106.2%	28.0%
Total %	**100.0%**	**100.0%**	**100.0%**

Source: Information Responses 3 and 6
*In 2013 Duke Energy Service Company was a combination of DEBS and PESC; however, in 2014 and 2015 it is only DEBS

Convenience Payments

Convenience payments (also referred to at Duke Energy as pass-through costs) typically include:[33]

- Finance and accounting services
- Insurance premium expense
- Advertising expense
- Community relations projects
- Donations
- Employee benefits expense
- Dues/subscriptions
- Signage/publications/printing
- Research and development
- Miscellaneous lease/rent expense

Exhibit III-5, for example, illustrates convenience payments involving revenues recorded by the Commercial Power segment of DEO for charges to DEK for 2013, 2014, and 2015.[34]

Exhibit III-5
DEO Commercial Power Convenience Payments
2013 to 2015

DEO Charges to DEK

Description	2013 Total	2014 Total	2015 1	2	3	2015 Total	Grand Total
DE KY pays Ohio for Ohio owned MF7-8 Equipment (Direct Lease)	64,956.00	245,388.00	20,449.00	20,449.00	32,248.00	73,146.00	383,490.00
CD equipment leased to DE Ohio subleased to DE Kentucky. KY pays OH who pays DP&L for a percent of CD owned equipment - Reverse Lease.	191,268.00	182,076.00	15,173.00	15,173.00	11,729.00	42,075.00	415,419.00
	256,224.00	427,464.00	35,622.00	35,622.00	43,977.00	115,221.00	798,909.00

Source: Information Response 41
No entries of equipment leases between DEO and DEK were made for the period April 2015 through December 2015, due to the sale of the Commercial Power generating assets effective April 2, 2015. Also, no other entries (such as (a) step-up transformers (East Bend, Woodsdale & Miami For or (b) transmission expenses from MISO, which were included in our prior audit report) are shown in 2013, 2014, or 2015, as they ended in 2012.

According to Duke Energy management, the trend in convenience payments associated with the direct lease exists due to a credit adjustment recorded in July 2013. This adjustment was recorded due to the fact that an incorrect lease rate had been used in the 2012 calculation. A similar adjustment was not necessary in 2014 or in 2015. DEO sold its ownership interest in Miami Fort in April 2015 and therefore stopped recording convenience payments after March 2015.[35]

In general numerous payments have been made by various affiliates on behalf of DEK in 2013, 2014, and 2015, or vice versa, as shown in *Exhibit III-6*.[36]

Exhibit III-6
General Convenience Payments
2013, 2014, and 2015

By Affiliates to DEK

	2013	2014	2015
Duke Energy Business Services			
Duke Energy Carolinas		\$3,145,056.02	\$16,300,258.09
Duke Energy Florida		\$7,122.11	\$16,2376.80
Duke Energy Indiana	\$2,985.11	\$66,030.36	\$27,264.21
Duke Energy Ohio	\$335,613.06	\$3,003,543.82	\$1,320,549.19
Duke Energy Progress		\$50,175.09	\$245,517.12
Duke Power Company			
Duke Commercial Enterprises	\$2,972,385.44		
KO Transmission Company			
Total	**\$3,310,983.61**	**\$6,271,927.40**	**\$17,909,825.84**

By DEK to Affiliates

	2013	2014	2015
Duke Energy Business Services	\$217,132.00	\$1,506.04	
Duke Energy Carolinas		\$3,709,785.41	\$408.11
Duke Energy Florida			
Duke Energy Indiana	\$11,336.59	\$98,826.12	\$74,914.51
Duke Energy Ohio	\$866,467.78	\$537,013.40	\$1,180,915.30
Duke Energy Progress		\$8,084.51	
Duke Power Company	\$11,433.70		
Duke Commercial Enterprises			
KO Transmission Company			\$127,103.50
Total	**\$1,106,370.07**	**\$4,355,215.48**	**\$1,383,341.42**

Source: Information Responses 41 and 65

Personnel Transfers

Exhibit III-7 displays personnel transfers from/to DEK for 2013 to 2015,[17] which indicates that more employees came from affiliates to DEK than from DEK to affiliates over this time period.

Exhibit III-7
Affiliate Personnel Transfers
2013 to 2015

From Affiliates to DEK				
From Company	**2013**	**2014**	**2015**	**Total 2013-2015**
Duke Energy Carolinas	1	0	0	**1**
Duke Energy Business Services	14	11	34	**59**
Duke Energy Commercial	2	6	2	**10**
Duke Energy Ohio	9	9	18	**36**
Total	**26**	**26**	**54**	**106**
From DEK to Affiliates				
To Company	**2013**	**2014**	**2015**	**Total 2013-2015**
Duke Energy Carolinas	0	0	0	**0**
Duke Energy Business Services	14	13	16	**43**
Duke Energy Commercial	0	0	0	**0**
Duke Energy Ohio	2	5	8	**15**
Total	**16**	**18**	**24**	**58**

Source: Information Response 4

Exhibit III-8 illustrates the difference in average fringe rates by company by year from 2013 to 2015.[18]

Exhibit III-8
Average Fringe Rates by Year

Company	2013	2014	2015
Duke Energy Carolinas	22.64%	18.49%	17.94%
Duke Energy Business Services	25.24%	21.27%	22.27%
Duke Energy Commercial	21.0%	20.48%	26.69%
Duke Energy Ohio	51.15%	32.15%	34.38%
Duke Energy Kentucky	38.06%	32.06%	32.10%

Source: Information Response 4

Asset Transfers

Exhibit III-9 displays asset transfers from/to DEK for 2013 to 2015.[19]

Exhibit III-9
Affiliate Asset Transfers
(Based on Original Cost)
2013 to 2015

From Affiliates to DEK	**2013**	**2014**	**2015**
Inventory Stock	$4,732,073.66	$5,990,852.47	$7,441,476.83
Meters			
Electric	$411,978.63	$602,566.37	
Gas	$105,719.19	$105,098.16	
Transformers	$533,007.34	$342,211.27	
Regulators	$0.00		
Other Miscellaneous Items	$0.00	$1,959,275.24	$251,236.60
Total	**$5,782,778.82**	**$9,000,003.51**	**$7,692,713.43**

From DEK to Affiliates	**2013**	**2014**	**2015**
Inventory Stock	$783.045.67	$697,938.26	$666.040.05
Meters			
Electric	$104,516.58	$110,588.51	
Gas	$65,067.56	$59,694.39	
Transformers	$0.00		
Regulators	$0.00		
Other Miscellaneous Items	$0.00	$10,900.25	$102,706.32
Total	**$952,629.81**	**$879,121.41**	**$768,746.37**

Source: Information Responses 5 and 64 and Interview 3

The 2015 transfers from DEK to affiliates (DEO) includes Gas-Mains/Land & Land Rights/Miscellaneous Equipment, while 2015 transfers from affiliates (DEO) to DEK includes Structure & Boiler Plant Equipment.

The 2013 to 2015 inventory stock figures do not include Accounting Store transactions. Specifically the data excludes Issue and Return transactions for a STORELOC labeled ACCTING Storeroom. An "Accounting Storeroom" is used in the Midwest when materials issued to one project are ultimately used on another project. While the materials are not returned to the warehouse, warehouse personnel administratively "return" and "re-issue" the materials to the project where the materials are used. This eliminates the need for a journal entry in the General Ledger. That's one of the reasons why 2013 inventory stock figures differed in the prior audit report, as it included these transactions. Also Direct Purchase materials may have been included in data provided to Schumaker & Company for our prior audit report, should not have been included, as 2013 this time does not.

In the past (2013 and prior) according to Duke Energy management, the reason for the continually increasing asset transfers of inventory from affiliates to DEK was primarily due to the location of the Brecon Warehouse in Ohio that serves both Ohio and Kentucky. However, the increases in inventory stock from DEK to affiliates and vice versa increased dramatically, as Duke Energy was trying to use what the company has, though it has subsequently reduced.[40] Then, in the 2013 to 2015 timeframe, the changes year over year in outbound transactions can be attributed to decreases in volume with certain locations, such as Erlanger, Wheatland, and Brecon. Fluctuations in volume were seen inbound from locations, such as Erlanger, Augustine, and Brecon. In addition, non-regulated assets were sold in early 2015, which reflects a decrease in transactions between Miami Fort (non-regulated units) and Miami Fort 6 (regulated unit).[41]

Separation

One of the expectations specified in affiliate relationships and transactions rules has to do with the physical separation of regulated and unregulated business and the sharing of information and assets between these entities. In fact, Kentucky regulatory standards provide the following guidelines shown in *Exhibit III-10.*[42]

Exhibit III-10
KRS 278.2213 Separate recordkeeping for utility and affiliate -- Prohibited business practices -- Confidentiality of information -- Notice of service available from competitor as of December 31, 2015

The provisions of this section shall govern a public utility company's activities related to the sharing of information, databases, and resources between its employees or an affiliate involved in the marketing or the provision of nonregulated activities and its employees or an affiliate involved in the provision of regulated activities.

1. A utility and its affiliate shall be separate corporate entities and maintain separate books and records. If a utility and nonregulated affiliate have common officers, directors, or employees, the fees, compensation, and expenses of the individuals involved shall be subject to the cost allocation requirements set forth in KRS 278.2203 and 278.2207. Any utility that provides nonregulated activities shall separately account for all investments, revenues, and expenses in accordance with its filed cost allocation manual.
2. A utility shall not provide advertising space in its billing envelope to its affiliates or for its nonregulated activities unless it offers the same to competing service providers on the same terms it provides to its affiliates. This subsection applies to nonregulated activities only.
3. A utility shall not attempt to persuade customers to do business with its affiliates by offering rebates or discounts on tariffed services.
4. All utility company employees engaged in the merchant function shall abide by all standards promulgated by applicable FERC orders and regulations.
5. No utility employee shall share any confidential customer information with the utility's affiliates unless the customer has consented in writing, or the information is publicly available or is simultaneously made publicly available.
6. All dealings between a utility and a nonregulated affiliate shall be at arm's length.
7. Employees transferring from the utility to an affiliate shall not disclose to the affiliate confidential information or take with them any competitively sensitive materials.
8. Neither a utility nor its employees or agents shall solicit business on behalf of an affiliate or for its nonutility services.
9. A utility that carries out any research and development or joint marketing and promotion with its affiliate for its nonregulated activities shall be subject to the cost allocation requirements set forth in KRS 278.2203.
10. Except as provided in subsection (5) of this section, if a utility is engaged in a nonregulated activity, marketing employees for the nonregulated activity shall not have access to the customer information provided to the utility when the customer places an order for regulated service.
11. A utility shall not provide any type of undue preferential treatment to a nonregulated affiliate to the detriment of a competitor.
12. A utility shall notify the customer that competing suppliers of a nonregulated service exist if:
    a. The utility receives a request for a recommendation from a customer seeking a specific service which is offered by the utility's affiliate or by the utility itself; and
    b. The utility mentions itself or its affiliate when making the recommendation to the customer.

The utility's name, trademark, brand, or logo shall not be used by a nonregulated affiliate in any type of visual or audio media without a disclaimer. The commission shall develop specifications for the disclaimer. The disclaimer shall be approved by the commission prior to use in any advertisement by the utility's affiliate.

13. A utility shall not enter into any arrangements for financing nonregulated activities through an affiliate that would permit a creditor upon default to have recourse to the assets of the utility.
14. A utility shall inform the commission of all new nonregulated activities begun by itself or by the utility's affiliate within a time to be set by the commission.
15. Start-up costs associated with the formation of a nonregulated affiliate shall not be included in the utility's rate base.
16. The commission may require the utility to file annual reports of information related to affiliate transactions when necessary to monitor compliance with these guidelines.

Source: KRS 278.2213

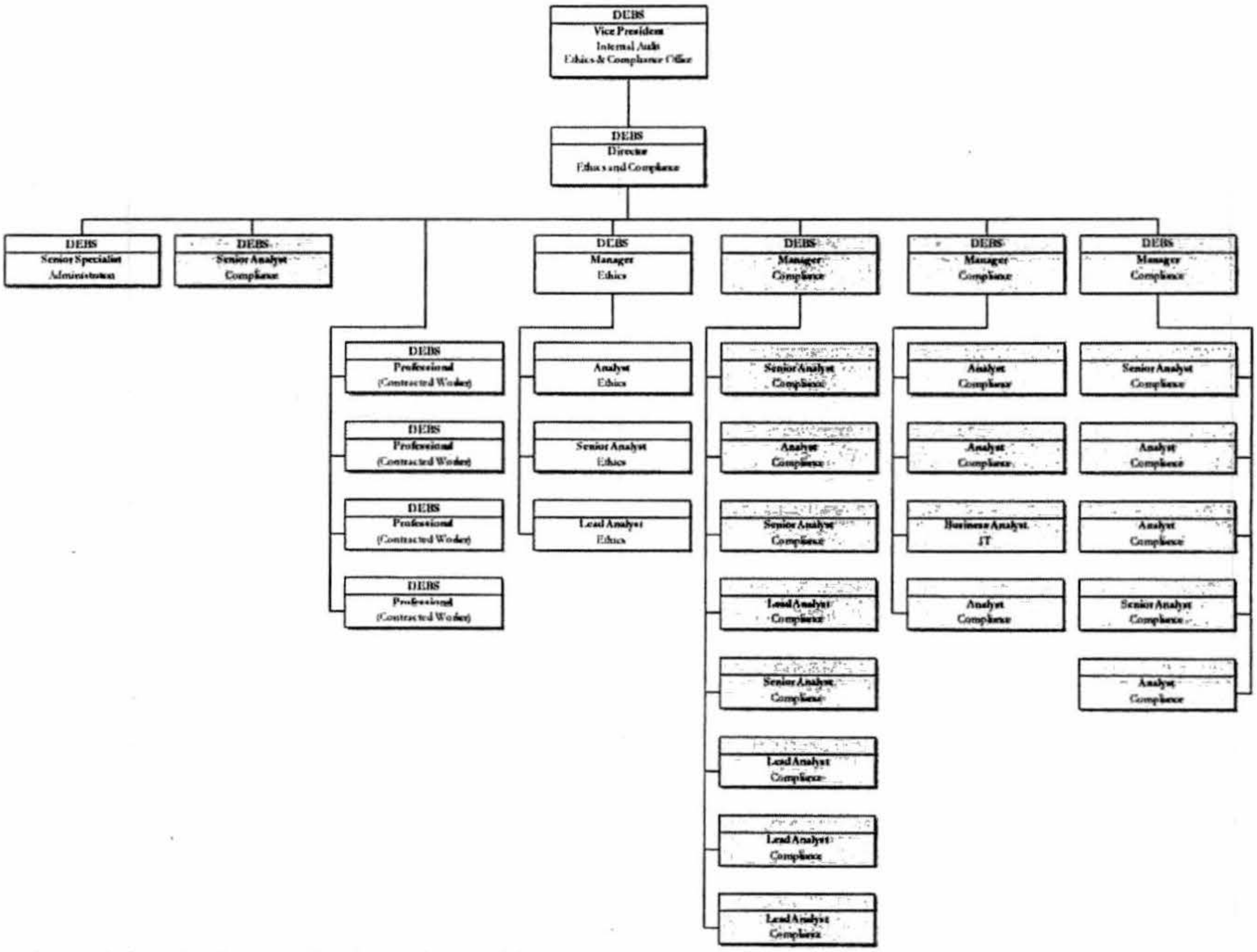
This section discusses Schumaker & Company's findings regarding compliance to the above non-accounting items in the Kentucky standards.

Ethics & Compliance Organization

Exhibit III-11 illustrates the 2015 DEBS Ethics & Compliance group, totaling 31 employees in Charlotte (NC), which reports to Audit Services (Internal Audit), and in turn the Chief Legal Officer. The three Compliance groups (highlighted in gray), plus the Senior Compliance Analyst, are responsible for state and federal regulatory compliance, including:[11]

- State and federal regulatory requirements
- Monitoring regulatory compliance policies and procedures
- Providing guidance, such as affiliate standards training and advice, to Duke Energy employees in regulatory compliance matters

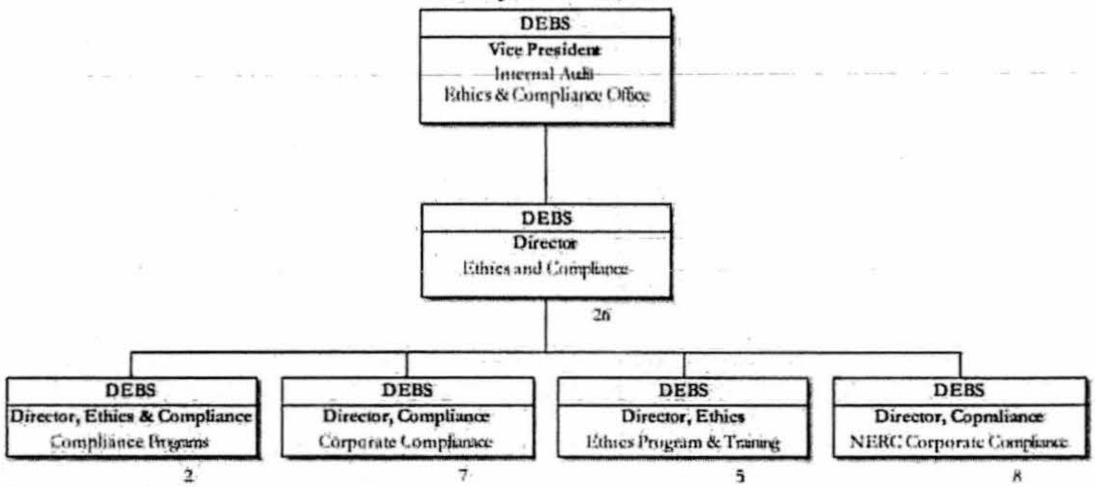
Exhibit III-11
DEBS Ethics & Compliance Organization
as of December 31, 2015



Source: Information Response 37 and Interviews 6 and 8

Exhibit III-12 illustrates that subsequently in 2016 that the number of employees is slightly down, plus the organization structure has been simplified.[44]

Exhibit III-12
DEBS Ethics & Compliance Organization
as of September 30, 2016



Source: Interviews 6 and 8

The Open Pages system is used to track compliance issues, such as merger conditions, filings, or system access reviews, in which ownership of these issues is also kept. The Regulatory Compliance Manager handles any requests for clarification on Kentucky Affiliate Rules training requirements.[45]

Other Organizations

At the time of Schumaker & Company's prior audit, Duke Energy had two separate organizational groups that were responsible for regulated and unregulated power functions:[46]

- The regulated electric business was located in Charlotte (NC). All of the offerings of generation resources into PJM or MISO and the requesting of day-ahead load requirements were handled from the Operations Center located in Charlotte (NC). The individual regulated generation units were dispatched from the Charlotte Operations Center and all trading activities were handled in the Charlotte Operations Center. Regulated wholesale sales were also handled in Charlotte (NC). The Operations Center was split between the Carolinas and Midwest (Kentucky and Indiana) organizations. At this time, there was another separate control centers for Duke Energy Progress located in Raleigh and another in Florida for the Florida properties.
- The unregulated electric business (Midwest Generation) was located in Cincinnati (OH). All of the offerings of generation resources into PJM Interconnection, LLC (PJM) and Midwest Independent System Operator (MISO) and the requesting of day-ahead load requirements were handled from the Operations Center located in Cincinnati (OH). The individual, formerly

regulated, generation units (which were in the process of being sold to Dynegy) were dispatched from the Cincinnati Operations Center and all trading activities were handled in the Cincinnati Operations Center. The Operations Center handled the dispatching of the former DEO generating plants, which were unregulated assets.

In early 2015, DEO closed on selling its generation assets in Ohio to Dynegy. Many of these assets were jointly owned with other utilities (primarily Dayton Power & Light Company and American Electric Power). Many of the personnel, dispatch, and trading functions went with the Dynegy acquisition. Thus Duke's Midwest unregulated electric business became for all purposes non-existent.[47]

In the same timeframe, Miami Fort #6 (163 MW), a unit that was assigned to Kentucky, was retired. Then Kentucky acquired Dayton Power and Light's 31% interest in East Bend generating station resulting in 186 MW of generation. DEO's 69% interest was sold to Dynegy.[48]

All dispatch and trading functions are located in Charlotte, NC. The unregulated generation business, which was located in Cincinnati, has been sold off resulting in the existence of no concern for regulated and unregulated generation, dispatch, and trading business being able to share facilities, equipment, and information. Kentucky now only has two generation units that are bid into PJM, specifically East Bend and Woodsdale Station (consisting of six simple cycle gas turbines).[49]

DEK power transactions are handled out of Charlotte (NC) by a group of traders and dispatchers that only handle Kentucky and Indiana power transactions. There is a separate group of traders and dispatchers that handle the Carolinas power transactions in Charlotte (NC).[50]

DEK's affiliated wholesale power marketers, as reported in the last audit operate separate from the regulated business. In many cases, they are located in other regulated jurisdictions and have purchase power agreements with power distributors in that geographic area. These entities were presented in the last management audit and little has changed since the last audit with the exception of the sales of certain generation assets to Dynegy.[51]

There is also no space occupied by DEK and non-regulated affiliated wholesale power marketers as defined. There are systems that are shared between DEK and the nonregulated affiliated wholesale power marketers, but there are controls in place to prevent information sharing. These two organizations operate independently. According to Duke Energy management, there were no situations during 2015 where DEK shared office space, computers, or any other assets with other Duke Energy affiliates. Schumaker & Company confirmed these statements by physical observations during our interviews.[52]

Competitive or Sensitive Information

When asked to provide any formal policies or procedures documentation regarding access by DEK and any affiliate to competitive or sensitive information, a copy of Duke Energy's *Affiliate Restrictions – Information Disclosure Procedures* was provided, as shown in *Exhibit III-13*. Its purpose is to provide a process for handling the disclosure of regulated market information to market regulated power sales affiliates.[53]

Exhibit III-13
Affiliate Restrictions – Information Disclosure Procedure
as of October 2015

DUKE ENERGY.

Regulatory Compliance
FERC Operations Manual

Affiliate Restrictions – Information Disclosure Procedure

Purpose: Document the process for handling the disclosure of regulated market information to market regulated power sales affiliates.

FERC Program Chapter:

Chapter 4 – Affiliate Restrictions & Standards of Conduct

Record Retention Rule:

Five years

Procedure:

- Legal shall be notified if regulated market information is shared with power sales affiliate employees, or if there are deviations from separation of functions, including during emergency situations.
- Legal will determine whether to make a posting of such information on its web site or a filing with the Commission, using procedures similar to those used for Standards of Conduct disclosures (see "Duke Energy FERC Page").
- Legal or Federal Regulatory Compliance will meet with the business unit involved in the inappropriate disclosure to discuss and offer recommendations to mitigate future occurrences. This information (which may include compliance measures) will be maintained by Federal Regulatory Compliance.

Periodic Review of Procedures:

Automatic reminders are forwarded annually through OpenPages (compliance tool).

Key Contacts for this Procedure

- Legal
- Federal Regulatory Compliance

Revision History

Revision No.	Description	Date	Revised By
Original		10-4-13	bsr
Update	Refreshed titles	11-3-14	bsr
Update	Reviewed – No Change	10-6-15	bsr

Source: Information Response 25

Training materials used by Duke Energy's or DEK's employees on sharing of competitive or sensitive information and/or sharing of office space, computers, or any other assets includes the following information:[54]

- Midwest (Kentucky, Indiana, and Ohio) state regulatory requirements for non-regulated products and services, including but not limited to:
  - The affiliate must be fully separated.
  - The affiliate must have separate accounting treatment.
  - The affiliate must not be given an unfair competitive advantage or be extended any undue preference by the utility (meeting guidelines, proprietary customer information/customer consent, customer leads/referrals, appropriate/inappropriate responses, etc.)
  - A code of conduct should be established that satisfies the commission rules.
- DEK expectations for customer care guidelines
- Non-regulated products and services comparison of Florida, Indiana, Kentucky, Ohio, and Carolinas.

Transfer Confidentiality Agreements

The Regulatory Compliance group manages and facilitates the employee transfer process from DEK to an affiliate.[55] Duke Energy's current process for informing employees of the regulatory conditions is to deploy annual training that explains entity separation, information sharing, joint marketing, regulated and non-regulated activities, and the regulatory conditions regarding each of these, respectively. There are materials in trainings that cover rules regarding the transfer of employees; therefore, Duke Energy does not currently use a process for employees to sign confidentiality agreements when transferring from the utility to an affiliate.[56]

Identified individuals (and their managers) who transfer from the utility to an affiliate are required to complete and confirm that they have reviewed system access, physical access, and email distribution lists. Also, automated emails are forwarded to impacted managers with required actions items.[57]

B. Findings & Conclusions

Affiliate Agreements

Finding III-1 **Only three affiliate agreements were changed in 2015 or the beginning of 2016.**

Exhibit III-14 summarizes existing affiliate agreements impacting DEK, including:[58]

- Service Company Utility Service Agreement
- Amended and Restated Operating Company / Non-utility Companies Service Agreement
- Asymmetrically Priced Duke Energy Kentucky, Inc. / Nonutility Companies Service Agreement
- Operating Companies Service Agreement
- Amended and Restated Miami Fort 6 Operation Agreement
- Gas and Propane Services Agreement with Respect to Woodsdale Generating Station
- Utility Money Pool Agreement
- First Amendment to Second Amended and Restated Purchase and Sale Agreement with Cinergy Receivables (updated December 18, 2015)
- Agreement for Filing Consolidated Income Tax Returns and for Allocation of Consolidated Income Tax Liabilities and Benefits
- Inter Company Asset Transfer Agreement
- Utility-Non-utility Asset Transfer Agreement

All of these agreements were established prior to 2015. Of these, only three (Service Company Utility Service Agreement, Amended and Restated Miami Fort 6 Operations Agreement, First Amendment to Second Amended and Restated Purchase & Sale Agreement with Cinergy Receivables) were changed in 2015 or the beginning of 2016.[59]

Exhibit III-14
Existing Affiliate Agreements (Page 1 of 4)
as of December 31, 2015

Merger-Related-Service Agreements			
Agreement	**Agreement Description**	**Effective**	**Compensation**
Service Company Utility Agreement	DEBS and various utilities, including DEC, DEO, DEI, DEK, DEP, DEF, involving DEBS functions: information systems; meters; transportation; system maintenance; marketing/customer relations; T&D engineering/construction; power engineering/ construction; human resources; supply chain; facilities; accounting; power and gas planning and operations; public affairs; legal; rate design and analysis, finance; rights of way; internal auditing; environmental, health, and safety; fuels; investor relations; planning; executive; and nuclear development.	January 1, 2016 supersedes and replaces the Second Amended and Restated Utility Service Agreement dated December 1, 2011, as July 2, 2012 (third amendment) included in past audit still in progress.	Cost except otherwise required by IRS 482
Amended and Restated Operating Company/ Non-Utility Companies Service Agreement*	DEK/various Duke Non-Utility companies involving services (including loans of employees), such as: • *DEK to Non-Utility:* engineering/construction; operation/maintenance; installation services; equipment testing; generation technical support; environmental, health/safety; and procurement services; plus use of assets, equipment, and facilities. • *Non-Utility to DEK:* information technology services; monitoring, surveying, inspecting, constructing, locating, and marking of overhead and underground utility facilities; meter reading materials management; vegetation management; and marketing/customer relations.	September 1, 2008 (amended and restated)	Cost except otherwise required by IRS 482
Asymmetrically Priced DEK/Non-Utility Companies Services Agreement*	DEK/various Duke Non-Utility companies involving services (including loans of employees), such as: • *DEK to Non-Utility:* engineering/construction; operation/maintenance; installation services; equipment testing; generation technical support; environmental, health/safety; and procurement services; plus use of assets, equipment, and facilities. • *Non-Utility to DEK:* information technology services; monitoring, surveying, inspecting, constructing, locating, and marking of overhead and underground utility facilities; meter reading materials management; vegetation management; and marketing/customer relations.	October 1, 2009	FERC pricing mechanism Greater of cost or market for services provided by DEK to Non-Utility Companies Lesser of cost or market for services provided by Non-Utility Companies to DEK
Operating Companies Service Agreement	DEC, DEO, DEI, DEK, DEP, DEF, involving services (including loans of employees), such as engineering/ construction; operation/maintenance; installation services; equipment testing; generation technical support; environmental, health, and safety; and procurement services; plus use of assets, equipment, and facilities. It specifically excludes affiliate transactions involving sales or other transfers of assets, goods, energy commodities (electricity, natural gas, coal, and other combustible fuels), or thermal energy products.	July 2, 2012 (fourth amendment)	Cost based only; with DEC and DEP exceptions

Source: Information Responses 2 and 68

* The pricing in the Amended and Restated Operating Company/Non-Utility Agreement was in effect prior to FERC Order 707, which required any service or asset transfer involving a franchised utility and a non-utility affiliate to be priced using asymmetrical pricing. As Order No. 707 allows any pre-existing pricing between franchised utilities and non-utility affiliates to remain in effect and be grandfathered, thus, the Amended Agreement is considered a grandfathered agreement. The Asymmetrically Priced DEK/Non-Utility Companies Service Agreement was entered into after Order No. 707 went into effect.

Exhibit III-14
Existing Affiliate Agreements (Page 2 of 4)
as of December 31, 2015

Generation Acquisition Service Agreements			
Agreement	**Agreement Description**	**Effective**	**Compensation**
Amended and Restated Miami Fort 6 Operations Agreement	Permits Duke Energy Miami Fort, LLC to operate the Miami Fort 6 generating station, including procurement of fuel, on behalf of DEK.	March 31, 2015 Miami Fort 6 has been retired and is out of the regulatory structure on June 1, 2015	All reimbursable costs, operating costs, and fee*
Gas & Propane Services Agreement with Respect to Woodsdale Generating Station	Permits DEO to provide certain operations and maintenance support to DEK related to the natural gas and propane facilities at the Woodsdale generating station.	January 24, 2009 (first amendment)	Described in other agreement above.

Source: Information Response 2

* Reimbursable costs included: costs incurred in response to an emergency; a reasonably allocable portion of the cost of the insurance maintained by the Operator in accordance with Section 9.1 of the agreement; costs of third party advisors, consultants, attorneys, accountants and contractors retained and managed by the Operator in support of, and reasonable allocable to, the services; and any other cost designated by the parties as a reimbursable cost pursuant to the terms of the agreement. In no event shall Operator add any mark-up to the reimbursable costs.

Exhibit III-14
Existing Affiliate Agreements (Page 3 of 4)
as of December 31, 2015

Other Affiliate Agreements			
Agreement	**Agreement Description**	**Effective**	**Compensation**
Intercompany Asset Transfer Agreement	DEC, DEI, DEK, DEO, PEC, and Progress Energy Florida asset transfers, in which "assets" means parts inventory, capital spares, equipment and other goods except for commodities, such as the following: coal; natural gas; fuel oil used for electric power generation; emission allowances; electric power; and environmental control reagents.	July 2, 2012	Except to the extent otherwise required by Section 482 of the Internal Revenue Code or analogous state tax law, Recipient Operating Company shall compensate Transferor Operating Company for any assets transferred at cost; provided however that any transfers of electric generation-related assets between DEO, on the one hand, and DEI or DEK on the other hand, will be priced in accordance with FERC affiliate transaction pricing requirements. *
Utility-Non-Utility Asset Transfer Agreement	DEK/Non-Utility asset transfers, in which "assets" means parts inventory, capital spares, equipment and other goods except for commodities, such as the following: coal; natural gas; fuel oil used for electric power generation; emission allowances; electric power; and environmental control reagents.	January 1, 2009	Except to the extent otherwise required by Section 482 of the Internal Revenue Code or analogous state tax law, a Recipient party under this Agreement shall compensate the Transferor for any assets transferred in accordance with the FERC affiliate transaction pricing requirements. Accordingly, assets transferred from DEK to a Non-Utility Company shall be priced at the greater of cost or market, and assets transferred from a Non-Utility Company to DEK shall be priced at no more than market. Alternatively, to the extent that an asset may be transferred under this Agreement, the Transferor and Recipient may agree that the asset transferred to the Recipient be replaced in kind.

Source: Information Response 2

* Accordingly, generation-related assets transferred from DEI or DEK to DEO shall be priced at the greater of cost or market, and generation-related assets transferred from DEO to DEI or DEK shall be priced at no more than market. Alternatively, to the extent that an asset may be transferred under this Agreement, the Transferor and Recipient may agree that the asset transferred to the recipient be replaced in kind.

Exhibit III-14
Existing Affiliate Agreements (Page 4 of 4)
as of December 31, 2015

Agreement Title	Agreement Description	Effective	Compensation
Utility Money Pool Agreement	A money pool arrangement to manage cash and working capital requirements in which those companies with surplus short-term funds provide short-term loans to affiliates (other than Duke Energy, Progress Energy, and Cinergy) participating under this arrangement.	July 3, 2012	Depends on whether internal and/or external fund used.
First Amendment to Second Amended and Restated Purchase & Sale Agreement with Cinergy Receivables	Allows the operating companies (DEI, DEO, and DEK) to sell their retail accounts receivables to this affiliate.	December 18, 2015 (first amendment to November 5, 2010 agreement	Fair market value of receivable on initial funding date
Agreement for Filing Consolidated Income Tax Returns and for Allocation of Consolidated Income Tax Liability and Benefits	Tax liability is allocated to Duke Energy subsidiaries on the basis of the percentage of the total tax which the tax of such an entity, if computed on a separate return, would bear to the total amount of the taxes for all entities.	July 2, 2012 (second amendment)	

Source: Information Response 2

Affiliate Training

Finding III-2 **Significant improvements have been made regarding Duke Energy's affiliate training sessions and communications with its employees regarding these sessions.**

A new training strategy has been developed at Duke Energy. Generally the various training sessions are by topic, not by jurisdiction as previously done; however, topics are keyed if different requirements in states occur. For example, relative to Kentucky, the content of training differs due to slightly different Affiliate Rules in Kentucky, although they are very similar to Ohio rules. One difference is that DEK is required to specifically report asset transfers $1 million or more to the Kentucky Public Service Commission (KPSC), but no differences regarding service charges involving Kentucky apply.[63]

For regulatory training deployed by the Ethics & Compliance Department, Duke Energy has revised its standard deployment period from 60 days to 90 days and made significant changes to the reminder and past due escalation schedules.[64]

Employees receive a total of five (5) reminders prior to the due date, including the initial notice. Duke Energy has also increased the escalation and automated system reminders (from *MyTraining*), which are also sent to immediate managers earlier in the process, prior to the due date. Previously Duke Energy began escalation two (2) weeks after the due date with management and escalated weekly thereafter, until it notified senior management.[62] Below is the current deployment reminder and escalation process now being used, which was started in June 2016:[63]

- **DAY 1** – *MyTraining* > initial notice to individual
- **DAY 45** – *MyTraining* > reminder to individual
- **DAY 60** – *MyTraining* > reminder to individual and copy to manager
- **DAY 70** – Manual reminder and incomplete report to management
- **DAY 80** – *MyTraining* > reminder to individual, copying manager, and manual > incomplete report to management
- **DAY 89** – *MyTraining* > reminder to individual
- **DAY 91** – *MyTraining* > overdue to individual, copy to manager, and manual > incomplete report to senior management
- **DAY 98** (and weekly thereafter) – *MyTraining* > overdue to individual, copy to manager, and manual > incomplete report senior management until 100% complete

In the past, Duke Energy only knew if employees passed a training course, but now it knows which areas employees are struggling with. As test questions are incorporated into the training sessions, the Compliance group can review how many employees missed specific questions and see how long employees have been with the company, thereby allowing the group to decide what to do in response.[64]

To identify the employees required to participate in training, Duke Energy identifies a deployment list, which is reviewed annually. It will also be updated throughout the year, if necessary. Those identified are not just Service Company employees but anyone within the Duke Energy organization whose function is likely to be impacted by Affiliate Rules requirements.[65]

All of the following training courses were deployed via the *Learning Management System*:[66]

- *State Regulatory – Compliance Standards Overview Training* – The State Regulatory Compliance Standards Overview Training (EC31115) is meant to serve as annual "awareness" training for targeted employees in all six regulated jurisdictions. The training course provides a high-level overview of the state regulatory requirements and rules affecting Duke Energy, its employees, and their interactions with affiliates/nonpublic utility operations as it relates to relationships, activities and transactions with the regulated utility business. The topics covered include corporate separation, customer information, marketing non-regulated products and services, asset transfers, affiliate transaction restrictions, and time reporting. Recipients will be those employees State Regulatory Compliance has determined as being:[67]
  - Only those employees who need general awareness on affiliate rules, and
  - Those employees who will not be receiving a more specific targeted training.

- *State Regulatory for Business Customers - Midwest* – The State Regulatory for Business Customers Midwest Training (EC30215) covers the rules and regulations for non-regulatory products in Ohio, Kentucky, and Indiana. This training stresses the importance of following Duke Energy's compliance standards specific to the jurisdiction. It included scenarios, questions, and facts around the rules and verbiage of the Midwest compliance standards for separation. It also provided specific points of contacts and referenced additional training materials on the State Regulatory Portal page. This training was deployed to large account managers and employees who deal with non-regulatory products and services within the Midwest jurisdiction. Recipients will be those employees State Regulatory Compliance has determined as being:[68]
  - Responsible for developing, marketing, selling, or managing non-regulatory products and services, or
  - Serve as a dedicated customer account representative who interfaces directly with customers who may have interest in non-regulatory products and services
- *State Regulatory - Services and Goods* – The State Regulatory - Services and Goods Training (EC31215) explains the state regulatory affiliate transaction restrictions across all six regulated jurisdictions. Specifically, it provides information related to service agreements, eForms, affiliate transactions, the Cost Allocation Manual, time reporting, core utility functions, direct charging, and asset management. Recipients are those employees State Regulatory Compliance has determined as being:[69]
  - Those employees who work directly with affiliate (service or asset transfer) transactions, or
  - Those employees who manage employees who review or perform affiliate (service or asset transfer) transactions
- *State Regulatory - Customer Information (Non Call Center)* – The State Regulatory Compliance Customer Information Training (EC31415) is meant to provide guidance on the use of customer information and how to appropriately handle requests for customer information in accordance with the regulatory requirements across the six regulated jurisdictions. Recipients are those employees State Regulatory Compliance has determined as being:[70]
  - Those employees who have access to customer information, and
  - Those employees who manage employees that have access to customer information.
- *State Regulatory - Customer Information (Call Center)* – The State Regulatory Compliance Customer Information Training (EC31415C) is meant to provide guidance on the use of customer information and how to appropriately handle requests for customer information in accordance with the regulatory requirements across the six regulated jurisdictions. Recipients are those employees State Regulatory Compliance has determined as being:[71]
  - Those employees who have access to customer information, and
  - Those employees who manage employees that have access to customer information.

This specific training was deployed to the above employees that work in the call centers.

In 2015, as shown in *Exhibit III-15*, are statistics regarding these five training types.[70]

Exhibit III-15
Duke Energy Training Sessions
2015

Training Type	Original Date Deployed	# Deployed	# Removed	# Completed	Dates Completed	# Completed > 90 Days
Compliance Standards Overview Training (EC31115)	11/04/2015	894	18	876	10/26/2015-2/09/2016	1
State Regulatory for Business Customers-Midwest (EC30215)	6/16/2015	83	0	83	6/17/2015-9/01/2015	
State Regulatory-Services and Goods (EC31215)	11/17/2015	1,532	98	1,434	11/17/2015-03/02/2016	7
State Regulatory-Customer Information (Non Call Center) (EC31415)	11/09/2015	761	49	712	11/10/2015-02/09/2016	
State Regulatory- Customer Information (Call Center) (EC31415C)	11/09/2015	1,520	247	1,273	11/10/2015-02/26/2016	27

Source: Information Response 19
Completed includes all employees that completed the training, even if they were not in the original deployment date shown above.

Some employees were deployed beyond the original date deployed, as they were not in the specific position at the time of the original deployment, so that's one of the reasons why some dates completed look like they were more than 90 days beyond the original date deployed. Therefore, the number of employees found to actually be more than 90 days is shown above in *Exhibit III-15* in the last column. For example, one (1) EC31115 employee was only seven days late, seven (7) EC31215) employees were up to 16 days late, and 27 EC31415C employees were only two days late. The number of days late is insignificant and completion subsequently occurred.

The focus of training is threefold, as follows:[71]

- A discussion of why guidance regarding affiliate relationships is important, including risks if not followed.
- A direct description of what that means.
- A reminder that, if employees have questions, who they should contact for further guidance.

Additionally, Duke Energy has an ethics line that allows employees to call in, anonymously if they like, any concerns that they have, although the company has also added a state regulatory mailbox (stateregcompliance@duke-energy.com), which is focused on compliance issues. Duke Energy encourages employees to use the mailbox for any questions or concerns that employees have with regarding to compliance issues, but they can use either the ethics line or the mailbox. Advertisements for the ethics line and mailbox include posters in buildings and mention in code of business and affiliate training sessions.[72]

Benchmarking

Finding III-3 **Duke Energy recently performed various market assessment studies as a means to compare costs to market values for services performed.**

Duke Energy targets its payroll rates to be median figures. If adjustments are made, individual employee's pay is not changed, but salary ranges are adjusted.[75] Therefore, annually Duke Energy performs assessments of core processes to review internal payroll rates versus external market rates, in which approximately $^1/_3$ are completed each year.[76] *Exhibit III-16* provides a listing of the latest benchmarking reports of DEBS' practice areas (both corporate/governance and transactional areas) involving cost and service competitiveness of these areas.[77] In 2015, for example, management positions only were included. As a result, very limited adjustments were made in 2015. In 2016 exempt professional positions were included, with non-exempt positions to be included in 2017.[78] The rate figures have been generally flat for several years, although changes are emerging in renewables (2015) and cybersecurity (2016).[79]

Exhibit III-16
Latest DEBS Benchmarking Studies

Survey Code	Survey Name	Data Effective Date
ACR-IR15	ACR Investor Relations, 2015	2015-04-01
DIET-DD15	Dietrich Drafting & Design, 2015	2015-03-01
EAP-DIS15	Energy Technical Craft Clerical, 2015	2015-04-01
EMPS-ASST15	Empsight Executive Administrative Support, 2015	2015-03-01
EMPS-CA15	Empsight Finance and Compliance, 2015	2015-03-01
EMPS-DIG15	Empsight Digital Marketing / Marketing Results, 2015	2015-03-01
EMPS-GOV15	Empsight Gov't Relations & Corp Communications, 2015	2015-03-01
EMPS-HR15	Empsight Human Resources, 2015	2015-03-01
EMPS-LAW15	Empsight Law Large Company Edition, 2015	2015-03-01
EMPS-SITS15	Empsight IT & Security Large Company Edition, 2015	2015-03-01
EQU-EXE-DUKE15	Equilar Executive Compensation Survey (Duke Energy), 2015	2015-05-01
FOU-ENV15	Foushee Environmental, Health & Safety, 2015	2015-04-01
FOU-SEC15	Foushee Security & Compliance, 2015	2015-01-01
GBS-AVI15	Gallagher Aviation, 2015	2015-02-01
HEW-EMT15	Aon Hewitt Energy Marketing and Trading, 2015	2015-03-01
HEW-EXE-T15	Aon Hewitt TCM Executive Total Comp by Industry Full Value LTI, 2015	2015-03-01
HEW-IEHRA15	Aon Hewitt IEHRA Energy Industry, 2015	2015-05-01
HEW-MP-IND-T15	Aon Hewitt TCM Mgmt & Prof Total Comp by Industry, 2015	2015-03-01
HEW-REN15	Aon Hewitt Renewable Energy, 2015	2015-05-01
HILD-LAW-DUKE15	Hildebrandt Law Department (Duke Energy), 2015	2015-03-15
MER-CON15	Mercer Contact Center, 2015	2015-03-01
MER-DCO15	Mercer US Digital Convergence Industry, 2015	2015-03-01
MER-EXE-R15	Mercer Executive - Revised, 2015	2015-03-01
MER-FAL-R15	Mercer Finance, Accounting & Legal - Revised, 2015	2015-03-01
MER-HRM-R15	Mercer Human Resources - Revised, 2015	2015-03-01
MER-ITS-R15	Mercer Information Technology - Revised, 2015	2015-03-01
MER-LSC-R15	Mercer Logistics & Supply Chain - Revised, 2015	2015-03-01
MER-MBC-NC-R15	Mercer Metro Benchmark - North Central - Revised, 2015	2015-03-01
MER-MBC-NE-R15	Mercer Metro Benchmark - Northeast - Revised, 2015	2015-03-01
MER-MBC-SC-R15	Mercer Metro Benchmark - South Central - Revised, 2015	2015-03-01
MER-MBC-SE-R15	Mercer Metro Benchmark - Southeast - Revised, 2015	2015-03-01
MER-MBC-WC-R15	Mercer Metro Benchmark - West Coast - Revised, 2015	2015-03-01
MER-SMC-R15	Mercer Sales, Mktg & Comm - Revised, 2015	2015-03-01
PER-PRO15	Perlin IT Professional - National, 2015	2015-01-01
TW-EMT15	Towers Watson CDB Energy Marketing and Trading, 2015	2015-03-01
TW-EXE15	Towers Watson CDB General Industry Executive, 2015	2015-03-01
TW-EXE-ES15	Towers Watson CDB Energy Services Executive, 2015	2015-03-01
TW-MMPS15	Towers Watson CDB Mid-Mgmt, Prof & Support, 2015	2015-03-01
TW-MMPS-ES15	Towers Watson CDB Energy Services Mid-Mgmt, Prof & Support, 2015	2015-03-01

Source: Information Response 16
Schumaker & Company reviewed a sampling of studies in Information Response 63

The DEBS State Regulatory Compliance team has also developed a market study methodology for annually assessing cost versus market for shared services based off the North Carolina Utilities Commission (NCUC) Regulatory Condition 5.2, as referenced in Duke Energy's procedure (2016 guidelines effective May 1, 2016):[81]

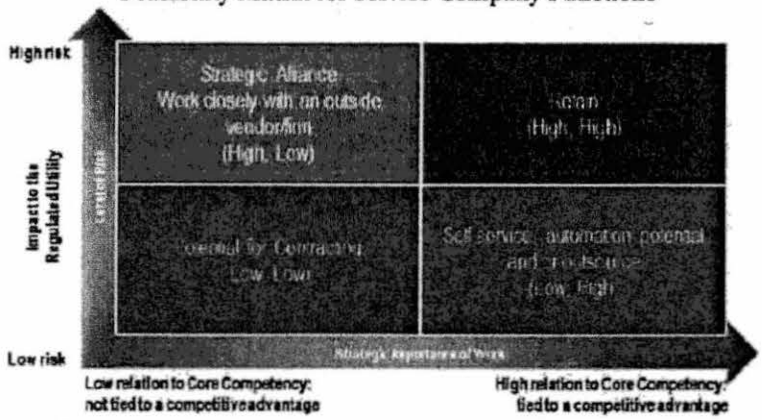
> DEC and DEP shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services, and shall have the burden of proving that any and all goods and services procured from their Utility Affiliates, Non-Utility Affiliates, and Nonpublic Utility Operations have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified nonAffiliate sources or that neither DEC nor DEP could have provided the services or goods for itself on the same basis at a lower cost. To this end, no less than every four years DEC and DEP shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services they receive from a Utility Affiliate, DEBS, PESC, another Non-Utility Affiliate, and a Nonpublic Utility Operation, including periodic testing of services being provided internally or obtained individually through outside providers. To the extent the Commission approves the procurement or provision of goods and services between and among DEC, DEP, and the Utility Affiliates, those goods and services may be provided at the supplier's Fully Distributed Cost.
>
> To the extent they are allowed to provide such goods and services, DEC and DEP shall have the burden of proving that all goods and services provided by either of them to Duke Energy, a Non-Utility Affiliate, any other Affiliate, or a Nonpublic Utility Operation have been provided on the terms and conditions comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price. To this end, no less than every four years DEC and DEP shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services provided by either of them to a Utility Affiliate, DEBS, another Non-Utility Affiliate, any other Affiliate, and a Nonpublic Utility Operation.
>
> The periodic assessments required by subdivisions (a) and (b) of this subsection may take into consideration qualitative as well as quantitative factors. To the extent that comparable goods or services provided to DEC or DEP or by DEC or DEP are not commercially available, this Regulatory Condition shall not apply.

The process assesses all service functions for all regulated utilities, including DEK. Duke Energy expects to execute the process at least every four years and is scheduled to be completed by December 31, 2016. This process, paired with Human Resources (HR) Compensation's benchmarking process, will be used by Duke Energy to assess cost versus market for the respective services functions.[61]

The market study methodology includes:[62]

- Insource versus outsource feasibility matrix for service company functions, as shown in *Exhibit III-17*, based on two ratings to compliance for service company functions:
  - Operational impact to the regulated utility (from 1(low risk) to 10 (high risk))
  - Relation to core competency (from 1 (low relation to core competency) to 10 (high relation to core competency)
- Instruction for documenting evidence of the study

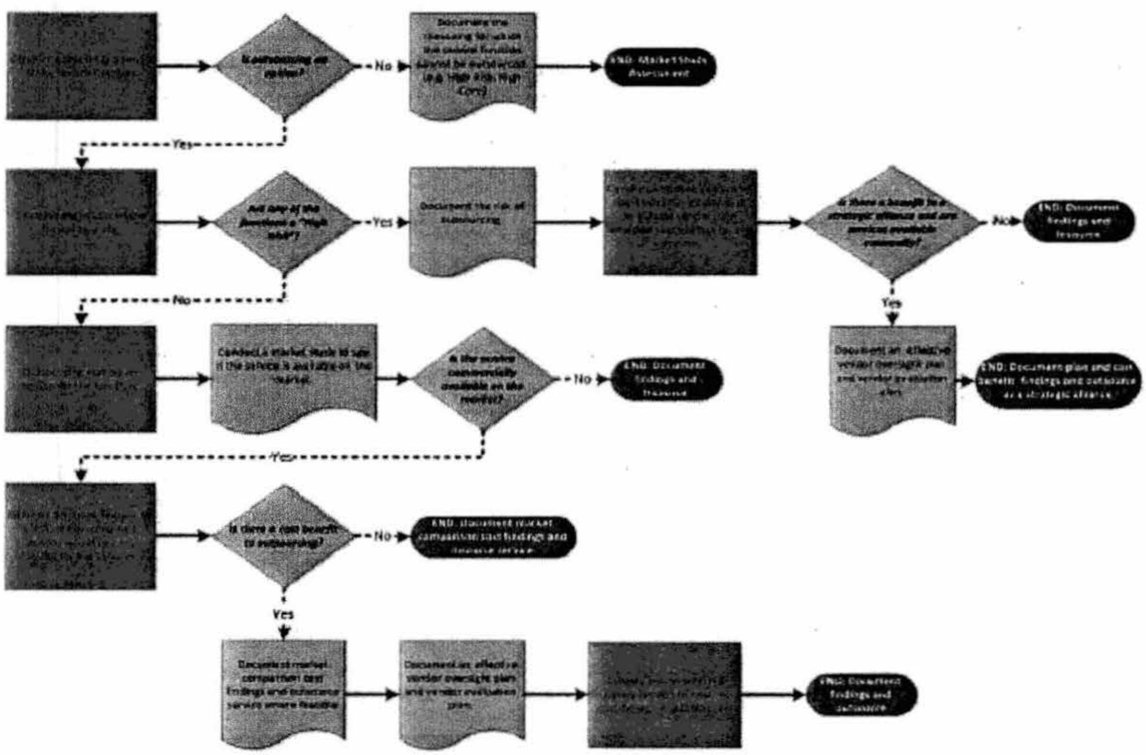
Exhibit III-17
Feasibility Matrix for Service Company Functions



Source: Information Response 14

Exhibit III-18 illustrates the process workflow diagram expected by Duke Energy.[83]

Exhibit III-18
Process Workflow Diagram



Source: Information Response 14

The DEBS services shown in *Exhibit III-19* are to be reviewed in the market study assessment process:[84]

Exhibit III-19
DEBS Services Part of Market Study Assessment Process
as of May 2016

Service	Official Description or Exception List
Accounting	Maintenance of financial books and records; preparation of financial and statistical reports and tax filings; supervision regarding compliance with related laws and regulations.
Environmental Health and Safety	Establishment of programs, policies and procedures, and governance framework for environmental and health and safety programs and compliance; provision of compliance support. Services related to the following functions: • Health & Safety • Duke Energy International EHS • EHS Risk Governance and Change Management • CCP Support • Meteorology • Env Svcs Midwest • Env Science • Env Projects and Programs • Env Permitting and Compliance Cars
Executive	Provision of general, administrative, and executive management oversight and direction; Services related to the following functions: Integration and improvement, sustainability, emerging technologies, federal policy and government affairs.
Facilities	Operation and maintenance of office and service buildings; security and housekeeping for such buildings; procurement of office furniture and equipment.
Finance	Services associated with investments, financing, cash management, risk management, budgeting, financial forecasting, and economic analyses.
Grid Solutions	Grid modernization services: planning, outreach, technology and engineering planning and standards, project management and governance, project execution.
Human Resources	Establishment and administration of policies, and supervision of compliance with legal requirements, in the areas of employment, compensation, benefits and employee health and safety; payroll and employee benefits payment processing; supervision of contract negotiations and relations with labor unions.
Information Systems	Development and support of mainframe and distributed computer software applications; procurement and support of personal computers and related network and software applications; installation and operation of communication systems; and management and support of information systems.
Internal Auditing	Review of internal controls and procedures to ensure that assets are safeguarded and that transactions are properly authorized and recorded.
Investor Relations	Preparation of communications to investors and the financial community; performance of transfer agent and shareholder record keeping functions; administration of stock plans; regulatory reporting related to stock
Legal	Services related to labor and employment law, litigation, contracts, rates and regulatory affairs, environmental matters, financing, financial reporting, real estate and other legal matters.
Meters	Procurement of meters.
Nuclear Development	Provision of design, engineering, project management and licensing for new operating units.
Planning	Facilitation of strategic and operating plans preparation; monitoring of trends; evaluation of business opportunities.
Power Engineering and Construction	Services related to the following functions: Enterprise Project Management Center of Excellence; Project Development and Initiation; Project Management and Construction fossil/hydro retrofits; major project Engineering and Construction Services; Commercial and International Project Management and Construction; performance improvement/management.
Power Planning and Operations	Production cost modeling and data management; Services related to the following functions: • Strategic Programs • Bus Svcs Workforce Strategy • Engineering Services • Doc Con/Config Mgmt • Technical Apps • NERC Compliance
Public Affairs	Preparation and dissemination of information to employees, customers, government official, communities, and the media; provision of associated communications materials.
Rate Design and Analysis	Services related to rate design and analysis, and rates support.
Rights of Way	Purchases, sales, management, surveying, and recording of real estate interests.
Supply Chain	Procurement of materials and contract services and related strategy and support
Transportation	Procurement and maintenance of aircraft and procurement and maintenance of vehicles and other power-operated equipment.

Source: Information Response 14

Separations

Finding III-4 There was no use of the DEK logo by any non-utility affiliate.

The Duke Energy Logo is shown in *Exhibit III-20*.[85] In the past, most Duke Energy entities used an older Duke Energy logo with a geographic identifier for the utility companies. However, now only the Duke Energy logo is used to identify the company, regardless of application or media. Other logos may not be created or used for offices, generating stations, facilities, departments or events. Only DEP (previously Progress Energy Carolinas) has "Progress" following the Duke Energy logo, also shown in *Exhibit III-20*.[86] The geographic identifiers shown in *Exhibit III-20* are to be used only in the following applications:[87]

- Regulatory filings in the franchised jurisdictions and other public documents (press releases, fact sheets, etc.) referring to those filings
- Utility-specific reports presented to regulators
- Limited internal uses (financial reports, customer data, etc.)
- Business cards and stationery for large customer/regulator/legislator-facing employees in the respective utility organizations (this applies to all employees in the organizations reporting to the utility presidents)

Any non-regulatory communications, print or electronic, should refer to Duke Energy only and use the Duke Energy logo; geographic identifiers should not be used. Regional operations can be described in terms of "doing business in the Carolinas" or "the company's Kentucky operations." Geographic identifier logos should never be used on hard hats, apparel, vehicles, signage or company-branded merchandise.[88]

According to Duke Energy management, DEK's non-regulated affiliates do not use the DEK name, brand, trademark, or logo for any visual or audio media.[89]

Exhibit III-20
Duke Energy Logos

Geographic Identifiers

Source: Information Response 49

Filings

Finding III-5 There have been no KPSC filings in 2015 relative to service agreements.

Only three (Service Company Utility Service Agreement, Amended and Restated Miami Fort 6 Operations Agreement, First Amendment to Second Amended and Restated Purchase & Sale Agreement with Cinergy Receivables) were changed in 2015 or the beginning of 2016." Agreements that changed in 2015 were required to be submitted to the KPSC. Therefore, according to Duke Energy management, the agreements were most recently approved as part of the settlement of the Duke Energy/Progress Energy merger in Case No. 2011-00124. The minor modifications to the agreements that have occurred since then have been to remove affiliates or to provide clarification to language and have not resulted in a substantive change to require new KPSC approvals, so no additional submittals have been needed."

C. Recommendations

Affiliate Agreements

None.

Affiliate Training

None

Benchmarking

Recommendation III-1 **Provide the KPSC in early 2017 a copy of the results from the market study assessments performed in 2016. (Refer to Finding III-3.)**

As new market study assessments have been performed in 2016 using the new market study methodology established in 2015 for assessing cost versus market for shared services included in service company functions, DEK should provide these results to the KPSC.

Separations

None.

Filings

None.

provided. This type of agreement seems even more essential in an affiliate relationship and, as we have indicated, does not exist for DEK.

Finding IV-3 Appropriate cost allocation factors are being used.

Four primary categories of cost allocations affect DEK and its affiliates, including:

- Cost allocations from service company, specifically DEBS, to DEK
- Cost allocations between DEK and DEO for common costs shared by both utility organizations
- Cost allocations between DEK and its sister regulated utilities and non-regulated utilities regarding various services and goods
- Administrative and general (A&G) cost allocations between its gas and electric operations for both capital and expense accounts

The allocation factors used at Duke Energy are illustrated in *Exhibit IV-4*, with those identified by function are illustrated in *Exhibit IV-5*. Schumaker & Company's review of factors used by function indicate that appropriate allocation factors are being used.

Finding IV-4 Appropriate levels of direct charging are generally occurring with regard to DEK's affiliate transactions.

For 2015, as well as the prior two years (2013 and 2014), the percentage of direct charges shown previously in *Exhibit III-3* and *Exhibit III-4* illustrate that generally a large portion of charges were directly charged, not allocated charges.

Finding IV-5 Sufficient policy and associated documentation has not been available in past years regarding accounting for asset loans.

Regarding asset loans, Duke Energy started (in 2012) considering putting a value on asset loans, but did not value them in 2011. The thought by DEBS management was to use the Storage, Freight, and Handling cost (Account # 163) as the value of an asset loan. Duke Energy also considered the use of the service eForm for services as management considers this more like a service (rental) than an asset transfer, especially for loans lasting less than three to four months. If it is longer than three to four months, then Duke Energy was considering selling the asset and buying it back on the associated entity's books. In 2012 during Schumaker & Company's prior audit, DEBS did not have a formal policy regarding asset loans nor sufficient documentation describing the proper accounting for such transactions.[16] Although no such loans occurred in 2013 involving asset loans from/to DEK, other Duke Energy entities, such as DEI, did have such loans. In 2014 during the Schumaker & Company 2013 audit, Duke Energy management indicated that DEK does not have a formal policy regarding asset loans; however, a slide discussing asset loans was incorporated into asset transfer training courses, but is not sufficient documentation describing the proper accounting for such transactions. However, Duke

IV. Affiliate Transactions and Cost Accumulation and Assignment

A. Background & Perspective

The primary Duke Energy Corporation (Duke Energy) accounting system is Financial Management Information System (FMIS), a PeopleSoft system with general ledger, accounts receivable, accounts payable, asset management, project costing (i.e., Power Plant), contract, and billing applications, plus feeder systems that also pass information to the general ledger. The FMIS processes charges to/from Duke Energy Business Service (DEBS) and Duke Energy Kentucky (DEK) affiliates.[92] All legacy Progress Energy companies no longer used Oracle in 2015, which they had previously used.[93] Also, both PE Carolinas and PE Florida used the utility allocation factor unless direct billing used, when charging other affiliates.[94]

The system has a terminology and method of operation, and each uses a code block/chart field that comprises a set of elements that classify financial information. The code block/chart field contains multiple elements that describe five aspects of a financial transaction as follows:[95]

- *When* – defines the timing of the work performed
- *Who* – identifies who performed the work on whose behalf
- *What* – defines the nature of the work performed
- *How* – defines the resource used to perform the work
- *Where* – identifies the location the work was performed or performed for

The corporate organization is broken down into thousands of responsibility centers, which roll up into other higher level responsibility centers based on reporting responsibility. FMIS uses responsibility center (RC) codes to designate parties to a transaction. FMIS records an accounting entry for a direct charge transaction by designating an RC code that represents the work group performing the service and an Operating Unit (OU) code that represents the group for which the work was performed. The OU To code can be specific or not; for example, it can designate a particular plant or just fossil/hydro plants in general. The business unit receiving the charge designates the OU code to which the amount should be charged. The accounting entry also includes an account, process, project number, resource type (*e.g.*, labor, materials, outside contractor), and amount; the FERC account number is usually embedded in the accounting code block numbering. For allocated charges, the OU code represents an allocation pool, such as governance or enterprise accounting. The FMIS system processes allocation pools at month-end, distributing the charges according to the appropriate allocation pool percentages.[96]

Methodologies Used

Description of Transactions

Services

According to Duke Energy management, there has essentially been no changes regarding services since Schumaker & Company's prior audit report in 2013, nor any upcoming changes except system updates, although more detailed descriptions are now required than previously done.[illegible]

For all cross affiliate services provided, an eForm, which is the same form throughout Duke Energy, is required. This process has been in place for approximately 12 years for most Duke Energy companies, except legacy Progress Energy companies, which began using prior to 2015.[illegible]

The Allocations & Reporting – Corporate Accounting group for Ohio, Kentucky, and Indiana is responsible for month-end close, account reconciliation, data requests from audits, and management reporting.[illegible] Among the duties of the Allocations & Reporting – Corporate Accounting group for all Duke Energy entities is the reasonability for developing and maintaining a basis data binder used to allocate Service Company costs and tracking and reporting Service Company allocations to receiving departments, as well as answering requests from individual departments. The basis data used for developing allocation factors for a calendar year is updated annually based on the 12 months of actual results ending the prior June 30th of each year, or December 31st, if FERC Form 1 & 2 items. The only exception is for basis data involving capital expenditures (Electric T&D Engineering & Construction and Power Engineering & Construction), which the capital budget data for the upcoming year. June 30 data is available and used to update the basis data in the July through September time frame, so this data can be used to complete the budget for the upcoming year.[illegible]

As shown later in *Exhibit IV-4*, Duke Energy uses approximately 20 factors for allocating Service Company costs. The allocation factors used do not change often because the methodologies have been agreed to and included in the various Service Company agreements. Adding a methodology/factor would require modifying the agreement documents and getting buy-in from the various states and regulatory bodies. A major change in business operations, such as the merger with Cinergy or Progress Energy, causes the methodologies (and the service agreements) to be modified. The real test of the methodologies used rests with the owners of the function. They have a vested interest in how the allocations are calculated and how much is allocated to affiliates in an area. A good example of different charge allocations using the same factor ratio is the Human Resources function based on number of employees ratio in which (a) governance activities are charged to all entities, including small portion to the international affiliates); (b) enterprise HR only is charged to all affiliates, except international ones, and (c) Utilities HR is charged only to the regulated industries.[illegible]

DEBS is basically a net $ entity, in which most costs are charged to Duke Energy subsidiaries; exceptions include DEBS income tax, which is not allocated; selected interest charges that remain with the service company entity; and return on DEBS assets area also excluded from DEBS charges to affiliates.[102]

Departmental employees are directed to direct charge if they can and only include their costs in the allocation pools if they cannot direct charge. Duke Energy's time reporting system, *MyTime*, which has been used approximately three years, was fully implemented on an enterprise basis in April 2011. The time reporting system has a default for employees' time and it is charged unless changed. According to DEBS management, employees were trained to use the new system when it was implemented, so all employees should know how to change their time from the default. However, legacy Progress Energy employees did not use *MyTime* in 2013, but their own system, referred to as the *Corporate Time Entry* (CTE) system. Therefore, starting July 2, 2012 (when merger was effective), all legal Progress Energy employees had to submit timesheets. By the end of 2013 (employees converted over by group during 2013), all legacy Duke Energy employees (even exempt) also had to submit timesheets; however, in the beginning of 2013, exception time reporting was still used. All DEBS employees, including legacy Progress Energy employees, used *MyTime* in 2014 and 2015.[103]

Timekeepers enter time into *MyTime* from approved employee timesheets, or in some areas the employee enters time into *MyTime* and the data is approved by the manager or delegate. The time data is extracted and exported to Aon Hewitt for biweekly pay processing through a series of programs, which loads the time data to the individual employee pay sheets in its HRMS system. Once the time data from *MyTime* has been processed to the individual employee pay sheets, a series of pay calculations occur in the payroll system to finalize the check process. Following the pay confirmation process, files are generated from the payroll system for processing through the Labor Distribution System (LDS). Aon Hewitt balances the labor files before sending the files and control totals to Duke Energy for labor distribution processing to the general ledger. All exempt employees are required to enter their vacation taken into *MyTime* and each business unit determines other time reporting requirements for their area. Some employees enter actual time data, while other employees have their time data generated based on their standard schedule and their default labor allocation. The time data, both entered and generated, is extracted and exported to LDS for processing to the general ledger.[104]

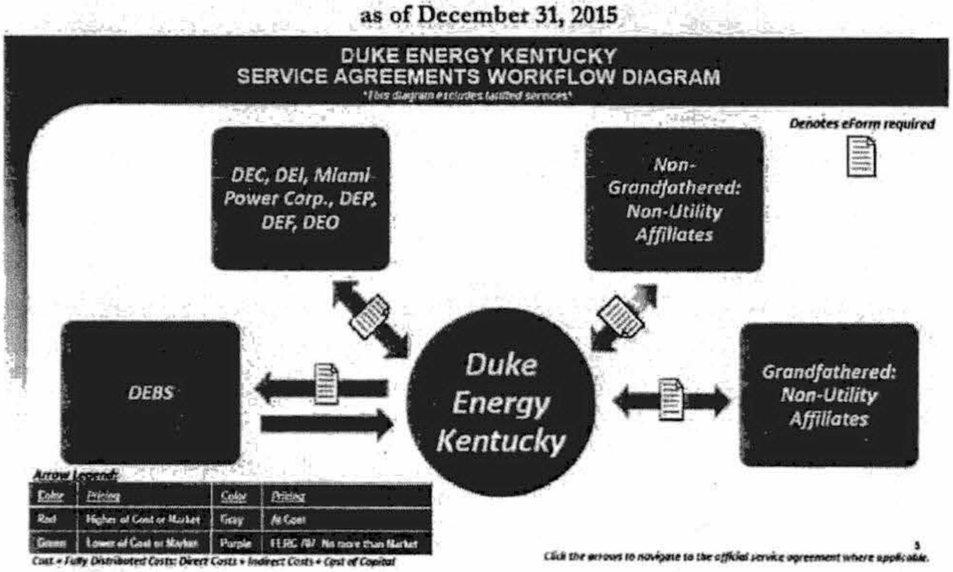
For allocated charges, one of the following three methodologies is used for recording intercompany transactions, as identified in Duke Energy's *Accounting for Intercompany Transactions Policy* documentation effective February 25, 2015.[105] According to Duke Energy management, revisions to simplify reporting roll-ups and settlements were also made subsequent to this audit period starting January 14, 2016.[106]

- *Auto-generating:* Intercompany transactions required for recording loans, cash sweeps, or that generate the booking of revenue and generation of a receivable where both affiliates are on the enterprise PeopleSoft ledger may be recorded using the auto-generating methodology. It only handles US$ transactions; therefore, any non US$ transactions are exempt from using this methodology. This methodology automatically generates the *purchaser/receiver* transaction based on the *seller/sender* transaction and is available to all Duke Energy business units using the enterprise PeopleSoft general ledger.

- *Manual Balancing*: Although manual balancing is not the preferred methodology for recording inter-business unit transactions, manual balancing can be used when deemed necessary. Examples include: intercompany transactions that are required for recording investment/equity, intercompany derivatives, non-US$ transactions, or, in the case where the transaction is with an affiliate who is not on the enterprise-wide PeopleSoft general ledger. Prior to recording inter-business unit transactions using the manual balancing methodology, both the *seller/sender* and *purchaser/receiver* must submit a request for approval (including the reason for using this methodology and documentation of the mitigating controls in place to ensure compliance with policy) to the Enterprise Intercompany Process Owner (IPO), defined as the person who is in the role of IPO for all of Duke Energy and its consolidated subsidiaries.
- *Automated Crossbill*: All intercompany transactions that are required for recording allocations or expense/revenue transfers between corporate/business units are to be recorded using the automated crossbill methodology. Allocations or expense/revenue transactions recorded using this methodology may be recorded to third-party accounts rather than designated intercompany accounts as long as individuals responsible for the transaction ensure the propriety of the effect to the consolidated financial statement line items. The PeopleSoft system automatically generates the related receivable or payable to intercompany accounts.

Exhibit IV-1 illustrates a summary for affiliate service charges.

Exhibit IV-1
Summary Pricing Guide
Services
as of December 31, 2015



Source: Information Response 42

Exhibit IV-2 illustrates the prior summary pricing guide for services, which was included in Schumaker & Company's prior audit report. Although it still applies, when new training was implemented by Duke Energy (as discussed in the Training section of *Chapter III – Affiliate Relationships*), the Compliance group decided to make the guide simpler for inclusion in training.[107]

Exhibit IV-2
Summary Pricing Guide
Services
as of December 31, 2013

TRANSFER TO

TRANSFER FROM	DE Carolinas	DE Indiana	DE Kentucky	DE Ohio (T&D)	Miami Power	PE Carolinas	PE Florida	DE Ohio (Gen)	other non-reg utility[2]	non-utility[3] (excl. Svc. Co.)	Service Company
DE Carolinas		At Cost	At Cost	At Cost	At Cost	At Cost	At Cost	Higher Cost / Mkt	Higher Cost / Mkt	Higher Cost / Mkt	Higher Cost / Mkt
DE Indiana	At Cost		At Cost	At Cost	At Cost	At Cost	At Cost	Higher Cost / Mkt	Higher Cost / Mkt		At Cost
DE Kentucky	At Cost	At Cost		At Cost	At Cost	At Cost	At Cost	Higher Cost / Mkt	Higher Cost / Mkt		At Cost
DE Ohio (T&D)	At Cost	At Cost	At Cost		At Cost	At Cost	At Cost	At Cost	Higher Cost / Mkt		At Cost
Miami Power	At Cost	At Cost	At Cost	At Cost		At Cost	At Cost	Higher Cost / Mkt	Higher Cost / Mkt		At Cost
DE Progress	At Cost	At Cost	At Cost	At Cost	At Cost		At Cost	Higher Cost / Mkt	Higher Cost / Mkt	Higher Cost / Mkt	Higher Cost / Mkt
DE Florida	At Cost	At Cost	At Cost	At Cost	At Cost	At Cost		Higher Cost / Mkt	Higher Cost / Mkt	Higher Cost / Mkt	Higher Cost / Mkt
DE Ohio (Gen)	Lower Cost / Mkt	Lower Cost / Mkt[1]	At Cost[5]	At Cost	Lower Cost / Mkt	Lower Cost / Mkt	Lower Cost / Mkt		Negotiated Rates		At Cost
other non-reg utility[2]	Lower Cost / Mkt	Lower Cost / Mkt[1]	Lower Cost / Mkt	Lower Cost / Mkt	Lower Cost / Mkt	Lower Cost / Mkt	Lower Cost / Mkt	Negotiated Rates	Negotiated Rates	Negotiated Rates	Negotiated Rates
non-utility[3] (excl. Svc. Co.)	Lower Cost / Mkt					Lower Cost / Mkt	Lower Cost / Mkt		Negotiated Rates	Negotiated Rates	Negotiated Rates
Service Company	At Cost	At Cost	At Cost	At Cost	At Cost	At Cost	At Cost	At Cost	At Cost	At Cost	

Footnotes:

1. The IRUC requires DE Indiana to follow FERC's asymmetrical pricing rules. However, since several of the Duke regulated utilities must follow more restrictive state pricing rules, it has been recommended that DEI affiliate transfers be priced at the more restrictive pricing.

2. Non-Regulated Utility Affiliates currently include: DEO-Generation, St. Paul Cogeneration, DE Trading & Marketing, Duke Energy Commercial Asset Management, Inc, CinCap IV, CinCap V, Duke Energy Commercial Enterprises, Inc., Happy Jack Windpower, North Allegheny Wind, Silver Sage Wind, Three Buttes Windpower, LLC., Kit Carson Windpower, LLC., Top of the World Windpower, LLC., Duke Energy Retail Sales, LLC, Duke Energy Lee, II, LLC, Duke Energy Hanging Rock II LLC and Duke Energy Fayette II, LLC, Cimarron Windpower II, LLC, Laurel Hill Windpower and Ironwood Windpower II, LLC.

3. Non-Utility Affiliates are all other affiliates not identified in footnote 3 or the regulated utilities: DE Carolinas, DE Progress, DE Florida, DE Indiana, DE Kentucky, DE Ohio (T&D) and Miami Power.

[redacted]

5. FERC No Action Letter allows DEO Gen to provide services to DEK Plants (Woodsdale, EastBend, and Miami Fort Unit 6) at cost.

[redacted]

Source: Schumaker & Company prior audit report

Asset Transfers

According to Duke Energy management, there has been no changes regarding asset transfers since Schumaker & Company's prior audit report in 2013, nor any upcoming changes.[108]

The FERC accounts in which asset transfers (e.g. utility, emission allowances, materials and supplies) between DEK and its affiliates are recorded as follows:[109]

- *Utility Plant in Service*: 300 level electric plan accounts
- *Emission Allowances*: 158 emission allowance inventory account

- *Materials and Supplies*: Although transactions of materials and supplies could be recorded in capital accounts and O&M accounts, the following accounts were used in recording materials and supplies asset transfers between DEK and its affiliates in 2011:
  - 107000 Construction Work in Process
  - 154100 Plant Materials and Operating Supplies

The asset transfer rules for DEK and other Duke Energy utilities in the Midwest are different from the rules that govern asset transfers in the Carolinas. Transfers in the Carolinas require the use of eForms (a burdensome form that is needed to comply with specific regulations in the Carolinas). Because of the number of transfers within the Midwest, Duke Energy put in a process that did not require the use of eForms in these states, unless dollars associated with asset transfers exceed $1 million. Duke Energy uses an IBM Maximo system, previously called eMax, to track inventory stock-to-stock transfers between entities, although Progress Energy didn't start using it until 2014. DEK generally carries a smaller amount of inventory stock on its books than the other Midwest entities. Transfers of in-service assets are tracked in other systems, typically PowerPlant, which DEK uses. Asset transfers typically occur fossil plant to fossil plant or nuclear plant to nuclear plant as the part needs are similar. Typical transfers are low cost items, such as pumps or valves, although (as shown in *Exhibit III-9*) transfers may also include meters, transformers, regulators, and other miscellaneous items, which are not considered inventory stock transfers.[110] According to Duke Energy management, the biggest change in asset transfers due to the Duke Energy/Progress Energy merger was in the Carolinas with regard to e-Forms caused by the nuclear service agreement. In 2013 Progress Energy's nuclear organization used Passport software, but was expected to be converting to eMax, which occurred in 2015.[111]

Additionally, any individual asset transfers involving DEK that are $1 million or higher must be reported to the KPSC for approval, as follows:[112]

- In KRS 278.218 (approval of commission for change in ownership or control of assets owned by utility) indicates the following:
  1) No person shall acquire or transfer ownership of or control, or the right to control, any assets that are owned by a utility as defined under KRS 278.010(3)(a) without prior approval of the commission, if the assets have an original book value of one million dollars ($1,000,000) or more and:
     a) The assets are to be transferred by the utility for reasons other than obsolescence; or
     b) The assets will continue to be used to provide the same or similar service to the utility or its customers.
  2) The commission shall grant is approval if the transaction is for a proper purpose and is consistent with public interest.
- Also, regarding the KPSC Order in Case No. 2008-122, DEK agreed to be bound by KRS 278.218 for transactions involving its gas utility assets.

The KPSC grants its approval if the transaction is for a proper purpose and is consistent with the public interest.[114]

The IBM Maximo system is used for all inventory issues, returns, and transfers, regardless of entity.[115] It includes inventory stock transfers (Account # 154-Plant Materials and Operating Supplies in the sending entity to Account # 154 in the receiving entity); at the end of the month an automatic charge from Account # 163 (Storage, Freight, and Handling) of the sending entity is also transferred to Account # 163 in the receiving entity. On a monthly basis, in the Midwest, Duke Energy generates a report from the system and uses it to determine if fair market value is to be calculated and, where appropriate, book the differential between fair market value and cost to comply with asset transfer standards. The asset valuation of fair market value for the transfers is done in one of three ways:[116]

- If goods were acquired using a blanket purchase order, the value is the blanket average unit price (AVP).
- If not acquired using a blanket purchase order, Duke Energy uses a recent purchase order (typically less than six months old but no longer than a year) cost for the item.
- If there is no purchase order, Duke Energy will get quotes; there is no prescribed number of quotes that must be received.

Transfers of assets not in inventory, such as capital spares, are performed in PowerPlant by the Asset Accounting organization. Similarly, on a quarterly basis, Duke Energy generates a report from PowerPlant, and uses it to if fair market value is to be calculated and, where appropriate, book the differential between fair market value and cost (original cost minus depreciation reserve equals net book value cost) to comply with asset transfer standards.[117]

Cost is handled automatically in the systems; market rate differentials must be handled via a journal entry. The reports for transfers, both inventory stock and in-service assets, go to the Manager, Asset Accounting and a General Ledger journal entry (multiple lines) is created, if necessary. For transfers of in-service assets between regulated and non-regulated entities, rather than simply make a transfer, Asset Accounting retires the asset from the sending entity and adds it formally to the receiving entity, creating a salvage amount to reflect the market differential amount.[118]

Following the Duke Energy/Progress Energy merger, according to DEBS management, there's been more opportunity for transferring capital assets. Both Duke Energy and Progress Energy used PowerPlant for non-inventory assets; however, they were on different versions. Therefore, manual entry was needed for transferring assets between versions. Then in 2014, both began using the same version, resulting in more system-generated transfers.[119]

Affiliate transfers of assets are governed by Federal Energy Regulatory Commission (FERC) 707 and asset transfer agreements. FERC 707 requires that transfers between regulated and non-regulated affiliates be priced using asymmetrical pricing. This requires that transfers from DEK to a non-regulated affiliate must be valued at the higher of cost or market, and transfers from non-regulated affiliates to DEK be valued at the lower of cost or market price, referred to as asymmetrical pricing. Therefore, if a transfer is regulated to non-regulated and a market value adjustment is needed, then a gain is added via a journal entry. Conversely if a transfer is non-regulated to regulated, an adjustment via a journal entry is made, if needed. For regulated-to-regulated transfers, asymmetrical pricing is not required, but is done at cost.[119]

There's a No Action letter in Kentucky. In 2006 Duke Energy made a request to FERC, when it transferred Miami Fort Unit 6 from DEO (then CG&E) to DEK (then ULH&P), to allow inventory stock transfers at "at cost" rather than "asymmetrical pricing," even though they would be transferred from a non-regulated entity, such as DEO Miami Fort 7/8, to a regulated entity, such as DEK. If any inventory stock transfers go from DEK to DEO, however, "asymmetrical pricing" is required.[120]

Exhibit IV-3 illustrates a summary pricing guide for affiliate asset transfers.[121]

Exhibit IV-3
Summary Pricing Guide
Asset Transfers
as of December 31, 2015

TRANSFER FROM \ TRANSFER TO	DE Carolinas[1A, 1B]	DE Indiana	DE Kentucky	DE Ohio (T&D)	PE Carolinas	PE Florida	DE Ohio (Gen)	other non-reg utility[3]	non-utility[4]
DE Carolinas[5]		At Cost[1A]	At Cost[1A]	At Cost[1A]	At Cost[1A]	At Cost[1A]	Higher Cost / Mkt[1B]	Higher Cost / Mkt[1B]	Higher Cost / Mkt[1B]
DE Indiana	At Cost[1A]		At Cost	At Cost	At Cost[1A]	At Cost[1A]	Higher Cost / Mkt	Higher Cost / Mkt	Higher Cost / Mkt
DE Kentucky[6]	At Cost[1A]	At Cost		At Cost	At Cost[1A]	At Cost[1A]	Higher Cost / Mkt	Higher Cost / Mkt	Higher Cost / Mkt
DE Ohio (T&D)	At Cost[1A]	At Cost	At Cost		At Cost[1A]	At Cost[1A]	At Cost	Higher Cost / Mkt	Higher Cost / Mkt
DE Progress	At Cost[1A]	At Cost[1A]	At Cost[1A]	At Cost[1A]		At Cost[1A]	Higher Cost / Mkt[1B]	Higher Cost / Mkt[1B]	Higher Cost / Mkt[1B]
DE Florida	At Cost[1A]	At Cost[1A]	At Cost[1A]	At Cost[1A]	At Cost[1A]		Higher Cost / Mkt[1B]	Higher Cost / Mkt[1B]	Higher Cost / Mkt[1B]
DE Ohio (Gen)	Lower Cost / Mkt[1B]	Lower Cost / Mkt[2]	At Cost[7]	At Cost	Lower Cost / Mkt[1B]	Lower Cost / Mkt[1B]		Negotiated Rates	Higher Cost / Mkt
other non-reg utility[3]	Lower Cost / Mkt[1B]	Lower Cost / Mkt[2]	Lower Cost / Mkt	Lower Cost / Mkt	Lower Cost / Mkt[1B]	Lower Cost / Mkt[1B]	Negotiated Rates	Negotiated Rates	Negotiated Rates
non-utility[4] (excl. Svc. Co.)	Lower Cost / Mkt[1B]	Lower Cost / Mkt[2]	Lower Cost / Mkt	Lower Cost / Mkt	Lower Cost / Mkt[1B]	Lower Cost / Mkt[1B]	Lower Cost / Mkt	Negotiated Rates	Negotiated Rates

Footnotes:

1A. Goods may be transferred "At Cost" with regulated utility affiliates. LEGAL MUST BE CONTACTED when a transfer is >$100K so that a separate legal agreement can be developed and filed. All Goods Transfers >$ from require SC Commission Approval.

1B. Prior to transferring goods at the Higher of Cost / Mkt or receiving goods at the Lower of Cost / Mkt., DE Carolinas must file an agreement. CONTACT LEGAL.

2. The IRUC requires DE Indiana to follow FERC's asymmetrical pricing rules. However, since several of the Duke regulated utilities must follow more restrictive state pricing rules, it has been recommended that DEI affiliate transfers be priced at the more restrictive pricing.

3. Non-Regulated Utility Affiliates currently include: DEO-Generation, Duke Energy Beckjord, Duke Energy Conesville Duke Energy Dicks Creek, Duke Energy Killen, Duke Energy Miami Fort, Duke Energy Stuart, Duke Energy Zimmer, St. Paul Cogeneration, DE Trading & Marketing, Duke Energy Commercial Asset Management, Inc, CinCap IV, CinCap V, Duke Energy Commercial Enterprises, Inc., Happy Jack Windpower, North Allegheny Wind, Silver Sage Wind, Three Buttes Windpower, LLC., Kit Carson Windpower, LLC., Top of the World Windpower, LLC., Duke Energy Retail Sales, Duke Energy Lee, II, LLC, Duke Energy Hanging Rock II, LLC and Duke Energy Fayette II, LLC, Cimarron Windpower II, LLC, Laurel Hill Windpower and Ironwood Windpower II, LLC.

4. Non-Utility Affiliates are all other affiliates not identified in footnote 3 or the regulated utilities: DE Carolinas, DE Progress, DE Florida, DE Indiana, DE Kentucky, DE Ohio (T&D) and Miami Power. Confirmation must be made that they are party to the existing agreements, if not, CONTACT LEGAL.

5. Transfers from DE Carolinas involving an asset over $1 million must be approved by the SCPSC.

6. DE Kentucky cannot transfer assets valued at $1 million or more without prior approval of the KYPSC.

7. FERC No Action Letter allows DEO Gen to provide services to DEK Plants at cost.

Source: Information Response 42

Cost Accumulation, Assignment, & Allocation

When a DEBS employee of performs services for a client company, costs are to be directly assigned or allocated. Duke Energy uses 20 factors, as shown in *Exhibit IV-4*, for allocating Service Company costs. The allocation factors used do not change often because the methodologies have been agreed to and included in the various Service Company agreements. Adding a methodology/factor would require modifying the agreement documents and getting buy-in from the various states and regulatory bodies. A major change in business operations, such as when the merger with Cinergy or Progress Energy happened in the past, causes the methodologies (and the service agreements) to be modified. The real test of the methodologies used rests with the owners of the function. They have a vested interest in how the allocations are calculated and how much is allocated to affiliates in an area. A good example of different charge allocations using the same factor ratio is the Human Resources function based on number of employees ratio in which (a) governance activities are charged to all entities, including small portion to the international affiliates); (b) enterprise HR only is charged to all affiliates, except international ones, and (c) Utilities HR is charged only to the regulated industries.[122]

Exhibit IV-4
Allocation Factors
as of December 31, 2015

Factor	Utility	Non-Utility
Circuit miles of electric transmission lines	Yes	No
Construction expenditures	Yes	Yes
Electric peak load	Yes	Yes
Generating unit MW capability/maximum dependable capacity (MDC)	Yes	Yes
Gross margin	Yes	Yes
Inventory	Yes	Yes
Labor dollars	Yes	Yes
Miles of distribution lines	Yes	No
Millions of instructions per second (MIPS) (previously number of central processing unit (CPU) seconds used)	Yes	Yes
Number of customers	Yes	Yes
Number of employees	Yes	Yes
Number of information systems servers	Yes	Yes
Number of meters	Yes	No
Number of personal computer (PC) work stations	Yes	Yes
O&M expenditures	Yes*	Yes*
Procurement spending	Yes	Yes
Revenues	Yes	Yes
Sales	Yes	Yes
Square footage	Yes	Yes
Total property, plant, and equipment	Yes	Yes

Source: Information Responses 2 and 8 and Interview _
* Although a valid factor for charging service company costs to utility companies, it is not used by Duke Energy.

For allocated services, the Service Company Utility Service Agreement prescribes 24 functions with their associated allocation methodologies, as follows:[121]

Exhibit IV-5
DEBS Allocation Factors by Function
as of December 31, 2015

Information Systems	♦ Millions of Instructions per Second Ratio ♦ Number of Personal Computer Workstations Ratio ♦ Number of Information Systems Servers Ratio ♦ Number of Employees Ratio
Meters	♦ Number of Customers Ratio
Transportation	♦ Number of Employees Ratio ♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E)
System Maintenance	♦ Circuit Miles of Electric Transmission Lines Ratio ♦ Circuit Miles of Electric Distribution Lines Ratio ♦ Labor Dollars Ratio (Gas Distribution) (Kentucky)
Marketing and Customer Relations	♦ Number of Customers Ratio
T&D Engineering & Construction	♦ Electric Transmission Plant Construction - Expenditures Ratio ♦ Electric Distribution Plant Construction - Expenditures Ratio
Power Engineering & Construction	♦ Electric Production Plant Construction - Expenditures Ratio
Human Resources	♦ Number of Employees Ratio
Supply Chain	♦ Procurement Spending Ratio ♦ Inventory Ratio
Facilities	♦ Square Footage Ratio
Accounting	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E) ♦ Generating Unit MW Capability Ratio (certain merger related costs associated with nuclear organizations in Progress Florida, Progress Carolinas, and Duke Energy Carolinas)
Power and Gas Planning and Operations	♦ Electric Peak Load Ratio ♦ Construction - Expenditures Ratio (Gas Distribution Planning and Operations-KY) ♦ Sales Ratio ♦ Weighted Average of Circuit Miles of Electric Distribution Lines Ratio and the Electric Peak Load Ratio ♦ Weighted Average of Circuit Miles of Electric Transmission Line Ratio and the Electric Peak Load Ratio ♦ Generating Unit MW Capability/MDC Ratio
Public Affairs	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E) ♦ Weighted Average of Number of Customers Ratio and Number of Employees Ratio
Legal	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E)
Rate Design and Analysis	♦ Sales Ratio
Finance	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E)
Rights of Way	♦ Circuit Miles of Electric Transmission Lines Ratio ♦ Circuit Miles of Electric Distribution Lines Ratio (added 2014) ♦ Electric Peak Load Ratio (added 2014, but not used in 2014 or 2015)
Internal Auditing	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E)
Environmental, Health and Safety	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E) ♦ Sales Ratio
Fuels	♦ Sales Ratio
Investor Relations	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E)
Planning	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E)
Executive	♦ Three Factor Formula (Gross Margin, Labor Dollars, PP&E)
Nuclear Development	♦ Directly assigned/charged to participating jurisdictions

Source: Information Responses 2 and 8 and Interview 1

Billing Mechanisms

During Year

Most affiliate billing mechanisms are automatically performed at month-end (based on direct charges and allocations) with offsetting entries to the charging entity (A/R) and receiving entity (A/P). This information is rolled up and summarized, then sent to Treasury, who in turn moves monies between the associated bank accounts. For regulated entities, settlement is required monthly, although some transactions happen more frequently, such as payroll or supply chain, which typically happen weekly. For non-regulated entities, such as commercial renewables or international organizations, it is not done until a capital infusion is required.[124]

True-up Procedures

Labor and Overhead Items

The Duke Energy Financial Management Information System (FMIS) automatically applies labor loaders for fringe benefits, payroll taxes, unproductive time, incentives, and Service Company overhead (O/H) allocations. Accounting personnel enter into FMIS the percentage for each labor loader item each month. These rates typically remain constant for most of the year. Accounting personnel record actual costs for the four labor-related costs in separate accounts that they monitor to make sure that the rates it has been applying are staying in line with actual costs. They typically adjust loader rates in the fourth quarter to clear any residuals compared to actual costs. Any journal entries recorded after monthly allocations run are either manually allocated in the current month or recorded in the following month.[125] Only DEC and DEP do not incorporate these items into transactions between each other.[126]

Late Journal Entries

Any journal entries recorded after the monthly allocations run are either manually allocated in the current month or recorded in the following month. As Duke Energy employees can only enter JEs until the second business day following month-end, large items after the second business day are manually allocated, while small items may be delayed to the next month. At year-end, however, any missing items, regardless of size, must be manually allocated.[127]

B. Findings & Conclusions

Finding IV-1 **The DEK cost allocation manual includes KPSC requirements, but continues to miss key elements of comprehensive CAM documentation used by other utility organizations.**

Kentucky Revised Statutes (KRS) 278.2205 provides that any Kentucky utility engaged in non-regulated activities, which produce aggregate revenue exceeding the lesser of two percent (2%) of the utility's total revenue of one million dollars ($1,000,000) annually, shall develop and file a cost allocation manual (CAM) with the KPSC. The DEK CAM is based solely on KPSC requirements; it does not include various elements, which would make it more useful, such as those discussed in the recommendation associated with this finding.[128]

DEK's 2015 CAM was developed during the first quarter of 2015 and the affidavit for the 2015 CAM is dated March 29, 2016. Consistent with KRS 278.2205, DEK revises its CAM periodically for material changes. DEK also conducts an annual comprehensive review during the first quarter of each year to determine if there are any changes (both material and non-material) that need to be reflected. DEK conducts this CAM review along with its preparation of various annual financial and statistical reports that are filed with the KPSC on or about March 31st of each year. These additional annual reports include, but are not limited to, vegetation and reliability, resource planning updates, non-regulated revenues, and other reports required pursuant to various KPSC Administrative proceedings.[129] The 2015 changes primarily account for changes in names to parties and the clarification of definitions and terms, which were inadvertently omitted from the prior version, plus updates recommended by Schumaker & Company in our prior audit report.[130] The 2015 changes also reflect updates to the various reporting requirements of non-regulated activities and changes in the percentage for cost allocation details, not new steps.[131]

DEK's CAM includes the following segments:[132]

- Description of Duke Energy and DEK
- Policies and procedures/guidelines for transactions between DEK and its affiliates, including four primary categories of cost allocations involving DEK, such as:
  - Guidelines for charging DEK for costs originating with service company
  - Cost allocations from DEBS, a wholly-owned subsidiary service company of Duke Energy
  - Cost allocations between DEK and DEO for common costs shared by DEO and DEK
  - Cost allocations for goods and services provided between and among Duke Energy Kentucky and its sister regulated utilities.
  - Additionally, DEK, as a combination gas and electric utility, also receives administrative and general (A&G) cost allocations between its gas and electric operations for both capital and expense accounts.
- Cost distribution processes for affiliate transactions
  - Guidelines and procedures for charging affiliates for costs originating with DEK
  - Guidelines and procedures for charging DEK for costs originating with utility affiliates, excluding the service company
  - Guidelines and procedures for charging DEK for costs originating with non-regulated affiliates

- Typical transactions between DEK and affiliates covered under separate agreements
- Audit principles and guidelines

♦ CAM requirements, including:

- KRS 278.2205 (2) (a): A listing of regulated and non-regulated divisions within the utility (not applicable, as DEK does not have any non-regulated divisions).
- KRS 278.2205 (2) (b): A listing of all regulated and non-regulated affiliates of the utility to which the utility provides services or products and where the affiliates provide non-regulated activities, as defined in KRS 278.010 (21) (CAM Appendix O, with further description in agreements)
- KRS 278.2205 (2) (c): A listing of services and products provided by the utility, and identification of each as regulated or non-regulated, and the cost allocation methodology generally applicable to each category
- KRS 278.2205 (2) (d): A listing of incidental, non-regulated activities that are subject to the provisions of KRS 278.2203 (4)
- KRS 278.2205 (2) (e): A description of the nature of transactions between the utility and its affiliates
- KRS 278.2205 (2) (f): For each Uniform System of Accounts (USofA) account and subaccount, a report that identifies whether the account contains costs attributable to regulated operations and non-regulated operations, including an identification of whether the costs are joint costs that cannot be directly identified; if allocated a description of the methodology used, which are subject to the provisions of KRS 278.2203

♦ Appendices

- Kentucky revised statutes
- Affiliate agreements, including:
  - Service Company Utility Service Agreement
  - Amended and Restated Operating Company / Non-utility Companies Service Agreement
  - Asymmetrically Priced Duke Energy Kentucky, Inc. / Nonutility Companies Service Agreement
  - Operating Companies Service Agreement
  - Amended and Restated Miami Fort 6 Operation Agreement
  - Gas and Propane Services Agreement with Respect to Woodsdale Generating Station
  - Utility Money Pool Agreement
  - Second Amended and Restated Purchase and Sale Agreement (updated October 27, 2010)

- Agreement for Filing Consolidated Income Tax Returns and for Allocation of Consolidated Income Tax Liabilities and Benefits
- Inter Company Asset Transfer Agreement
- Utility-Non-utility Asset Transfer Agreement

– Report of 2015 inventory transfers

– Shared service cost distribution detail

– Listing of DEK affiliates

– Incidental non-regulated activities and associated revenue (2015)

– FERC uniform system of accounts

– FERC affiliate transactions report

Although DEK's CAM has significantly improved, several key elements of a comprehensive CAM are still missing from DEK's CAM, including (but not limited to) elements such as:[155]

- Detailed description of cost accumulation, assignment, and allocation (direct and allocated charges) methodologies
- Detailed description of allocation methodologies and listing of factors
- Detailed policies, guidelines, and procedures, even though a summary level of policies and procedures/guidelines has been added since the prior audit
- Detailed description of processes and systems used for affiliate charges, etc.

Previously Duke Energy management indicated that it was evaluating transferring the maintenance of the CAM to the Rates Department for revision consistent with how the North Carolina CAM is maintained; however, it is still being performed by the Legal Department.[156]

Finding IV-2 DEK does not have service level agreement documentation included in its agreements with affiliates.

Schumaker & Company looked for a service level agreement or similar documentation that would specify standards of performance by affiliates providing services to DEK. DEK confirms that there is no service level agreements between DEK and its affiliates.[157]

A service level agreement is important and, in recent years, it is a commonly used document that defines a certain "level" of service that is to be provided by one organization to another. This agreement is expressed as a set of defined tasks and processes, each party's roles and responsibilities, and associated metrics of performance. Many companies, in utility industries, operating in a shared-services environment now have service level agreements in place that specify the resources dedicated to a specific unit. They also typically have clear metrics that define the quality and efficiency of the services

Energy management indicated that it is currently the company's practice not to loan assets.[177] Therefore, in 2015, no asset loans involving DEK were made.[178]

As each asset loan is considered unique; therefore, a company-wide policy does not exist and Duke Energy does not believe it would be beneficial. Each asset loan requires significant discussions between legal, asset accounting, and supply chain to determine the best strategy and ensure all affiliate requirements are met. As Duke Energy has affiliate transfer training, this training program includes information about asset loans. Given the rarity of an asset loan, Duke Energy believes this information is sufficient to ensure all affiliate guidelines are followed when there is an asset loan. Supply Chain is not aware of any loans in 2015 for any jurisdiction.[179]

C. Recommendations

Recommendation IV-1 **Continue to develop an improved formal comprehensive cost allocation manual that brings together all required elements of such documentation. (Refer to Finding IV-1)**

As described in *Finding IV-1*, many improvements have been incorporated into DEK's CAM documentation; however, DEK is still in need of improved formal documentation, such as that used by DEC, which in one package with any associated appendices comprehensively describes its affiliate relationships/organization structure; affiliate standards to which it is subject; affiliate agreements; description of cost accumulation, assignment, and allocation (direct and allocated charges); allocation methodologies and factors; policies, guidelines, and procedures; description of processes and systems used for affiliate charges; etc.

Among the requirements of further CAM documentation are to include:

- Detailed description of cost accumulation, assignment, and allocation (direct and allocated charges) activities
- Detailed description of allocation methodologies and factors, including how calculated and results of year's calculations
- Detailed description of policies, guidelines, and procedures, even though a summary level of policies and procedures/guidelines has been added since the prior audit
- Detailed description of processes and systems used for affiliate charges; etc.

Duke Energy should continue to include KPSC requirements, but also incorporate recommended changes.

Recommendation IV-2 Develop service level agreements for key functions providing affiliate services to DEK. (Refer to Finding IV-2.)

For example, DEBS is a shared service provider to Duke Energy affiliates. In addition to its service agreements, Duke Energy should have specific service level agreements (SLAs) as its standard in shared services environments. The SLA should specify the services provided and the standards associated with the service. These standards should specify volume, time, and condition (quality) of service. Performance metrics and associated results should be reported regularly and the agreement should be modified periodically. Specifically, a good SLA includes topics such as the following:

- Introduction, including scope and objectives; definition of business partners, including the function providing services to DEK and DEK business units served by the function; associated roles and responsibilities of both types of business partner, plus governance committee roles and responsibilities, and corporate/executive roles and responsibilities; plus the agreement's underlying assumptions.
- A detailed listing of target metrics, including metric, metric calculation, goal, target, owner, responsible department, and explanation (if necessary), with the reporting structure and frequency identified.
- Required management activities, such as:
  - Identification of material variance and corrective actions
  - Performance accountability for function employees providing services to DEK
  - Process to be followed for period reviews of the SLAs
  - Methodology for revision of service levels relative to changing service needs and priorities
  - Results of annual business performance surveys
- Business partner signatures

By implementing such an SLA, the organization providing services to DEK is formally required to be accountable to business units for its activities on their behalf.

Recommendation IV-3 Develop a formal policy and associated documentation regarding process for handling asset loans, so that they exist going forward in situations where asset loans are actually done. (Refer to Finding IV-5.)

Even though asset loans are extraordinarily rare, they have been incorporated in summary form into training materials and they are handled on a case-by-case basis similar to asset transfers, Duke Energy should also develop a formal policy and associated written documentation describing the process for how and why it handles asset loans among affiliates, as it has performed such activities in the past, although it indicated that it is currently not done. Nevertheless, Duke Energy should ensure that it develops a formal policy and create such procedural documentation, so that they exist going forward in situations where asset loans are actually done.

V. Financial Arrangement/Obligation Compliance

This chapter reviews the financial arrangement/obligation compliance between Duke Energy Kentucky (DEK) and its affiliates, including its parent organizations.

A. Background & Perspective

The specific governing regulatory section that is addressed in this chapter is KRS # 278.2207 - Transactions between utility and affiliates – Pricing requirements – Request for deviation, as follows:

1. The terms for transactions between a utility and its affiliates shall be in accordance with the following
   a. Services and products provided to an affiliate by the utility pursuant to a tariff be at the tariffed rate, with nontariffed items priced at the utility's fully distributed cost but in no event less than market, or in compliance with the utility's existing (United States Department of Agriculture) USDA, Securities & Exchange Commission (SEC), or Federal Energy Regulatory Commission (FERC) approved cost allocation methodology.
   b. Additionally, services and products provided to the utility by an affiliate are to be priced at the affiliate's fully distributed cost but in no event greater than market or in compliance with the utility's existing USDA, SEC, or FERC approved cost allocation methodology.
2. A utility may file an application with the commission requesting a deviation from the requirements of this section for a particular transaction or class of transactions, but the utility has the burden of demonstrating that the requested pricing is reasonable. The commission may grant the deviation if it determines the deviation is in the public interest.
3. Nothing in this section should be construed to interfere with the commission's requirement to ensure fair, just, and reasonable rates for utility services.

The financial services and products provided to DEK by affiliates and provided by DEK to its affiliates consist of long-term and short-term debt and investments.

Long-term Debt

Long-term Debt Composition

DEK's long-term debt at the end of calendar year 2015 consisted of capital leases, first mortgage bonds, pollution control bonds, and unsecured debt totaling $319 million. The long-term debt balance for the entire Duke family of affiliated companies was almost $40 billion. Details of the long-term debt for DEK and its affiliates at the end of 2015 are shown in *Exhibit V-1*.[illegible]

Exhibit V-1
Duke Energy Long-Term Debt
as of December 31, 2015

Entity	Balance ($000)
Duke Energy Kentucky	319,027,487
Duke Energy Business Services	139,100,582
Duke Energy Carolina	8,437,433,330
Duke Energy Indiana	3,767,344,337
Duke Energy Ohio	1,278,506,197
Duke Energy Corporation	6,413,320,653
Duke Energy International	701,300,923
Commercial Portfolio	1,093,611,244
Duke Energy Progress	6,518,115,446
Duke Energy Florida	4,266,296,112
Progress Energy, Inc.	3,679,189,590
Cinergy Receivables	324,616,791
Purchase Accounting Adjustments	2,701,510,597
Total	39,569,373,289

Source: Duke Energy Web Site, Fixed Income Investors, Long-Term Debt Details

Duke Energy Corporation (Duke Energy) and its subsidiaries issued 11 long-term debt instruments in 2014 and 2015. Schumaker & Company auditors reviewed the documentation from all the long-term debt instruments issued during these two years. Although DEK did not issue any long-term debt in those two years, this review was made to determine if the debt documentation contained clauses or covenants that could possibly expose DEK to financial damage or risk. The long-term debt instruments reviewed are shown in *Exhibit V-2*.[141]

Exhibit V-2
Sampled Long-term Debt Instruments
as of December 31, 2015

No.	Entity	Description	Amount ($Millions)	Rate	Type	Settlement Date	Maturity Date
	2015 Issuances						
1	Duke Energy Corporation	Unsecured Notes	400	3.75%	Fixed	11/19/15	4/15/24
2	Duke Energy Corporation	Unsecured Notes	600	4.80%	Fixed	11/19/15	12/15/45
3	Duke Energy Progress	First Mortgage Bonds	500	3.25%	Fixed	8/13/15	8/15/25
4	Duke Energy Progress	First Mortgage Bonds	700	4.20%	Fixed	8/13/15	8/15/45
5	Duke Energy Carolinas	First Mortgage Bonds	500	3.75%	Fixed	3/12/15	6/1/45
	Total 2015 Issuances		2,700				
	2014 Issuances						
6	Duke Energy Progress	First Mortgage Bonds	500	4.15%	Fixed	11/20/14	12/1/44
7	Duke Energy Progress	First Mortgage Bonds	200	(1)	Floating	11/20/14	11/20/17
8	Duke Energy Corporation	Senior Notes	400	(2)	Floating	4/4/14	4/3/17
9	Duke Energy Corporation	First Mortgage	600	3.755	Fixed	4/4/14	4/15/24
10	Duke Energy Progress	First Mortgage Bonds	400	4.375%	Fixed	3/6/14	3/30/44
11	Duke Energy Progress	First Mortgage Bonds	250	(1)	Floating	3/6/14	3/6/17
	Total 2014 Issuances		2350				
	TOTAL ISSUANCES		5,050				

Notes:
(1) 3 month LIBOR plus 20 Basis Points
(2) 3 month LIBOR plus 38 Basis Points

Source: Duke Energy Web Site, Fixed Income Investors, Recent Issuances & Prospectuses

Credit Ratings

DEK's credit ratings for its senior unsecured debt at the end of 2015 was listed as "A-" by Standard & Poor's (S&P), "Baa1" by Moody's Investor Service (Moody's), and "A-" by Fitch Ratings, Inc. (Fitch). The Outlook for DEK was "Negative" from S&P and "Stable" from Moody's and Fitch. These ratings and outlook designations were comparable to those of DEK's affiliates. In 2015 S&P raised the ratings on Duke Energy and its subsidiaries, including DEK, from BBB+ to A-. Also in 2015, S&P lowered its Outlook for Duke Energy and its subsidiaries, including DEK, from "Positive" to "Negative". The S&P ratings increase was based on Duke's exit from the U.S. merchant generation and retail marketing business, thus reducing its business risk and management's distraction and allowing increased focus on its regulated utility business. The Outlook revision to "Negative" reflected the potential for lower ratings if the company's financial profile weakens because of its proposed acquisition of Piedmont Natural Gas. DEK's credit rating and Outlook was based on the consolidated credit profile of Duke Energy and reflected the consolidated credit profiles of all the Duke Energy domestic operating subsidiaries. Moody's and Fitch mention strong credit metrics, cash flow, and financial coverage, supportive and constructive Kentucky regulation, and corporate support as strengths and positive factors in supporting DEK's rating. Both these credit rating agencies listed DEK's expected increase in the level of capital expenditures and its relatively small size as challenges or limitations to credit ratings.[142]

Ratings for all the Duke Energy operating companies at December 31, 2015 are shown in *Exhibit V-3*.[143]

Exhibit V-3
Duke Energy Credit Ratings
as of December 31, 2015

Entity	December 31, 2015		
	S&P	**Moody's**	**Fitch**
Duke Energy Kentucky			
Outlook	Negative	Stable	Stable
Senior Unsecured	A-	Baa1	A-
Duke Energy Corporation			
Outlook	Negative	Negative	Watch-N
Corporate Credit Rating	A-	Baa1	BBB+
Senior Unsecured	BBB+	Baa1	BBB+
Junior Subordinate Debt	BBB	Baa2	BBB-
Commercial Paper	A-2	P-2	F-2
Duke Energy Carolinas			
Outlook	Negative	Stable	Stable
Senior Secured	A	Aa2	AA-
Senior Unsecured	A-	A1	A+
Duke Energy Florida			
Outlook	Negative	Stable	Stable
Senior Secured	A	A1	A
Senior Unsecured	A-	A3	A-
Duke Energy Indiana			
Outlook	Negative	Stable	Positive
Senior Secured	A	Aa3	A
Senior Unsecured	A-	A2	A-
Duke Energy Ohio			
Outlook	Negative	Stable	Stable
Senior Secured	A	A2	A
Senior Unsecured	A-	Baa1	A-
Progress Energy			
Outlook	Negative	Stable	Stable
Senior Unsecured	BBB+	Baa2	BBB
Duke Energy Progress			
Outlook	Negative	Stable	Stable
Senior Secured	A	Aa3	A+

Source: Information Response 24

Short-Term Debt

DEK's short-term debt requirements are managed by Duke Energy's Treasury Department in a consolidated manner for all of Duke Energy's utility industry companies. Short-term cash requirements for the Duke Energy companies are fulfilled through use of a consolidated money pool arrangement.[114]

Money Pool

Duke's Utility Money Pool Agreement (Agreement), dated July 2, 2012, authorizes DEK and its utility and nonutility affiliates to participate in a short-term borrowing and lending arrangement to help manage their cash and working capital requirements. Under this Agreement, short-term funds borrowed may be from either internal or external sources. Internal funds come from Agreement participants with surplus short-term funds. External funds come from the sale of commercial paper.[115]

Each Agreement participant can contribute funds to the Money Pool. Each participant's chief financial officer, Treasurer, or their designee determines the amount of excess cash that is available to be contributed to the Money Pool daily. Any participant may withdraw their funds from the Money Pool at any time with notice given to Duke Energy Business Services (DEBS) as administrative agent of the Money Pool.[116]

All Agreement participants, except Duke Energy, Progress Energy, and Cinergy, are authorized to borrow cash on a short-term basis from the Money Pool, subject to the availability of funds. The decision to borrow from the Money Pool is made by the borrower's chief financial officer, treasurer, or their designee. If a Money Pool participant is authorized to borrow from other sources (banks or by the sale of its own commercial paper) it cannot be required to borrow from the Money Pool if it is determined that money can be borrowed at a lower cost from other sources.[117]

The participants in the Duke Energy Money Pool Agreement are shown in *Exhibit V-4.*[148]

Exhibit V-4
Duke Energy Money Pool Participants
as of December 31, 2015

No.	Participant	State of Registration	Relationship	Money Pool Rights Lend	Money Pool Rights Borrow
1	Duke Energy	Delaware	Parent	X	
	Holding Companies				
2	Cinergy	Delaware	Sub of Duke Energy	X	
3	Progress Energy	North Carolina	Sub of Duke Energy	X	
	Public Utility Companies				
4	Duke Energy Kentucky	Kentucky	Sub of Duke Energy Ohio	X	X
5	Duke Energy Ohio	Ohio	Sub of Cinergy	X	X
6	Duke Energy Indiana	Indiana	Sub of Cinergy	X	X
7	Duke Energy Carolinas	North Carolina	Sub of Duke Energy	X	X
8	Miami Power	Indiana	Sub of Duke Energy Ohio	X	X
9	Progress Energy Carolinas	North Carolina	Sub of Progress Energy	X	X
10	Progress Energy Florida	Florida	Sub of Progress Energy	X	X
	Service Companies				
11	Duke Energy Business Services	Delaware	Sub of Duke Energy	X	X
12	Progress Energy Service Company	Florida	Sub of Progress Energy	X	X
	Nonutility Company				
13	KO Transmission Company	Kentucky	Sub of Duke Energy Ohio	X	X

Source: Information Response 23

The source of funds available in the Money Pool to be borrowed comes from the following sources:[149]

- *Internal funds* – surplus funds from other participants in the Money Pool Agreement. Borrowers borrow their funds from each Money Pool lending party in proportion to the amount loaned to the Money Pool by each lender in relation to the total amount loaned at any one time. If only internal funds are borrowed, the interest rate applied to the loan is the CD yield equivalent of the 30-day Federal Reserve "AA" Industrial Commercial Paper Composite Rate.
- *External funds* – proceeds from borrowings by participants, including the sale of commercial paper by Duke Energy, Progress Energy, Cinergy, Duke Energy Carolinas (DEC), Duke Energy Indiana (DEI), Duke Energy Ohio (DEO), DEK, Progress Energy Carolinas, and Progress Energy Florida. If the source of funds is external, the interest rate applied to the loan is the lending party's cost of acquiring the funds. If the borrowed funds come from several external sources this can be a composite rate (weighted average of cost incurred by all parties involved).

If the borrowed funds come from a combination of internal and external sources, the interest rate charged would be a composite or blended rate. In all cases, the rate charged is to be the Money Pool's cost of the money borrowed, and there is no fee added to the rate charged.[150]

During four months in 2015, DEK lent over $1.1 billion in short term funds to five of its affiliates through the Money Pool. The period of each loan was one day except for weekends, which were three or four days. The annual interest rate charged by DEK ranged from 0.13% to 0.26%, with a weighted average annual interest rate of 0.18%. DEK received $8,133 in interest in 2015.[151]

A summary of funds lent by DEK through the Money Pool are shown in *Exhibit V-5.*[152]

Exhibit V-5
Money Pool Funds Lent by DEK
as of December 31, 2015

Borrower	Period	Principal Amount Lent ($)	Average Daily Amount Lent ($)	Weighted Par Value ($)	Interest Received ($)	Weighted Average Annual Interest Rate
Duke Energy Business Services	4/06/2015 – 7/31/2015	934,167,000	12,421,342	1,341,505,000	6,692	0.1796%
Duke Energy Progress	4/06/2015 – 7/31/2015	86,149,000	1,123,665	121,358,000	607	0.1800%
Duke Energy Florida	4/06/2015 – 7/31/2015	86,101,000	1,201,320	120,132,000	614	0.1840%
Duke Energy Indiana	4/10/2015 – 6/23/2015	28,425,000	556,890	40,653,000	205	0.1814%
Duke Energy Ohio	4/10/2015 – 6/23/2015	1,998,000	282,400	2,824,000	15	0.1913%
Totals/Weighted Average		**1,136,840,000**		**1,626,472,000**	**8,133**	**0.1800%**

Source: Information Response 23, Attachment 1

Throughout 2015 DEK borrowed over $10 billion in short-term funds from seven of its affiliates through the Money Pool. More than 75% of short-term funds borrowed by DEK were provided by its parent, Duke Energy. The period of each loan was one day except for weekends, which were three days and in a few instances four days. The annual interest rate charged to DEK ranged from 0.12% to 0.7545%, with a weighted average annual interest rate of 0.4631%. The rate charged by Duke Energy Corporation was more than double the rate charged to DEK by its other affiliates, reflecting the source of the funds - the cost of commercial paper for the funds from Duke Energy vs the CD yield equivalent of the 30-day Federal Reserve "AA" Industrial Commercial Paper Composite Rate for the funds from the other affiliates. DEK paid a total of $189,031 in interest in 2015.[153]

A summary of Money Pool funds borrowed by DEK in 2015 is shown in *Exhibit V-6.*[154]

Exhibit V-6
Money Pool Funds Borrowed by DEK
as of December 31, 2015

Lender	Period	Principal Amount Borrowed	Average Amount Lent ($)	Weighted Par Value ($)	Interest Paid ($)	Weighted Average. Annual Interest Rate
Duke Energy Corporation	12/31/2014 – 1/04/2016	7,674,694,000	20,402,498	11,098,959,000	167,412	0.5430%
Duke Energy Carolinas	12/31/2014 – 1/04/2016	1,072,943,000	6,129,406	1,556,869,000	9,407	0.2175%
Duke Energy Progress	12/31/2014 – 12/31/2015	555,075,000	4,187,605	816,583,000	4,858	0.2142%
Progress Energy Service Company	12/31/2014 – 12/31/2015	525,400,000	3,030,578	775,828,000	4,827	0.2240%
Duke Energy Indiana	3/12/2015 – 1/04/2016	174,817,000	1,377,253	256,169,000	1,649	0.2318%
Duke Energy Ohio	12/31/2014 – 8/19/2015	127,093,000	1,619,435	186,235,000	860	0.1663%
Duke Energy Florida	3/11/2015 – 8/26/2015	2,923,000	387,222	3,485,000	18	0.1877%
Totals/Weighted Average		**10,132,945,000**		**14,694,128,000**	**189,031**	**0.4631%**

Source: Information Response 23, Attachment 1

Credit Facility

Duke Energy has a $7.5 billion master Credit Agreement (Amendment No. 2, dated January 30, 2015) that includes DEK, and its affiliates: DEC, DEO, DEI, Duke Energy Progress (DEP), and DEF as borrowers and 32 international banks as lenders. The participating banks involved are shown in *Exhibit V-7.*[155]

Exhibit V-7
Duke Energy Credit Agreement Participants
as of December 31, 2015

Bank	Participation	
	Position in Agreement	**Commitments ($)**
Wells Fargo Bank, National Association	Administrative Agent and Swingline Lender	340,000,000
Bank of America, N.A.	Issuing Lender	340,000,000
Royal Bank of Scotland PLC	Issuing Lender	340,000,000
Bank of China, New York Branch	Issuing Lender	340,000,000
Barclays Bank PLC	Issuing Lender	340,000,000
Citibank, N.A.	Issuing Lender	340,000,000
Credit Suisse AG, Cayman Islands Branch	Issuing Lender	340,000,000
JPMorgan Chase Bank, N.A.	Issuing Lender	340,000,000
The Bank of Tokyo-Mitsubishi UFJ, Ltd.	Issuing Lender	340,000,000
UBS AG, Stamford Branch	Issuing Lender	340,000,000
BNP Paribas	Lender	264,000,000
Goldman Sachs Bank USA	Lender	264,000,000
Mizuho Bank, Ltd.	Lender	264,000,000
Morgan Stanley Bank, N.A.	Lender	264,000,000
Royal Bank of Canada	Lender	264,000,000
Sun Trust Bank	Lender	264,000,000
The Bank of Nova Scotia	Lender	264,000,000
U. S. Bank National Association	Lender	264,000,000
Banco Bilbao Vizcaya Argentaria, SA, NY Branch	Lender	142,000,000
Industrial and Commercial Bank of China, Limited	Lender	142,000,000
KeyBank National Association	Lender	142,000,000
The Bank of New York Mellon	Lender	142,000,000
The Northern Trust Company	Lender	142,000,000
Fifth Third Bank	Lender	142,000,000
Credit Agricole Corporate and Investment Bank	Lender	142,000,000
PNC Bank, National Association	Lender	142,000,000
Santander Bank, N.A.	Lender	142,000,000
TD Bank, N.A.	Lender	142,000,000
Canadian Imperial Bank of Commerce, NY Branch	Lender	142,000,000
DNB Bank ASA, Grand Cayman Branch	Lender	142,000,000
HSBC Bank USA, National Association	Lender	142,000,000
Sumitomo Mitsui Banking Corporation	Lender	142,000,000
TOTAL COMMITMENTS		**7,500,000,000**

Source: Duke Energy Website, Fixed-Income Investors, Credit Facility & Liquidity, Master Credit Facility Agreement

DEK's maximum sublimit in this agreement is $175 million. This is less than the limits assigned to DEO ($725 million), DEI ($1 billion), DEI ($1.2 billion), DEP ($1.4 billion), DEC ($1.8 billion), and Duke Energy ($4.7 billion). The interest rate that applies to each loan from the Credit Facility is dependent on the type of loan and the credit rating of the borrower. Credit ratings are based on the borrower's non-credit-enhanced, senior unsecured long-term debt and must be issued by S&P, Moody's, or Fitch. Credit ratings used are based on the following rules:[156]

- If ratings issued by two of the rating agencies are the same and one differs, the pricing level is determined based on the two ratings that are the same
- If none of the ratings are the same, the pricing level is determined based on the middle rating
- If only two ratings exist and they differ by one level, then the pricing level for the higher of such ratings applies
- If only two ratings exist and they differ by more than one level, then the pricing level that is one level lower than the pricing level of the higher rating applies
- If only one rating exists, the pricing level is determined based on that rating
- If no such rating exists then a corporate credit rating from S&P and the issuer ratings from Moody's and Fitch should be used

The interest and facility fee rates that apply to borrowings based on the borrower's credit rating are shown in *Exhibit V-8*.[157]

Exhibit V-8
Duke Energy Credit Agreement Pricing Schedule
as of December 31, 2015
(Basis Points per Annum)

	S&P or Fitch	Moody's	S&P or Fitch	Moody's	S&P or Fitch	Moody's	S&P or Fitch	Moody's	S&P or Fitch	Moody's	S&P or Fitch	Moody's
Borrower's	≥ A+	≥ A1	≥ A	≥ A2	≥ A-	≥ A3	≥ BBB+	≥ Baa1	≥ BBB	≥ Baa2	< BBB	< Baa2
Facility Fee Rate	7.5		10.0		12.5		17.5		22.5		27.5	
Applicable Margin Euro-Dollar and Swingline Loans	80.0		90.0		100.0		107.5		127.5		147.5	
Base Rate Loans	0.0		0.0		0.0		7.5		27.5		47.5	

Source: Duke Energy Website, Fixed-Income Investors, Credit Facility & Liquidity, Master Credit Facility Agreement

Capital Structure

Dividend Payouts

Duke Energy dividend policy, subject to approval of the Board of Directors, is a long-term payout to shareholders of approximately 65% to 70% of adjusted diluted earnings per share. DEK and the other utility subsidiaries are also expected to follow this policy over time, but have flexibility to vary their annual dividends to their parent based on their capital structure and capital spending requirements.[158] Dividend policy is governed by desire to keep the DEK capital structure approximately 50% debt and

50% equity. Targets are consistent with the equity percentages allowed by state regulators.[159] A schedule displaying DEK's dividend payouts to Duke Energy over the past nine years is shown in *Exhibit V-9.*[160]

Exhibit V-9
DEK's Dividend Payout History
2007 to 2015

Financial Data	Years								
	2007	2008	2009	2010	2011	2012	2013	2014	2015
Dividend/(Infusion) ($ millions)	(3.1)	30.0	0	0	135.0	10.0	40.0	0	55.0
Net Income ($ millions)	33.5	37.5	28.1	43.3	24.3	28.2	45.1	35.3	46.2
Payout Ratio	N/A	80%	0%	0%	555%	36%	89%	35.3%	119%

Source: Information Responses 12 and 58

Capitalization

DEK's capital structure over the past five years is shown in *Exhibit V-10.*[161]

Exhibit V-10
DEK's Capital Structure History
2011 to 2015

Financial Data	For Years Ended December 31									
	2011		2012		2013		2014		2015	
	$ Millions	%	$ Millions	%	$ Millions	%	$ Millions	%	$ Millions	%
Debt	337.6	49	336.2	47	335.0	47	318.8	44	317.3	44
Equity	354.7	51	372.9	53	377.9	53	413.3	56	404.4	56
Total Capitalization	692.3	100	709.1	100	712.9	100	732.1	100	721.7	100

Source: Information Response 59

B. Findings & Conclusions

Finding V-1 **The long-term indebtedness DEK or that of its affiliates does not expose DEK or its ratepayers to undue risk.**

Duke Energy and its subsidiaries issued 11 long-term debt instruments in 2014 and 2015. DEK did not issue any long-term debt in this time period. A review of the documentation of 100% of the long-term debt instruments issued during these two years was conducted to determine if the debt documentation contained clauses or covenants that could expose DEK to financial damage or risk. The value of the debt instruments reviewed represented approximately 13% of the value of the long-term debt issues for all the Duke Energy entities, and the number of debt instruments reviewed was approximately 5% of the total number of Duke Energy debt instruments outstanding at December 31, 2015.

Documentation for each of these long-term debt obligations was reviewed to identify any clauses or codicils that might affect DEK or could possibly require DEK to assume some future obligation because of an action or inaction by one of its affiliates. There was no indication DEK or its ratepayers were at greater risk due to its long-term debt obligations or those held by its affiliates. Additionally, Duke Energy asserted that DEK did not have any financial instruments that included credit-rating triggers or provisions leading to collateral calls.

Finding V-2 **The financial agreements in which DEK is a participant do not obligate or increase the financial risk for DEK.**

DEK is a participant in the Duke Energy Utility Money Pool Agreement and the $7.5 billion master Credit Agreement. Neither of these agreements obligate DEK to come to the financial aid of, or otherwise support, the other Duke affiliates. DEK was listed as lender and borrower in the Duke Energy Money Pool Agreement and as borrower in the Credit Agreement. There was no terminology in either document to indicate that DEK was responsible for credit or funds extended to the other participants in the agreements.

Finding V-3 **During 2014 and 2015 DEK has not issued any security for the purpose of financing the acquisition, ownership, or operation of an affiliate.**

DEK long-term debt as of the end of 2015 consisted of capital leases, pollution control bonds, unsecured debt, and commercial paper treated as long-term debt. In 2014 and 2015 DEK did not issue any debt instruments.

Finding V-4 **DEK has not assumed any obligation or liability as guarantor, endorser, surety, or otherwise in respect of any security of an affiliate.**

Reviews of funding agreements and sampled debt obligation documentation did not reveal any instance in which DEK was listed as guarantor, endorser, surety, or was otherwise obligated to assume the debt of one of its affiliates. An attestation from Duke Energy's Director of Corporate Finance and Assistant Treasurer, responsible for the establishment of treasury/capitalization policies for the corporation and research/execution of corporate financing transactions (including credit facilities for DEK and its affiliates), verified that DEK does not have any financial instruments that include credit-rating triggers or provisions leading to collateral calls.

Finding V-5 **DEK has not pledged, mortgaged, or otherwise used as collateral any of its assets for the benefit of an affiliate.**

A review of Duke's funding agreements (Utility Money Pool Agreement and Credit Agreement), sampled debt obligation documents, and DEK's financial statements did not reveal any instance of DEK pledging, mortgaging, or otherwise using as collateral any of its assets for the benefit of an affiliate. An attestation from Duke Energy's Director of Corporate Finance and Assistant Treasurer, responsible for the establishment of treasury/capitalization policies for the corporation and research/execution of corporate financing transactions (including credit facilities for DEK and its affiliates), verified that DEK does not have any financial instruments that include credit-rating triggers or provisions leading to collateral calls.

Finding V-6 DEK has maintained a consistent credit rating since mid-2012.

DEK's credit ratings for its senior unsecured debt at the end of 2015 was listed as A- by Standard & Poor's (S&P), Baa1 by Moody's Investor Service (Moody's), and A- by Fitch Ratings, Inc. (Fitch). The Outlook for DEK was "Negative" from S&P and "Stable" from Moody's and Fitch. These ratings and outlook designations were comparable to those of DEK's affiliates. Moody's rating and outlook has remained unchanged since 2009, and Fitch has maintained the same rating since it started rating DEK in mid-2012. S&P's rating was increased from BBB+ (where it has been since 2012) to A- in 2015. S&P's Outlook for DEK and all the Duke Energy companies was listed as "Negative" reflecting the proposed acquisition of Piedmont Natural Gas by Duke Energy.

Finding V-7 DEK's Money Pool transactions in 2015 have caused it to incur unnecessary expense.

During 2015 DEK received $8,133 in interest for $1.1 billion in short-term funds lent (usually for 1-day periods) to five of its affiliates, and paid $189,031 in interest for $10 billion borrowed (also usually for 1-day periods) from seven of its affiliates. DEK lent funds during four months of the year (April through July), while it borrowed funds during every month in 2015.

During the April through July period, DEK lent a total of $1,136,840,000 to DEBS, Duke Energy Progress, Duke Energy Florida, DEO, and DEI at interest rates that ranged from 0.13% to 0.26%, and borrowed $1,925,000,000 from Duke Energy at interest rates that ranged from 0.4871% to 0.6466%. During this four-month period DEK borrowed more money than it needed and lent out the excess money to its affiliates at less than its cost for the funds. Comparing interest rates of funds borrowed and lent on the same day reveals that DEK paid $12,209.56 in excess interest charges for funds borrowed from its parent that were then lent out to its affiliates.

C. Recommendations

Recommendation V-1 **Change the way DEK calculates interest expense for the use of excess borrowed short-term funds. (Finding V-7)**

Comparing interest rates of funds borrowed and lent on the same day reveals that DEK could have saved $12,209.56 in interest charges by either not borrowing funds that were not needed from Duke Energy or by charging the affiliates to whom it lent the excess funds the same interest rates that it paid for the funds. DEK lent out funds to its affiliates at the "Internal Funds" rate (CD yield equivalent of the 30-day Federal Reserve "AA" industrial Commercial Paper Composite Rate) that it had borrowed at the "External Funds" rate (the lending party's cost for such External Funds). DEK should have lent out the funds at the "External Funds" rate or its cost, or it should have limited its borrowing to the amount of funds that it actually needed.

VI. Internal Controls

A. Background & Perspective

In 2011, Duke Energy Ohio, Inc. (DEO), the parent company of Duke Energy Kentucky (DEK), merged with Progress Energy, Inc. (Progress). As part of its approval of the merger in Case No. 2011-00124, DEK was ordered to adhere to 46 merger commitments the Kentucky Public Service Commission (KPSC) established in Case No. 2005-00228, of which four (4), specifically Commitments 10, 11, 12, and 13 specifically relate directly to this audit. They apply as follows:

- DEK is in compliance with its Commitment 10, which requires proper accounting of costs (accounting and reporting system used by Duke Energy Kentucky will be adequate to provide assurance that directly assignable utility and non-utility costs are accounted for properly and that reports on the utility and non-utility operations are accurately presented).
- DEK is in compliance with its Commitment 11, which requires that it implement and maintain appropriate cost allocation procedures that will accomplish the objective of preventing cross-subsidization, and be prepared to fully disclose all allocated costs, the portion allocated to Duke Energy Kentucky, complete details of the allocations methods, and justification for the amount and the method, plus giving the Commission 30 days' advance notice of any changes in cost allocation methods set forth in agreements approved as part of the merger transactions.
- DEK is in compliance with its Commitment 12, which requires that it commit to third-party independent audits of the affiliate transactions under the affiliate agreements approved as part of the merger transaction.
- DEK is in compliance with its Commitment 13, which requires that it protect against cross-subsidization in transactions with affiliates.

Also within the scope of this audit is DEK's compliance with KPSC regulations, including:

- 807 KAR 5:080 SECTION 2 — Annual reports
- 807 KAR 5:080 SECTION 3 — Filing of cost allocation manual and amendments
- 807 KAR 5:080 SECTION 4 — Notice of establishment of new non-regulated activity

With the approval of the merger of Duke Energy with Progress Energy Corporation (Progress Energy), the KPSC imposed three additional conditions on its approval of the merger, specifically:

- Duke Energy Kentucky must continue to offer a full range of cost-effective energy conservation and efficiency programs.
- The Board of Directors of the combined company must include at least one non-employee member who resides in the company's service territory in Kentucky, Indiana, or Ohio.
- No merger costs may be passed on to Duke Energy Kentucky ratepayers.

Refer to *Chapter II – Merger Order Requirements* for a discussion of Duke Energy's responses.

SOx Controls

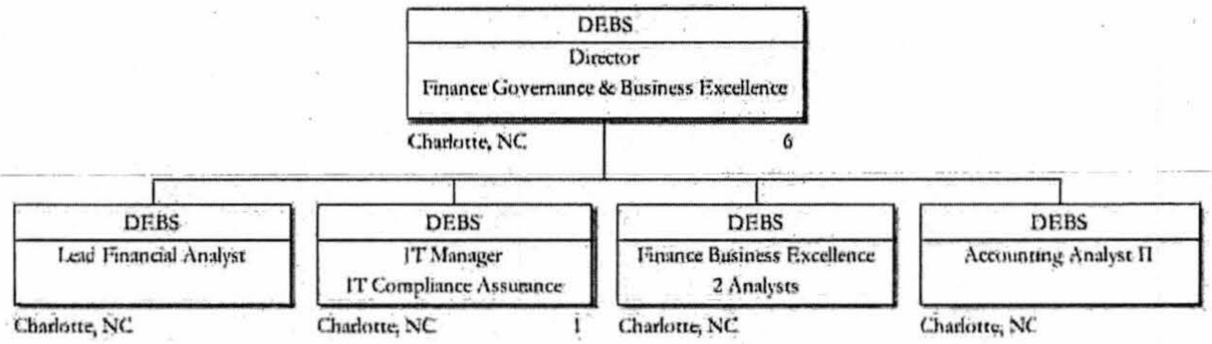
SOx controls were the ultimate result of an act passed by U.S. Congress in 2002 to protect investors from the possibility of fraudulent accounting activities by corporations. The Sarbanes-Oxley Act mandated strict reforms to improve financial disclosures from corporations and prevent accounting fraud. As a part of this Act, year-end financial reports were mandated to contain an assessment of the effectiveness of the internal controls and the company's auditing firm would be required to attest to that assessment. This has resulted in public companies registered with the SEC to list specific controls and test them regularly and determine that the controls are operating effectively and as intended. These listed controls are referred to as SOx controls.

The Duke Energy organization has approximately 1,500 SOx controls in 2015 (and is reduced again in 2016 to approximately 1,100 controls). Of these controls, approximately 10 are directly applicable to affiliate relationships and charges and the USF&G OH/KY group and three of these were tested in 2015. The controls tested were considered "effective," none were "ineffective" or "undetermined." Also, the SOx controls regarding accounting for services and asset transfers, such as inventory stock transfers, are generic and not specifically focused on affiliate charges, as affiliate charges do not impact Duke Energy's consolidated financial statements, since affiliate charges are eliminated during consolidation.[62]

SOx Testing

SOx testing occur at random and specific times during the year. When the Director of Accounting, Internal Controls, notifies the SOx representatives, each SOx representative verifies that the SOx control owners for which they are responsible are still valid. Once validity is confirmed, the SOx representative directs the control owners to begin the SOx testing. The testing results are documented ultimately in the Open Pages system with a narrative and any supporting documentation needed to confirm that the control is working as intended. When the documentation is complete in Open Pages, the SOx representative reviews the information provided. The Internal Controls group, referred to as the Finance Governance & Business Excellence organization shown in *Exhibit VI-1*, also monitors this activity and documentation on an ongoing basis.[63]

Exhibit VI-1
Finance Governance & Business Excellence Organization
2015



Source: Information Response 37 and Interview 9

Duke Energy has approximately ten SOx controls that apply to the affiliate relations and charges, and the USFE&G Ohio/Kentucky group. The controls have been relabeled between 2013 and 2015. The newly labeled controls are:[164]

- Affiliate Overhead Run Report
- Affiliate Allocations Phire Form
- Balance Sheet Review (previously called Subregistrant Balance Sheet Review)
- Subregistrant Financial Results Summary (FRS)
- Intercompany Balances Review
- Intercompany Elimination Review
- Intercompany Elimination Review
- Composite Rates are Entered Correctly in FMIS
- Service Company Allocations Posted Properly
- Corporate Allocation Calculation Review

Subregistrant Financial Results Summary and Corporate Allocation Review were the two controls selected for testing and determined to be operating effectively during 2013,[165] while Subregistrant Financial Results Summary (FRS), Balance Sheet Review, and Corporate Allocation Calculation Review were the three controls selected for testing and determined to be operating effectively during 2015,[166] as illustrated in *Exhibit VI-2*.[167]

Exhibit VI-2
2015 Sox Controls Involving Affiliate Relationships and Charges and OH/KY Group
Page 1 of 4

Entity Name	Control Name	Description	Control Description	Selected for Testing	Operating Effectiveness	Test Steps (if applicable)
FCR_Franchised	FCR-ALLC02	Affiliate Overhead Run Control Report	Regulated Utilities Accounting reviews the Run Control Report during the month-end close process to verify no errors have occurred in the running of the allocations for the Affiliate Overhead.	No	Undetermined	NA
FCR_Franchised	FCR-ALLC04	Affiliate Allocations Plus Form	Regulated Utilities Accounting contacts Functional User Support (via a CR Plus form) in order to make affiliate overhead allocation rate changes within PeopleSoft.	No	Undetermined	NA
FCR_Franchised	FCR-FEG 08 DEO	Balance Sheet Review	Monthly, a Balance Sheet Review is prepared by an Analyst for DEO. On quarter end months the analysis compares current month to December year to date; and on nonquarter months the analysis compares current month to prior month (month to date). Variances greater than 5% and over $10 million are explained. The analysis is reviewed by the respective Accounting Manager, or designee, then a review is conducted with the respective Director, or Director level designee.	Yes	Effective	1. Select two months for testing (ensure to select one quarter end and one non-quarter end month). 2. For the months selected for testing, obtain a listing of the analyses of key financial data prepared by each subregistrant's (DEO) Accounting Regulated Group. 3. Verify that Balance Sheet Variances of $10 million and 5% are explained. 4. Verify that the comparisons for the quarter months are for quarter-end vs. December of the prior year and for the non-quarter months are current month vs. prior month. 5. Examine the analyses to verify that they were reviewed by the Director of Regulated Accounting in a timely manner. 6. Evaluate reports, queries, spreadsheets, or databases used in performing the control. If there are reports, queries, spreadsheets, or databases, review and update the EUT Questionnaire.

Source: Information Response 36

Exhibit VI-2
2015 Sox Controls Involving Affiliate Relationships and Charges and OH/KY Group
Page 2 of 4

Entity Name	Control Name	Description	Control Description	Selected for Testing	Operating Effectiveness	Test Steps (if applicable)
FCR_Franchised	FCR-FEG 07 DEO	Subregistrant Financial Results Summary (FRS)	Each of the subregistrant's Accounting and Reporting groups prepare their respective Financial Results Summary (FRS) which supports the RU Adjusted Segment Income reporting. In the FRS, significant AvB variances for month and YTD are discussed monthly and AvA variances for QTD and YTD are discussed quarterly. All subregistrants' FRSs are reviewed with the respective Director, or Director-level designee.	Yes	Effective	1. Select a quarter for testing. 2. For the period selected for testing, obtain a listing of the analyses of key financial data prepared by each of the USFE&G Subregistrant's Financial Reporting and General Accounting group. 3. Verify that for the additional variance analysis schedules (support for Adjusted Segment Income, including O&M), variances deemed material are explained. 4. Verify that the AvA variances for quarter and YTD are prepared and discussed quarterly. 5. Examine the analyses to verify that they were reviewed by the Director of Regulated Accounting in a timely manner. 6. Evaluate reports, queries, spreadsheets, or databases used in performing the control. If there are reports, queries, spreadsheets, or databases, review and update the EUT Questionnaire.
FCR_Shared	FCR-CON-07	Intercompany Balances Review	The EIPO, or designee, reviews out of balance reports to ensure out of balances are resolved or deemed immaterial. If balances exist, EIPO reviews the final disputed balances with Corporate Controller.	No	Undetermined	NA

Source: Information Response 36.

Exhibit VI-?
2015 Sox Controls Involving Affiliate Relationships and Charges and OH/KY Group
Page 3 of 4

Entity Name	Control Name	Description	Control Description	Selected for Testing	Operating Effectiveness	Test Steps (if applicable)
FCR_Shared	FCR-CON-08	Intercompany Elimination Review	Monthly, the Corporate Consolidations Manager or designee, ensures that all intercompany balances eliminate to zero on the consolidated financial statements.	No	Undetermined	NA
FCR_Shared	FCRA-ASC44	Composite Rates are Entered Correctly in FMIS	The Business Analyst runs a Business Objects query monthly to verify allocation percentages entered into PeopleSoft total 100% for each cost pool to ensure accuracy.	No	Undetermined	NA
FCR_Shared	FCRA-ASC45	Service Company Allocations Posted Properly	The Business Analyst reviews the allocation results (run control) report monthly sent by e-mail from the PeopleSoft Financials Support Team. This report identifies errors received from the allocations run. This report also indicates whether or not any entries were posted to the allocations suspense account. Any errors or postings to the suspense account, are identified and investigated by the Business Analyst and the correct accounting is communicated to the appropriate people for correction via journal entry.	No	Undetermined	NA

Source: Information Response 36

Exhibit VI-?
2015 Sox Controls Involving Affiliate Relationships and Charges and OH/KY Group
Page 4 of 4

Entity Name	Control Name	Description	Control Description	Selected for Testing	Operating Effectiveness	Test Steps (if applicable)
FCR_Shared	FCRA-ASC46	Corporate Allocations Posted Properly	The Business Analyst runs a Business Objects query monthly to verify that the job ran without errors, completely and accurately. The query is used to determine if the dollars allocated to the BU's and offset the cost pools appropriately. A Hyperion Financial Management report is also run to review the EBIT impact for Service Company.	No	Undetermined	NA
FCR_Shared	FCRA-ASC50	Corporate Allocation Calculation Review	Annually, the service company allocation calculations undergo the prepare/review process to ensure accuracy and completeness.	Yes	Effective	1) Obtain the service company allocation calculations for the test period. 2) Verify that the service company allocation calculations contain evidence of review and approval. 3) Verify that the service company allocation calculations are complete and accurate. 4) Note and investigate calculations that were not approved. 5) Note the date the calculation was prepared and approved. Note and investigate any time lags. 6) Evaluate reports, queries, spreadsheets, or databases used in performing the control. If there are reports, queries, spreadsheets, or databases, review and update the existing EUT Questionnaire.

Source: Information Response 36

Internal Audits

Three internal audits regarding affiliate transactions, cost allocations, or other Affiliate Rules aspects have been conducted in the last three years. The Corporate Audit Services group did not specifically perform any audits regarding the Kentucky/Ohio Accounting & Reporting group in 2013 through 2015; however, routine internal control reviews have been performed during this time period, and three audits were conducted that pertained to affiliated relationships or transactions. These audits are briefly described in *Exhibit VI-3.*[168]

Exhibit VI-3
Internal Audits Associated with Affiliate Relationships/Transactions
2013 to 2015

Audit #	Audit Title	Date Completed
113042	Annual Audit of Affiliate Transactions-12 month period ended September 30, 2013	December 20, 2013
114011	Annual Audit of Affiliate Transactions-12 month period ended September 30, 2014	January 30, 2015
115027	Annual Audit of Affiliate Transactions-12 month period ended September 30, 2015	February 2, 2016

Source: Information Response 15

According to the Director, Corporate & Commercial Audit – Internal Audit and as documented in the audit memorandums listed in *Exhibit VI-3*, no recommendations were made that required management action. Actions specified were to continue process as is, with few changes.[169]

In accordance with condition 5.12 of the Regulatory Conditions required by the North Carolina Utilities Commission, an annual audit is conducted of affiliate transactions by Duke Corporate Audit Services (CAS) which includes a detailed review of those transactions for a one-year period ending September 30. This audit has been conducted three times over the last years with minor findings only. Per discussions with the Director, Corporate & Commercial Audit – Internal Audit, it is due to the ongoing work of Financial Planning and Analysis (FP&A) who is responsible for ongoing monthly review of all affiliate transactions and will adjust for coding and pricing issues on an ongoing basis.[170] Each audit and the findings are detailed on the following pages. Note the audits included transactions with DEK, but were not only DEK transactions. Specific findings below, may or may not have been related to DEK.[171]

Annual Audit of Affiliate Transactions-2013 #113042

During the 2013 audit, it was determined that two employees incorrectly charged time to DEC for one pay period by entering an incorrect code on their timesheet. These two mistakes were corrected with journal entries.[172] Also, another employee related instance had employees transferred but their default labor allocations were not updated to reflect the change. A detailed review was performed to capture all similar instances and a journal entry posted to correct.[173]

Based on the findings in this audit memorandum, several actions were called for. New requirements were communicated regarding employee payroll company changes to management of FP&A, Regulated Utility Financial Planning (RUFP), HR Business Partners, and HR Business Staffing for employee transfers. The new requirements provided additional assurance that employee's labor charges will indeed originate from the appropriate entity. Additionally, enhanced Business Object queries were developed to assist in monitoring, researching, and if necessary, correcting affiliate transactions. Lastly, improved guidance will be given for time reporting including training, reference materials, and other communications to evaluate roles and responsibilities in the performance of SOX controls around default labor.[174]

Annual Audit of Affiliate Transactions-2014 #114011

During the 2014 audit, eight of 80 transactions were determined to have been coded incorrectly and two of these led to cross-subsidization of $2,539. One of these errors was an expense coding error and the other was a labor coding error. Both were determined to be isolated human error. A deep dive to uncover other errors with similar attributes led to an additional $9,979 being identified and corrected.[175]

No new actions were deemed to be necessary, based on the findings in this audit memorandum. Monthly review and analysis will continue as well as ongoing adjustments based on those monthly reviews.[176]

Annual Audit of Affiliate Transactions-2015 #115027

During the 2015 audit of affiliate transactions, 60 transactions were selected and of those 60, two were found to have coding errors with immaterial dollar impact, less than $1,000 in total. Additional analysis was performed and $6,249 determined to be the total dollar amount of similar errors.

Like the previous year, no new recommendations were made. The "Next Steps" section of the memorandum notes that FP&A will review and enhance areas of the Monthly Affiliate Transaction Review process documentation that require some additional clarification. Further, the next steps section notes that FP&A will continue to perform the Monthly Affiliate Transaction Review and respond to monthly findings with correcting journal entries and additional guidance for proper guidance, as necessary.

B. Findings & Conclusions

Finding VI-1 **Internal audit reports regarding affiliate transactions, cost allocations, or other Affiliate Rules aspects have been addressed by DEBS staff in a timely manner.**

For each of the audits identified previously in *Exhibit VI-3*, Schumaker & Company investigated if the resulting audit recommendations were addressed by DEBS staff in a timely manner. The Director of Audit Services confirmed during this audit that all corrective actions were completed and implemented by the agreed upon completion dates.

AG
Exhibit 2

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

ORDER

Kentucky Power Company ("Kentucky Power"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP") is an electric utility that generates, transmits, distributes, and sells electricity to approximately 168,000 consumers in all or portions of 20 counties in eastern Kentucky.[1] Kentucky Power owns and operates a 285-megawatt ("MW") gas-fired steam-electric generating unit in Louisa, Kentucky, and owns and operates a 50 percent undivided interest in a coal-fired generating station in Moundsville, West Virginia; Kentucky Power's share consists of 780 MW. Kentucky Power obtains an additional 393 MW from Rockport (Indiana) Plant Generating Units No. 1 and No. 2 under a unit power agreement ("Rockport UPA"). Kentucky Power's transmission system is operated by PJM Interconnection, LLC ("PJM"), a regional

[1] Application at 2. Kentucky Power also furnishes electric service at wholesale to the Cities of Olive Hill and Vanceburg, Kentucky.

electric grid and market operator. Kentucky Power's most recent general rate increase was granted in June 2015 in Case No. 2014-00396.[2]

BACKGROUND

On April 26, 2017, Kentucky Power filed notice of its intent to file an Application ("Application") for approval of an increase in its electric rates based on a historical test year ending February 28, 2017. By Order entered May 24, 2017, the Commission granted Kentucky Power's motion to deviate from certain filing requirements, which Kentucky Power requested in order to obtain additional time to review its Application before its proposed filing date of June 28, 2017.

Kentucky Power tendered its Application on June 28, 2017, which included new rates to be effective on or after July 29, 2017, based on a request to increase its electric revenues by $65,387,987, or 11.80 percent. On August 7, 2017, Kentucky Power supplemented its Application to reflect the impact of refinancing of certain debts in June 2017, which reduced Kentucky Power's requested annual increase in revenues to $60,397,438. In its Application, Kentucky Power also requested approval of its environmental compliance plan, and proposed to revise, add, and delete various tariffs applicable to its electric service. After Kentucky Power cured filing deficiencies, its Application was deemed filed as of July 20, 2017. To determine the reasonableness of these requests, the Commission suspended the proposed rates for five months from their effective date, pursuant to KRS 278.190(2), up to and including January 18, 2018.

[2] Case No. 2014-00396, *Application of Kentucky Power Company for: (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; and (4) An Order Granting All Other Required Approvals and Relief* (Ky. PSC June 22, 2015) ("Case No. 2014-00396, Final Order").

The following parties requested and were granted full intervention: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Kentucky Commercial Utility Customers, Inc. ("KCUC"); Kentucky Cable Telecommunications Association ("KCTA"); and Wal-Mart Stores East, LP and Sam's East, Inc. (jointly, "Walmart").

By order entered on July 17, 2017, the Commission established a procedural schedule that provided for discovery, intervenor testimony, rebuttal testimony from Kentucky Power,[3] a formal evidentiary hearing, and an opportunity for the parties to file post hearing briefs.[4] On October 26, 2017, and November 7, 2017, an informal conference ("IC") was held at the Commission's offices to discuss procedural matters and the possible resolution of pending issues. All parties participated in the IC held on October 26, 2017, with the exception of KCTA, who engaged in separate discussions with Kentucky Power regarding possible resolution of issues pertaining to the Cable Television Pole Attachment Tariff ("Tariff C.A.T.V.") The Attorney General did not attend the November 7, 2017 IC due to a scheduling conflict, but indicated that the IC should proceed as scheduled. At the November 7, 2017 IC, the parties in attendance,

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[3] On October 11, 2017, the Attorney General filed a motion to amend the procedural schedule to permit him to file rebuttal testimony. Kentucky Power and KLC each filed responses in opposition. By order issued October 24, 2017, the Commission found the Attorney General failed to establish good cause to amend the procedural schedule and denied the Attorney General's motion.

[4] The Commission conducted public meetings in Kentucky Power's service territory on November 2, 2017, in Prestonsburg, Kentucky; on November 6, 2017, in Hazard, Kentucky; and on November 8, 2017, in Ashland, Kentucky.

with the exception of KCUC, arrived at an agreement in principle for the resolution of the issues raised in this case.

On November 22, 2017, Kentucky Power, KIUC, KLC, KSBA, KCTA, and Walmart ("Settling Intervenors") filed a Settlement Agreement ("Settlement") that addressed all of the issues raised in this proceeding. The Attorney General and KCUC are not signatories to the Settlement. The Settlement is attached as Appendix A to this Order.

Because the Settlement was not unanimous, the December 6, 2017, evidentiary hearing was held as scheduled for the purposes of hearing testimony in support of the Settlement and on contested issues. On January 5, 2018, Kentucky Power, the Attorney General, KIUC, and KCUC filed their respective post hearing briefs. The matter now stands submitted to the Commission for a decision.

SETTLEMENT AGREEMENT

The Settlement reflects the agreement of the parties, except for the Attorney General and KCUC, on all issues raised in this case. The major substantive areas addressed in the Settlement are as follow:

- Kentucky Power's electric retail revenues should be increased by $31,780,734, effective January 19, 2018.[5] This amount consists of a base rate revenue reduction of $28,616,704 from the $60,397,438 requested in Kentucky Power's August 7, 2017 supplemental filing.

[5] Settlement, paragraphs 2(a) and 17.

- Establishment of deferral mechanisms for $50 million in non-fuel, non-environmental Rockport UPA expenses.[6]

- Amendment of the Purchase Power Adjustment tariff ("Tariff P.P.A.") to recover incremental PJM Open Access Transmission Tariff ("OATT") Load Serving Entity ("LSE") charges and credits above or below net PJM OATT LSE charges and credits in base rates.[7]

- Amendment of Tariff P.P.A. as described in the Direct Testimony of Alex E. Vaughan ("Vaughan Direct Testimony") to collect from, or credit to, customers the amount of purchased power costs that are excluded from recovery through the Fuel Adjustment Clause ("FAC"), and gains and losses from incidental sales of natural gas purchased for use at Big Sandy Unit 1, but not used or stored.[8]

- Establishment of 20-year service life for Big Sandy Unit 1 for depreciation rates.[9]

- Establishment of a return on equity of 9.75 percent.[10]

- Agreement to lower the Kentucky Economic Development Surcharge rate ("Tariff K.E.D.S.") for residential customers and increase the rate for non-residential customers, with matching contribution by Kentucky Power.[11]

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[6] *Id.* at paragraph 3.

[7] *Id.* at paragraph 4.

[8] *Id.* at paragraph 6.

[9] *Id.* at paragraph 7.

[10] *Id.* at paragraph 8.

[11] *Id.* at paragraph 10.

- Agreement to continue Tariff K-12 School as a permanent customer class instead of a pilot rate.[12]

- Agreement that Kentucky Power will not request a general adjustment of base rates for rates that would be effective prior to the January 2021 billing cycle.[13]

- Increase Kentucky Power's customer charge for Residential Service customers to $14.00 per month.[14]

CONTESTED REVENUE REQUIREMENT AND REVENUE ALLOCATION ISSUES

Kentucky Power proposed an annual increase in its electric revenues of $60,397,438 in its August 7, 2017 supplemental filing. Through testimony, the Attorney General contended that Kentucky Power should be allowed to increase its electric revenues by $39.9 million.[15] Through testimony, KCUC contended that the revenue allocation contained in the Settlement does not provide fair or reasonable treatment for customers in the Large General Service class ("Tariff L.G.S."). Because the parties have not reached a unanimous settlement on the increase in revenues, the Commission must consider the evidentiary record on these issues as presented by Kentucky Power, the Attorney General, and KCUC, and render a decision based on a determination of Kentucky Power's capital, rate base, operating revenues, operating expenses, and revenue allocation, as would be done in a fully litigated rate case

[12] *Id.* at paragraphs 1213.

[13] *Id.* at paragraph 5.

[14] *Id.* at paragraph 16.

[15] Direct Testimony of Ralph C. Smith ("Smith Testimony") at 12.

TEST PERIOD

Kentucky Power proposed the 12-month period ending February 28, 2017, as the test period for determining the reasonableness of its proposed rates. None of the Intervenors contested the use of this period as the test period. The Commission finds it is reasonable to use the 12-month period ending February 28, 2017, as the test period in this case. Due to the timing of Kentucky Power's filing, the 12-month period ending February 28, 2017, is the most recent feasible period to use for setting rates and, except for the adjustments approved herein, the revenues and expenses incurred during that period are neither unusual nor extraordinary.[16] In using this historic test period, the Commission has given full consideration to appropriate known and measurable changes.

RATE BASE

Jurisdictional Rate Base Ratio

Kentucky Power proposed a test-year-end Kentucky jurisdictional rate base of $1,323,494,246.[17] The Kentucky jurisdictional rate base is divided by Kentucky Power's test-year-end total company rate base to derive the Kentucky jurisdictional rate base ratio ("jurisdictional ratio"). This jurisdictional ratio is then applied to Kentucky Power's total company capitalization to derive the Kentucky jurisdictional capitalization. The jurisdictional ratio uses the test-year-end rate base before any ratemaking adjustments

[16] On May 22, 2017, Kentucky Power filed a motion to deviate from filing requirement 807 KAR 5:001, Section 12(1)(a), which requires the submission of a detailed financial exhibit for the 12-month test period ending not more than 90 days prior to the date of its application. Kentucky Power requested to deviate by filing the required financial exhibit for 12-month period ending 120 days, rather than 90 days, prior to the date of its application. By Order, the Commission approved Kentucky Power's motion to deviate from 807 KAR 5:001, Section 12(1)(a) (Ky. PSC May 24, 2017).

[17] Application, Section V, Exhibit 1, Schedule 4.

applicable to either Kentucky jurisdictional operations or other jurisdictional operations. Kentucky Power used a jurisdictional ratio of 98.3 percent.[18] The Commission finds the calculation of Kentucky Power's test-year electric rate base reasonable for purposes of establishing the jurisdictional ratio.

Pro Forma Jurisdictional Rate Base

Kentucky Power calculated a pro forma jurisdictional rate base of $1,194,888,447,[19] which reflects the types of adjustments made by the Commission in prior rate cases to determine the pro forma rate base.

The Attorney General proposed one adjustment to Kentucky Power's proposed rate base for the Cash Working Capital ("CWC") allowance. The Attorney General proposed an allowance of $18,953,980, which is $740,459 lower than the $19,694,529 proposed by Kentucky Power in its Application. While indicating a preference for using a lead-lag study, the Attorney General stated that if CWC is to be calculated using the Commission's long-standing 1/8th formula approach, then the proper level of CWC for ratemaking purposes should be based on the pro forma operations and maintenance expenses allowed by the Commission.[20] The Attorney General also stated that since Kentucky Power's revenue requirement is calculated based upon its jurisdictional capitalization rather than its adjusted jurisdictional rate base, any adjustment to CWC would have no impact on the revenue requirement.[21]

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[18] *Id.* The non-jurisdictional percentage of approximately 1.7 percent is due to the furnishing of electric service at wholesale to the City of Olive Hill and the City of Vanceburg.

[19] *Id.*

[20] Smith Testimony at 22.

[21] *Id.* at 23.

While the Commission agrees with the methodology the Attorney General utilized for calculating the CWC, the Commission does not agree with the Attorney General's proposed CWC. The CWC allowance included in the rate base, as shown below, is based on the adjusted operation and maintenance ("O&M") expenses discussed in this Order, as approved by the Commission. The Commission has determined Kentucky Power's pro forma jurisdictional rate base for ratemaking purposes for the test year to be as follows:

Total Utility Plant in Service	$2,264,648,845
Add:	
Materials & Supplies	36,344,575
Prepayments	49,905,719
Cash Working Capital Allowance	18,905,292
Subtotal	$105,155,586
Deduct:	
Accumulated Depreciation	764,544,392
Customer Advances	27,076,876
Accumulated Deferred Income Taxes	384,084,108
Contributions in Aid of Construction	
Subtotal	$1,175,705,376
Pro Forma Rate Base	$1,194,099,055

Reproduction Cost Rate Base

KRS 278.290 (1) states, in relevant part, that:

> [T]he commission shall give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for ratemaking purposes.

Neither Kentucky Power, the Attorney General, nor KCUC provided information regarding Kentucky Power's proposed Kentucky jurisdictional reproduction cost rate base. Therefore, the Commission finds that using Kentucky Power's historic costs for deriving its rate base is appropriate and consistent with Commission precedent involving Kentucky Power, as well as other Kentucky jurisdictional utilities.

CAPITALIZATION

Kentucky Power proposed an adjusted Kentucky jurisdictional capitalization of $1,191,785,493.[22] This amount was derived through adjustments to exclude certain environmental compliance investments that remain part of the environmental rate base and are included in Kentucky Power's environmental surcharge mechanism.

Kentucky Power determined its electric capitalization by multiplying its total company capitalization by the rate base jurisdictional allocation ratio described earlier in this Order. This is consistent with the approach used in previous Kentucky Power rate cases.

The Attorney General did not recommend any adjustments to Kentucky Power's capitalization. The Attorney General proposed one adjustment to rate base for CWC, since it does not affect Kentucky Power's jurisdictional capitalization, but recommended no change to the amount proposed by Kentucky Power.

The Commission finds the proposed amount of Kentucky Power's jurisdictional capitalization is reasonable.

REVENUES AND EXPENSES

For the test year, Kentucky Power reported actual net operating income from its electric operations of $85,033,742.[23] Kentucky Power proposed 55 adjustments to

[22] Application, Section II, Exhibit L.

[23] Application, Section V, Exhibit 1, Supplemental Schedule 4 (filed Aug. 7, 2017).

revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income of $43,690,670.[24] With this level of net operating income, Kentucky Power reported an adjusted test year revenue deficiency of $60,397,438.[25]

The Attorney General accepted 45 of Kentucky Power's proposed adjustments to its test-year revenues and expenses.

A list of the non-contested adjustments is contained in Appendix B to this Order. The Attorney General proposed 14 additional adjustments to Kentucky Power's operating income relating to: 1) theft recovery revenue; 2) payroll expense – employee merit increase; 3) overtime payroll expense related to employee merit increase; 4) payroll tax expense; 5) incentive compensation expense; 6) stock-based compensation; 7) savings plan expense; 8) supplemental executive retirement program expense; 9) affiliate charge for corporate aviation expense; 10) storm damage expense; 11) relocation expense; 12) gain on sale of utility property; 13) cash surrender value of life insurance policies; and 14) rate case expense.

The Attorney General's proposed adjustments pertain solely to Kentucky Power's base rate revenue requirements. The Commission makes the following determinations regarding the Attorney General's proposed base rate adjustments.

Theft Recovery Revenue

The Attorney General proposed an adjustment to increase Kentucky Power's theft recovery revenue by $166,698 based upon Kentucky Power's estimate of

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[24] *Id.*

[25] *Id.* at Schedule V, Supplemental Exhibit 2 (filed Aug. 7, 2017).

increased theft recovery revenue.[26] Kentucky Power expects to increase theft recovery revenue due to the addition of a new administrative assistant who would allow Kentucky Power's field investigators to spend more time on suspected energy theft.

The Commission finds that the Attorney General's proposed adjustment regarding theft recovery revenue is reasonable, and therefore the proposed adjustment for theft recovery revenue of $166,698 should be allowed for ratemaking purposes.

Payroll Expenses: Employee Merit Increase, Overtime Payroll Expense, and Payroll Taxes

The Attorney General proposed adjustments to payroll expense for employee merit increases for non-exempt salaried employees, overtime payroll expense related to employee merit increases, and associated payroll taxes in the amount of $57,205, $4,148, and $48,362, respectively. The Attorney General argued that Kentucky Power did not justify basing its proposed payroll expense adjustment on an annual merit increase of 3.5 percent. The Attorney General maintained that the payroll expense adjustment should be based upon a 3.0 percent merit increase.[27] Limiting the merit increase to 3.0 percent results in corresponding adjustments to overtime and payroll tax expenses. The payroll tax adjustment includes the impact of limiting the merit increase to 3.0 percent and other adjustments to incentive compensation and stock-based compensation proposed by the Attorney General.

Kentucky Power maintained that the test year wage increases are reasonable. A comparison of Kentucky Power's total target compensation with the 2016 EAPDIS

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[26] Smith Testimony at 24; Kentucky Power's Response to the Attorney General's First Request for Information ("Attorney General's First Request"), Item 319.

[27] *Id.* at 26-30.

Energy, Technical, Craft & Clerical Survey (Southeast region data) reveals that, on average, Kentucky Power's compensation was 5.4 percent below the average for the region.[28] Kentucky Power claimed that, in light of the survey results, the test year wage increases were necessary to provide market competitive wages to target and retain employees.

The Commission finds that Kentucky Power's test year wages are reasonable and that the Attorney General's proposed adjustments to payroll expense for employee merit increases for non-exempt salaried employees, overtime payroll expense related to employee merit increase and payroll taxes should be denied.

Incentive Compensation and Stock Based Compensation

Kentucky Power included $3,900,806 of incentive compensation plan ("ICP") costs[29] and $1,758,874 in Long-Term Incentive Plan ("LTIP") costs in its Kentucky jurisdictional revenue requirement.[30] These amounts reflect the adjustments made by Kentucky Power.[31] In the Settlement, Kentucky Power and the Settling Intervenors agreed to reduce incentive compensation expenses by $3.15 million, which included incentive compensation and stock-based compensation.

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[28] Application, Direct Testimony of Andrew J. Carlin ("Carlin Direct Testimony"), Exhibit ARC-4.

[29] Kentucky Power's Response to Commission Staff's Second Request for Information (Staff's Second Request"), Item 85; Kentucky Power's Response to KIUC's First Request for Information ("KIUC's First Request"), Item 31.

[30] Smith Testimony at 31. This consists of Kentucky Power direct-charged jurisdictional O&M expense of $2,255,760, AEP allocated amount of $3,118,781 and charges from other affiliates of $51,300 less $1,525,035 that was removed from the revenue requirement per the Application, Section V, Exhibit 2, Workpaper 32.

[31] Application, Direct Testimony of Tyler H. Ross ("Ross Direct Testimony") at 14.

The Attorney General recommended reducing incentive compensation expense by a total of $3,096,868. The Attorney General recommended an adjustment of ICP costs that decreased test year expense by $1,350,120 on a Kentucky jurisdictional basis, which represented the removal of the 25 percent of ICP costs that represent performance measures tied to increasing shareholder value.[32] The Attorney General maintained that ratepayers should not be responsible for those costs because Kentucky Power's shareholders are the main beneficiaries of the 25 percent performance measure for quantitative financial objectives, which include earnings per share.[33] Similarly, the Attorney General argued that $1,746,748 in stock-based compensation costs should be removed because ratepayers should not be required to pay management compensation based on the performance of Kentucky Power's stock price, which primarily benefits Kentucky Power's parent company.[34] In support of his argument, the Attorney General pointed to previous cases in which the Commission held that ratepayers should not bear the cost of stock-based compensation programs unless there is clear and definitive quantitative evidence demonstrating a benefit to ratepayers.[35]

In response, Kentucky Power argued that the Attorney General's adjustment to the proposed incentive compensation expense was not warranted because the

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[32] Smith Testimony at 35, Exhibit RCS-1, page 3 of 32; Smith Testimony at 30-31. The 2016 ICP was weighted 75 percent to AEP's earnings per share and 25 percent to other metrics

[33] *Id.* at 31.

[34] *Id.* at 39.

[35] Case No. 2014-00397, Final Order at 27-28; Case No. 2005-00042, *An Adjustment of the Gas Rates of the Union Light, Heat and Power Company* (Ky. PSC Feb. 2, 2006); Case No. 2010-00036, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Dec. 14, 2010).

incentive compensation programs provide benefits to both Kentucky Power's customers and its shareholders.[36]

The Commission finds that the Settlement provision that reduces incentive compensation by $3.15 million, which is a greater reduction than the adjustment recommended by the Attorney General, is reasonable and should be approved.

Savings Plan Expense

Kentucky Power included $1,662,975 in its jurisdictional revenue requirement for savings plan expense for employees who participate in a defined benefit plan and have matching 401(k) contributions from Kentucky Power.[37]

The Attorney General proposed a Kentucky jurisdictional adjustment of $1,102,496 for savings plan expense for employees who participate in a defined benefit plan and have matching 401(k) contributions from Kentucky Power.

In rebuttal, Kentucky Power explained that participation in the defined benefit plan ended in 2000 and benefits were frozen in 2010.[38] Therefore, Kentucky Power does not contribute to a defined benefit plan and 401(k) matching plan at the same time. The Commission has disallowed such matching contributions when both a defined benefit plan and 401(k) matching contribution exist concurrently. This is not the case with Kentucky Power.

The Commission finds that Kentucky Power's savings plan expense is reasonable and should be allowed for ratemaking purposes.

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[36] Rebuttal Testimony of Andrew R. Carlin ("Carlin Rebuttal Testimony") at 7.

[37] Kentucky Power's Response to Staff's Second Request, Item 56.h. and i.

[38] Dec. 7, 2017 H.V.T. at 4:50:20.

Supplemental Executive Retirement Plan ("SERP")

The Attorney General proposed an adjustment of $52,453 for the expense associated with Kentucky Power's Supplemental Executive Retirement Plan ("SERP"). The Attorney General argued that such plans provide benefits to executives that exceed amounts limited in qualified retirement plans by the Internal Revenue Service.[39] The Attorney General also maintained that the provision of additional retirement compensation to Kentucky Power's highest paid executives is not a reasonable expense that should be recovered in rates.

In rebuttal, Kentucky Power stated that the total benefit it provides under both its qualified and non-qualified plan is equal to the benefit that would be produced by the formulas utilized under the qualified plans if these plans were not subject to the benefit limitations imposed on qualified plans.[40]

The Commission finds the SERP expenses reasonable and, therefore, should be allowed for ratemaking purposes.

Affiliate Charge for Corporate Aviation Expense

The Attorney General proposed an adjustment of $382,769 to remove the cost of the AEP corporate aviation expense charged to Kentucky Power during the test year.[41] The Attorney General argued that AEP corporate aviation is a perquisite for AEP executives and directors and, as such, shareholders should bear the cost, not ratepayers.

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[39] Smith Testimony at 42.

[40] Carlin Rebuttal Testimony at R-32.

[41] Smith Testimony at 43-44.

The Commission disagrees with the Attorney General's proposed adjustment for corporate aviation expense. While private jet travel may appear to be an extravagance, legitimate travel expenses would have been incurred through commercial airlines. The Commissions finds that the aviation expense proposed by Kentucky Power is reasonable and should be approved.

Storm Damage Expense

Kentucky Power proposed an adjustment of $595,932 for storm damage expense based upon a three-year average of major storm expense. The Attorney General proposed an adjustment to reduce storm damage expense by $595,932, arguing that Kentucky Power had not demonstrated a compelling reason to increase test year storm damage expense.[42]

Kentucky Power explained that it used a three-year average to normalize the level of costs to address the uncertainty regarding when, and how much, a major storm will affect Kentucky Power and because using only the test year amount in a base rate filing could lead to major swings in adjustments for storm damage expense.[43]

The Commission finds that Kentucky Power's storm damage expense adjustment is reasonable and should be allowed for ratemaking purposes.

Test Year Relocation Expense

Kentucky Power included a $318,073 adjustment for relocation expense in its test year revenue requirement.[44] The Attorney General proposed an adjustment to

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[42] *Id.* at 44.

[43] Rebuttal Testimony of Ranie K. Wohnhas ("Wohnhas Rebuttal Testimony") at R-18 – R-19.

[44] Kentucky Power's Response to the Attorney General's First Request, Item 251.

normalize relocation expenses that reduced the test year operating expenses by $140,972 on a Kentucky jurisdictional basis.[45]

In response to Commission Staff's Post-Hearing Data Request, Item 14, Kentucky Power stated that its relocation expense for the eight-month period March 1, 2017 to October 31, 2017 totaled $125,736. Annualized over a twelve-month period ending February 28, 2018, relocation expenses are forecasted to total $188,604. On a Kentucky jurisdictional basis, relocation expenses for the twelve months ending February 28, 2018 amount to $185,964.

The Commission finds that the relocation expense should be adjusted based upon the Kentucky jurisdictional relocation expenses for the twelve months ending February 28, 2018. This results in a decrease to the Kentucky jurisdictional relocation expense of $132,109.

Gain on Sale of Utility Property

The Attorney General proposed an adjustment to amortize a $996,669 gain on the sale of utility property ("Carrs Site") over three years for $327,240 per year on a Kentucky jurisdictional basis.[46] The Attorney General maintained that the Kentucky jurisdictional gain on the sale of utility property should flow back to customers.

In rebuttal, Kentucky Power argued that the gain on the sale of the property should not be adjusted to reduce its revenue requirement because the Carrs Site had not been included in rate base, and thus Kentucky Power had not received a return on

[45] Smith Testimony at 46.

[46] *Id.* at 47.

the Carrs Site for the last 33 years.[47] Kentucky Power also noted that it removed $60,539 in property taxes from its cost of service in this case.[48]

The Commission finds that, since Kentucky Power has not received a return on this investment and has excluded the property taxes from its cost of service, the proposed adjustment by the Attorney General is not reasonable and should be denied.

<u>Cash Surrender Value of Life Insurance</u>

Kentucky Power recorded expense in the test year associated with the cash surrender value of life insurance of former executives in a Kentucky jurisdictional amount of $26,941.[49]

The Attorney General asserted that Kentucky Power's ratepayers should not be responsible for paying the expenses for the cash surrender value of life insurance for former executives and recommended the $26,941 of expense be denied for ratemaking purposes.[50]

In rebuttal, Kentucky Power explained that the expense is part of the total compensation/benefit package given to executives (current or former) that should be recovered whether or not the executive is a current or a former employee.[51]

The Commission finds that the proposed expense is reasonable, and therefore the Attorney General's proposed adjustment should be denied.

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[47] Wohnhas Rebuttal Testimony at R-20.

[48] *Id.*

[49] Smith Testimony at 48.

[50] *Id.*

Rate Case Expense

The Attorney General proposed an adjustment to remove $458,333 in rate case expenses.[52] The Attorney General proposed to remove certain rate case expenses billed by a consultant who conducted witness preparation but did not sponsor testimony on Kentucky Power's behalf. The Attorney General also proposed to remove remaining rate case expenses as a penalty for Kentucky Power not seeking a reduction in the Rockport UPA ROE, which was established by the Federal Energy Regulatory Commission ("FERC").

In rebuttal, Kentucky Power argued that witness preparation is a necessary part of litigating a base rate case and that, regardless of who performs the function, the cost should be recovered.[53] Kentucky Power further argued that FERC's determination of the Rockport UPA ROE was fair, just, and reasonable, and that the decision was within FERC's exclusive jurisdiction. Kentucky Power asserted that the Attorney General's proposal to deny rate case expense as a penalty for the Rockport UPA ROE was an unlawful and unconstitutional attempt to overturn a FERC decision.

The Commission finds that the Attorney General's adjustment to remove rate case expenses for witness preparation and as a penalty for the Rockport UPA ROE is unreasonable, and should be denied. Given the type of service provided, the Attorney General's argument to remove the witness preparation consultant's fees is not

[51] Wohnhas Rebuttal Testimony at 17.

[52] Smith Testimony at 52.

[53] Wohnhas Rebuttal Testimony at R-20.

persuasive.[54] In regard to adjusting the rate case expenses as a penalty not related to ratemaking, as set forth in *South Central Bell v. Utility Reg. Comm'n*, 637 S.W.2d 649, 653 (Ky. 1982), the imposition of penalty that is not germane to the factors that go into the ratemaking process is arbitrary and subjective. If the Attorney General objects to the ROE awarded by FERC, the appropriate forum to address that issue is at FERC, and not the Commission.

COMMISSION ADJUSTMENTS TO REVENUES AND EXPENSES

Off System Sales ("OSS") Margins, System Sales Clause Tariff ("Tariff S.S.C.")

During the test year, Kentucky Power included OSS margins in the amount of $7,163,948. Kentucky Power operated the converted Big Sandy Unit 1 for only nine months of the test period. While Kentucky Power annualized the plant maintenance expense for Big Sandy Unit 1,[55] there was no adjustment or annualization to OSS margins.

The Commission finds that OSS margins should be adjusted to reflect an annualized amount. For the 12-month period ending September 30, 2017, Kentucky Power had OSS margins of $7,650,360.[56] Therefore, the Commission will utilize the OSS margins of $7,650,360 for the 12-month period ending September 30, 2017, rather than the test year amount, resulting in an increase in operating revenue of $486,412. Additionally, the amount of OSS margins to be collected in base rates is $7,650,360, rather than the $7,163,948 proposed in the application.

[54] *See* Kentucky Power Fifth Supplemental Response to Staff's First Request (filed Jan. 2, 2018), Item 56. The witness preparation fees were $42,623; Kentucky Power's other legal fees were $677,547.

[55] Application, Section V, Exhibit 2, Workpaper 41.

[56] Response to Commission Staff's Fourth Request for Information, Item 2.

Weather Normalized Commercial Sales

Kentucky Power proposed an adjustment to increase revenues to reflect normal temperatures, but its adjustment applied only to residential customer sales. In discovery, Kentucky Power stated that commercial revenues would have been $914,000 greater based on weather normalized temperatures.[57] After the related variable expenses are removed from revenues, the rate increase is reduced by $400,000.

The Commission finds this adjustment reasonable as temperatures affect the revenues in both the residential and commercial classes. Therefore, the Commission will reduce the rate increase by $400,000 to reflect this adjustment.

Purchased Power Limitation and Forced Outage Purchase Power Limitation Expense

Kentucky Power proposed adjustments to include the purchased power limitation and forced outage purchase power limitation expense in base rates in its application in the amount of $3,150,582 and $882,204, respectively.

As discussed under the FAC Purchase Power Limitation section below, the Commission is denying Kentucky Power's proposal to recover such costs under Tariff P.P.A. Accordingly, the Commission finds these adjustments unreasonable and should be denied.

Net Operating Income Summary

After considering all pro forma adjustments and applicable income taxes, Kentucky Power's adjusted net operating income is as follows:

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[57] Direct Testimony of Lane Kollen at 16-17.

Operating Revenues	$568,163,551
Operating Expenses	519,965,870
Adjusted Net Operating Income	$ 48,197,681

RATE OF RETURN

Capital Structure and Cost of Debt

Kentucky Power proposed an adjusted test-year-end capital structure consisting of 54.45 percent long-term debt at 5.32 percent; zero percent short-term debt at 0.80 percent; 3.87 percent accounts receivable financing at 1.95 percent; and 41.68 percent common equity at a return of 10.31 percent.[58] On August 7, 2017, Kentucky Power filed a supplement to its Application reflecting the results of Kentucky Power's June 2017 refinancing of $325 million 6.00 percent Senior Unsecured Notes, and $65 million WVEDA Mitchell Project, Series 2014A Variable Rate Demand Notes as authorized in Case No. 2016-00345.[59] This refinancing reduced the annual cost of long-term debt to 4.36 percent.[60] The capital structure proposed by the Settlement downwardly adjusts the long-term debt by one percent and places this percent onto the short-term debt at an interest rate of 1.25 percent.[61]

[58] Application, Direct Testimony of Zachary C. Miller ("Miller Direct Testimony") at 3.

[59] Case No. 2016-00345 *Electronic Application of Kentucky Power Company for Authority Pursuant to KRS 278.300 to Issue and Sell Promissory Notes of One or More Series and for Other Authorizations* (Ky. PSC Dec. 21, 2016).

[60] Supplemental Direct Testimony of Zachary C. Miller at 5.

[61] Settlement Testimony of Mattew J. Satterwhite ("Satterwhite Settlement Testimony") at Exhibit 6a.

The Attorney General employed Kentucky Power's proposed capital structure and senior capital cost rates.[62] KCUC was silent on this topic.

Kentucky Power stated that it sells its receivables to AEP for cost savings due to default risks and to improve cash flow.[63] However, Kentucky Power's uncollectible accounts remain with Kentucky Power and are not sold with the accounts receivable.[64] The Commission notes that the cost of accounts receivable financing is higher than traditional short-term financing. The Commission believes that selling the receivables but maintaining the bad debt places an undue burden onto Kentucky Power's customers. Therefore, the Commission will blend the funds between short-term debt and accounts receivable financing so that the weighted average cost percentage of accounts receivable financing is decreased three basis points and placed on the short-term debt weighted average cost percentage. This reduces the percent of accounts receivable financing to 1.67 percent of the total capital structure and increases the percent of short-term debt to 3.20 percent of the total capital structure. The Commission finds that the cost of long-term debt and short-term debt of 4.36 percent and 1.25 percent, respectively, to be reasonable.

Return on Equity

In its Application, Kentucky Power developed its return on equity ("ROE") using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the empirical capital asset pricing model ("ECAPM"), and the utility risk premium ("RP"). In

[62] Direct Testimony of J. Randall Woolridge, Ph.D. ("Woolridge Testimony") at 3.

[63] Dec. 8, 2017 H.V.T. at 12:15:22.

[64] Dec. 6, 2017 H.V.T. at 5:43:36.

addition, Kentucky Power referenced the expected earnings approach.[65] Based on the results of the methods employed in its analysis, Kentucky Power recommended an ROE range of 9.71 percent to 10.91 percent, including flotation cost.[66] Kentucky Power recommended awarding the midpoint of this range, 10.31 percent, to maintain financial integrity and to support additional capital investment.[67] Kentucky Power further stressed that consideration of all models, not just the DCF model, is important as the DCF model results may reflect the impact from the recent recession and such financial inputs are not representative of what may prevail in the near future.[68]

Direct testimony and analysis regarding ROE was provided by the Attorney General. The Attorney General employed the DCF and CAPM models for his analysis and both models were evaluated using Kentucky Power's proxy group and the Attorney General's own proxy group. This was mostly for comparison purposes, as the Attorney General stated that, on balance, the two proxy groups were similar in risk.[69] The Attorney General's DCF model results indicated equity cost rates of 8.25 percent and 8.7 percent for the Attorney General and Kentucky Power proxy groups, respectively. The Attorney General disagreed with Kentucky Power's DCF analysis, specifically noting Kentucky Power's elimination of low-end DCF results and the use of growth forecasts that the Attorney General believes are overly optimistic and upwardly biased.[70]

[65] Application, Direct Testimony of Adrian M. McKenzie, CFA ("McKenzie Direct Testimony") at 6.

[66] *Id.* at Exhibit AMM-2 at 1.

[67] Id. at 6.

[68] Id. at 7.

[69] *Id.* at 25.

[70] *Id.* at 65.

The Attorney General's CAPM results were 7.6 percent for both proxy groups. The Attorney General stated that Kentucky Power's CAPM analysis is flawed as the ECAPM version of the CAPM was used, which the Attorney General claims makes an inappropriate adjustment to the risk-free rate and the market risk premium.[71] Additionally, the Attorney General stated that Kentucky Power's CAPM analysis employed an inflated projected interest rate, an unwarranted size adjustment, and an excessive market or equity risk premium.[72]

The Attorney General recommended relying primarily on the DCF model, determined the ROE range of the two proxy groups, 8.25 percent and 8.7 percent, to be reasonable, and recommended an ROE of 8.6 percent.[73] In support of his recommendation, the Attorney General noted that: as investment risk, Kentucky Power's credit ratings are on par with the proxy groups; capital costs for utilities remain at historical low levels and are likely to remain at low levels; the risk associated with the electric utility industry is among the lowest and, as such, the cost of equity capital is amongst the lowest; and authorized ROEs have been gradually decreasing in recent years.[74]

The Attorney General also disagreed with Kentucky Power's upward adjustment of 0.11 percent to the equity cost rate recommendation to account for flotation costs. The Attorney General argued that Kentucky Power did not identify any flotation costs

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[71] *Id.* at 68.

[72] *Id.*

[73] Woolridge Testimony at 58.

[74] *Id.* at 59.

that are specifically associated with Kentucky Power.[75] The Attorney General stated that it is commonly argued that a flotation cost adjustment is necessary to recover issuance costs, but should not be recovered through the regulatory process, as these costs are already known to the investor upon buying the stock.[76]

The parties to the Settlement agreed that the revenue requirement increases for Kentucky Power will reflect a 9.75 percent ROE as applied to Kentucky Power's capitalization and capital structure of the proposed revenue requirement increases as modified through discovery. As a result, use of a 9.75 percent ROE reduced Kentucky Power's proposed electric revenue requirement by $4.7 million.[77] In his post hearing brief, the Attorney General recognized the significant reduction from the original ROE, but still believes it is in excess of the return shareholders require.[78] The Attorney General further argued that utilities seem to overstate necessary ROE, and does not support the 9.75 percent.[79] For the reasons discussed below, the Commission finds a ROE of 9.75 percent to be unreasonable, and for the purpose of base rate revenues and certain tariffs, an ROE of 9.70 percent should be applied.

In his testimony, the Attorney General noted that differing opinions between Kentucky Power and the Attorney General regarding capital market conditions result in differing ROE recommendations.[80] Kentucky Power's analysis assumes higher interest

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[75] *Id.* at 80.

[76] *Id.* at 81.

[77] Settlement at 4.

[78] Attorney General's Post Hearing Brief ("Attorney General's Brief") (filed Jan. 5, 2018) at 18.

[79] *Id.* at 19 and 20.

[80] Woolridge Testimony at 5.

rates and capital costs whereas the Attorney General concludes that interest rates and capital costs are at low levels and likely to remain low for some time.[81] The Commission agrees with the Attorney General that, although interest rates are increasing, they are doing so slowly and are still historically low. In fact, the Federal Reserve noted the following:

> 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.[82]

The Commission further agrees that models supporting the low interest rate environment should be given more weight than those supporting high interest rate expectations.

The Commission also agrees with the Attorney General that flotation costs should be excluded from the analysis. The Commission believes that flotation costs are accounted for in the current stock prices, as the price includes the underwriting spread and adding the adjustment amounts to double counting. Removal of the flotation costs from Kentucky Power's initial cost of equity range lowers the range to 9.6 percent from 10.8 percent.[83]

The 2017 economic environment has shown signs of relative improvement. In response to low inflation and low unemployment, the Federal Reserve increased interest rates a quarter of a percent three times in 2017. Current outlooks for 2018 are

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[81] *Id.*

[82] Testimony of Richard A. Baudino at 8.

[83] McKenzie Direct Testimony, Exhibit AMM-2 at 1.

healthy, with gross domestic product growth rates expected to remain between two and three percent, unemployment forecasted to continue at the natural rate, and inflation expected to hover at around two percent.[84] However, notwithstanding these improvements, the economy of Eastern Kentucky has lagged behind national and state trends. Employment trends have not recovered to pre-recession levels, earnings trends remain stagnant and lag behind the state trends, and poverty rates in the majority of Kentucky Power's service territory are 24.4 percent or higher.[85]

The Commission is cognizant of the risk inherent to Kentucky Power's service territory and load profile. The Commission notes the Attorney General's position that Eastern Kentucky has been economically depressed for the past decade and that the Commission should consider the economic conditions of the region in evaluating the overall rates and rate design.[86] Therefore, given the adverse economic situation of the service territory of high unemployment, low earnings, and high poverty rates, the Commission finds a lower ROE will allow Kentucky Power to earn a fair return while reflecting the economic situation of its customers.

For 2016, the median ROE of the utilities in the Attorney General's proxy group was 9.3 percent; for Kentucky Power's proxy group, the median ROE was 9.4 percent.[87] In addition, the average authorized ROE reported by SNL Financial for 2017 is

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[84] https://www.thebalance.com/us-economic-outlook-3305669.

[85] Attorney General's Brief at 12; Dismukes Testimony at 5-6; Dec. 6, 2017 H.V.T., PSC Exhibit 1.

[86] Dismukes Testimony at 6.

[87] Woolridge Testimony, Exhibit JRW-4 at 1.

approximately 9.7 percent.[88] The Commission agrees with Kentucky Power that this is a benchmark worthy of consideration, but disagrees that a downward adjustment will be injurious to customers and the Kentucky economy.[89] Based on the entire record developed in this proceeding, we find that an ROE of 9.7 falls within the range of the Attorney General's proposed 8.6 percent to the initial proposed ROE of 10.31 percent, and within Kentucky Power's original range of 9.6-10.8 percent, adjusted for flotation costs. Additionally, an ROE of 9.7 is within the range of the benchmarks provided by SNL, the proxy groups, and recent Commission Orders[90].

Rate-of-Return Summary

Applying the rates of 4.36 percent for long-term debt, 1.25 percent for short-term debt, 1.95 percent for accounts receivable financing, and 9.70 percent for common equity to the Commission adjusted capital structure produces an overall cost of capital of 6.44 percent.[91] The cost of capital produces a return on Kentucky Power's rate base of 6.42 percent.

BASE RATE REVENUE REQUIREMENTS

In the Settlement, Kentucky Power and the Settling Intervenors agreed to a base rate increase of $31.8 million. The Attorney General's expert witness proposed a base

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[88] Direct Testimony and Exhibits of Gregory W. Tillman on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. at 11.

[89] Rebuttal Testimony of Adrien M. McKenzie, CFA at 73.

[90] 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 (Ky. PSC Jun. 22, 2017) and 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 (Ky. PSC Jun. 22, 2017).

rate increase of \$39.8 million. The Commission finds that, subject to the adjustments discussed in this Order, a base rate increase of \$12.35 million is reasonable, as is discussed in the Total Jurisdictional Revenue Requirement section below.

REVENUE REQUIREMENT-RELATED RIDERS AND DEFERRALS

Big Sandy Retirement Rider

In its Application, Kentucky Power proposed to rename the Big Sandy Retirement Rider to the Decommissioning Rider to alleviate customer confusion regarding the purpose of the rider. Pursuant to the settlement agreement approved in Case No. 2014-00396, Kentucky Power recovers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2, and other site-related retirement costs through this rider. Only the rider name will change; the rider will continue to operate in the manner approved by the Commission in Case No. 2014-00396.

The Commission finds the name change reasonable and that it should be approved. The Commission further finds that the carrying charges associated with this rider should be based on the weighted average cost of capital ("WACC"), after reflecting the impacts of the reduction in the federal corporate income tax rates approved in this Order, should become effective as of the date of this Order. However, the monthly amounts collected will not change until Kentucky Power makes its annual filing on or before August 15, 2018, to adjust the amounts collected under this rider.

Big Sandy Unit 1 Operation Rider

In its Application, Kentucky Power proposed to eliminate the Big Sandy Unit 1 Operation Rider ("Tariff B.S.1.O.R.") and to recover through base rates the costs

[91] The Commission adjusted capital structure consists of 54.45 percent long-term debt, 3.2

currently recovered through Tariff B.S.1.O.R. Once new rates become effective in this case, Tariff B.S.1.O.R. will have an under- or over-recovery balance. Therefore, Kentucky Power also requested authority to establish a regulatory asset or liability that will allow Kentucky Power to track and defer any under- or over-recovery balance until its next rate case.

In Case No. 2014-00396, the Commission approved Tariff B.S.1.O.R. to permit Kentucky Power to recover the non-fuel costs of operating Big Sandy Unit 1 as a coal burning unit until its conversion to natural gas, the non-fuel costs of its operation as a natural gas unit and capital investment required for its conversion to natural gas once it is placed in service. Tariff B.S.1.O.R. was designed to be in effect until the rates established in Kentucky Power's next base rate case were implemented.

The Commission has previously approved regulatory assets for other jurisdictional utilities. Such approval has been granted when a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry-sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[92] Since Tariff B.S.1.O.R. was approved by the Commission in Case No. 2014-00396, the establishment of a regulatory asset to address the under-

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percent of short term debt, 1.67 percent of accounts receivable financing, and 41.68 percent of common equity.

[92] Case No. 2008-00436, *The Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages* (Ky. PSC Dec. 23, 2008), at 4. *See also* Case No. 2010-00449, *Application of East Kentucky Power Cooperative, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Amount Expended on Its Smith 1 Generating Unit* (Ky. PSC Feb, 28, 2011), at 7.

recovery of Tariff B.S.1.O.R. is consistent with the second example listed above. Regarding a possible regulatory liability, the Commission notes that it is appropriate that Kentucky Power customers be the beneficiaries of any over-recovery of Tariff B.S.1.O.R.

The Commission finds the establishment of a regulatory asset or liability due to the elimination of Tariff B.S.1.O.R. to be reasonable and that it should be approved. This approval is for accounting purposes only, and the appropriate ratemaking treatment for the regulatory asset or liability account will be addressed in Kentucky Power's next general rate case.

Tariff A.T.R.

In its Application, Kentucky Power proposed to eliminate Tariff Asset Transfer Rider ("Tariff A.T.R."). Given that Kentucky Power has recovered the full amount that Tariff A.T.R. was designed to recover, the Commission finds the elimination of Tariff A.T.R. to be reasonable and that it should be approved.

Tariff K.E.D.S.

In its Application, Kentucky Power proposed to increase Tariff K.E.D.S. from \$0.15 per meter per month to \$0.25 per meter per month. In the Settlement, Kentucky Power and the Settling Intervenors agreed to a surcharge of \$0.10 per meter for residential customers and \$1.00 per meter for non-residential customers. KCUC did not provide testimony regarding Tariff K.E.D.S.

Tariff K.E.D.S. imposes an economic development surcharge, which was approved in Kentucky Power's last rate case,[93] to fund economic development initiatives

[93] Case No. 2014-00396, Final Order at 49-51.

in Kentucky Power's service territory, with funds collected through the surcharge matched equally by Kentucky Power from AEP shareholder funds. As a basis for the increase, Kentucky Power argued that additional economic development funds were needed to grow its load and customer base. One of the reasons for Kentucky Power's proposed rate increase is a significant decline in load and customers since the economic downturn in 2008.[94] A decrease in customers and load concentrates costs among a smaller customer base, which results in fewer customers paying a larger share of the cost. Correspondingly, a growth in load and customer base spreads costs among a greater number of customers.

The Attorney General recommended that the economic development surcharge be eliminated.[95] The Attorney General asserted that Kentucky Power failed to provide evidence of a direct tie between Kentucky Power's economic development efforts and increased jobs and electricity sales.[96] The Attorney General further asserted that the economic development surcharge simply redistributes ratepayer dollars without evidence of an identifiable benefit for ratepayers.

In rebuttal, Kentucky Power countered that it maintains economic development metrics, including job counts, investments, and grants, which it uses to evaluate the

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[94] Application, Direct Testimony of Brad N. Hall ("Hall Direct Testimony") at 5. Between 2008 and 2016, Kentucky Power lost 6,931 customers, and its total annual sales declined from 7.24 GWh to 5.80 GWh.

[95] Direct Testimony of David E. Dismukes ("Dismukes Testimony") at 4; Direct Testimony of Roger McCann ("McCann Testimony") at 6, 17.

[96] Dismukes Testimony at 4, 41.

success of its economic development program.[97] In a subsequent discovery response, Kentucky Power provided its written economic development action plan with strategic goals and metrics set forth in specific detail.[98] Kentucky Power contended that its economic development program achieves identifiable goals, and that Kentucky Power's customers receive benefits from the economic development surcharge. As an example, Kentucky Power asserted that its economic development efforts are projected to create 1,705 new full-time positions, with an additional 1,000 construction jobs.[99]

The Commission recognizes the importance of economic development efforts, especially given the economic needs of Kentucky Power's service area. However, the Commission also recognizes that 26 percent, or 35,756, of Kentucky Power's residential customers are at or below the poverty level.[100] In 2016, Kentucky Power disconnected more than 11,000 residential customers who could not pay their electric bill.[101] In the course of this proceeding, the Commission received a large number of public comments from residential customers who questioned why they are charged for Kentucky Power's economic development efforts, particularly given the difficulty that residential customers have in paying their electric bills. Residential customers, especially those on fixed incomes, cannot pass along their costs; to a certain extent, non-residential customers

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[97] Dec. 8, 2017 H.V.T. at 10:44:56.

[98] Kentucky Power Response to KCUC's Post Hearing Data Request ("Response to KCUC Post Hearing Request"), Item No. 1, Attachment 1.

[99] Hall Direct Testimony at 12; Dec. 8, 2017 H.V.T. at 10:31:23. On December 7, 2017, there was an announcement that 875 jobs would result from a business locating in Pikeville, Kentucky. Prior to that announcement, there were 830 projected new jobs created from Kentucky Power economic development efforts.

[100] Dec. 8, 2017 H.V.T. at 11:58:01 and 5:33:49.

[101] *Id.* at 11:58:19.

can pass along their costs to their customers. The Commission finds that the residential customer economic development surcharge of $0.10 per meter per month, as set forth in the Settlement, is unreasonable and therefore should be denied. The Commission further finds that the residential customer economic development surcharge should be eliminated. However, the Commission finds that the economic development surcharge on non-residential customers of $1.00 per meter per month, as set forth in the Settlement, is reasonable. Therefore, the Commission approves the portion of the Settlement applicable to the economic development surcharge for non-residential customers only.

Home Energy Assistance Program Surcharge

In its Application, Kentucky Power proposed to increase the HEAP surcharge from $0.15 per residential meter per month to $0.20 per residential meter per month. Similar to the economic development surcharge, funds collected through the HEAP surcharge are matched equally by Kentucky Power from AEP shareholder funds.

HEAP funds provide subsidies to assist eligible low-income customers in Kentucky Power's service territory to pay electric bills during seven peak heating and cooling months.[102] There is a waiting list of eligible customers because there are not sufficient HEAP funds available to assist all eligible customers.[103]

The Attorney General supported the five-cent increase to $0.20 per residential meter per month, but argued that the increase was inadequate to keep pace with

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[102] McCann Testimony at 5-6, 14. Subsidies are available in January, February, March, July, August, September, and December.

[103] *Id.* at 15. As of Sept. 20, 2017, there were 1,475 eligible customers on a wait-list for HEAP subsidies.

Kentucky Power's rate increases. The Attorney General proposed that the Commission approve the HEAP surcharge increase and, if the Commission discontinued the economic development surcharge, that the HEAP surcharge be increased in the same amount by which the economic development is reduced.[104]

Kentucky Power's President, Matthew J. Satterwhite, testified that, if the Commission modified the Settlement to eliminate the $0.10 per meter per month economic development surcharge for residential customers, Kentucky Power could agree to a commensurate increase in the HEAP surcharge by $0.10 per residential meter per month, with matching shareholder funds.[105]

The Settlement is silent as to the HEAP surcharge.

The Commission finds that the proposed increase in the HEAP surcharge is insufficient to address the demonstrable need to assist eligible low-income customers with their electric bills. The Commission further finds that the HEAP surcharge should be increased by the corresponding amount that the economic development surcharge for residential customers is reduced. Therefore, the Commission rejects Kentucky Power's proposed increase in the HEAP surcharge to $0.20 per residential meter per month. The Commission finds an increase of the HEAP surcharge to $0.30 per residential meter per month is reasonable and should be approved.

Rockport Deferral Mechanism

In the Settlement, Kentucky Power and the Settling Intervenors agreed to defer $50 million of non-fuel and non-environmental lease expenses from Rockport Unit 2

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[104] McCann Testimony at 6, 17; Dismukes Testimony at 4.

over five years, with the establishment of a regulatory asset for later recovery ("Rockport Deferral Regulatory Asset") of these expenses. This Rockport Deferral Regulatory Asset, plus a carrying charge based on a WACC of 9.11 percent, will be recovered through Kentucky Power's Tariff P.P.A. over five-years starting in December of 2022. The dates of the end of the deferral period and the start of the five-year amortization period coincide with the anticipated end of the Rockport UPA lease agreement.[106]

The Settlement proposed a deferral of $15 million in 2018 and 2019, $10 million in 2020, and $5 million in 2021 and 2022. The Settlement's annual revenue requirement reflects a decrease to base rates of the 2018 $15 million adjustment. In 2020, 2021 and 2022 the decrease in the deferral will be offset with an increase in the amount recovered through Tariff P.P.A. Additionally, in 2022, the increase in the amount recovered through Tariff P.P.A. will be prorated through December 8, 2022, as the Rockport UPA will terminate on that date. By utilizing Tariff P.P.A., Kentucky Power is able to reduce the annual deferral amount and concurrently keep base rates unchanged. Beginning in December 2022, the five-year deferral period will end and the recovery of the Rockport Deferral Regulatory Asset will begin. The Rockport Deferral Regulatory Asset will be amortized through 2027 and be subject to carrying charges until it is fully recovered. Kentucky Power estimates that the Rockport Deferral

[105] Dec. 7, 2017 H.V.T. at 10:53:09.

[106] Satterwhite Settlement Testimony at S-10.

Regulatory Asset will total approximately $59 million in December 2022. That amount will decrease incrementally until fully collected over the five-year amortization period.[107]

Neither the Attorney General nor KCUC offered testimony concerning the Rockport Deferral. However, during the hearing and in his post-hearing brief, the Attorney General expressed his concerns about the "very large financing costs" associated with the deferrals, stating that the "$50M over the entire deferral period is going to have financing costs piled on top of it... [t]hese financing costs are at the weighted average cost of capital including the 9.75 percent return of equity which then gets a tax gross up on top of it."[108] The Attorney General further stated that a concern that the costs of the deferral will eventually require rate recovery in future rate proceedings.[109] The Attorney General recommended that the carrying charge be reduced to 4.36 percent for Kentucky Power's current long term debt.[110]

In response, Kentucky Power argued that the 9.11 percent WACC made Kentucky Power financially whole because of its need to finance the deferral through a combination of debt and equity, and therefore was appropriate.[111]

The recovery period of the proposed Rockport Deferral Mechanism is contingent upon Kentucky Power not renewing the Rockport UPA.[112] If the lease is not renewed,

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[107] *See* Appendix A, paragraph 3 for details of the Rockport UPA Expense Deferral.

[108] Dec. 6, 2017 H.V.T. at 04;01:19; *See also* Attorney General's Brief at 31.

[109] Dec. 6, 2017 H.V.T. at 04:01:19

[110] Attorney General's Brief at 31.

[111] Kentucky Power's Post Hearing Brief ("Kentucky Power's Brief") (filed Jan. 5, 2018) at 48.

[112] Kentucky Power stated that it is unlikely that the Rockport lease will be renewed. Dec. 6, 2017 H.V.T. at 5:47:44; Kentucky Power Response to Staff's Second Request, Item 72.

the expenses associated with the Rockport UPA will be removed from rate base, which allows the regulatory asset to be funded without a change in rate base. However, if the lease is renewed, the deferred expenses will have to be recovered from future ratepayers, and possibly through an increase in rate base.[113] The Commission recognizes that there are inherent risks associated with any deferral mechanism, especially since the deferral recovery is contingent upon not renewing the Rockport UPA. Given Kentucky Power's excess capacity and slow load growth, the Commission believes the benefits of the deferral outweigh the associated risks, and approves the Rockport Deferral Mechanism and the associated $15 million decrease to rate base. The carrying charges associated with this rider shall be based on the WACC approved in this Order and are effective as of the date of this Order. This approval is for accounting purposes only, and the appropriate ratemaking treatment for this regulatory asset account will be addressed in Kentucky Power's next general rate case.

Environmental Surcharge Tariff E.S.

Kentucky Power proposed an addition to its Environmental Compliance Plan to recover the cost of installing Selective Catalytic Reduction ("SCR") technology at Rockport Unit 1, affecting the amounts collected under Tariff E.S The project is discussed later in the Environmental Compliance Plan section of this Order. Kentucky Power estimated the revenue requirement for the SCR project to be $3,903,065.[114] The Commission finds the Rockport Unit 1 revenue requirement to be reasonable.

[113] Satterwhite Settlement Testimony at S-13.

[114] Elliott Testimony, Exhibit AJE-5.

TOTAL JURISDICTIONAL REVENUE REQUIREMENTS

The Commission has found that Kentucky Power's required ROE falls within a range of 8.60 percent to 10.31 percent, and approves an ROE of 9.70 percent. The Settlement proposed a base rate increase of $31.8 million and environmental surcharge revenues of $3.9 million, for a total of $35.7 million. The environmental surcharge is discussed farther below. Because Kentucky Power recovers the costs associated with the decommissioning of coal-related assets at Big Sandy through the Decommissioning Rider, those costs are not included for recovery in the base rates. However, for the twelve months ending September 30, 2018, Kentucky Power will recover approximately $20.2 million through the Decommissioning Rider,

Due to the modifications the Commission makes to the Settlement and the provision for the reduction in the federal corporate income tax rate from 35 percent to 21 percent in the Tax Cuts and Jobs Act, the Commission finds that an increase in base rate revenues of $12.35 million, as shown in Appendix F to this Order, exclusive of the environmental surcharge, will result in fair, just, and reasonable electric rates for Kentucky Power and its ratepayers. The Commission utilized Kentucky Power's equity gross up revenue conversion factor ("GRCF"), as provided in Kentucky Power's revised Environmental Surcharge forms filed on January 3, 2018, to reflect the reduction in the federal corporation income tax rate effective with the date of this Order. Additionally, the adjustments the Commission makes to the test year operating income and expense items reflect the income tax rate reduction and change in the GRCF. The excess accumulated deferred income tax ("ADIT") impacts resulting from the reduction federal corporate income tax rate will be addressed in Case No. 2017-00477. The Commission also finds that Kentucky Power should establish a mechanism to track the over/under-collection of federal income taxes, and that a true-up of any over/under-collections be addressed in Case No. 2017-00477.

Due to the economic conditions in Kentucky Power's service territory, the Commission believes that the impact of the federal corporate income tax reduction on rates should be put into place effective with the date of this Order. In addition, the lower rates should serve as an impetus for economic development through recruiting new businesses as well as maintaining existing business customers.

NONREVENUE REQUIREMENT RIDERS AND TARIFFS

The following sections address riders and a tariff that have no direct impact on Kentucky Power's revenue requirement. The discussion covers both those that have been contested, and those that are included in the Settlement.

Non-Utility Generator Tariff

In its Application, Kentucky Power proposed to revise the Non-Utility Generator Tariff ("Tariff N.U.G.") to eliminate a provision that requires a 30-day written notice to customers taking service under Tariff N.U.G. if a transmission provider implements charges for transmission congestion. Kentucky Power asserted that this clause is no longer necessary because PJM has already created transmission congestion charges.[115] Kentucky Power also proposed to revise language in the special terms and conditions section of Tariff N.U.G. to clarify the requirement to take service for remote

[115] Application, Vaughan Direct Testimony at 25.

self-supply.[116] The Settlement is silent as to Tariff N.U.G. Neither KCUC nor the Attorney General contested the proposed revisions to Tariff N.U.G.

The Commission finds the revisions to Tariff N.U.G. to be reasonable and that they should be approved.

Systems Sales Clause

In its Application, Kentucky Power proposed to reduce monthly bill volatility by revising its Tariff S.S.C. to change from a monthly system sales adjustment factor to an annual sales adjustment factor. Kentucky Power further proposed to set the Tariff S.S.C. rate to $0, with the difference between actual off-system sales margins and a base amount of $7,163,948 deferred based on the current 75/25 customer sharing mechanism approved in Case No. 2014-00396.[117] The net deferred credit or charge to customers would then be the base for the annual Tariff S.S.C. rate update.[118] Kentucky Power proposed to file the required true-up information no later than August 15 of each year, with rates to be effective with Cycle 1 of October. The first filing would be made by August 15, 2018. The Settlement is silent as to Tariff S.S.C. Neither the Attorney General nor KCUC contested the proposed revisions to Tariff S.S.C.

The Commission finds the revisions to Tariff S.S.C., as adjusted to include $7,650,350 in base rates, to be reasonable and should be approved.

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[116] Sharp Direct Testimony at 28.

[117] Kentucky Power credits 75 percent of the difference between base and actual off system sales margins amounts to customers and retains 25 percent.

[118] Vaughan Direct Testimony at 36-37.

PJM Billing Line Items

In the Application, Kentucky Power proposed to include additional PJM Billing Line Items ("BLIs") for recovery through its FAC. Kentucky Power stated that these BLIs represent items that either require generation resources to be running and online, or are associated with other BLIs that require generation resources to be running and online. Kentucky Power stated that all of the service functions represented by the BLIs are related to fuel-related services previously received by Kentucky Power when it was a member of the AEP East Pool, and that those amounts were previously included in Kentucky Power's base fuel cost. The Settlement is silent as to the BLIs. Neither the Attorney General nor KCUC contested this proposal.

The Commission has reviewed the additional BLIs and finds that they are appropriate for inclusion in the FAC, as these BLIs represent charges and credits that relate to fuel consumed by resources that are running and online. Furthermore, the Commission finds that when Kentucky Power files its compliance tariff, it should amend its Tariff F.A.C to include PJM BLIs 2211, 2215, and 2415, as those BLIs have replaced BLI 2210.

MODIFICATIONS TO TERMS AND CONDITIONS OF SERVICE TARIFFS

In its Application, Kentucky Power proposed certain revisions to its terms and conditions for service. The revisions include: verification of a customer's identity and proof of ownership or lease of property where service is requested at the time an application for service is filed; information to be considered when evaluating whether to waive a deposit; payment arrangements; mobile alerts; elimination of the employee discount; modifying the equal payment plan; and denial or discontinuance of service.

Kentucky Power also requested a deviation from 807 KAR 5:006, Section 14(2)(a) to amend when a customer can sign up for the Equal Payment Plan, and the annual settle-up month for certain customers.

Neither the Attorney General nor KCUC contested the revisions.

The Commission finds that the proposed revisions to the terms and conditions of service as contained in the Application are reasonable, with the exception of the denial or discontinuance of service, and should be approved. The Commission further finds that Kentucky Power established good cause to deviate from 807 KAR 5:006, Section 14(2)(a), and that its request for a deviation should be granted.

As to the denial or discontinuance of service, the Commission finds that the proposed revisions as contained in the Application are overbroad and do not comply with Commission precedent.[119] In response to Commission Staff's Post Hearing Data Request, Kentucky Power revised the terms for denial or discontinuance of service as follows:

> The Company reserves the right to refuse or discontinue service to any customer if the customer is indebted to the Company for any service theretofore rendered at any location. Service will not be supplied or continued to any premises if at the time of application for service the Applicant is merely acting as an agent of a person or former customer who is indebted to the Company for service previously supplied at the same, or other premises, until payment of such indebtedness shall have been made;

The Commission finds that the revised language regarding denial or discontinuance of service as filed on in the Supplemental Response on December 21, 2017, is reasonable and should be approved.

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[119] *See* H.V.T., PSC Exhibits 2, 3, 4, and 6.

RATE DESIGN, TARIFFS AND OTHER ISSUES

Rate Design

Kentucky Power filed a fully allocated jurisdictional cost-of-service study ("COSS") to determine the cost to service each customer class as well as the rate of return on rate base for each class during the test year. The results of the COSS illustrate the amount of cross-subsidization between the rate classes and show that all non-residential rate classes subsidize the residential class. In its Application, Kentucky Power proposed to reduce these subsidies by five percent in its proposed rates. The Settlement modifies this proposed revenue allocation and proposes to use the first $5.8 million of any Commission-authorized revenue increase to the Industrial General Service ("IGS") rate class to fully eliminate the subsidy Rate IGS would have paid under the rate increase as originally proposed by Kentucky Power.[120] The remaining revenue increase is spread uniformly among the rate classes, further reducing interclass subsides.[121]

The Attorney General did not offer any testimony concerning the allocation of any proposed revenue increase, aside from recommending limiting any revenue increase, and stating that Kentucky Power's customers are unable to afford a rate increase and that a large increase would set the entire economy of Eastern Kentucky back, counteracting any economic expansion.[122]

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[120] Satterwhite Settlement Testimony at S-9; Dec. 8, 2017 H.V.T. at 2:59:20; Direct Testimony of Stephen J. Baron ("Baron Testimony") at 15 and Table 2.

[121] Satterwhite Settlement Testimony at S-9.

[122] Dismukes Testimony at 3.

The KCUC does not support the revenue allocation as set forth in the Settlement, contending that the Settlement does not provide fair or reasonable treatment of the Tariff L.G.S. customer class. KCUC stated that in addition to bearing a subsidy burden associated with the overall rate structure, the L.G.S. class must also absorb an additional $500,000 subsidy resulting from the Public and Private School service ("PS") tariff.[123] To remedy this, the KCUC proposes that the first $500,000 of any additional Commission-directed decrease in the revenue requirement be applied to the Tariff L.G.S. customer class and any revenue reduction beyond $500,000 be uniformly spread among all the rate classes in proportion to each class's revenue requirement.[124]

Residential Customer Charge

In its Application, Kentucky Power proposed an increase in the residential customer charge from $11.00 to $17.50, an increase of 59 percent. The cost-of-service study filed by Kentucky Power in this proceeding supports a customer charge of $37.88.[125] The Settlement allows for an increase in the residential customer charge to $14.00, an increase of 27 percent.

The Attorney General objected to any increase on the residential customer charge.[126] The Attorney General contended that shifts towards fixed cost recovery disproportionally hurt low-income customers and Kentucky Power did not provide

[123] Settlement Testimony of Kevin Higgins ("Higgins Settlement Testimony") at 2.

[124] *Id.* at 4.

[125] Vaughan Direct Testimony, Exhibit AEV-2 at 1.

[126] Dismukes Testimony at 6.

sufficient evidence to justify an increase.[127] The Attorney General argued that Kentucky Power's fixed cost calculation of almost $38.00 is flawed because a portion of demand-related costs are assigned as fixed costs, which the Attorney General argued is fundamentally incorrect.[128] The Attorney General noted that none of the parties to the proposed Settlement represent the interests of residential ratepayers, and the proposed $14 would recover too much of any potential revenue increase through the customer charge and undermine future incentives for efficiency, resulting in an erosion of LIHEAP funds.[129]

The Commission believes an increase to the Residential Basic Service Charge is warranted, and finds that the Settlement's increase to $14.00 is reasonable. The proposed 27 percent increase is consistent with the principle of gradualism that the Commission has long employed. Consistent with this change, the Commission also approves the customer charges of $14.00 as set forth in the Settlement for the three optional residential tariffs: 1) Residential Service Load Management Time-of-Day; 2) Residential Service Time-of-Day; 3) and Experimental Residential Service Time-of-Day 2. The Commission also approves a customer charge of $14.50 for the new optional Residential Demand Metered Electric Service ("Tariff R.S.D.").[130]

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[127] *Id.*

[128] *Id.* at 20.

[129] Attorney General's Brief at 32-33.

[130] The Settlement and supporting testimony state that Kentucky Power and the Settling Intervenors agreed to a residential customer charge of $14.00. Settlement at paragraph 16(a); Satterwhite Settlement Testimony at S-22. The proposed Settlement Tariff R.S.D. filed on Dec. 1, 2017, inadvertently contains a monthly customer charge of $17.50.

General Service Rate Class

Kentucky Power proposed to combine the Small General Service ("S.G.S.") and Medium General Service ("M.G.S.") rate classes into a single General Service ("G.S.") rate class under which all general service customers with average demands up to 100 kilowatts ("kW") will take service. Kentucky Power stated that both the S.G.S. and M.G.S. rate classes currently incur a monthly service charge and a blocked energy charge. Additionally, the M.G.S. rate class incurs a demand charge. Due to this current tariff structure, there is movement between the S.G.S. and M.G.S. rate classes as load characteristics vary month to month for many commercial customers. Kentucky Power stated that combining the S.G.S. and M.G.S. into a single tariff allows for administration efficiencies by eliminating this movement between the two rate classes.[131] The new G.S. tariff combines rate design features from the S.G.S. and M.G.S. tariffs, and will include a monthly service charge, two blocked energy charges, and a demand charge for monthly billing demand greater than 10 kW. The blocked energy charge transition point is 4,450 kilowatt hours ("kWh"). Kentucky Power stated that setting the kWh block at 4,450 kWh ensures that almost all usage that was billed under the current S.G.S. tariff will continue to be billed on an energy charge only and such a rate design will minimize bill impact on current S.G.S. and M.G.S. customers.[132]

Although the proposed rate design minimizes the impact on an average commercial customer, due to the proposed increase in the demand charge from $1.91

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[131] Vaughan Direct Testimony at 21.

[132] *Id.* at 21.

for all kW to $7.95 for all kW greater than 10 kW, it negatively affects customers whose load characteristics include low usage coupled with high demand.[133] The Commission believes that Kentucky Power's proposed increase in the demand charge of over 300 percent is excessive. For this reason, the Commission will minimize the impact on high demand commercial customers, apply a 2-step phase-in increase of demand rates, and limit the increase in year 2 to $6.00 per kW. In addition, Kentucky Power must identify and contact G.S. class customers whose average monthly demand is 25 kW or greater to meet to discuss the impacts of the rate increase on those customers' bills and analyze other tariff options, such as time-of-day rates, that may offer relief to these customers. Last, Kentucky Power should file with the Commission, within twelve months of this Order, a report listing the commercial customers who meet this load profile and the results of each meeting.

Rate Adjustment

In setting the rates shown in Appendix C, the Commission maintained the basic service charge for each class that was included in the Settlement. The reduction of Kentucky Power's revenue increase was allocated to the energy charges of those customer classes for which revenue increases were proposed. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set forth in the Settlement.

[133] Dec. 8, 2017 H.V.T. at 4:53:40.

Tariff Purchased Power Adjustment

In its Application, Kentucky Power proposed to include the following additional cost of service items to be tracked and recovered through Tariff P.P.A.: (1) PJM OATT charges and credits that it incurs or receives from its participation as a LSE in the organized wholesale power markets of PJM; (2) purchased power costs excluded from recovery through the FAC as a result of the purchased power limitation; and (3) gains and losses from incidental gas sales. In addition, Kentucky Power proposed to change Tariff P.P.A. from a monthly adjusting surcharge to an annually updated surcharge.

The Attorney General filed testimony stating that these cost-of-service items should continue to be collected through base rates as Kentucky Power has not demonstrated a compelling reason to have these items tracked and recovered through Tariff P.P.A.[134]

1. PJM LSE OATT Charges and Credits

Kentucky Power proposed to include the following PJM LSE transmission charges and credits to costs recoverable through Tariff P.P.A.: network integration transmission service ("NITS"); transmission owner scheduling system control and dispatch service ("TO"); regional transmission expansion plan ("RTEP"); point-to-point transmission service; and RTO start-up cost recovery. An adjusted level of the net OATT charges and credits in the amount of $74,377,364 will be included in base rates.[135] The amount above or below the base rate level would be tracked monthly and the annual net over- or under-collection would then be collected from or credited to customers through the operation of Tariff P.P.A.

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[134] Smith Testimony at 70.

Kentucky Power stated that the proposed tracking mechanism for PJM OATT LSE Charges is necessary due to the volatility of these PJM charges and credits, which Kentucky Power claimed are largely out of its control. Kentucky Power estimated that its PJM OATT LSE expenses will increase in 2018 by approximately $14 million, or 19 percent over the test year amount.[136] Kentucky Power expects increasing investment in the transmission grid by PJM member transmission owners, which will increase transmission charges allocated to LSEs in PJM. Kentucky Power stated that tracking the PJM LSE charges and credits via Tariff P.P.A. could preclude it from seeking more frequent rate cases.[137]

Finally, two proceedings currently before the FERC may affect the level of PJM LSE OATT charges incurred by Kentucky Power. One proceeding is a challenge to the ROE included in the AEP Zone formula, which determines the PJM transmission costs of service for the AEP Transmission Zone. Kentucky Power stated that at this time, any change resulting from this proceeding is not known and measurable. Therefore, an adjustment in this case is not possible. The second proceeding is a pending non-unanimous settlement regarding the cost allocation methodology historically used by PJM to allocate costs of transmission enhancement projects to the LSEs in its footprint. If approved, the proposed stipulation is expected to result in lower PJM LSE OATT

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[135] Vaughan Direct Testimony at 29.

[136] Satterwhite Settlement Testimony at S-14–S-15.

[137] Vaughan Direct Testimony at 27-28.

charges. However, the timing or magnitude of the possible cost allocation changes are not currently known.[138]

The Settlement revised the proposal regarding the PJM OATT LSE charges and credits as follows:

- Kentucky Power will recover and collect 80 percent of the annual over- or under-collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through Tariff P.P.A.

- Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100 percent of the difference between the return on its incremental transmission investments calculated using the FERC approved PJM OATT return on equity, and the return on its incremental transmission investments calculated using the 9.75 percent return on equity provided for in the settlement.

- The changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise extended by the Commission.

Due to the volatility of the OATT charges and credits, the Commission finds the proposal to include the PJM LSE transmission charges and credits to the costs recoverable through Tariff P.P.A., as modified in the Settlement, reasonable with one modification. When calculating the credit against the Annual PJM OATT LSE Recovery, the return on equity amounts used to calculate the incremental transmission investments shall be 9.7 percent, the Commission-approved ROE amount.

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[138] *Id.* at 28-29.

In conjunction with approving the PJM OATT LSE tracker, the Commission finds that the three-year stay-out provision in the Settlement is reasonable and should be accepted. In approving the tracker, the Commission addresses Kentucky Power's primary concern, raised in the last rate case and in this case, that an increase in major expenses not directly under Kentucky Power's control would result in more frequent rate cases.

Regarding proposed transmission projects at PJM, the Commission expects Kentucky Power to work through the PJM stakeholder process to protect its customer interests.

2. <u>FAC Purchased Power Limitations.</u>

Kentucky Power proposed to track, on a monthly basis, the amount of purchased power costs excluded for recovery through the FAC over or above the base rate level using deferral accounting. The annual net over- or under-collection of these purchase power costs would be collected from or credited to customers through Tariff P.P.A.[139]

The FAC Purchase Power Limitation is a calculation that caps the amount of purchase power expense to be recovered through the monthly FAC surcharge. The calculation compares the cost of actual purchased power on an hourly basis to the cost of Kentucky Power's highest cost unit or the theoretical peaking unit equivalent, and caps the FAC-recoverable purchase power expense at the cost ($/MWh) of the highest generating unit (Kentucky Power owned or peaking unit equivalent). Kentucky Power claims that, because it relies on factors outside of its control, the FAC Purchase Power Limitation and the peaking unit equivalent calculation promote variability and volatility.

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[139] *Id.* at 29.

The Commission is not convinced that this issue requires special ratemaking treatment. The Commission has long held that any purchased power costs not recoverable through the FAC are eligible for recovery through base rates. The Commission finds Kentucky Power's proposal to include an estimated amount of FAC Purchased Power Limitation Expense in base rates, and to subsequently true up that amount through Tariff P.P.A., is unreasonable, and therefore should be denied. The Commission notes that Kentucky Power filed this case using a historic test period. The Commission will allow recovery of the test year amount of purchased power reasonably incurred, but excluded from the FAC. To the extent that Kentucky Power incurs any expense due to purchased power that is appropriately incurred after the test year, but excluded from the FAC, it can file a base rate case seeking recovery of those expenses. For the foregoing reasons, adjustments W26 and W27, which total $4,032,786, are unreasonable and should be removed from the revenue requirement.

3. Peaking Unit Equivalent Calculation

Kentucky Power proposed to change the methodology for calculating the peaking unit equivalent ("PUE") used in determining the FAC Purchased Power Limitation. In its Application, Kentucky Power proposes to include the cost of firm gas service as an expense in the calculation of its PUE. Kentucky Power stated that since the hypothetical combustion turbine ("CT") could be dispatched any day of the year, it requires firm gas service. The Commission disagrees. While firm gas service would certainly allow the CT to be dispatched any day of the year, the Commission is unaware of any jurisdictional utility utilizing firm gas service for a CT. Because CTs typically operate at low capacity factors and are primarily utilized during the summer peaking months, when pipeline capacity would typically not be constrained, the Commission finds the inclusion of firm gas service in the calculation of the PUE to be unreasonable, and therefore, this change in the PUE calculation should be denied. Kentucky Power's proposal to include startup costs and variable O&M expense is reasonable and should be approved.

4. Gains and Losses from Incidental Gas Sales.

Kentucky Power proposed to recover gains and losses from incidental sales of natural gas through Tariff P.P.A. Kentucky Power nominates Big Sandy Unit 1 in the PJM day-ahead electric power market based in part on the price of natural gas purchased for delivery the next day. If the Big Sandy Unit 1 Day Ahead nomination price is higher than the PJM electric power market clearing price, Big Sandy Unit 1 is not selected to run in the Real Time Market. In such a case, the natural gas purchased must either be stored by Columbia Gas or be sold. Kentucky Power stated that in August, September, and November of 2016, there were days that it was required to sell natural gas that had been purchased for delivery because Big Sandy Unit 1 was not selected by PJM to run.[140]

In Case No. 2014-00078, Duke Energy Kentucky ("Duke Energy") proposed similar treatment of gains and losses it experienced in January and February of 2014 from incidental sales of natural gas.[141] Duke Energy amended its request to apply to similar losses or gains occurring in the future. The Commission approved the treatment of the January and February 2014 gains and losses. However, the Commission found

[140] Application, Direct Testimony of John A. Rogness at 26-27

[141] Case No. 2014-00078, *An Investigation of Duke Energy Kentucky, Inc.'s Accounting Sale of Natural Gas Not Used in Its Combustion Turbines* (Ky. PSC Nov. 25, 2014).

Duke Energy's proposal to apply such treatment to similar losses or gains in the future to be overly broad and did not approve such treatment, finding that such gains and losses should be investigated on a case-by-case basis.

In this case, the Commission finds, as it did in Case No. 2014-00078, that gains and losses from the incidental sale of natural gas should be investigated on a case-by-case basis. If such gains or losses occur in the future, Kentucky Power should notify the Commission so those matters may be addressed in a formal proceeding. For purposes of this case, the Commission finds that the gain on the incidental sale of natural gas of $13,982 should be utilized to reduce Kentucky Power's revenue requirement.

Tariff K-12 School

In its Application, Kentucky Power proposed to discontinue the pilot Tariff K-12 School under which public schools in Kentucky Power's service territory took service under discounted rates. Kentucky Power stated that its load research and class cost of service study demonstrated that Tariff K-12 School customers would be better off in the Tariff L.G.S. customer class than they were previously a part of prior to the pilot Tariff K-12.

Tariff Pilot K-12 School was approved as part of the settlement agreement in Case No. 2014-00396. In Case No. 2014-00396, KSBA argued, as it does in this proceeding, that public school load characteristics were sufficiently unique to justify a distinct rate class for K-12 schools. Because school load data did not exist, Kentucky Power agreed to establish a pilot tariff with load research meters at 30 K-12 schools.

Kentucky Power further agreed to evaluate whether to continue Tariff K-12 School in its next base rate case using the load research data.

Tariff K-12 School rates were designed to produce an annual revenue requirement that was $500,000 less than would be produced under the L.G.S. rates from customers eligible to take service under Tariff K-12 School.[142] Tariff L.G.S. and Tariff M.G.S. customers rates were designed to include the $500,000 subsidy to Tariff K-12 Schools.[143]

Under the Settlement, Tariff K-12 School would cease to be a pilot, and would continue as a separate rate class. The tariff would be available to all K-12 schools, public and private, in Kentucky Power's service territory with normal maximum demands greater than 100 kW. Tariff K-12 School rates continue to be designed with a $500,000 subsidy absorbed by Tariff L.G.S. customers.

In its Settlement Testimony, KCUC asserted that the Settlement is unfair and unreasonable because L.G.S. customers had to absorb the subsidy to provide a $500,000 benefit for Tariff K-12 School customers, in addition to a significant inter-class subsidy burden as part of the overall rate structure.[144] KCUC stated that it did not object to the $500,000 discount to Tariff K-12 School customers, but instead objected that the discount is funded by L.G.S. customers, and not spread out among all customer classes. As a remedy, KCUC proposed that, if the Commission reduced the revenue requirement, that the first $500,000 of any reduction be applied first to reduce the revenue requirement of the L.G.S. class.

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[142] Case No. 2014-00396, Final Order, at 19.

[143] *Id.*

The Commission finds that load research data collected and analyzed by Kentucky Power demonstrates that a separate, discounted K-12 schools tariff is not justified and that public school usage characteristics do not support the discounted rates paid by Tariff K-12 School customers relative to the L.G.S. class. The Commission finds that it is unreasonable to continue Tariff K-12 School, and therefore rejects this portion of the Settlement.

Green Pricing Option Rider/Renewable Power Option Rider

Kentucky Power proposed to revise its Green Pricing Option Rider to expand the categories of renewable energy credits available, to allow participating customers to purchase their full requirements from renewable energy generators, and to change the name of the rider to the Renewable Power Option Rider ("Rider R.P.O"). The Commission finds that the Rider R.P.O. provision in the Settlement is reasonable and should be approved.

Tariff C.A.T.V.

In its Application, Kentucky Power proposed to increase Tariff C.A.T.V. rates for pole attachments on a two-user pole from $7.21 per year to $11.97 per year, and for pole attachments on a three-user pole from $4.47 per year to $7.52 per year. In the Settlement, Kentucky Power and the Settling Intervenors agreed to a rate of $10.82 per year for attachments on a two-user pole, and $6.71 per year for attachments on a three-user pole.

The Commission finds that the rates for Tariff C.A.T.V. as set forth in the Settlement are reasonable and should be approved.

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[144] Higgins Settlement Testimony at 2.

Temporary Service Tariff

In its Application, Kentucky Power proposed to revise its Temporary Service Tariff ("Tariff T.S.") to limit service provided under Tariff T.S. to ensure that customers do not continue to take service under Tariff T.S. even after construction is complete and the facility is occupied. The Commission finds these changes to be reasonable and that they should be approved.

Optional Residential Demand Charge Tariff

Kentucky Power proposed a new optional residential rate schedule ("Tariff R.S.D.") that will be available to up to 1,000 residential customers. The rate structure will consist of a monthly service charge, on-peak and off-peak kWh energy charges, and an on-peak kW demand charge. Kentucky Power stated that the goal of Tariff R.S.D. is to send targeted price signals that will reward customers for shifting usage away from the peak time periods that cause Kentucky Power to incur higher costs. Kentucky Power also stated that certain electric heating customers may benefit from Tariff R.S.D. due to their potentially higher load factor usage characteristics, and that the rate design is revenue neutral to the standard residential tariff.[145]

The Commission finds the proposed Tariff R.S.D. to be reasonable, that it should be approved, and that the rates included in Appendix C of this Order should be approved.

Tariff C.S.-Coal, Tariff C.S.-I.R.P. and Tariff E.D.R.

The Settlement extends through December 31, 2018, Tariff C.S.-Coal and the amendments to Tariff C.S.-I.R.P. and Tariff E.D.R., which were due to expire December

[145] Vaughan Direct Testimony at 19

31, 2017. The Commission finds the extension of the tariffs reasonable and that they should be approved. Any financial loss incurred in connection with these tariffs will be deferred for review and recovery in Kentucky Power's next base rate proceeding.

ENVIRONMENTAL COMPLIANCE PLAN

In its Application, Kentucky Power requested Commission approval of an amended environmental Compliance Plan ("2017 Plan") and an amended Environmental Surcharge tariff ("Tariff E.S.").

The 2017 Environmental Compliance Plan

The 2017 Plan includes previously approved projects and two new projects, Project 19 and Project 20. The 20 projects included in the 2017 Plan are listed in Appendix D to this Order.

Project 19 will install SCR technology at Rockport Unit 1 ("Rockport Unit 1 SCR Project"). The Rockport Unit 1 SCR project will reduce the plant's nitrogen oxide emissions, and is required under terms of a 2007 Consent Decree ("Consent Decree") among several AEP entities including Kentucky Power and I&M, and the Environmental Protection Agency and several environmental plaintiffs.

Project 20 seeks to include a return on inventories for consumables used in conjunction with approved projects through Tariff E.S. Kentucky Power currently recovers the cost of the consumption of consumables through Tariff E.S. The return on consumable inventories is currently part of the general rate base. Kentucky Power proposed that the return on consumable inventories be recovered through Tariff E.S. to align that cost with the cost recovery of items consumed.

Kentucky Power stated that the pollution control projects included in the 2017 Plan amendment are necessary to comply with the Federal Clean Air Act ("CAA") and other federal, state, and local regulations that apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal. Kentucky Power asserted that the costs associated with its 2017 Plan are reasonable, and that the projects are a reasonable and cost-effective means to comply with environmental requirements.

The Attorney General argued that Kentucky Power should not be permitted to recover the cost of the Rockport Unit 1 SCR Project.[146] The Attorney General asserted that Kentucky Power's customers have been paying increasing amounts for environmental costs resulting from the Consent Decree because AEP voluntarily made environmental upgrades at generating stations, including the Rockport generating units, that were not identified in the original EPA litigation that led to the Consent Decree. Because Rockport was not part of the original litigation, the Attorney General asserts Kentucky Power should not recover the costs for the Rockport Unit 1 SCR project from its ratepayers.

In rebuttal, Kentucky Power stated that the decision to include Rockport in the Consent Decree settlement was a way to remove the significant risk of additional litigation at those units not named in any pending complaints, as well as to provide a more favorable outcome than would be expected on an individual basis.[147] Kentucky Power further stated that the Consent Decree provided certainty regarding the timing of

[146] Smith Testimony at 59.
[147] Rebuttal Testimony of John McManus at 3.

additional control installations across the AEP fleet. At the time of the settlement, Kentucky Power was still participating in the AEP Pool, which meant that the outcome of litigation involving all units across the AEP fleet contributing to the pool was in the best interest of Kentucky Power and its customers.

The Settlement was silent on the 2017 Environmental Compliance Plan.

The Commission finds that the 2017 Plan is reasonable as set forth in the Application and should be approved.

ENVIRONMENTAL SURCHARGE TARIFF MODIFICATIONS

Kentucky Power updated its Tariff E.S. to reflect the changes proposed in its Application and the Settlement. Kentucky Power updated the list of projects in the tariff to match the projects included in the 2017 Plan as noted previously in this Order. Kentucky Power updated Tariff ES to reflect the rate of return included in the Settlement to this case. Kentucky Power also updated the tariff to reflect the new monthly base environmental costs based on that rate of return. Kentucky Power determined the annual base revenue requirement level for environmental cost recovery to be $47,513,461.[148] The Commission has determined that the correct annual base revenue requirement is $44,379,316, which reflects the Commission authorized return on equity, capital structure changes, reduction of the federal corporate income tax rate from 35 percent to 21 percent and the depreciation rates set forth in Exhibit 5 of the

[148] In the Tariff E.S. filed December 1, 2017, Kentucky Power reflected an annual base revenue requirement of $47,811,215. Kentucky Power updated this amount to $47,513,461 to reflect the depreciation rates included in Exhibit 5 to the Settlement Agreement. See Response to Commission Staff's Post-Hearing Request for Information ("Staff's Post-Hearing Request"), Item 20 attachment KPCO_R_KPSC_PH_20_Attachment1.xls.

Settlement.[149] Kentucky Power shall file a revised Tariff ES to reflect the Commission authorized return on equity and capitalization discussed in this Order, and the annual base revenue requirement as shown on Appendix E attached to this order. Per the settlement agreement in Case No. 2012-00578,[150] all costs associated with the Mitchell FGD equipment are excluded from base rates and therefore are not included in the base revenue requirement noted above, but will be included as part of the current period environmental revenue requirement. The Commission finds that Tariff E.S. as discussed and modified in this Order should become effective for service rendered on and after the date of this Order.

Costs Associated with the 2015 Plan

Tariff E.S. revenue requirement is determined by comparing the base period revenue requirement with the current period revenue requirement. Kentucky Power proposed to incorporate the costs associated with the 2017 Plan into the existing surcharge mechanism used for previous compliance plans. Kentucky Power identified the environmental compliance costs for the 2017 Plan projects, which Kentucky Power proposed to recover through its environmental surcharge. Kentucky Power proposed to apply a gross-up factor to environmental expenses to account for uncollectible accounts and the Commission assessment fee. The factor will be applied to the incremental change in operating, maintenance, and other expenses from the base period. The

[149] Response to Staff's Post-Hearing Request, Item 20.

[150] Case No. 2012-00578, *Application of Kentucky Power Company for (1) a Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Associated Assets; (2) Approval of the Assumption by Kentucky Power Company of Certain Liabilities in Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred in Connection with the Company's Efforts to Meet Federal Clean Air Act and Related Requirements; and (5) All Other Required Approvals and Relief* (Ky. PSC Oct. 7, 2013).

costs identified by Kentucky Power are eligible for surcharge recovery if they are shown to be reasonable and cost-effective for complying with the environmental requirements specified in KRS 278.183. The Commission finds that the costs identified for the 2017 Plan projects have been shown to be reasonable and cost-effective for environmental compliance. Thus, they are reasonable, and should be approved for recovery through Kentucky Power's environmental surcharge.

Qualifying Costs

As stated previously, the qualifying costs included in Kentucky Power's annual baseline level for environmental cost recovery under the tariff shall be $44,379,316. The qualifying costs included in the current period revenue requirement will reflect the Commission-approved environmental projects from Kentucky Power's 1997, 2005, 2007, 2015 and 2017 Plans. Per the settlement agreement in Case No 2012-00578, all costs associated with Mitchell Units 1 and 2 FGD equipment have been excluded from base rates and the environmental baseline level and shall be recovered exclusively through Tariff E.S. Should Kentucky Power desire to include other environmental projects in the future, it will have to apply for an amendment to its approved compliance plans.

Rate of Return

Paragraph 8(a) of the Settlement authorizes Kentucky Power to use a 9.75 percent ROE to be utilized in Tariff E.S. to determine the WACC for non-Rockport environmental projects. However as previously noted, the Commission has authorized a 9.70 percent ROE that should be used for all non-Rockport environmental projects.

Kentucky Power's ROE for environmental projects at the Rockport Plant is 12.16 percent as established by the FERC-approved Rockport Unit Power Agreement.

Capitalization and Gross Revenue Conversion Factor

Paragraph 3(c) and Exhibit 6 of the Settlement provide that Kentucky Power shall utilize a WACC of 6.48 percent and a gross revenue conversion factor ("GRCF") of 1.6433 to determine a rate of return of 9.11 percent to be used in the monthly environmental surcharge filings. As a result of the reduction of the federal corporate tax rate from 35 percent to 21 percent, the Commission has determined that Kentucky Power should use a GRCF of 1.352116. Because of the change in the authorized ROE, capitalization, and the GRCF, the WACC to be used for non-Rockport environmental projects is 6.44 percent. Utilizing a WACC of 6.44 percent and a GRCF produces a rate of return of 7.88 percent to be used in the monthly environmental surcharge filings. The WACC and GRCF shall remain constant until the Commission sets base rates in Kentucky Power's next base rate case proceeding.

Surcharge Formulas

The inclusion of the 2017 Plan into Kentucky Power's existing surcharge mechanism will not result in changes to the surcharge formulas. The costs associated with the Mitchell FGD will be excluded from base rates and the base rate revenue requirement of the environmental surcharge at least until June 30, 2020, but will be included in the current period revenue requirement for the environmental surcharge. The Commission finds that the formulas used to determine the environmental surcharge revenue requirement as proposed by Kentucky Power should be approved.

Surcharge Allocation

The retail share of the revenue requirement will be allocated between residential and non-residential customers based upon their respective total revenue during the previous calendar year. The environmental surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

Monthly Reporting Forms

The inclusion of the 2017 Plan into the existing surcharge mechanism will require modifications to the monthly environmental surcharge reporting forms. Kentucky Power provided its proposed revised forms to be used in the monthly environmental reports. The revised forms include the changes necessary to reflect the proposed 2017 Plan, as well as changes necessitated by the application of a gross-up factor to the incremental operating, maintenance and other expenses. The Commission finds that Kentucky Power's proposed monthly environmental surcharge reporting forms as revised should be approved.

FINDINGS ON SETTLEMENT AGREEMENT

Based upon a review of all the provisions in the Settlement, an examination of the entire record, and being otherwise sufficiently advised, the Commission finds that the provisions of the Settlement are in the public interest and should be approved, subject to the modifications as discussed in this Order. Our approval of the Settlement as modified is based solely on its reasonableness and does not constitute precedent on any issue except as specifically provided for in this Order.

OTHER ISSUES

Vegetation Management

Kentucky Power's current Vegetation Management Plan ("2015 Vegetation Management Plan") was modified from its 2010 Vegetation Management Plan in Kentucky Power's last rate case, Case No. 2014-00396. In Case No. 2014-00396, it was determined that funding for the 2010 Vegetation Management Plan, which was scheduled to move to a four-year cycle within seven years of initial circuit clearing, needed modification. However, the work required to transition to a four-year cycle was significantly greater than initially estimated, and Kentucky Power could not wait until all circuits had an initial clearing ("Task 1") to begin re-clearing the circuits. Thus, the modification was approved allowing the continuation of Task 1 and a simultaneous undertaking of interim re-clearing ("Task 2"). Under this schedule, Task 1 would be completed by December 31, 2018, Task 2 would be completed by June 30, 2019, and on July 1, 2019, Kentucky Power's entire distribution system would commence to be re-cleared on a five-year cycle ("Task 3"), rather than a four-year cycle. Funding was approved for the 2015 Vegetation Management Plan, as well as a provision requiring Kentucky Power to obtain Commission approval prior to modifying its annual projected vegetation management spending on both an aggregate and a district basis if the change is more than 10 percent of the budget.

Kentucky Power is on pace to exceed the December 31, 2018 target for Task 1, and expects to complete Task 1 circuit clearing in the first quarter of 2018. In addition, Task 2 circuit re-clearing is expected to be completed by December 31, 2018, six months sooner than projected. To date, Kentucky Power has exceeded targets on budget as total expenditures are 101 percent of target level.[151] Reliability has increased

[151] Application, Direct Testimony of Everett G. Phillips ("Phillips Testimony") at 35.

and Kentucky Power customers have seen a 60 percent decrease in interruptions related to rights-of-way trees and vegetation.[152] Task 3 is estimated to begin in January 2019.

Embedded in Kentucky Power's current base rates are annual vegetation management O&M expenses of $27.661 million. Due to early completion of Tasks 1 and 2, Kentucky Power estimates a reduction of O&M expenses related to Tasks 1 and 2 from $27.661 million in 2017 to $21.639 million 2018. According to the 2015 Vegetation Management Plan, at the start of Task 3, O&M expenses are projected to decrease, resulting in a decrease of O&M expenses of $11.780 million. However, Kentucky Power has determined that the estimates of the annual O&M expenditures for Task 3 as estimated in the 2015 Vegetation Management Plan are undervalued and need to be increased.[153] Due to the re-clearing in Task 2, Kentucky Power now has a better grasp on regrowth, the effect of higher-than-average rainfall, and growing customer demand to remove tree debris, and proposes to increase the annual O&M expenses for Task 3. This re-estimation calculates costs for Task 3 to increase from the original $15.880 million to $21.284 million in 2019, and $21.473 in 2020.[154] Kentucky Power proposes the amount of vegetation management O&M expenses to be recovered through base rates for the instant case to be equal to the average of the revised estimated annual vegetation management plan O&M spending over 2018-2020, or $21.465 million.[155]

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152 *Id* at 40.

153 *Id.*

154 *Id.* at 46

Kentucky Power also proposes two changes to its current vegetation management reporting requirements. First, Kentucky Power proposes to modify the pre-approval requirement for deviation of 10 or more percent from projected annual vegetation management O&M expenditures to eliminate the district-specific threshold and retain only the requirement for pre-approval if overall Kentucky Power vegetation management expenditures deviate more than 10 percent. Second, Kentucky Power proposes to manage its vegetation work and expenditures on a calendar year basis, as opposed to managing its vegetation work on a fiscal year and expenditures on a calendar year. Kentucky Power stresses that neither modification will change their overall vegetation management obligation, but provides for more flexibility to manage its obligations.[156]

The 2015 Vegetation Management Plan included a one-way balancing account. In this balancing account, any annual shortfall or excess in vegetation management O&M expenditures that is over the amount in base rates is added to or subtracted from future expenditures over four years. At the end of the four-year period, Kentucky Power will record a cumulative shortfall as a regulatory liability that will either be refunded to the customers or used to reduce the revenue requirement in its next filed base-rate case. If Kentucky Power has overspent on a cumulative basis during the four-year period, it will not seek recovery of such costs in a future base-rate proceeding. As of the end of November 2017, Kentucky Power testified that cumulative expenditures were slightly over the budgeted amount.[157]

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[155] Application, Section V, Exhibit 2, page 59.

[156] *Id.* at 43.

The Commission finds that the one-way balancing adjustment should be continued; however due to the change in the annual revenue requirement as noted in the Application, it should be adjusted accordingly. All expenses will be recorded against the annual budget. The annual shortfall or excess will be applied to the balance account. Through 2023, or until Kentucky Power's next base rate application, whichever occurs first, the expenditures will be balanced against the annual projected expenditures as found in the Application.[158]

The Commission approves the proposed modifications allowing Kentucky Power to request Commission approval for any spending deviation greater than 10 percent on an aggregate level as opposed to a district level. The Commission also approves Kentucky Power's request to manage its vegetation management program on a calendar year basis to coincide with the budgetary year. The Commission notes that Kentucky Power has exceeded the goals of the 2015 Vegetation Management Plan resulting in a reduction of O&M expenses 24 months earlier than estimated. The Commission approves Kentucky Power's proposed revenue requirement of $21.465 million. All other provisions of the 2015 Vegetative Management Plan are to remain unchanged.

The Commission will continue to review closely the vegetation management annual work plans and expenditures filed by Kentucky Power. In addition, the Commission will monitor the progress of the five-year maintenance cycle.

<u>Bill Redesign</u>

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[157] Dec. 8, 2017 H.V.T. at 2:09:38.

[158] Phillips Testimony, Table 9 at 46.

On June 12, 2017, Kentucky Power filed an Application requesting approval to implement new bill formats that change the bill layout and composition, which is being implemented concurrently for all AEP operating companies, and to combine certain billing line items. That Application was docketed as Case No. 2017-00231.[159] By Order dated July 17, 2017, that case was consolidated into this proceeding. By further Order dated September 12, 2017, the Commission approved Kentucky Power's request to redesign the appearance of its bills, but stated that a decision on the proposed substantive changes to consolidate billing line items would be determined in the final Order in this proceeding.

Kentucky Power proposed to consolidate eight residential billing line items,[160] and seven commercial and industrial billing line items[161] into a single "Rate Billing" line item. Kentucky Power explained that customer satisfaction regarding billing correspondence was below the industry average according to a survey commissioned by Kentucky Power.[162] Kentucky Power asserted that its customers found the number of billing line

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[159] Case No. 2017-00231, *Electronic Application of Kentucky Power Company for (1) Approval of Its Revised Terms and conditions of Service Implementing New Bill Formats; (2) An Order Granting All other Required Approvals and Relief* (filed June 12, 2017).

[160] The residential billing line items Kentucky Power proposes to consolidate into a single line items are Rate Billing, Residential Home Energy Assistance Program Charge, Kentucky Economic Development Surcharge, Capacity charge, Big Sandy 1 Operation Rider, Big Sandy Retirement Rider, Purchased Power Adjustment, and Green Pricing Option. The residential charges that Kentucky Power proposes to continue to display as individual billing line items are the Fuel Adjustment Charge, Demand-Side Management Factor, Environmental Surcharge, School Tax, Franchise Fee, State Sales tax, and HomeServe Warranty.

[161] The commercial and industrial billing line items Kentucky Power proposes to consolidate into a single line items are Rate Billing, Kentucky Economic Development Surcharge, Capacity charge, Big Sandy 1 Operation Rider, Big Sandy Retirement Rider, Purchased Power Adjustment, and Green Pricing Option. The commercial and industrial charges that Kentucky Power proposes to continue to display as individual billing line items are the Fuel Adjustment Charge, Demand-Side Management Factor, Environmental Surcharge, School Tax, Franchise Fee, and State Sales tax.

[162] Case No. 2017-00231, Direct Testimony of Stephen L. Sharp, Jr. (filed June 12, 2017) at 2.

items were "unhelpful," made the bills "difficult to understand," and obscured the information customers most wanted to know, which was the total amount owed and payment due date.[163] Kentucky Power further asserted that customers requested that line items be consolidated in order to simplify the bills. Customers who want detailed billing information could contact a Kentucky Power customer service center.

In the Settlement, the Settling Intervenors agreed to Kentucky Power's proposed consolidation of billing line items.

Neither KCUC nor the Attorney General filed testimony in this proceeding regarding the consolidation of billing line items. However, in a motion filed in Case No. 2017-00231 before it was incorporated into this proceeding, the Attorney General argued that consolidating the billing line items would result in a lack of transparency that impeded customers' understanding of how rates and their bills are calculated.[164]

The Commission finds that Kentucky Power's proposed consolidation of billing line items is unreasonable and should be denied. The Commission concurs with the Attorney General that displaying discrete billing line items on customer bills promotes transparency and customer understanding of their billing amounts. Further, it is not reasonable to require customers to take additional steps in order to obtain a detailed accounting for their bills. This is especially so given that the billing line items that Kentucky Power wishes to consolidate represent charges in addition to the base rate charge for utility service.

<u>Analysis of Kentucky Power's Participation in PJM</u>

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[163] *Id.* at 3; *Id.* at Application, paragraph 11.

Kentucky Power currently elects to self-supply its PJM capacity requirements under the Fixed Resource Requirement ("FRR") alternative. As discussed in testimony at the hearing, AEP conducts regular evaluations to determine whether its operating companies in PJM should elect to participate in the Reliability Pricing Model ("RPM") capacity market, or to self-supply under FRR.[165]

The Commission finds that Kentucky Power should file an annual update of the FRR/RPM election analysis. The Commission recognizes that this information is deemed confidential during the AEP internal decision-making process. However, once PJM is notified of the election, the information becomes public and ceases to be confidential. Kentucky Power should file the annual update after the information becomes public.

Further, the Commission recognizes that Kentucky Power's interests may not be aligned with the interests of other AEP operating companies. The Commission is aware that PJM bills AEP based on a one-coincident peak methodology, and that AEP subsequently allocates those costs to its operating companies using a twelve-coincident peak methodology. The Commission finds that Kentucky Power should file an annual report with the supporting calculations used by AEP to allocate these costs.

Last, the Commission strongly encourages Kentucky Power to recognize that it must make a determination regarding its participation in PJM that aligns with the interests of Kentucky Power and its ratepayers.

Reduction in Corporate Tax Rates

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[164] Case No. 2017-00231, Attorney General's Motion to Consolidate Cases (filed July 13, 2017) paragraphs 4-5.

[165] Dec. 7, 2017 H.V.T. at 10:43:18, and Kentucky Power Exhibit 9.

Effective January 1, 2018, the federal corporate income tax rate was reduced from 35 percent to 21 percent. Consistent with Kentucky Power's revised gross-up factor calculation in certain riders, the Commission finds that it is reasonable to utilize the 21 percent corporate income tax rate in the gross-up factor calculation. The Commission will address the impact of the recently enacted tax cuts on the excess ADIT and the rates of all investor-owned utilities, including Kentucky Power, on a prospective basis in pending cases that were opened on December 27, 2017.[166]

Based on the evidence of record and the findings contained herein, HEREBY ORDERS that:

1. The rates and charges proposed by Kentucky Power are denied.

2. The provisions in the Settlement, as set forth in Appendix A to this Order, are approved, subject to the modifications and deletions set forth in this Order.

3. The rates and charges for Kentucky Power, as set forth in Appendix C to this Order, are the fair, just, and reasonable rates for Kentucky Power, and these rates are approved for service rendered on and after January 19, 2018.

4. Kentucky Power's request to deviate from 807 KAR 5:006, Section 14(2)(a) by limiting enrollment in its Equal Payment Plan to the months of April through December is granted.

5. Kentucky Power's proposed depreciation rates, with the exception of the changes proposed in the Settlement are approved.

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[166] Case No. 2017-00477, *Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company, and Duke Energy Kentucky, Inc.* (Ky PSC Dec. 27, 2017); Case No. 2017-00481, *An Investigation of the Impact of the Tax Cuts and Job Act on the Rates of Atmos Energy Corporation, Delta Natural Gas Company, Inc., Columbia Gas of Kentucky, Inc., Kentucky-American Water Company, and Water Service Corporation of Kentucky* (Ky. PSC Dec. 27, 2017).

6. The regulatory asset or liability account established by under- or over-recovery from the elimination of Tariff B.S.1.O.R. is approved for accounting purposes only.

7. The regulatory asset account established by the deferral of Rockport UPA expenses is approved for accounting purposes only.

8. Kentucky Power's 2017 Environmental Compliance Plan is approved.

9. Kentucky Power's environmental surcharge tariff is approved for service rendered on and after the date of this Order.

10. The base period and current period revenue requirements for the environmental surcharge shall be calculated as described in this Order.

11. The environmental reporting formats described in this Order shall be used for the monthly environmental surcharge filings. Previous reporting formats shall no longer be submitted.

12. The Commission approves the sample forms that were filed by Kentucky Power on January 3, 2018.

13. Within three months of the date of this Order, Kentucky Power shall identify and contact GS class customers whose average monthly demand is 25 kW or greater for the purpose of meeting to discuss the impact of the rate increase on their bills and analyze other available tariff options, such as time-of-day rates.

14. Within twelve months of the date of this Order, Kentucky Power shall file a report listing the names of each GS class customers whose average monthly demand is 25 kW or greater, and stating the date and method of contact with the customer, whether Kentucky Power has met with the customer, and the results of each meeting.

15. Kentucky Power's request to revise its billing format to consolidate billing line items, as set forth in the application, is denied.

16. Kentucky Power's Vegetation Management Plan, as set forth in the Application, is approved.

17. Kentucky Power's request to obtain Commission approval for any spending deviation from its Vegetation Management Plan greater than 10 percent on an aggregate level as opposed to a district level is approved.

18. Kentucky Power's request to manage its Vegetation Management Plan on a calendar year basis is approved.

19. Kentucky Power shall file an annual update of the FRR/RPM election analysis conducted by AEP and its operating companies within 30 days of notifying PJM of the election.

20. Kentucky Power shall file annually the supporting calculations for allocating PJM bills, which are based on a one-coincident peak methodology, AEP's operating companies using a twelve-coincident-peak methodology.

21. Within 20 days of the date of this Order, Kentucky Power shall, using the Commission's electronic Tariff Filing System, file its revised tariffs setting out the rates authorized herein and reflecting that they were approved pursuant to this Order.

By the Commission

ENTERED

JAN 18 2018

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Gwen R. Pinson

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

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 Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

SETTLEMENT AGREEMENT

This Settlement Agreement, made and entered into this 22nd day of November, 2017, by and among Kentucky Power Company ("Kentucky Power" or "Company"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA"); (collectively Kentucky Power, KIUC, KSBA, KLC, Wal-Mart, and KCTA, are "Signatory Parties").

RECITALS

1. On June 28, 2017 Kentucky Power filed an application pursuant to KRS 278.190, KRS 278.183, and the rules and regulations of the Public Service Commission of Kentucky ("Commission"), seeking an annual increase in retail electric rates and charges totaling $69,575,934, seeking approval of its 2017 Environmental Compliance Plan, an order approving accounting practices to establish regulatory assets or liabilities, and further seeking authority to implement or amend certain tariffs ("June 2017 Application").

2. On August 8, 2017, Kentucky Power supplemented its filing to reflect the impact of subsequent refinancing activities on the Company's Application ("August 2017 Refinancing Update"). The refinancing activities reduced the Company's requested annual increase in retail electric rates and charges from $69,575,934 to $60,397,438.

3. KIUC, KSBA, KLC, Wal-Mart, and KCTA filed motions for full intervention in Case No. 2017-00179. The Commission granted the intervention motions. Collectively KIUC, KSBA, KLC, Wal-Mart, and KCTA are referred to in this Settlement Agreement as the "Settling Intervenors."

4. The Attorney General of the Commonwealth of Kentucky ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") also filed motions to intervene. The Attorney General and KCUC, who are not parties to this agreement, were granted leave to intervene.

5. Certain of the Settling Intervenors, KCUC, and the Attorney General filed written testimony in Case No. 2017-00179 raising issues regarding Kentucky Power's Rate Application.

6. Kentucky Power, KCUC, the Attorney General, and the Settling Intervenors have had a full opportunity for discovery, including the filing of written data requests and responses.

7. Kentucky Power offered the Settling Intervenors, KCUC, and the Attorney General, along with Commission Staff, the opportunity to meet and review the issues presented by Kentucky Power's application in this proceeding and for purposes of settlement.

8. The Signatory Parties execute this Settlement Agreement for purposes of submitting it to the Kentucky Public Service Commission for approval pursuant to KRS 278.190 and KRS 278.183 and for further approval by the Commission of the rate increase, rate structure, and tariffs as described herein.

9. The Signatory Parties believe that this Settlement Agreement provides for fair, just, and reasonable rates.

NOW, THEREFORE, for and in consideration of the mutual promises set forth above, and the agreements and covenants set forth herein, Kentucky Power and the Settling Intervenors hereby agree as follows:

AGREEMENT

1. Kentucky Power's Application

(a) Except as modified in this Settlement Agreement, Kentucky Power's June 2017 Application as updated by the August 2017 Refinancing Update is approved.

2. Revenue Requirement

(a) Effective for service rendered on or after January 19, 2018, Kentucky Power shall implement a base rate adjustment sufficient to generate additional annual retail revenues of $31,780,734. This annual retail revenue amount represents a $28,616,704 million reduction from the $60,397,438 sought in the Company's August 2017 Refinancing Update.

(b) The $28,616,704 million reduction was the result of the following adjustments to the Company's request in the June 2017 Rate Application as modified in the August 2017 Refinancing Update:

Adjustment	Reduction in Revenue Requirement ($Millions)
Defer a portion of Rockport UPA non-fuel, non-environmental expenses	15.0
Increase revenues to Apply Weather Normalization to Commercial Sales Net of Variable O&M	0.40
Reduce Incentive Compensation	3.15
Reduce Amortization Expense to Recalibrate Storm Damage Amortization	1.22

Reduce Depreciation Expense by Extending Service Life of BS1 to 20 years	2.84
Reduce Depreciation Expense by Removing Terminal Net Salvage for BSU1	0.37
Reduce Depreciation Expense by Removing Terminal Net Salvage for Mitchell	0.57
Increase Short Term Debt to 1% and Set Debt Rate at 1.25%	0.36
Change in Return on Equity from 10.31% to 9.75%	4.70
Total Adjustments	**28.6**

(c) Kentucky Power agrees to allocate the $31,780,734 in additional annual revenue as illustrated on **Exhibit 1.** The Company will design rates and tariffs consistent with this allocation of additional revenue.

(i) As part of the Commission's consideration of the reasonableness of this Settlement Agreement, the tariffs designed in accordance with this subparagraph shall be filed with the Commission and served on counsel for all parties to this case no later than December 1, 2017.

(ii) Within ten days of the entry of the Commission's Order approving without modification this Settlement Agreement and the rates thereunder, Kentucky Power shall file with the Commission signed copies of the tariffs in conformity with 807 KAR 5:011.

3. Rockport UPA Expense Deferral

(a) Kentucky Power is a party to a FERC-approved Unit Power Agreement with AEP Generating Company for capacity and energy produced at the Rockport Plant ("Rockport UPA"). The Rockport UPA expires on December 8, 2022.

(b) Kentucky Power will defer a total of $50 million in non-fuel, non-environmental Rockport UPA Expense for later recovery as follows:

(i) Kentucky Power will defer $15M annually of Rockport UPA Expense in 2018 and 2019 for later recovery.

(ii) Kentucky Power will defer $10M of Rockport UPA Expense in 2020 for later recovery.

(iii) Kentucky Power will defer $5M annually of Rockport UPA Expense in years 2021 and 2022 for later recovery.

(c) The Rockport UPA Expense of $50 million described in Paragraph 3(b) above will be deferred into a regulatory asset ("the Rockport Deferral Regulatory Asset") and will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11%[1] until the Regulatory Asset is fully recovered. From January 1, 2018 through December 8, 2022, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset principal balance net of accumulated deferred income taxes ("ADIT"). From December 9, 2022 until the Rockport Deferral Regulatory Asset is fully recovered, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset balance including deferred carrying charges net of ADIT. The Rockport Deferral Regulatory Asset shall be recovered on a levelized basis through the demand component of Tariff P.P.A. and amortized over five years beginning on December 9, 2022. Kentucky Power estimates that the regulatory asset balance will total approximately $59 million on December 8, 2022.

(d) Additional expenses reflecting the declining deferral amount in years 2020 through 2022 will be recovered through the demand component of Tariff P.P.A. as follows:

(i) Kentucky Power will recover $5 million through Tariff P.P.A. in 2020

(ii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2021

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[1] 6.48% grossed up for applicable State and Federal taxes, uncollectible accounts expense, and the KPSC maintenance fee

(iii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2022, prorated through December 8, 2022.

(e) The Signatory Parties acknowledge that the Company's decision whether to seek Commission approval to extend the Rockport UPA will be made at a later date. Whether or not the Company seeks to extend the Rockport UPA, beginning December 9, 2022, the Capacity Charge recovered through Tariff C.C., approved in Case No. 2004-00420, will end. Any final over- or under-recovery balance will be included in the subsequent calculation of the purchase power adjustment under Tariff P.P.A. In the event that Kentucky Power elects not to extend the Rockport UPA, it will experience a reduction in Rockport UPA fixed costs ("Rockport Fixed Costs Savings").

(f) If Kentucky Power elects not to extend the Rockport UPA, it will, beginning December 9, 2022, credit the Rockport Fixed Cost Savings through the demand component of Tariff P.P.A. until new base rates are set. However, for 2023 only, the Rockport Fixed Cost Savings credit will be offset by the amount, if any, necessary for the Company to earn its Kentucky Commission-authorized return on equity (ROE) for 2023 ("Rockport Offset"). An example of the calculation of the Rockport Offset is included as **Exhibit 2**.

(g) For the purposes of implementing the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above, the following definitions apply:

(i) "Rockport Fixed Costs Savings" shall mean the annual amount of non-fuel, non-environmental Rockport UPA expense included in base rates for rates effective in November 2022.

(ii) "Estimated Rockport Offset" shall mean the amount of additional annual revenue the Company estimates would be necessary for it to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings.

(iii) "Actual Rockport Offset" shall mean the amount of additional annual revenue that would have been necessary for the Company to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings. The Company shall calculate the Actual Rockport Offset using a comparison of the per books return on equity for 2023 to the Commission-approved return on equity. The Actual Rockport Offset cannot exceed the Rockport Fixed Costs Savings.

(iv) "Rockport Offset True-Up" shall mean the difference between the Estimated Rockport Offset and the Actual Rockport Offset.

(h) The Company shall implement the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above as follows:

(i) By November 15, 2022, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective December 9, 2022. This filing shall reflect the impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset on the purchase power adjustment factor. This filing shall also reflect the commencement of recovery of the Rockport Deferral Regulatory Asset.

(ii) The Company shall make its normal August 15, 2023 Tariff P.P.A. filing for rates effective in October 2023. The Rockport Fixed Cost Savings and the Estimated Rockport Offset will continue to be factored into the calculation of the purchase power adjustment factor through the end of 2023. Beginning in January 2024, the Estimated Rockport Offset will not be factored into the calculation of the purchase power adjustment factor.

(iii) By February 1, 2024, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective March 1, 2024. This filing shall only reflect the impact of the Rockport Offset True-Up on the purchase power adjustment factor. The purchase power adjustment factor shall be established to recover or credit the Rockport Offset True-Up amount in three months.

(iv) Beginning with the August 15, 2024 Tariff P.P.A. filing, the Company will incorporate the Rockport Fixed Cost Savings in its annual calculation of the purchase power adjustment factor.

4. <u>PJM OATT LSE Expense Recovery</u>

(a) As described in the testimony of Company Witness Vaughan, Kentucky Power has included an adjusted test year amount of net PJM OATT LSE charges and credits in base rates. Kentucky Power will track, on a monthly basis, the amount of OATT LSE charges and credits above or below the base rate level using deferral accounting. Kentucky Power will recover and collect 80% of the annual over or under collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through the operation of Tariff P.P.A.

(b) Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100% of the difference between the return on its incremental transmission investments calculated using the FERC-approved PJM OATT return on equity and the return on its incremental transmission investments calculated using the 9.75% return on equity provided for in this settlement (the "Transmission Return Difference"). Kentucky Power shall calculate the Transmission Return Difference as shown in **Exhibit 3**.

(c) These changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise specifically extended by the Commission. Nothing in this Paragraph 4(c) prohibits Kentucky Power or any other Signatory Party from taking any position regarding the extension of the Annual PJM OATT LSE Recovery mechanism or any other treatment of the Company's PJM OATT LSE expenses.

5. Rate Case Stay Out

(a) Kentucky Power will not file an application for a general adjustment of base rates for rates that would be effective prior to the first day of the January 2021 billing cycle. This rate case "stay out" is expressly conditioned on Commission approval of this Settlement Agreement without modification including the recovery of the Rockport Deferral Regulatory Asset as described in Section 3 above and the incremental PJM OATT LSE expense through Tariff P.P.A. as described in Section 4 above.

(b) This stay out will not apply if a change in law occurs that will result in a material adverse effect on the Company's financial condition.

(c) Nothing in this stay out provision should be interpreted as prohibiting the Commission from altering the Company's rates upon its own investigation, or upon complaint, including to reflect changes in the tax code, including the federal corporate income tax rate, depreciation provisions, or upon a request by the Company to seek leave to address an emergency that could adversely impact Kentucky Power or its customers. In the event the Commission initiates an investigation or a complaint is filed with the Commission regarding the Company's rates, the Company retains the right to defend the reasonableness of its rates in such proceedings.

6. Tariff P.P.A.

(a) Kentucky Power's proposed changes to Tariff P.P.A., as set forth in the testimony of Company Witness Vaughan and modified by Sections 2 and 3 above, are approved.

(b) A revised version of Tariff P.P.A. incorporating the modifications described in Sections 2 and 3 above is included as **EXHIBIT 4.**

7. Depreciation Rates

(a) Kentucky Power and the Settling Intervenors agree that Big Sandy Unit 1 has an expected life of 20 years following its conversion from a coal-fired to a natural gas-fired generating unit. The depreciation rates for Big Sandy Unit 1 have been adjusted to reflect the 20 year expected life. Kentucky Power and the Signatory Parties retain the right to propose updated depreciation rates for Big Sandy Unit 1 in future proceedings to reflect updates to the expected life.

(b) Kentucky Power has adjusted depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Kentucky Power retains the right to propose updated depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant in future proceedings to include terminal net salvage costs, and the Settling Intervenors retain the right to challenge the inclusion of such costs in future proceedings.

(c) Kentucky Power's updated depreciation rates are included as **EXHIBIT 5**.

8. Return on Equity, Capitalization, WACC, and GRCF

(a) Kentucky Power shall be authorized a 9.75% return on equity. The authorized return on equity of 9.75% will be used in the calculation of the Company's Environmental Surcharge factor (for non-Rockport environmental projects) and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets.

(b) Kentucky Power will update its capitalization to reflect short term debt as 1% of the Company's total capital structure. The annual interest rate for the short term debt will be set at 1.25%.

(c) Kentucky Power shall utilize a weighted average cost of capital ("WACC") of 9.11% including a gross revenue conversion factor ("GRCF") of 1.6433%. The GRCF does not include a Section 199 deduction. This WACC and GRCF shall remain constant (including for the riders and surcharges described in Paragraph 8(a) above) until such time as the Commission sets base rates in the Company's next base rate case proceeding. The calculations of the WACC and GRCF are shown on **EXHIBIT 6**.

9. Storm Damage Expense Amortization

(a) Kentucky Power will recover and amortize the remaining unamortized balance of its deferred storm expense regulatory asset authorized in Case No. 2012-00445 over a period of five years beginning January 1, 2018, consistent with the recommendation of KIUC. The unamortized balance of the regulatory asset authorized in Case No. 2012-00445 will total $6,087,000 on December 31, 2017 and will be amortized over five years at an annual amount of $1,217,400.

(b) Kentucky Power will recover and amortize the deferred storm expense regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467.

(c) The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount authorized in Case No. 2016-00180) will total $10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of $2,092,867.

10. Kentucky Economic Development Surcharge

(a) Kentucky Power's new Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S.") shall be approved with rates amended as follows:

(i) The KEDS rate for residential customers will be set at $0.10 per meter instead of $0.25 as proposed by the Company.

(ii) The KEDS rate for non-residential customers for which the KEDS applies will be set at $1.00 per meter instead of $0.25 as proposed by the Company.

(b) All KEDS funds collected by Kentucky Power shall be matched dollar-for-dollar by Kentucky Power from shareholder funds. The proceeds of KEDS and Kentucky Power's shareholder contribution shall be used by Kentucky Power for economic development projects, including the training of local economic development officials, in the Company's service territory. The KEDS, and the matching shareholder contribution, shall remain in effect until changed by order of the Commission.

(c) Kentucky Power will continue to file on or before March 31st of each year a report with the Commission describing: (i) the amount collected through the Economic Development Surcharge; and (ii) the matching amount contributed by Kentucky Power from shareholder funds. The annual report to be filed by the Company shall also describe the amount, recipients, and purposes of its expenditure of the funds collected through the Economic Development Surcharge and shareholder contribution.

(d) Kentucky Power shall serve a copy of the annual report to be filed with the Commission in accordance with subparagraph (c) on counsel for all parties to this proceeding.

11. Backup and Maintenance Service

(a) In order for Marathon Petroleum LP ("Marathon") to evaluate the economics of self or co-generation, Kentucky Power and Marathon will begin negotiations regarding the terms, conditions and pricing for backup and maintenance service within 30 days of a Commission Order approving this provision and will complete negotiations within the next 120 days. Prior to the start of the 120 day negotiation period, Marathon will provide Kentucky Power with specific information regarding the MW size of a potential self or co-generation facility and the type of generation technology being considered.

(b) If Kentucky Power and Marathon cannot reach an agreement on backup and maintenance service within 120 days, Kentucky Power and Marathon agree to submit the issue to the Commission for resolution.

12. School Energy Manager Program

(a) Kentucky Power shall seek leave from the Commission to include up to $200,000 for the School Energy Manager Program in its each of its 2018 and 2019 DSM Program offerings.

(b) Kentucky Power and KSBA both expressly acknowledge that there is in Case No. 2017-00097 a currently-pending Commission investigation of the Company's DSM programs and funding and that the outcome of that investigation could impact the School Energy Manager Program.

13. Tariff K-12 School

(a) Kentucky Power shall continue its current Pilot Tariff K-12 School but shall remove the Pilot designation as set forth in **Exhibit 7**. Tariff K-12 School shall be available for general service to all K-12 schools in the Company's service territory, public and private, with normal maximum demands greater than 100 kW. Tariff K-12 School shall reflect rates for customers taking service under the tariff designed to produce annually in the aggregate $500,000 less from Tariff K-12 School customers than would be produced under the new L.G.S. rates to be established under this Settlement Agreement from customers eligible to take service under Tariff K-12 School. The aggregate total revenues to be produced by Tariff K-12 School and Tariff L.G.S. shall be equal to the revenues that would be produced in the aggregate by the new rates in the absence of Tariff K-12 School. Service under Tariff K-12 School shall be optional.

14. Bill Format Changes

(a) The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated into this case by Commission Order dated July 17, 2017, to the extent not already approved, are approved.

(b) Within 180 days of a Commission Order approving this Settlement, Kentucky Power will conduct a training session with representatives from its municipal clients and KLC to explain the new bill format and tools available to clients to evaluate their electric usage.

15. Renewable Power Option Rider

(a) The proposed changes to the Company's Green Pricing Option Rider, including renaming the rider to the Renewable Power Option Rider ("Rider R.P.O."), are approved except that the availability of service provision for Option B will state the following:

> "Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand."

A revised version of Rider R.P.O. incorporating the modifications described above is included as **Exhibit 8**. Bills for customers receiving service under Rider R.P.O. will include a separate line item for Rider R.P.O. charges.

(b) Beginning no later than March 31, 2018, and no later than each March 31 thereafter, Kentucky Power will file a report with the Commission describing the previous year's activity under Rider R.P.O. This annual report will replace the semi-annual reports filed in Case No. 2008-00151.

16. Modifications To Kentucky Power's Rate Tariffs

In addition to the rate and tariff changes described and agreed to above, Kentucky Power and the Settling Intervenors agree that the following tariffs shall be modified or implemented as described below:

(a) The Customer charge for the Residential Class ("Tariff R.S.") shall be increased to $14.00 per month instead of the $17.50 per month proposed by the Company in its filing in this case.

(b) The Company is extending the termination date for Tariff C.S. – Coal and the amendments to Tariff C.S. – I.R.P. and Tariff E.D.R. approved in Case No. 2017-00099 from December 31, 2017 to December 31, 2018.

(c) The pole attachment rate under Tariff C.A.T.V. shall be $10.82 for attachments on two-user poles and $6.71 for attachments on three-user poles for all attachments instead of the $11.97 for attachments on two-user poles and $7.42 for attachments on three-user poles proposed by the Company in its filing in this case.

17. Filing Of Settlement Agreement With The Commission And Request For Approval

Following the execution of this Settlement Agreement, Kentucky Power and the Settling Intervenors shall file this Settlement Agreement with the Commission along with a joint request to the Commission for consideration and approval of this Settlement Agreement so that Kentucky

Power may begin billing under the approved adjusted rates for service rendered on or before January 19, 2018.

18. Good Faith And Best Efforts To Seek Approval

(a) This Settlement Agreement is subject to approval by the Public Service Commission.

(b) Kentucky Power and the Settling Intervenors shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be approved in its entirety and without modification and that the rates and charges set forth herein be implemented.

(c) Kentucky Power and the Settling Intervenors filed testimony in this case. Kentucky Power also filed testimony in support of the Settlement Agreement. For purposes of any hearing, the Settling Intervenors and Kentucky Power waive all cross-examination of the other Signatory Parties' witnesses except for purposes of supporting this Settlement Agreement unless the Commission disapproves this Settlement Agreement. Each further stipulates and recommends that the Notice of Intent, Application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record.

(d) The Signatory Parties further agree to support the reasonableness of this Settlement Agreement before the Commission, and to cause their counsel to do the same, including in connection with any appeal from the Commission's adoption or enforcement of this Settlement Agreement.

(e) No party to this Settlement Agreement shall challenge any Order of the Commission approving the Settlement Agreement in its entirety and without modification.

19. Failure Of Commission To Approve Settlement Agreement

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. 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 rehearing's 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.

20. Continuing Commission Jurisdiction

This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

21. Effect of Settlement Agreement

This Settlement Agreement shall inure to the benefit of, and be binding upon, the parties to this Settlement Agreement, their successors, and assigns.

22. Complete Agreement

This Settlement Agreement constitutes the complete agreement and understanding among the parties to this Settlement Agreement, and any and all oral statements, representations, or agreements. Any and all such 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 this Settlement Agreement.

23. Independent Analysis

The terms of this Settlement Agreement are based upon the independent analysis of the parties to this Settlement Agreement, are the product of compromise and negotiation, and reflect a fair, just, and reasonable resolution of the issues herein. Notwithstanding anything contained in this Settlement Agreement, Kentucky Power and the Settling Intervenors recognize and agree that the effects, if any, of any future events upon the income of Kentucky Power are unknown and this Settlement Agreement shall be implemented as written.

24. Settlement Agreement And Negotiations Are Not An Admission

(a) This Settlement Agreement shall not be deemed to constitute an admission by any party to this Settlement Agreement that any computation, formula, allegation, assertion, or contention made by any other party in these proceedings is true or valid. Nothing in this Settlement Agreement shall be used or construed for any purpose to imply, suggest or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of the Signatory Parties.

(b) Neither the terms of this Settlement Agreement nor any statements made or matters raised during the settlement negotiations shall be admissible in any proceeding, or binding on any of the parties to this Settlement Agreement, or be construed against any of the parties to this Settlement Agreement, except that in the event of litigation or proceedings involving the approval, implementation or enforcement of this Agreement, the terms of this Settlement Agreement shall be admissible. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

25. Consultation With Counsel

The parties to this Settlement Agreement warrant that they have informed, advised, and consulted with their respective counsel with regard to the contents and significance of this Settlement Agreement and are relying upon such advice in entering into this agreement.

26. Authority To Bind

Each of the signatories to this Settlement Agreement hereby warrant they are authorized to sign this agreement upon behalf of, and bind, their respective parties.

27. Construction Of Agreement

This Settlement Agreement is a product of negotiation among all parties to this Settlement Agreement, and no provision of this Settlement Agreement shall be construed in favor of or against any party hereto. This Settlement Agreement is submitted for purposes of this case only and is not to be deemed binding upon the parties hereto in any other proceeding, nor is it to be offered or relied upon in any other proceeding involving Kentucky Power or any other utility.

28. Counterparts

This Settlement Agreement may be executed in multiple counterparts.

29. Future Rate Proceedings

Nothing in this Settlement Agreement shall preclude, prevent, or prejudice any party to this Settlement Agreement from raising any argument or issue, or challenging any adjustment, in any future rate proceeding of Kentucky Power.

IN WITNESS WHEREOF, this Settlement Agreement has been agreed to as of this 22nd day of November 2017.

KENTUCKY POWER COMPANY

By: ________________

Its: Counsel

KENTUCKY INDUSTRIAL UTILITY
CUSTOMERS, INC.

By: Michael L. Kurtz

Its: Counsel

KENTUCKY SCHOOL BOARDS
ASSOCIATION, INC.

By: [signature]

Its: Legal Counsel

KENTUCKY LEAGUE OF CITIES

By: [signature]

Its: Director of Municipal Law & Training

KENTUCKY CABLE
TELECOMMUNICATION
ASSOCIATION, INC.

By: Jason Keller

Its: KCTA Board Chairman

WAL-MART STORES EAST, LP AND
SAM'S EAST, INC.

By: [signature]

Its: Counsel

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

Adjustments	Amounts
Capacity Charge Revenues Removal	($6,396,832)
Removal of Effects of Decommissioning Rider Revenue and Expenses	($18,512,331)
Eliminate Mitchell FGD Operating Expenses	($13,308,197)
Remove Mitchell plant FGD and Consumable inventory from Rate Base	($1,610,192)
Removal of Mitchell FGD Environmental Surcharge Rider Revenues	($538,417)
Remove Big Sandy Unit 1 Operation Rider Deferrals	($4,333,902)
Fuel Under (Over) Revenues	$4,574,472
Reset OSS Margin Baseline to 2016 Test Year OSS Margins	($8,800,856)
PPA Rider Synchronization Adjustment	$372,542
Remove DSM Revenue Expense	($5,503,380)
Remove HEAP Revenue and Expense	($246,772)
Remove Economic Development Surcharge Revenue and Expense	($303,011)
Tariff Migration Adjustment	$1,026,263
Customer Annualization Revenue Adjustment	($1,342,364)
Weather Normal Load Revenue Adjustment	$4,080,748
O&M Expense Interest on Customer Deposit	$67,254
Amortization of Major Storm Cost Deferral	$874,592
Postage Rate Decrease Adjustment	($6,656)
Eliminate Advertising Expense	$100,444
Adjust Pension and OPEB Expense	$148,679
Employee Related Group Benefit Expense	$429,241
Remove PJM BLIs From Base for FAC Inclusions	($516,659)
Adjustment to Include Purchase Power Limitation Expense in Rate Base	$3,150,582
Adjustment to Include Forced Outage Purchase Power Limitation in Base Rates	$882,204
Annualize NITS/PJM LSE OATT Expense	$3,825,858
Annualize PJM Admin Charges	$118,606
Amortization of NERC Cost Deferral	$14,275
Severance Expense Adjustment	$2,363
Annualization of Payroll Expense Adjustment	$244,837
Social Security Tax Base Adjustment	$26,009
Eliminate Non-Recoverable Business Expenses	$14,914
Plant Maintenance Normalization	($274,334)
Depreciation Annualization Adjustment Electric Plant in Service	$2,037,359
Decrease ARO Depreciation Expense to an Annualized Level	($3,818)
Decrease ARO Accretion Expense to an Annualized Level	($109,495)
Annualization of Cable Pole Attachment Revenue	$532,369
KPSC Maintenance Assessment	($1,801)
State Gross Receipts Tax Adjustment	$78,776

Interest Synchronization Adjustment (Per 8/7/2017 Amendment)	$6,449,828
AFUDC Offset Adjustment (Per 8/17/2017 Amendment)	$28,197
Adjustment to Recognize Accrued Surcharge Revenue Differences	($62,588)
Mitchell Plant ADSIT Amortization	$1,292,491
Decrease O&M for Vegetation Management Tree Trimming	($6,794,282)
Annualization of Property Taxes	$595,507

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

The following rates and charges are prescribed for the customers in the area served by Kentucky Power 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.

TARIFF R.S.
RESIDENTIAL SERVICE

Service Charge per month	$	14.00
Energy Charge per kWh	$	.09660
Storage Water Heating Provision - Per kWh	$	.06072
Load Management Water Heating Provision - Per kWh	$	.06072
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-L.M.-T.O.D.
RESIDENTIAL SERVICE LOAD MANAGEMENT TIME-OF-DAY

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.14346
All kWh used during off-peak billing period	$	.06072
Separate Metering Provision Per Month	$	3.75
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-T.O.D.
RESIDENTIAL SERVICE TIME-OF-DAY

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.14386
All kWh used during off-peak billing period	$	.06072
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-T.O.D. 2
EXPERIMENTAL RESIDENTIAL SERVICE TIME-OF-DAY 2

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during summer on-peak billing period	$	.17832
All kWh used during winter on-peak billing period	$	.15342
All kWh used during off-peak billing period	$	.08094
Home Energy Assistance Program Charge		
Per meter per month	$	.30

TARIFF R.S.D.
RESIDENTIAL DEMAND-METERED ELECTRIC SERVICE

Service Charge per month	$	17.50
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.09738
All kWh used during off-peak billing period	$	.07029
Demand Charge per kW	$	4.02
Home Energy Assistance Program Charge		
Per meter per month	$	.30

TARIFF G.S.
GENERAL SERVICE

Secondary Service:		
Service Charge per month	$	22.50
Energy Charge per kWh:		
Phase 1		
First 4,450 kWh per month	$	.10198
Over 4,450 kWh per month	$	.10188
Phase 2		
First 4,450 kWh per month	$	.09807
Over 4,450 kWh per month	$	.09798
Demand Charge per kW greater than 10 kW		
Phase 1	$	4.00
Phase 2	$	6.00
Primary Service:		
Service Charge per month	$	75.00
Energy Charge per kWh:		
First 4,450 kWh per month	$	.08629
Over 4,450 kWh per month	$	.08659
Demand Charge per kW greater than 10 kW	$	7.18

Subtransmission Service:

Service Charge per month	$ 364.00
Energy Charge per kWh:	
First 4,450 kWh per month	$ .07822
Over 4,450 kWh per month	$ .07855
Demand Charge per kW greater than 10 kW	$ 5.74

TARIFF G.S.
GENERAL SERVICE
RECREATIONAL LIGHTING SERVICE PROVISION

Service Charge per month	$ 22.50
Energy Charge per kWh	$ .09968

TARIFF G.S.
GENERAL SERVICE
LOAD MANAGEMENT TIME-OF-DAY PROVISION

Service Charge per month	$ 22.50
Energy Charge per kWh:	
All kWh used during on-peak billing period	$ .14423
All kWh used during off-peak billing period	$ .06072

TARIFF G.S.
GENERAL SERVICE
OPTIONAL UNMETERED SERVICE PROVISION

Service Charge per month	$ 14.00
Energy Charge per kWh:	
Phase 1	
First 4,450 kWh per month	$ .10198
Over 4,450 kWh per month	$ .10188
Phase 2	
First 4,450 kWh per month	$ .09807
Over 4,450 kWh per month	$ .09798

TARIFF S.G.S.-T.O.D.
SMALL GENERAL SERVICE TIME-OF-DAY

Service Charge per month	$ 22.50
Energy Charge per kWh:	
All kWh used during summer on-peak billing period	$ .17034
All kWh used during winter on-peak billing period	$ .14372
All kWh used during off-peak billing period	$ .07511

TARIFF M.G.S.-T.O.D.
MEDIUM GENERAL SERVICE TIME-OF-DAY

Service Charge per month	$	22.50
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.16747
All kWh used during off-peak billing period	$	.06072

TARIFF L.G.S.
LARGE GENERAL SERVICE

Secondary Service Voltage:		
Service Charge per month	$	85.00
Energy Charge per kWh	$	.07712
Demand Charge per kW	$	7.97
Primary Service Voltage:		
Service Charge per month	$	127.50
Energy Charge per kWh	$	.06711
Demand Charge per kW	$	7.18
Sub-transmission Service Voltage:		
Service Charge per month	$	660.00
Energy Charge per kWh	$	.05112
Demand Charge per kW	$	5.74
Transmission Service Voltage:		
Service Charge per month	$	660.00
Energy Charge per kWh	$	.04997
Demand Charge per kW	$	5.60
All Service Voltages:		
Excess Reactive Charge per KVA	$	3.46

TARIFF L.G.S.
LARGE GENERAL SERVICE
LOAD MANAGEMENT TIME-OF-DAY PROVISION

Service Charge per month	$	85.00
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.14063
All kWh used during off-peak billing period	$	.06088

TARIFF L.G.S. – T.O.D.
LARGE GENERAL SERVICE TIME-OF-DAY

Secondary Service Voltage:	
Service Charge per month	$ 85.00
Energy Charge:	
On-Peak Energy Charge per kWh	$ .09670
Off-Peak Energy Charge per kWh	$ .04132
Demand Charge per kW	$ 10.87
Primary Service Voltage:	
Service Charge per month	$ 127.50
Energy Charge:	
On-Peak Energy Charge per kWh	$ .09300
Off-Peak Energy Charge per kWh	$ .04010
Demand Charge per kW	$ 7.84
Sub-transmission Service Voltage:	
Service Charge per month	$ 660.00
Energy Charge:	
On-Peak Energy Charge per kWh	$ .09176
Off-Peak Energy Charge per kWh	$ .03970
Demand Charge per kW	$ 1.52
Transmission Service Voltage:	
Service Charge per month	$ 660.00
Energy Charge:	
On-Peak Energy Charge per kWh	$ .09049
Off-Peak Energy Charge per kWh	$ .03928
Demand Charge per kW	$ 1.49
All Service Voltages:	
Excess Reactive Charge per KVA	$ 3.46

TARIFF I.G.S.
INDUSTRIAL GENERAL SERVICE

Secondary Service Voltage:	
Service Charge per month	$ 276.00
Energy Charge per kWh	$ .02663
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 24.13
Of Monthly Off-Peak Billing Demand	$ 1.60

Primary Service Voltage:

Service Charge per month	$ 276.00
Energy Charge per kWh	$ .02553
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 20.57

Sub-transmission Service Voltage:

Service Charge per month	$ 794.00
Energy Charge per kWh	$ .02793
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 13.69
Of Monthly Off-Peak Billing Demand	$ 1.51

Transmission Service Voltage:

Service Charge per month	$1,353.00
Energy Charge per kWh	$ .02792
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 13.26
Of Monthly Off-Peak Billing Demand	$ 1.49

All Service Voltages:
Reactive demand charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the kW of monthly metered demand is $.69 per KVAR.

Minimum Demand Charge
The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates per kW:

Secondary	$ 25.83
Primary	$ 22.21
Subtransmission	$ 15.30
Transmission	$ 14.86

TARIFF M.W.
MUNICIPAL WATERWORKS

Service Charge per month	$ 22.90
Energy Charge - All kWh per kWh	$ .09135

Subject to a minimum monthly charge equal to the sum of the service charge plus $8.89 per kW as determined from customer's total connected load.

TARIFF O.L.
OUTDOOR LIGHTING

OVERHEAD LIGHTING SERVICE

High Pressure Sodium per Lamp:		
100 Watts (9,500 Lumens)	$	8.50
150 Watts (16,000 Lumens)	$	9.30
200 Watts (22,000 Lumens)	$	10.90
250 Watts (28,000 Lumens)	$	15.04
400 Watts (50,000 Lumens)	$	16.01
Mercury Vapor per Lamp:		
175 Watts (7,000 Lumens)	$	9.04
400 Watts (20,000 Lumens)	$	14.64

POST-TOP LIGHTING SERVICE

High Pressure Sodium per Lamp:		
100 Watts (9,500 Lumens)	$	14.05
150 Watts (16,000 Lumens)	$	23.30
100 Watts Shoe Box (9,500 Lumens)	$	29.50
250 Watts Shoe Box (28,000 Lumens)	$	24.99
400 Watts Shoe Box (50,000 Lumens)	$	36.16
Mercury Vapor per Lamp:		
175 Watts (7,000 Lumens)	$	10.59

FLOOD LIGHTING SERVICE

High Pressure Sodium per Lamp:		
200 Watts (22,000 Lumens)	$	13.10
400 Watts (50,000 Lumens)	$	17.06
Metal Halide		
250 Watts (20,500 Lumens)	$	15.27
400 Watts (36,000 Lumens)	$	18.39
1,000 Watts (110,000 Lumens)	$	30.94
250 Watts Mongoose (19,000 Lumens)	$	20.57
400 Watts Mongoose (40,000 Lumens)	$	23.59

Per Month:		
Wood Pole	$	3.40
Overhead Wire Span not over 150 Feet	$	2.00
Underground Wire Lateral not over 50 Feet	$	7.40

Per Lamp plus $0.02725 x kWh in Sheet No. 14-3 in Company's tariff

TARIFF S.L.
STREET LIGHTING

Rate per Lamp:

Overhead Service on Existing Distribution Poles	
High Pressure Sodium	
100 Watts (9,500 Lumens)	$ 7.02
150 Watts (16,000 Lumens)	$ 7.55
200 Watts (22,000 Lumens)	$ 8.95
400 Watts (50,000 Lumens)	$ 11.71
Service on New Wood Distribution Poles	
High Pressure Sodium	
100 Watts (9,500 Lumens)	$ 10.80
150 Watts (16,000 Lumens)	$ 11.55
200 Watts (22,000 Lumens)	$ 12.95
400 Watts (50,000 Lumens)	$ 16.61
Service on New Metal or Concrete Poles	
High Pressure Sodium	
100 Watts (9,500 Lumens)	$ 27.45
150 Watts (16,000 Lumens)	$ 28.15
200 Watts (22,000 Lumens)	$ 26.70
400 Watts (50,000 Lumens)	$ 27.11

Per Lamp plus $0.02725 x kWh in Sheet No. 15-2 in Company's tariff

TARIFF C.A.T.V.
CABLE TELEVISION POLE ATTACHMENT

Charge for attachments	
On a two-user pole	$ 10.82
On a three-user pole	$ 6.71

TARIFF COGEN/SPP I
COGNERATION AND/OR SMALL POWER PRODUCTION
100 KW OR LESS

Monthly Metering Charges:	
Single Phase:	
Standard Measurement	$ 9.25
Time-of-Day Measurement	$ 9.85

Polyphase:		
Standard Measurement	$	12.10
Time-of-Day Measurement	$	12.40
Energy Credit per kWh:		
Standard Meter – All kWh	$	.03240
Time-of-Day Meter:		
On-Peak kWh	$	.03860
Off-Peak kWh	$	.02790
Capacity Credit:		
Standard Meter per kW	$	3.11
Time-of-Day Meter per kW	$	7.47

TARIFF COGEN/SPP II
COGNERATION AND/OR SMALL POWER PRODUCTION
OVER 100 KW

Metering Charges:		
Single Phase:		
Standard Measurement	$	9.25
Time-of-Day Measurement	$	9.85
Polyphase:		
Standard Measurement	$	12.10
Time-of-Day Measurement	$	12.40
Energy Credit per kWh:		
Standard Meter – All kWh	$	.03240
Time-of-Day Meter:		
On-Peak kWh	$	.03860
Off-Peak kWh	$	.02790
Capacity Credit:		
Standard Meter per kW	$	3.11
Time-of-Day Meter per kW	$	7.47

TARIFF K.E.D.S.
KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE

Per month per account:		
Residential	$	.00
All Other	$	1.00

TARIFF C.C.
CAPACITY CHARGE

Energy Charge per kWh:		
Service Tariff		
I.G.S.	$	.000749
All Other	$	.001435

RIDER R.P.O.
RENEWABLE POWER OPTION RIDER
OPTION A

Solar RECs:		
Block Purchase per 100 kWh per month	$	1.00
All Usage Purchase per kWh consumed	$	.01000
Wind RECs:		
Block Purchase per 100 kWh per month	$	1.00
All Usage per kWh consumed	$	.01000
Hydro & Other RECs:		
Block Purchase per 100 kWh per month	$	.30
All Usage per kWh consumed	$	.00300

RIDER A.F.S.
ALTERNATE FEED SERVICE RIDER

Monthly Rate for Annual Test of Transfer Switch/Control Module	$	14.67
Monthly Capacity Reservation Demand Charge per kW	$	6.29

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 1 8 2018

ENVIRONMENTAL COMPLIANCE PLAN

Project	Plant	Pollutant	Description	In-Service Year
			Previously Approved Environmental Compliance Projects	
1	Mitchell	NOx, SO2, and SO3	Mitchell Units 1 & 2, Water Injection, Low NOx Burners, Low NOx Burner Modification, SCR, FGD, Landfill, Coal Blending Facilities & SO3 Mitigation	1993-1994-2002-2007
2	Mitchell	SO2, NOx and Gypsum	Mitchell Plant Common CEMS, Replace Burner Barrier Valves & Gypsum Material Handling Facilities	1993-1994-2007
3	Rockport	SO2 / NOx	Continuous Emission Monitors ("CEMS")	1994
4	Rockport	NOx, Fly Ash, & Bottom Ash	Rockport Units 1 & 2 Low NOx Burners, Over Fire Air & Landfill	2003-2008
5	Mitchell & Rockport	SO2, NOx, Particulates & VOC and etc.	Title V Air Emissions Fees at Mitchell and Rockport Plants	Annual
6	Big Sandy, Mitchell & Rockport	NOx	Costs Associated with NOx Allowances	As Needed
7	Big Sandy, Mitchell & Rockport	SO2	Costs Associated with SO2 Allowances	As Needed
8	Big Sandy, Mitchell & Rockport	SO2 / NOx	Costs Associated with the CSAPR Allowances	As Needed
9	Mitchell	Particulates	Mitchell Units 1 & 2 - Precipitator Modifications	2007-2013
10	Mitchell	Particulates	Mitchell Units 1 & 2 - Bottom Ash & Fly Ash Handling	2008-2010
11	Mitchell	Mercury	Mitchell Units 1 & 2 - Mercury Monitoring ("MATS")	2014
12	Mitchell	Selenium	Mitchell Units 1 & 2 - Dry Fly Ash Handling Conversion	2014
13	Mitchell	Fly Ash, Bottom Ash, Gypsum & WWTP Solids	Mitchell Units 1 & 2 - Coal Combustion Waste Landfill	2014
14	Mitchell	Particulates	Mitchell Unit 2 - Electrostatic Precipitator Upgrade	2015
15	Rockport	Particulates	Rockport Units 1 & 2 - Precipitator Modifications	2004-2009
16	Rockport	Mercury	Rockport Units 1 & 2 - Activated Carbon Injection ("ACI") & Mercury Monitoring	2009-2010

17	Rockport	Hazardous Air Pollutants ("HAPS")	Rockport Units 1 & 2 - Dry Sorbent Injection	2015
18	Rockport	Fly Ash & Bottom Ash	Rockport Plant Common - Coal Combustion Waste Landfill Upgrade to Accept Type 1 Ash	2013 & 2015
			<u>Proposed Environmental Compliance Projects</u>	
19	Rockport	NOx	Rockport Unit 1 - Selective Catalytic Reduction equipment	2017
20	Mitchell Rockport	SO2 / NOx, Mercury, Particulates, Hazardous Air Pollutants ("HAPS")	Cost of consumables used in conjunction with approved ECP projects including the cost of the consumables used and a return on consumable inventories. Consumables include, but are not limited to sodium bicarbonate, activated carbon, anhydrous ammonia, trona, lime hydrate, limestone, polymer, and urea.	As Needed

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

MONTHLY BASE PERIOD REVENUE REQUIREMENT

Billing Month	Base Period Cost
January	$ 3,664,681
February	3,581,017
March	3,353,024
April	3,661,574
May	3,595,145
June	3,827,332
July	3,747,320
August	3,888,262
September	3,636,247
October	3,824,697
November	3,717,340
December	3,882,677
	$ 44,379,316

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

Commission Staff Adjustments to the Revenue Requirement in the Settlement Agreement
Case No. 2017-00179
Kentucky Power Company (Kentucky Jurisdiction)

	Pre-Tax Operating Income Amount	NOI Amount	GRCF		Staff RR Amount
Increase Per Settlement					31,780,734
Operating Income Issues					
OSS Rider Adjustment	(486,412)	(361,693)	1.352116	$	(489,051)
Theft Recovery Revenue	(166,198)	(123,584)	1.352116	$	(167,100)
Purchased Power Adj (WP 26&27)	(4,032,786)	(2,998,755)	1.352116	$	(4,054,664)
Relocation Expense	(132,109)	(98,235)	1.352116	$	(132,826)
Cost of Capital Issues					
Total Change in ROE and capitalization		(476,714)	1.352116	$	(644,573)
Change in GCRF					(13,943,890)
Total Adjustments to the Settlement Agreement				$	(19,432,104)
Recommended Change in Base Rates				$	12,348,630

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AG
Exhibit 3

DOMINION ENERGY NYSE-D

RECENT PRICE 81.39 | P/E RATIO 21.3 (Trailing: 24.0; Median: 19.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 4 Lowered 8/11/17
SAFETY 2 Raised 9/11/98
TECHNICAL 4 Lowered 11/10/17
BETA .65 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	42.2	49.4	48.5	39.8	45.1	53.6	55.6	68.0	80.9	79.9	79.0	82.1
Low:	34.4	39.8	31.3	27.1	36.1	42.1	48.9	51.9	63.1	64.5	66.3	70.9

Target Price Range
2020 | 2021 | 2022

2020-22 PROJECTIONS

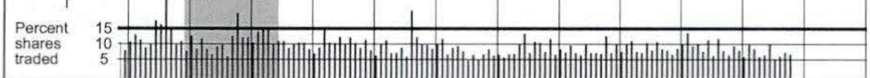
	Price	Gain	Ann'l Total Return
High	110	(+35%)	12%
Low	80	(Nil)	4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	0	0	0	0	0	0	0
Options	1	8	1	0	6	1	0	0	0
to Sell	1	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2016	1Q2017	2Q2017
to Buy	449	434	463
to Sell	400	414	401
Hld's(000)	407763	465004	459958



% TOT. RETURN 10/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.1	21.4
3 yr.	27.3	27.5
5 yr.	85.4	92.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
19.94	16.58	18.57	20.54	25.96	23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	19.35	19.90	Revenues per sh	22.50
3.92	4.45	3.97	4.18	3.70	4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.33	6.85	7.65	"Cash Flow" per sh	9.25
1.49	2.41	1.96	2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.50	4.00	Earnings per sh A	4.75
1.29	1.29	1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	3.04	3.32	Div'd Decl'd per sh B ■	4.40
2.31	2.17	5.20	3.88	4.83	5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.69	8.95	7.80	Cap'l Spending per sh	8.75
15.81	16.57	16.20	16.79	14.96	18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.26	25.20	25.90	Book Value per sh C	24.75
529.40	616.20	650.40	680.40	695.00	698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.80	643.50	643.50	Common Shs Outst'g D	615.00
20.9	12.0	15.2	15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	Bold figures are	Value Line	Avg Ann'l P/E Ratio	19.5
1.07	.66	.87	.80	1.33	.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	estimates		Relative P/E Ratio	1.20
4.1%	4.4%	4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%			Avg Ann'l Div'd Yield	4.7%

CAPITAL STRUCTURE as of 9/30/17
Total Debt $36734 mill. **Due in 5 Yrs** $15323 mill.
LT Debt $30886 mill. **LT Interest** $1226 mill.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $72 mill.

Pension Assets-12/16 $7016 mill. **Oblig** $8132 mill.

Pfd Stock None

Common Stock 643,529,769 shs. as of 10/13/17
MARKET CAP: $52 billion (Large Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
15674	16290	15131	15197	14379	13093	13120	12436	11683	11737	12450	12800	Revenues ($mill)	13850
1414.0	1781.0	1585.0	1724.0	1603.0	1594.0	1806.0	1793.0	1899.0	2123.0	2340	2510	Net Profit ($mill)	3130
33.4%	37.1%	33.2%	38.6%	34.6%	36.2%	33.0%	28.1%	32.0%	22.8%	27.5%	27.5%	Income Tax Rate	27.5%
7.3%	4.9%	4.8%	5.9%	5.3%	5.7%	3.7%	4.5%	5.3%	7.5%	5.0%	5.0%	AFUDC % to Net Profit	4.0%
57.8%	59.1%	57.5%	56.3%	59.8%	60.9%	61.9%	65.4%	65.1%	67.4%	67.0%	65.5%	Long-Term Debt Ratio	70.0%
41.1%	39.8%	41.5%	42.8%	39.3%	38.2%	37.3%	34.6%	34.9%	32.6%	33.0%	34.5%	Common Equity Ratio	30.0%
22898	25290	26923	28012	29097	27676	31229	33360	36280	44836	48900	48300	Total Capital ($mill)	51100
21352	23274	25592	26713	29670	30773	32628	36270	41554	49964	53550	56275	Net Plant ($mill)	64300
8.0%	8.7%	7.5%	7.7%	7.0%	7.5%	7.3%	6.6%	6.5%	6.0%	6.0%	7.0%	Return on Total Cap'l	7.5%
14.6%	17.2%	13.9%	14.1%	13.7%	14.7%	15.2%	15.5%	15.0%	14.5%	14.0%	15.5%	Return on Shr. Equity	19.5%
14.9%	17.5%	14.0%	14.2%	13.9%	14.9%	15.4%	15.4%	15.0%	14.5%	14.0%	15.5%	Return on Com Equity E	19.5%
5.0%	8.4%	4.7%	5.3%	4.0%	3.5%	4.2%	3.3%	2.9%	2.7%	2.0%	3.0%	Retained to Com Eq	2.0%
67%	52%	67%	63%	71%	77%	73%	79%	81%	81%	83%	79%	All Div'ds to Net Prof	87%

ELECTRIC OPERATING STATISTICS

	2014	2015	2016
% Change Retail Sales (KWH)	+1.6	+.7	NA
Avg. Indust. Use (MWH)	13847	13433	NA
Avg. Indust. Revs. per KWH (¢)	6.12	6.17	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+.9	NA
Fixed Charge Cov. (%)	266	352	310

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '20-'22
Revenues	-1.5%	-5.0%	2.0%
"Cash Flow"	3.5%	4.0%	7.5%
Earnings	5.0%	3.0%	6.5%
Dividends	7.0%	7.0%	9.0%
Book Value	2.5%	1.5%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	3630	2813	3050	2943	12436
2015	3409	2747	2971	2556	11683
2016	2921	2598	3132	3086	11737
2017	3384	2813	3179	3074	12450
2018	3500	2900	3250	3150	12800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.03	.60	.95	.47	3.05
2015	.91	.70	1.00	.59	3.20
2016	.88	.73	1.10	.73	3.44
2017	1.01	.62	1.03	.84	3.50
2018	1.10	.85	1.15	.90	4.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.562	.562	.563	.563	2.25
2014	.60	.60	.60	.60	2.40
2015	.647	.647	.648	.648	2.59
2016	.70	.70	.70	.70	2.80
2017	.755	.755	.755	.77	

BUSINESS: Dominion Energy, Inc. (formerly Dominion Resources, Inc.) is a holding company for Virginia Power & North Carolina Power, which serve 2.6 mill. customers in VA & northeastern NC. Serves 2.3 mill. gas customers in OH, WV, & UT. Nonutility ops. incl. independent power production. Owns 70.9% of Dominion Midstream Partners. Acq'd Questar 9/16. Elec. rev. breakdown: residential, 46%; commercial, 32%; industrial, 7%; other, 15%. Generating sources: nuclear, 31%; gas, 31%; coal, 24%; other, 6%; purch., 8%. Fuel costs: 25% of revs. '16 reported depr. rates: 2.3%-4.1%. Has 16,200 employees. Chairman, Pres. & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dom.com.

Dominion Energy has revised its dividend policy. The company intends to raise its disbursement by 10% a year through 2020. Previously, it had expected to raise the dividend by 8% annually. In the fourth quarter of 2017, the board of directors hiked the quarterly payout by $0.15 a share (2%), and we look for a $0.06-a-share boost in the first period of 2018. Growing (22% a year) cash distributions from Dominion Energy's stake in Dominion Midstream Partners, a natural gas master limited partnership, give the company the wherewithal to provide significant dividend growth. This also enables Dominion Energy to have a higher payout ratio than most utilities.

We estimate earnings will advance just slightly this year, but a much greater increase is likely in 2018. Several factors have combined to hold down profit growth: integration expenses from the purchase of Questar last year; a decline in solar tax credits; lower merchant power margins; and an additional refueling outage at the Millstone nuclear plant. Next year, the conversion of the Cove Point liquefied natural gas terminal from an import to an export facility will add an estimated $0.40-$0.45 a share to the bottom line. We think our previous forecast for 2018 was too conservative, so we raised it by $0.20 a share, to $4.00.

Virginia Power is building a gas-fired plant. This will add 1,588 megawatts of capacity at an estimated cost of $1.3 billion. The plant is expected to achieve commercial operation in December of 2018.

The company has other opportunities to invest capital. Virginia Power plans to spend $800 million a year on electric transmission for at least the next decade. The utility is also building solar projects. Dominion Energy is a 48% owner of a gas pipeline that is expected to be completed in mid-2019. Finally, the company is seeking regulatory approval for a program to modernize its gas transportation infrastructure (about $250 million annually).

This stock is untimely, but has a dividend yield and 3- to 5-year total return potential that are superior to those of most utilities. Thus, the equity has some appeal for accounts seeking income and dividend growth.

Paul E. Debbas, CFA *November 17, 2017*

(A) Dil. egs. Excl. nonrec. gains (losses): '01, (42¢); '03, ($1.46); '04, (22¢); '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); losses from disc. ops.: '06, 26¢; '07, 1¢; '10, 26¢; '12, 4¢; '13, 16¢. '14 & '15 EPS don't add due to rounding. Next egs. due early Feb. (B) Div'ds histor. paid in mid-Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '16: $15.12/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earn. on avg. com. eq., '16: 15.8%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	90

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AG Exhibit 4

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number	Exact name of registrants as specified in their charters	I.R.S. Employer Identification Number
001-08489	DOMINION ENERGY, INC.	54-1229715
000-55337	VIRGINIA ELECTRIC AND POWER COMPANY	54-0418825
001-37591	DOMINION ENERGY GAS HOLDINGS, LLC	46-3639580

VIRGINIA
(State or other jurisdiction of incorporation or organization)
120 TREDEGAR STREET
RICHMOND, VIRGINIA 23219
(Address of principal executive offices) *(Zip Code)*
(804) 819-2000
(Registrants' telephone number)

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
DOMINION ENERGY, INC.	Common Stock, no par value	New York Stock Exchange
	2016 Series A 6.75% Corporate Units	New York Stock Exchange
	2016 Series A 5.25% Enhanced Junior Subordinated Notes	New York Stock Exchange
DOMINION ENERGY GAS HOLDINGS, LLC	2014 Series C 4.6% Senior Notes	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
VIRGINIA ELECTRIC AND POWER COMPANY
Common Stock, no par value
DOMINION ENERGY GAS HOLDINGS, LLC
Limited Liability Company Membership Interests

Indicate by check mark whether the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act.

Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Dominion Energy, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Energy Gas Holdings, LLC Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Dominion Energy, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Energy Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Dominion Energy, Inc. ☐ Virginia Electric and Power Company ☒ Dominion Energy Gas Holdings, LLC ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Dominion Energy, Inc.

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐ Emerging growth company ☐

Virginia Electric and Power Company

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐ Emerging growth company ☐

Dominion Energy Gas Holdings, LLC

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act).

Dominion Energy, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Energy Gas Holdings, LLC Yes ☐ No ☒

The aggregate market value of Dominion Energy, Inc. common stock held by non-affiliates of Dominion Energy was approximately $48.1 billion based on the closing price of Dominion Energy's common stock as reported on the New York Stock Exchange as of the last day of Dominion Energy's most recently completed second fiscal quarter. Dominion Energy is the sole holder of Virginia Electric and Power Company common stock. At February 15, 2018, Dominion Energy had 651,524,668 shares of common stock outstanding and Virginia Power had 274,723 shares of common stock outstanding. Dominion Energy, Inc. holds all of the membership interests of Dominion Energy Gas Holdings, LLC.

DOCUMENT INCORPORATED BY REFERENCE.

Portions of Dominion Energy's 2018 Proxy Statement are incorporated by reference in Part III.

This combined Form 10-K represents separate filings by Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC make no representations as to the information relating to Dominion Energy, Inc.'s other operations.

VIRGINIA ELECTRIC AND POWER COMPANY AND DOMINION ENERGY GAS HOLDINGS, LLC MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I(1)(a) AND (b) OF FORM 10-K AND ARE FILING THIS FORM 10-K UNDER THE REDUCED DISCLOSURE FORMAT.

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Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC

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Glossary of Terms

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
2013 Equity Units	Dominion Energy's 2013 Series A Equity Units and 2013 Series B Equity Units issued in June 2013
2014 Equity Units	Dominion Energy's 2014 Series A Equity Units issued in July 2014
2015 Biennial Review Order	Order issued by the Virginia Commission in November 2015 concluding the 2013—2014 biennial review of Virginia Power's base rates, terms and conditions
2016 Equity Units	Dominion Energy's 2016 Series A Equity Units issued in August 2016
2017 Tax Reform Act	An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (previously known as The Tax Cuts and Jobs Act) enacted on December 22, 2017
2018 Proxy Statement	Dominion Energy 2018 Proxy Statement, File No. 001-08489
ABO	Accumulated benefit obligation
AFUDC	Allowance for funds used during construction
AMI	Advanced Metering Infrastructure
AMR	Automated meter reading program deployed by East Ohio
AOCI	Accumulated other comprehensive income (loss)
APCo	Appalachian Power Company
ARO	Asset retirement obligation
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC, a limited liability company owned by Dominion Energy, Duke and Southern Company Gas
Atlantic Coast Pipeline Project	The approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina which will be owned by Dominion Energy, Duke and Southern Company Gas and constructed and operated by DETI
BACT	Best available control technology
bcf	Billion cubic feet
bcfe	Billion cubic feet equivalent
Bear Garden	A 590 MW combined cycle, natural gas-fired power station in Buckingham County, Virginia
BGEPA	Bald and Golden Eagle Protection Act
Blue Racer	Blue Racer Midstream, LLC, a joint venture between Dominion Energy and Caiman
BP	BP Wind Energy North America Inc.
Brayton Point	Brayton Point power station
BREDL	Blue Ridge Environmental Defense League
Brunswick County	A 1,376 MW combined cycle, natural gas-fired power station in Brunswick County, Virginia
CAA	Clean Air Act
Caiman	Caiman Energy II, LLC
CAISO	California ISO
CAO	Chief Accounting Officer
CCR	Coal combustion residual
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as Superfund
CFO	Chief Financial Officer
CGN Committee	Compensation, Governance and Nominating Committee of Dominion Energy's Board of Directors
Clean Power Plan	Regulations issued by the EPA in August 2015 for states to follow in developing plans to reduce CO_2 emissions from existing fossil fuel-fired electric generating units, stayed by the U.S. Supreme Court in February 2016 pending resolution of court challenges by certain states
CNG	Consolidated Natural Gas Company
CO_2	Carbon dioxide
COL	Combined Construction Permit and Operating License
Companies	Dominion Energy, Virginia Power and Dominion Energy Gas, collectively
COO	Chief Operating Officer
Cooling degree days	Units measuring the extent to which the average daily temperature is greater than 65 degrees Fahrenheit, calculated as the difference between 65 degrees and the average temperature for that day
Corporate Unit	A stock purchase contract and 1/20 or 1/40 interest in a RSN issued by Dominion Energy
Cove Point	Dominion Energy Cove Point LNG, LP
Cove Point Holdings	Cove Point GP Holding Company, LLC
CPCN	Certificate of Public Convenience and Necessity
CWA	Clean Water Act
DECG	Dominion Energy Carolina Gas Transmission, LLC
DES	Dominion Energy Services, Inc.
DETI	Dominion Energy Transmission, Inc.
DGI	Dominion Generation, Inc.

Abbreviation or Acronym	Definition
DGP	Dominion Gathering and Processing, Inc.
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
DOE	U.S. Department of Energy
Dominion Energy	The legal entity, Dominion Energy, Inc., one or more of its consolidated subsidiaries (other than Virginia Power and Dominion Energy Gas) or operating segments, or the entirety of Dominion Energy, Inc. and its consolidated subsidiaries
Dominion Energy Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
Dominion Energy Gas	The legal entity, Dominion Energy Gas Holdings, LLC, one or more of its consolidated subsidiaries or operating segment, or the entirety of Dominion Energy Gas Holdings, LLC and its consolidated subsidiaries
Dominion Energy Midstream	The legal entity, Dominion Energy Midstream Partners, LP, one or more of its consolidated subsidiaries, Cove Point Holdings, Iroquois GP Holding Company, LLC, DECG and Dominion Energy Questar Pipeline (beginning December 1, 2016) or operating segment, or the entirety of Dominion Energy Midstream Partners, LP and its consolidated subsidiaries
Dominion Energy Questar	The legal entity, Dominion Energy Questar Corporation, one or more of its consolidated subsidiaries or operating segment, or the entirety of Dominion Energy Questar Corporation and its consolidated subsidiaries
Dominion Energy Questar Combination	Dominion Energy's acquisition of Dominion Energy Questar completed on September 16, 2016 pursuant to the terms of the agreement and plan of merger entered on January 31, 2016
Dominion Energy Questar Pipeline	Dominion Energy Questar Pipeline, LLC (formerly known as Questar Pipeline, LLC), one or more of its consolidated subsidiaries, or the entirety of Dominion Energy Questar Pipeline, LLC and its consolidated subsidiaries
Dominion Iroquois	Dominion Iroquois, Inc., which, effective May 2016, holds a 24.07% noncontrolling partnership interest in Iroquois
DSM	Demand-side management
Dth	Dekatherm
Duke	The legal entity, Duke Energy Corporation, one or more of its consolidated subsidiaries or operating segments, or the entirety of Duke Energy Corporation and its consolidated subsidiaries
East Ohio	The East Ohio Gas Company, doing business as Dominion Energy Ohio
Eastern Market Access Project	Project to provide 294,000 Dths/day of firm transportation service to help meet demand for natural gas for Washington Gas Light Company, a local gas utility serving customers in D.C., Virginia and Maryland, and Mattawoman Energy, LLC for its new electric power generation facility to be built in Maryland
Elwood	Elwood power station
Energy Choice	Program authorized by the Ohio Commission which provides energy customers with the ability to shop for energy options from a group of suppliers certified by the Ohio Commission
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPS	Earnings per share
ERISA	Employee Retirement Income Security Act of 1974
ERM	Enterprise Risk Management
ERO	Electric Reliability Organization
ESA	Endangered Species Act
Excess Tax Benefits	Benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Ltd.
Four Brothers	Four Brothers Solar, LLC, a limited liability company owned by Dominion Energy and Four Brothers Holdings, LLC, a wholly-owned subsidiary of NRG effective November 2016
Fowler Ridge	Fowler I Holdings LLC, a wind-turbine facility joint venture with BP in Benton County, Indiana
FTA	Free Trade Agreement
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
Gas Infrastructure	Gas Infrastructure Group operating segment
GHG	Greenhouse gas
Granite Mountain	Granite Mountain Holdings, LLC, a limited liability company owned by Dominion Energy and Granite Mountain Renewables, LLC, a wholly-owned subsidiary of NRG effective November 2016
Green Mountain	Green Mountain Power Corporation
Greensville County	An approximately 1,588 MW natural gas-fired combined-cycle power station under construction in Greensville County, Virginia
Hastings	A natural gas processing and fractionation facility located near Pine Grove, West Virginia
HATFA of 2014	Highway and Transportation Funding Act of 2014

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Abbreviation or Acronym	Definition
Heating degree days	Units measuring the extent to which the average daily temperature is less than 65 degrees Fahrenheit, calculated as the difference between 65 degrees and the average temperature for that day
Hope	Hope Gas, Inc., doing business as Dominion Energy West Virginia
Idaho Commission	Idaho Public Utilities Commission
IRCA	Intercompany revolving credit agreement
Iron Springs	Iron Springs Holdings, LLC, a limited liability company owned by Dominion Energy and Iron Springs Renewables, LLC, a wholly-owned subsidiary of NRG effective November 2016
Iroquois	Iroquois Gas Transmission System, L.P.
IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO New England
July 2016 hybrids	Dominion Energy's 2016 Series A Enhanced Junior Subordinated Notes due 2076
June 2006 hybrids	Dominion Energy's 2006 Series A Enhanced Junior Subordinated Notes due 2066
Kewaunee	Kewaunee nuclear power station
Kincaid	Kincaid power station
kV	Kilovolt
Liability Management Exercise	Dominion Energy exercise in 2014 to redeem certain debt and preferred securities
LIBOR	London Interbank Offered Rate
LIFO	Last-in-first-out inventory method
Line TL-388	A 37-mile, 24-inch gathering pipeline extending from Texas Eastern, LP in Noble County, Ohio to its terminus at Dominion Energy's Gilmore Station in Tuscarawas County, Ohio
Liquefaction Project	A natural gas export/liquefaction facility at Cove Point
LNG	Liquefied natural gas
Local 50	International Brotherhood of Electrical Workers Local 50
Local 69	Local 69, Utility Workers Union of America, United Gas Workers
LTIP	Long-term incentive program
MAP 21 Act	Moving Ahead for Progress in the 21st Century Act
Massachusetts Municipal	Massachusetts Municipal Wholesale Electric Company
MATS	Utility Mercury and Air Toxics Standard Rule
MBTA	Migratory Bird Treaty Act of 1918
mcf	Thousand cubic feet
mcfe	Thousand cubic feet equivalent
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MGD	Million gallons a day
Millstone	Millstone nuclear power station
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master limited partnership, also known as publicly traded partnership
Moody's	Moody's Investors Service
Morgans Corner	Morgans Corner Solar Energy, LLC
MW	Megawatt
MWh	Megawatt hour
NAV	Net asset value
NedPower	NedPower Mount Storm LLC, a wind-turbine facility joint venture between Dominion Energy and Shell in Grant County, West Virginia
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquid
NJNR	NJNR Pipeline Company
North Anna	North Anna nuclear power station
North Carolina Commission	North Carolina Utilities Commission
Northern System	Collection of approximately 131 miles of various diameter natural gas pipelines in Ohio
NOx	Nitrogen oxide
NRC	Nuclear Regulatory Commission
NRG	The legal entity, NRG Energy, Inc., one or more of its consolidated subsidiaries (including, effective November 2016, Four Brothers Holdings, LLC, Granite Mountain Renewables, LLC and Iron Springs Renewables, LLC) or operating segments, or the entirety of NRG Energy, Inc. and its consolidated subsidiaries
NSPS	New Source Performance Standards
NYSE	New York Stock Exchange
October 2014 hybrids	Dominion Energy's 2014 Series A Enhanced Junior Subordinated Notes due 2054

Abbreviation or Acronym	Definition
ODEC	Old Dominion Electric Cooperative
Ohio Commission	Public Utilities Commission of Ohio
Order 1000	Order issued by FERC adopting new requirements for electric transmission planning, cost allocation and development
Philadelphia Utility Index	Philadelphia Stock Exchange Utility Index
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPP	Percentage of Income Payment Plan deployed by East Ohio
PIR	Pipeline Infrastructure Replacement program deployed by East Ohio
PJM	PJM Interconnection, L.L.C.
Power Delivery	Power Delivery Group operating segment
Power Generation	Power Generation Group operating segment
ppb	Parts-per-billion
PREP	Pipeline Replacement and Expansion Program, a program of replacing, upgrading and expanding natural gas utility infrastructure deployed by Hope
PSMP	Pipeline Safety Management Program deployed by East Ohio to ensure the continued safe and reliable operation of East Ohio's system and compliance with pipeline safety laws
PSD	Prevention of significant deterioration
Questar Gas	Questar Gas Company
RCC	Replacement Capital Covenant
Regulation Act	Legislation effective July 1, 2007, that amended the Virginia Electric Utility Restructuring Act and fuel factor statute, which legislation is also known as the Virginia Electric Utility Regulation Act, as amended in 2015
RGGI	Regional Greenhouse Gas Initiative
Rider B	A rate adjustment clause associated with the recovery of costs related to the conversion of three of Virginia Power's coal-fired power stations to biomass
Rider BW	A rate adjustment clause associated with the recovery of costs related to Brunswick County
Rider GV	A rate adjustment clause associated with the recovery of costs related to Greensville County
Rider R	A rate adjustment clause associated with the recovery of costs related to Bear Garden
Rider S	A rate adjustment clause associated with the recovery of costs related to the Virginia City Hybrid Energy Center
Rider T1	A rate adjustment clause to recover the difference between revenues produced from transmission rates included in base rates, and the new total revenue requirement developed annually for the rate years effective September 1
Rider U	A rate adjustment clause associated with the recovery of costs of new underground distribution facilities
Rider US-2	A rate adjustment clause associated with Woodland, Scott Solar and Whitehouse
Rider W	A rate adjustment clause associated with the recovery of costs related to Warren County
Riders C1A and C2A	Rate adjustment clauses associated with the recovery of costs related to certain DSM programs approved in DSM cases
ROE	Return on equity
ROIC	Return on invested capital
RSN	Remarketable subordinated note
RTEP	Regional transmission expansion plan
RTO	Regional transmission organization
SAFSTOR	A method of nuclear decommissioning, as defined by the NRC, in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated to levels that permit release for unrestricted use
SAIDI	System Average Interruption Duration Index, metric used to measure electric service reliability
SBL Holdco	SBL Holdco, LLC, a wholly-owned subsidiary of DGI
SCANA	The legal entity, SCANA Corporation, one or more of its consolidated subsidiaries, or operating segments, or the entirety of SCANA Corporation and its consolidated subsidiaries
SCANA Merger Agreement	Agreement and plan of merger entered on January 2, 2018 between Dominion Energy and SCANA in which SCANA will become a wholly-owned subsidiary of Dominion Energy upon closing
SCE&G	South Carolina Electric & Gas Company, a wholly-owned subsidiary of SCANA
Scott Solar	A 17 MW utility-scale solar power station in Powhatan County, VA
SEC	Securities and Exchange Commission
September 2006 hybrids	Dominion Energy's 2006 Series B Enhanced Junior Subordinated Notes due 2066
Shell	Shell WindEnergy, Inc.
SO_2	Sulfur dioxide
South Carolina Commission	South Carolina Public Service Commission
Standard & Poor's	Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc.

Abbreviation or Acronym	Definition
SunEdison	The legal entity, SunEdison, Inc., one or more of its consolidated subsidiaries (including, through November 2016, Four Brothers Holdings, LLC, Granite Mountain Renewables, LLC and Iron Springs Renewables, LLC) or operating segments, or the entirety of SunEdison, Inc. and its consolidated subsidiaries
Surry	Surry nuclear power station
Terra Nova Renewable Partners	A partnership comprised primarily of institutional investors advised by J.P. Morgan Asset Management—Global Real Assets
Three Cedars	Granite Mountain and Iron Springs, collectively
TransCanada	The legal entity, TransCanada Corporation, one or more of its consolidated subsidiaries or operating segments, or the entirety of TransCanada Corporation and its consolidated subsidiaries
TSR	Total shareholder return
UEX Rider	Uncollectible Expense Rider deployed by East Ohio
Utah Commission	Public Service Commission of Utah
VDEQ	Virginia Department of Environmental Quality
VEBA	Voluntary Employees' Beneficiary Association
VIE	Variable interest entity
Virginia City Hybrid Energy Center	A 610 MW baseload carbon-capture compatible, clean coal powered electric generation facility in Wise County, Virginia
Virginia Commission	Virginia State Corporation Commission
Virginia Power	The legal entity, Virginia Electric and Power Company, one or more of its consolidated subsidiaries or operating segments, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries
VOC	Volatile organic compounds
Warren County	A 1,350 MW combined-cycle, natural gas-fired power station in Warren County, Virginia
West Virginia Commission	Public Service Commission of West Virginia
Western System	Collection of approximately 212 miles of various diameter natural gas pipelines and three compressor stations in Ohio
Wexpro	The legal entity, Wexpro Company, one or more of its consolidated subsidiaries, or the entirety of Wexpro Company and its consolidated subsidiaries
Wexpro Agreement	An agreement effective August 1981, which sets forth the rights of Questar Gas to receive certain benefits from Wexpro's operations, including cost-of-service gas
Wexpro II Agreement	An agreement with the states of Utah and Wyoming modeled after the Wexpro Agreement that allows for the addition of properties under the cost-of-service methodology for the benefit of Questar Gas customers
Whitehouse	A 20 MW utility-scale solar power station in Louisa County, VA
White River Hub	White River Hub, LLC
Woodland	A 19 MW utility-scale solar power station in Isle of Wight County, VA
Wyoming Commission	Wyoming Public Service Commission

Part I

Item 1. Business

GENERAL

Dominion Energy, headquartered in Richmond, Virginia and incorporated in Virginia in 1983, is one of the nation's largest producers and transporters of energy. Dominion Energy's strategy is to be a leading provider of electricity, natural gas and related services to customers primarily in the eastern and Rocky Mountain regions of the U.S. As of December 31, 2017, Dominion Energy's portfolio of assets includes approximately 26,000 MW of generating capacity, 6,600 miles of electric transmission lines, 57,900 miles of electric distribution lines, 14,800 miles of natural gas transmission, gathering and storage pipelines and 51,800 miles of gas distribution pipeline, exclusive of service lines. As of December 31, 2017, Dominion Energy serves nearly 6 million utility and retail energy customers and operates one of the nation's largest underground natural gas storage systems, with approximately 1 trillion cubic feet of storage capacity.

In September 2016, Dominion Energy completed the Dominion Energy Questar Combination for total consideration of $4.4 billion and Dominion Energy Questar, a Rockies-based integrated natural gas company, became a wholly-owned subsidiary of Dominion Energy. Questar Gas, a wholly-owned subsidiary of Dominion Energy Questar, is consolidated by Dominion Energy, and is a voluntary SEC filer. However, its Form 10-K is filed separately and is not combined herein.

In March 2014, Dominion Energy formed Dominion Energy Midstream, an MLP designed to grow a portfolio of natural gas terminaling, processing, storage, transportation and related assets. In October 2014, Dominion Energy Midstream launched its initial public offering and issued 20,125,000 common units representing limited partner interests. Dominion Energy has and may continue to investigate opportunities to acquire assets that meet its strategic objective for Dominion Energy Midstream. At December 31, 2017, Dominion Energy owns the general partner, 50.6% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Energy Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DECG, Dominion Energy Questar Pipeline and a 25.93% noncontrolling partnership interest in Iroquois. Dominion Energy Midstream is consolidated by Dominion Energy, and is an SEC registrant. However, its Form 10-K is filed separately and is not combined herein.

Dominion Energy is focused on expanding its investment in regulated electric generation, transmission and distribution and regulated natural gas transmission and distribution infrastructure. Dominion Energy expects approximately 90% of earnings from its primary operating segments to come from regulated and long-term contracted businesses.

Dominion Energy continues to expand and improve its regulated and long-term contracted electric and natural gas businesses, in accordance with its existing five-year capital investment program. A major impetus for this program is to meet the anticipated increase in demand in its electric utility service territory. Other drivers for the capital investment program include the construction of infrastructure to handle the increase in natural gas production from the Marcellus and Utica Shale formations, to upgrade Dominion Energy's gas and electric transmission and distribution networks, and to meet environmental requirements and standards set by various regulatory bodies. Investments in utility-scale solar generation are expected to be a focus in meeting such environmental requirements, particularly in Virginia. In September 2014, Dominion Energy announced the formation of Atlantic Coast Pipeline. Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina, to increase natural gas supplies in the region.

Dominion Energy has transitioned over the past decade to a more regulated, less volatile earnings mix as evidenced by its capital investments in regulated infrastructure, including the Dominion Energy Questar Combination, and in infrastructure whose output is sold under long-term purchase agreements as well as the sale of the electric retail energy marketing business in March 2014. Dominion Energy's nonregulated operations include merchant generation, energy marketing and price risk management activities and natural gas retail energy marketing operations. Dominion Energy's operations are conducted through various subsidiaries, including Virginia Power and Dominion Energy Gas.

Virginia Power, headquartered in Richmond, Virginia and incorporated in Virginia in 1909 as a Virginia public service corporation, is a wholly-owned subsidiary of Dominion Energy and a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and North Carolina. In Virginia, Virginia Power conducts business under the name "Dominion Energy Virginia" and primarily serves retail customers. In North Carolina, it conducts business under the name "Dominion Energy North Carolina" and serves retail customers located in the northeastern region of the state, excluding certain municipalities. In addition, Virginia Power sells electricity at wholesale prices to rural electric cooperatives, municipalities and into wholesale electricity markets. All of Virginia Power's stock is owned by Dominion Energy.

Dominion Energy Gas, a limited liability company formed in September 2013, is a wholly-owned subsidiary of Dominion Energy and a holding company. It serves as the intermediate parent company for certain of Dominion Energy's regulated natural gas operating subsidiaries, which conduct business activities through a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states, regulated gas transportation and distribution operations in Ohio, and gas gathering and processing activities primarily in West Virginia, Ohio and Pennsylvania. Dominion Energy Gas' principal wholly-owned subsidiaries are DETI, East Ohio, DGP and Dominion Iroquois. DETI is an interstate natural gas transmission pipeline company serving a broad mix of customers such as local gas distribution companies, marketers, interstate and intrastate pipelines, electric power generators and natural gas producers. The DETI system links to other major pipelines and markets in the mid-Atlantic, Northeast, and Midwest including Dominion Energy's Cove Point pipeline. DETI also operates one of the largest underground natural gas storage systems in the U.S. In August 2016, DETI transferred its gathering and processing facilities to DGP. East Ohio is a regulated natural gas distribution operation serving residential, commercial and industrial gas sales and transportation customers. Its service territory includes Cleveland, Akron, Canton, Youngstown and other eastern and western Ohio communities. In May 2016, Dominion Energy Gas sold 0.65% of the noncontrolling partnership interest in Iroquois, a FERC-regulated interstate natural gas pipeline in New York and Connecticut, to TransCanada. At December 31, 2017, Dominion Energy Gas holds a 24.07% noncontrolling partnership interest in Iroquois. All of Dominion Energy Gas' membership interests are owned by Dominion Energy.

Amounts and information disclosed for Dominion Energy are inclusive of Virginia Power and/or Dominion Energy Gas, where applicable.

EMPLOYEES

At December 31, 2017, Dominion Energy had approximately 16,200 full-time employees, of which approximately 5,200 are subject to collective bargaining agreements. At December 31, 2017, Virginia Power had approximately 6,900 full-time employees, of which approximately 3,100 are subject to collective bargaining agreements. At December 31, 2017, Dominion Energy Gas had approximately 3,000 full-time employees, of which approximately 2,100 are subject to collective bargaining agreements.

WHERE YOU CAN FIND MORE INFORMATION ABOUT THE COMPANIES

The Companies file their annual, quarterly and current reports, proxy statements and other information with the SEC. Their SEC filings are available to the public over the Internet at the SEC's website at http://www.sec.gov. You may also read and copy any document they file at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

The Companies make their SEC filings available, free of charge, including the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports, through Dominion Energy's internet website, http://www.dominionenergy.com, as soon as reasonably practicable after filing or furnishing the material to the SEC. Information contained on Dominion Energy's website is not incorporated by reference in this report.

ACQUISITIONS AND DISPOSITIONS

The following are significant acquisitions and divestitures by the Companies during the last five years.

PROPOSED ACQUISITION OF SCANA

Under the terms of the SCANA Merger Agreement announced in January 2018, Dominion Energy has agreed to issue 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock upon closing. In addition, Dominion Energy will provide the financial support for SCE&G to make a $1.3 billion up-front, one-time rate credit to all current electric service customers of SCE&G to be paid within 90 days of closing and a $575 million refund along with the benefit of the 2017 Tax Reform Act resulting in at least a 5% reduction to SCE&G electric service customers' bills over an estimated eight-year period as well as the exclusions from rate recovery of approximately $1.7 billion of costs related to the V.C. Summer Units 2 and 3 new nuclear development project and approximately $180 million to purchase the Columbia Energy Center power station. Subject to receipt of SCANA shareholder and any required regulatory approvals and meeting closing conditions, Dominion Energy targets closing by the end of 2018. See Note 3 to the Consolidated Financial Statements for additional information.

ACQUISITION OF DOMINION ENERGY QUESTAR

In September 2016, Dominion Energy completed the Dominion Energy Questar Combination for total consideration of $4.4 billion and Dominion Energy Questar became a wholly-owned subsidiary of Dominion Energy. In December 2016, Dominion Energy contributed Dominion Energy Questar Pipeline to Dominion Energy Midstream. See Note 3 to the Consolidated Financial Statements for additional information.

ACQUISITION OF WHOLLY-OWNED MERCHANT SOLAR PROJECTS

Throughout 2017, Dominion Energy completed the acquisition of various wholly-owned merchant solar projects in California, North Carolina and Virginia for $356 million. The projects cost $541 million to construct, including the initial acquisition cost, and generate 259 MW.

Throughout 2016, Dominion Energy completed the acquisition of various wholly-owned merchant solar projects in North Carolina, South Carolina and Virginia for $32 million. The projects cost $421 million to construct, including the initial acquisition cost, and generate 221 MW.

Throughout 2015, Dominion Energy completed the acquisition of various wholly-owned merchant solar projects in California and Virginia for $381 million. The projects cost $588 million to construct, including the initial acquisition cost, and generate 182 MW.

Throughout 2014, Dominion Energy completed the acquisition of various wholly-owned solar development projects in California for $200 million. The projects cost $578 million to construct, including the initial acquisition cost, and generate 179 MW.

See Note 3 to the Consolidated Financial Statements for additional information.

ACQUISITION OF VIRGINIA POWER SOLAR PROJECTS

In 2017, Virginia Power entered into agreements to acquire two solar development projects in North Carolina. The projects are expected to close in 2018 and 2019 with a total expected cost of $280 million once constructed, including the initial acquisition cost, and will generate approximately 155 MW combined. See Note 10 to the Consolidated Financial Statements for additional information.

SALE OF CERTAIN RETAIL ENERGY MARKETING ASSETS

In October 2017, Dominion Energy entered into an agreement to sell certain assets associated with its nonregulated retail energy marketing operations for total consideration of $143 million, subject to customary approvals and certain adjustments. Pursuant to the agreement, upon the first closing in December 2017, Dominion Energy entered into a commission agreement under which the buyer will pay a commission in connection with the right to use Dominion Energy's brand in marketing materials and other services over a ten-year term. See Note 10 to the Consolidated Financial Statements for additional information.

Assignment of Tower Rental Portfolio

Virginia Power rents space on certain of its electric transmission towers to various wireless carriers for communications antennas and other equipment. In March 2017, Virginia Power sold its rental portfolio to Vertical Bridge Towers II, LLC for $91 million in cash. See Note 10 to the Consolidated Financial Statements for additional information.

Acquisition of Non-Wholly-Owned Merchant Solar Projects

In 2015, Dominion Energy acquired 50% of the units in Four Brothers and Three Cedars from SunEdison for $107 million. In November 2016, NRG acquired the 50% of units in Four Brothers and Three Cedars previously held by SunEdison. The facilities began commercial operations in the third quarter of 2016, with generating capacity of 530 MW, at a cost of $1.1 billion. See Note 3 to the Consolidated Financial Statements for additional information.

Sale of Interest in Merchant Solar Projects

In September 2015, Dominion Energy signed an agreement to sell a noncontrolling interest (consisting of 33% of the equity interests) in all of its then wholly-owned merchant solar projects, 24 solar projects totaling 425 MW, to SunEdison. In December 2015, the sale of interest in 15 of the solar projects closed for $184 million with the sale of interest in the remaining projects completed in January 2016 for $117 million. Upon closing, SunEdison sold its interest in these projects to Terra Nova Renewable Partners. See Note 3 to the Consolidated Financial Statements for additional information.

Dominion Energy Midstream Acquisition of Interest in Iroquois

In September 2015, Dominion Energy Midstream acquired from NG and NJNR a 25.93% noncontrolling partnership interest in Iroquois. The investment was recorded at $216 million based on the value of Dominion Energy Midstream's common units at closing. The common units issued to NG and NJNR are reflected as noncontrolling interest in Dominion Energy's Consolidated Financial Statements. See Note 3 to the Consolidated Financial Statements for additional information.

Acquisition of DECG

In January 2015, Dominion Energy completed the acquisition of 100% of the equity interests of DECG from SCANA for $497 million in cash, as adjusted for working capital. In April 2015, Dominion Energy contributed DECG to Dominion Energy Midstream. See Note 3 to the Consolidated Financial Statements for additional information.

Assignments of Shale Development Rights

In December 2013, Dominion Energy Gas closed on agreements with two natural gas producers to convey over time approximately 100,000 acres of Marcellus Shale development rights underneath several natural gas storage fields. The agreements provided for payments to Dominion Energy Gas, subject to customary adjustments, of approximately $200 million over a period of nine years, and an overriding royalty interest in gas produced from that acreage. In March 2015, Dominion Energy Gas and a natural gas producer closed on an amendment to a December 2013 agreement, which included the immediate conveyance of approximately 9,000 acres of Marcellus Shale development rights and a two-year extension of the term of the original agreement. The conveyance of development rights resulted in the recognition of $43 million of previously deferred revenue. In April 2016, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the immediate conveyance of a 32% partial interest in the remaining approximately 70,000 acres. This conveyance resulted in the recognition of the remaining $35 million of previously deferred revenue. In August 2017, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the finalization of contractual matters on previous conveyances, the conveyance of Dominion Energy Gas' remaining 68% interest in approximately 70,000 acres and the elimination of Dominion Energy Gas' overriding royalty interest in gas produced from all acreage. As a result of this amendment, Dominion Energy Gas will receive total consideration of $130 million, with $65 million received in November 2017 and $65 million to be received by the end of the third quarter of 2018 in connection with the final conveyance.

In March 2015, Dominion Energy Gas conveyed to a natural gas producer approximately 11,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields and received proceeds of $27 million and an overriding royalty interest in gas produced from the acreage.

In September 2015, Dominion Energy Gas closed on an agreement with a natural gas producer to convey approximately 16,000 acres of Utica and Point Pleasant Shale development rights underneath one of its natural gas storage fields. The agreement provided for a payment to Dominion Energy Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage.

In November 2014, Dominion Energy Gas closed on an agreement with a natural gas producer to convey over time approximately 24,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields. The agreement provided for payments to Dominion Energy Gas, subject to customary adjustments, of approximately $120 million over a period of four years, and an overriding royalty interest in gas produced from the acreage. In January 2018, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the conveyance of Dominion Energy Gas' remaining 50% interest in approximately 18,000 acres and the elimination of Dominion Energy Gas' overriding royalty interest in gas produced from all acreage for proceeds of $28 million.

See Note 10 to the Consolidated Financial Statements for additional information on these sales of Marcellus acreage.

SALE OF ELECTRIC RETAIL ENERGY MARKETING BUSINESS

In March 2014, Dominion Energy completed the sale of its electric retail energy marketing business. The proceeds were $187 million, net of transaction costs. The sale of the electric retail energy marketing business did not qualify for discontinued operations classification.

SALE OF PIPELINES AND PIPELINE SYSTEMS

In March 2014, Dominion Energy Gas sold the Northern System to an affiliate that subsequently sold the Northern System to Blue Racer for consideration of $84 million. Dominion Energy Gas' consideration consisted of $17 million in cash proceeds and the extinguishment of affiliated current borrowings of $67 million and Dominion Energy's consideration consisted of cash proceeds of $84 million.

In September 2013, DETI sold Line TL-388 to Blue Racer for $75 million in cash proceeds.

SALE OF BRAYTON POINT, KINCAID AND EQUITY METHOD INVESTMENT IN ELWOOD

In August 2013, Dominion Energy completed the sale of Brayton Point, Kincaid and its equity method investment in Elwood to Energy Capital Partners and received proceeds of $465 million, net of transaction costs. The historical results of Brayton Point's and Kincaid's operations are presented in discontinued operations.

OPERATING SEGMENTS

Dominion Energy manages its daily operations through three primary operating segments: Power Delivery, Power Generation and Gas Infrastructure. Dominion Energy also reports a Corporate and Other segment, which includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's other operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Virginia Power manages its daily operations through two primary operating segments: Power Delivery and Power Generation. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Dominion Energy Gas manages its daily operations through its primary operating segment: Gas Infrastructure. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Energy Gas as a result of Dominion Energy's basis in the net assets contributed.

While daily operations are managed through the operating segments previously discussed, assets remain wholly-owned by the Companies and their respective legal subsidiaries.

A description of the operations included in the Companies' primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion Energy	Virginia Power	Dominion Energy Gas
Power Delivery	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Power Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Gas Infrastructure	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG terminalling and storage	X		
	Nonregulated retail energy marketing	X		

(1) Includes remaining producer services activities.

For additional financial information on operating segments, including revenues from external customers, see Note 25 to the Consolidated Financial Statements. For additional information on operating revenue related to the Companies' principal products and services, see Notes 2 and 4 to the Consolidated Financial Statements, which information is incorporated herein by reference.

Power Delivery

The Power Delivery Operating Segment of Dominion Energy and Virginia Power includes Virginia Power's regulated electric transmission and distribution (including customer service) operations, which serve approximately 2.6 million residential, commercial, industrial and governmental customers in Virginia and North Carolina.

Power Delivery's existing five-year investment plan includes spending approximately $8.5 billion from 2018 through 2022 to upgrade or add new transmission and distribution lines, substations and other facilities to meet growing electricity demand within its service territory and maintain reliability and regulatory compliance. The proposed electric delivery infrastructure projects are intended to address both continued customer growth and increases in electricity consumption. In addition, data centers continue to contribute to anticipated demand growth.

Revenue provided by electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Variability in earnings is driven primarily by changes in rates, weather, customer growth and other factors impacting consumption such as the economy and energy conservation, in addition to operating and maintenance expenditures. Operationally, electric distribution continues to focus on improving service levels while striving to reduce costs and link investments to operational results. SAIDI performance results, excluding major events, were 117 minutes at the end of 2017, down from the three-year average of 123 minutes. Virginia Power's overall customer satisfaction improved year over year when compared to 2016 J.D.

Power and Associates' scoring. In the future, safety, electric service reliability, outage durations and customer service will remain key focus areas for electric distribution. Modernizing the electric grid will become a key focus area to support the enhancement of the customer service experience, build upon improvements in resiliency and security and support enhanced innovation and renewable generation.

Revenue provided by Virginia Power's electric transmission operations is based primarily on rates approved by FERC. The profitability of this business is dependent on its ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability in earnings primarily results from changes in rates and the timing of property additions, retirements and depreciation.

Virginia Power is a member of PJM, a RTO, and its electric transmission facilities are integrated into PJM wholesale electricity markets. Consistent with the increased authority given to NERC by EPACT, Virginia Power's electric transmission operations are committed to meeting NERC standards, modernizing its infrastructure and maintaining superior system reliability. Virginia Power's electric transmission operations will continue to focus on safety, operational performance, NERC compliance and execution of PJM's RTEP.

COMPETITION

Power Delivery Operating Segment— Dominion Energy and Virginia Power

There is no competition for electric distribution service within Virginia Power's service territory in Virginia and North Carolina and no such competition is currently permitted. Historically, since its electric transmission facilities are integrated into PJM and electric transmission services are administered by PJM, there was no competition in relation to transmission service provided to customers within the PJM region. However, competition from non-incumbent PJM transmission owners for development, construction and ownership of certain transmission facilities in Virginia Power's service territory is now permitted pursuant to Order 1000, subject to state and local siting and permitting approvals. This could result in additional competition to build and own transmission infrastructure in Virginia Power's service area in the future and could allow Dominion Energy to seek opportunities to build and own facilities in other service territories.

REGULATION

Power Delivery Operating Segment—Dominion Energy and Virginia Power

Virginia Power's electric distribution service, including the rates it may charge to jurisdictional customers, is subject to regulation by the Virginia and North Carolina Commissions. Virginia Power's wholesale electric transmission rates, tariffs and terms of service are subject to regulation by FERC. Electric transmission siting authority remains the jurisdiction of the Virginia and North Carolina Commissions. However, EPACT provides FERC with certain backstop authority for transmission siting. See *State Regulations and Federal Regulations* in *Regulation* and Note 13 to the Consolidated Financial Statements for additional information.

PROPERTIES

Power Delivery Operating Segment—Dominion Energy and Virginia Power

Virginia Power has approximately 6,600 miles of electric transmission lines of 69 kV or more located in North Carolina, Virginia and West Virginia. Portions of Virginia Power's electric transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, any surplus capacity that may exist in these lines. While Virginia Power owns and maintains its electric transmission facilities, they are a part of PJM, which coordinates the planning, operation, emergency assistance and exchange of capacity and energy for such facilities.

As a part of PJM's RTEP process, PJM authorized the following material reliability projects (including Virginia Power's estimated cost):

- Surry-to-Skiffes Creek-to-Whealton ($325 million);
- Mt. Storm-to-Dooms ($240 million);
- Idylwood substation ($110 million);
- Dooms-to-Lexington ($130 million);
- Cunningham-to-Elmont ($110 million);
- Landstown voltage regulation ($70 million);
- Warrenton (including Remington CT-to-Warrenton, Vint Hill-to-Wheeler-to-Gainesville, and Vint Hill and Wheeler switching stations) ($110 million);
- Remington/Gordonsville/Pratts Area Improvement (including Remington-to-Gordonsville, and new Gordonsville substation transformer) ($110 million);
- Gainesville-to-Haymarket ($55 million);
- Kings Dominion-to-Fredericksburg ($50 million);
- Loudoun-Brambleton line-to-Poland Road Substation ($60 million);
- Cunningham-to-Dooms ($60 million);
- Carson-to-Rogers Road ($55 million);
- Dooms-Valley rebuild ($65 million);
- Mt. Storm-Valley rebuild ($225 million);
- Glebe-to-Station ($320 million);
- Idylwood-to-Tysons ($125 million);
- Chesterfield-to-Lakeside ($35 million); and
- Landstown-to-Thrasher ($25 million).

In addition, in December 2017, the Virginia Commission granted Virginia Power a CPCN to rebuild and operate in Lancaster County, Virginia and Middlesex County, Virginia, approximately 2 miles of existing 115 kV transmission lines to be constructed under the Rappahannock River between Harmony Village Substation and White Stone Substation. The total estimated cost of the project is approximately $85 million.

Virginia Power plans to increase transmission substation physical security and expects to invest $250 million—$300 million through 2022 to strengthen its electrical system to better protect critical equipment, enhance its spare equipment process and create multiple levels of security.

In addition, Virginia Power's electric distribution network includes approximately 57,900 miles of distribution lines, exclusive of service level lines, in Virginia and North Carolina. The grants for most of its electric lines contain rights-of-way that have been obtained from the apparent owners of real estate, but underlying titles have not been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many electric lines are on publicly-owned property, where permission to operate can be revoked.

Virginia legislation in 2014 provides for the recovery of costs, subject to approval by the Virginia Commission, for Virginia Power to move approximately 4,000 miles of electric distribution lines underground. The program is designed to reduce restoration outage time by moving Virginia Power's most outage-prone overhead distribution lines underground, has an annual investment cap of approximately $175 million and is expected to be completed over the next decade. In August 2016, the Virginia Commission approved the first phase of the program encompassing approximately 400 miles of converted lines and $140 million in capital spending (with approximately $123 million recoverable through Rider U). In September 2017, the Virginia Commission approved recovery through Rider U of a total capital investment of $40 million for second phase conversions.

SOURCES OF ENERGY SUPPLY

Power Delivery Operating Segment—Dominion Energy and Virginia Power

Power Delivery's supply of electricity to serve Virginia Power customers is produced or procured by Power Generation. See *Power Generation* for additional information.

SEASONALITY

Power Delivery Operating Segment—Dominion Energy and Virginia Power

Power Delivery's earnings vary seasonally as a result of the impact of changes in temperature, the impact of storms and other catastrophic weather events, and the availability of alternative sources for heating on demand by residential and commercial customers. Generally, the demand for electricity peaks during the summer and winter months to meet cooling and heating needs. An increase in heating degree days for Power Delivery's electric utility-related operations does not produce the same increase in revenue as an increase in cooling degree days, due to seasonal pricing differentials and because alternative heating sources are more readily available.

Power Generation

The Power Generation Operating Segment of Virginia Power includes the generation operations of the Virginia Power regulated electric utility and its related energy supply operations. Virginia Power's utility generation operations primarily serve the supply requirements for Power Delivery's utility customers. *The Power Generation Operating Segment of Dominion Energy* includes Virginia Power's generation facilities and its related energy supply operations as well as the generation operations of Dominion Energy's merchant fleet and energy marketing and price risk management activities for these assets.

Power Generation's existing five-year investment plan includes spending approximately $8.3 billion from 2018 through 2022 to construct new generation capacity and extend the life of nuclear generation facilities to meet growing electricity demand within its service territory and maintain reliability. The most significant project currently under construction is Greensville County, which is estimated to cost approximately $1.3 billion, excluding financing costs. See *Properties* and *Environmental Strategy* for additional information on this and other utility projects.

In addition, Dominion Energy's merchant fleet includes numerous renewable generation facilities, which include a fuel cell generation facility in Connecticut and solar generation facilities in operation or development in nine states, including Virginia. The output of these facilities is primarily sold under long-term power purchase agreements with terms generally ranging from 15 to 25 years. See Notes 3 and 10 to the Consolidated Financial Statements for additional information regarding certain solar projects.

Earnings for the *Power Generation Operating Segment of Virginia Power* primarily result from the sale of electricity generated by its utility fleet. Revenue is based primarily on rates established by state regulatory authorities and state law. Approximately 82% of revenue comes from serving Virginia jurisdictional customers. Base rates for the Virginia jurisdiction are set using a modified cost-of-service rate model, and are generally designed to allow an opportunity to recover the cost of providing utility service and earn a reasonable return on investments used to provide that service. Earnings variability may arise when revenues are impacted by factors not reflected in current rates, such as the impact of weather on customers' demand for services. Likewise, earnings may reflect variations in the timing or nature of expenses as compared to those contemplated in current rates, such as labor and benefit costs, capacity expenses, and the timing, duration and costs of scheduled and unscheduled outages. The cost of fuel and purchased power is generally collected through fuel cost-recovery mechanisms established by regulators and does not materially impact net income. The cost of new generation facilities is generally recovered through rate adjustment clauses in Virginia. Variability in earnings from rate adjustment clauses reflects changes in the authorized ROE and the carrying amount of these facilities, which are largely driven by the timing and amount of capital investments, as well as depreciation. See Note 13 to the Consolidated Financial Statements for additional information.

The Power Generation Operating Segment of Dominion Energy derives its earnings primarily from the sale of electricity generated by Virginia Power's utility and Dominion Energy's merchant generation assets, as well as from associated capacity and ancillary services. Variability in earnings provided by Dominion Energy's nonrenewable merchant fleet relates to changes in market-based prices received for electricity and capacity. Market-based prices for electricity are largely dependent on commodity prices, primarily natural gas, and the demand for electricity, which is primarily dependent upon weather. Capacity prices are dependent upon resource requirements in relation to the supply available (both existing and new) in the forward capacity auctions, which are held approximately three years in advance of the associated delivery year. Dominion Energy manages the electric price volatility of its merchant fleet by hedging a substantial portion of its expected near-term energy sales with derivative instruments. Variability also results from changes in the cost of fuel consumed, labor and benefits and the timing, duration and costs of scheduled and unscheduled outages. Variability in earnings provided by Dominion Energy's renewable merchant fleet is primarily driven by weather.

COMPETITION

Power Generation Operating Segment—Dominion Energy and Virginia Power

Virginia Power's generation operations are not subject to significant competition as only a limited number of its Virginia jurisdictional electric utility customers have retail choice. See *Electric* under *State Regulations* in *Regulation* for more information. Currently, North Carolina does not offer retail choice to electric customers.

Power Generation Operating Segment—Dominion Energy

Power Generation's recently acquired and developed renewable generation projects are not currently subject to significant competition as the output from these facilities is primarily sold under long-term power purchase agreements with terms generally ranging from 15 to 25 years. Competition for the nonrenewable merchant fleet is impacted by electricity and fuel prices, new market entrants, construction by others of generating assets and transmission capacity, technological advances in power generation, the actions of environmental and other regulatory authorities and other factors. These competitive factors may negatively impact the merchant fleet's ability to profit from the sale of electricity and related products and services.

Unlike Power Generation's regulated generation fleet, its nonrenewable merchant generation fleet is dependent on its ability to operate in a competitive environment and does not have a predetermined rate structure that provides for a rate of return on its capital investments. Power Generation's nonrenewable merchant assets operate within functioning RTOs and primarily compete on the basis of price. Competitors include other generating assets bidding to operate within the RTOs. Power Generation's nonrenewable merchant units compete in the wholesale market with other generators to sell a variety of products including energy, capacity and ancillary services. It is difficult to compare various types of generation given the wide range of fuels, fuel procurement strategies, efficiencies and operating characteristics of the fleet within any given RTO. However, Dominion Energy applies its expertise in operations, dispatch and risk management to maximize the degree to which its nonrenewable merchant fleet is competitive compared to similar assets within the region.

In November 2017, Connecticut adopted the Act Concerning Zero Carbon Solicitation and Procurement, which allows nuclear generating facilities to compete for power purchase agreements in a state sponsored procurement for electricity. In February 2018, Connecticut regulators recommended pursuing the procurement. They are expected to issue a request for proposals by May 1, 2018. Millstone will participate in the state sponsored procurement. If successful in the competitive bid process, Millstone would receive a long-term power purchase agreement for between three and ten years.

REGULATION

Power Generation Operating Segment—Dominion Energy and Virginia Power

Virginia Power's utility generation fleet and Dominion Energy's merchant generation fleet are subject to regulation by FERC, the NRC, the EPA, the DOE, the Army Corps of Engineers and other federal, state and local authorities. Virginia Power's utility generation fleet is also subject to regulation by the Virginia and North Carolina Commissions. See *Regulation, Future Issues and Other Matters* in Item 7. MD&A and Notes 13 and 22 to the Consolidated Financial Statements for more information.

PROPERTIES

For a listing of Dominion Energy's and Virginia Power's existing generation facilities, see Item 2. Properties.

Power Generation Operating Segment—Dominion Energy and Virginia Power

The generation capacity of Virginia Power's electric utility fleet totals approximately 20,800 MW. The generation mix is diversified and includes gas, coal, nuclear, oil, renewables, biomass and power purchase agreements. Virginia Power's generation facilities are located in Virginia, West Virginia and North Carolina and serve load in Virginia and northeastern North Carolina.

Virginia Power is developing, financing and constructing new generation capacity to meet growing electricity demand within its service territory. Significant projects under construction or development are set forth below:

- Virginia Power plans to acquire or construct certain solar facilities in Virginia and North Carolina. See Notes 10 and 13 to the Consolidated Financial Statements for more information.
- Virginia Power continues to consider the construction of a third nuclear unit at a site located at North Anna. See Note 13 to the Consolidated Financial Statements for more information on this project.
- Virginia Power is considering the construction of a hydroelectric pumped storage facility in Southwest Virginia.
- In March 2016, the Virginia Commission authorized the construction of Greensville County and related transmission interconnection facilities. Commercial operations are expected to commence in late 2018, at an estimated cost of approximately $1.3 billion, excluding financing costs.
- In June 2017, Virginia Power signed an agreement to develop two 6 MW wind turbines off the coast of Virginia for the Coastal Virginia Offshore Wind project. The project is expected to cost approximately $300 million and to be installed by the end of 2020.
- In October 2017, Virginia Power received a permit by rule from the VDEQ to construct and operate the Hollyfield solar facility, a 17 MW solar facility in King William County, Virginia and related distribution interconnection facilities. The total estimated cost of the Hollyfield solar facility is approximately $33 million, excluding financing costs. The facility is the subject of a public-private partnership whereby the University of Virginia, an agency of the Commonwealth of Virginia and a non-jurisdictional customer, will compensate Virginia Power for the facility's net electrical energy output.

Power Generation Operating Segment—Dominion Energy

The generation capacity of Dominion Energy's merchant fleet totals approximately 5,100 MW. The generation mix is diversified and includes nuclear, natural gas and renewables. Merchant nonrenewable generation facilities are located in Connecticut, Pennsylvania and Rhode Island, with a majority of that capacity concentrated in New England. Dominion Energy's merchant renewable generation facilities include a fuel cell generation facility in Connecticut, solar generation facilities in California, Connecticut, Georgia, Indiana, North Carolina, South Carolina, Tennessee, Utah and Virginia, and wind generation facilities in Indiana and West Virginia.

Sources of Energy Supply

Power Generation Operating Segment—Dominion Energy and Virginia Power

Power Generation uses a variety of fuels to power its electric generation and purchases power for utility system load requirements and to satisfy physical forward sale requirements, as described below. Some of these agreements have fixed commitments and are included as contractual obligations in *Future Cash Payments for Contractual Obligations and Planned Capital Expenditures* in Item 7. MD&A.

Nuclear Fuel—Power Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. Worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices which are dependent on the market environment. Current agreements, inventories and spot market availability are expected to support current and planned fuel supply needs. Additional fuel is purchased as required to ensure optimal cost and inventory levels.

Fossil Fuel—Power Generation primarily utilizes natural gas and coal in its fossil fuel plants. All recent fossil fuel plant construction for Power Generation involves natural gas generation.

Power Generation's natural gas and oil supply is obtained from various sources including purchases from major and independent producers in the Mid-Continent and Gulf Coast regions, purchases from local producers in the Appalachian area and Marcellus and Utica regions, purchases from gas marketers and withdrawals from underground storage fields owned by Dominion Energy or third parties. Power Generation manages a portfolio of natural gas transportation contracts (capacity) that provides for reliable natural gas deliveries to its gas turbine fleet, while minimizing costs.

Power Generation's coal supply is obtained through long-term contracts and short-term spot agreements from domestic suppliers.

Biomass—Power Generation's biomass supply is obtained through long-term contracts and short-term spot agreements from local suppliers.

Purchased Power—Power Generation purchases electricity from the PJM spot market and through power purchase agreements with other suppliers to provide for utility system load requirements.

Power Generation also occasionally purchases electricity from the PJM and ISO-NE spot markets to satisfy physical forward sale requirements as part of its merchant generation operations.

Power Generation Operating Segment—Virginia Power

Presented below is a summary of Virginia Power's actual system output by energy source:

Source	2017	2016	2015
Nuclear(1)	**32%**	31%	30%
Natural gas	**32**	31	23
Coal(2)	**17**	24	26
Purchased power, net	**14**	8	15
Other(3)	**5**	6	6
Total	**100%**	100%	100%

(1) Excludes ODEC's 11.6% ownership interest in North Anna.
(2) Excludes ODEC's 50.0% ownership interest in the Clover power station.
(3) Includes oil, hydro, biomass and solar.

Seasonality

Power Generation Operating Segment—Dominion Energy and Virginia Power

Sales of electricity for Power Generation typically vary seasonally as a result of the impact of changes in temperature and the availability of alternative sources for heating on demand by residential and commercial customers. See *Power Delivery-Seasonality* above for additional considerations that also apply to Power Generation.

Nuclear Decommissioning

Power Generation Operating Segment—Dominion Energy and Virginia Power

Virginia Power has a total of four licensed, operating nuclear reactors at Surry and North Anna in Virginia.

Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. Amounts collected from ratepayers are placed into trusts and are invested to fund the expected future costs of decommissioning the Surry and North Anna units.

Virginia Power believes that the decommissioning funds and their expected earnings for the Surry and North Anna units will be sufficient to cover expected decommissioning costs, particularly when combined with future ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. This reflects the long-term investment horizon, since the units will not be decommissioned for decades, and a positive long-term outlook for trust fund investment returns. Virginia Power will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirements, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC.

The estimated cost to decommission Virginia Power's four nuclear units is reflected in the table below and is primarily based upon site-specific studies completed in 2014. These cost studies are generally completed every four to five years. The current cost estimates assume decommissioning activities will begin shortly after cessation of operations, which will occur when the operating licenses expire.

Under the current operating licenses, Virginia Power is scheduled to decommission the Surry and North Anna units during the period 2032 to 2078. NRC regulations allow licensees to apply for extension of an operating license in up to 20-year increments. Virginia Power has announced its intention to apply for operating life extensions for Surry and North Anna.

Power Generation Operating Segment—Dominion Energy

In addition to the four nuclear units discussed above, Dominion Energy has two licensed, operating nuclear reactors at Millstone in Connecticut. A third Millstone unit ceased operations before Dominion Energy acquired the power station. In May 2013, Dominion Energy ceased operations at its single Kewaunee unit in Wisconsin and commenced decommissioning activities using the SAFSTOR methodology. The planned decommissioning completion date is 2073, which is within the NRC allowed 60-year window.

As part of Dominion Energy's acquisition of both Millstone and Kewaunee, it acquired decommissioning funds for the related units. Any funds remaining in Kewaunee's trust after decommissioning is completed are required to be refunded to Wisconsin ratepayers. Dominion Energy believes that the amounts currently available in the decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. Dominion Energy will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirements, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC. The estimated cost to decommission Dominion Energy's eight units is reflected in the table below and is primarily based upon site-specific studies completed for Surry, North Anna and Millstone in 2014 and for Kewaunee in 2013.

The estimated decommissioning costs and license expiration dates for the nuclear units owned by Dominion Energy and Virginia Power are shown in the following table:

(dollars in millions)	NRC license expiration year	Most recent cost estimate (2017 dollars)(1)	Funds in trusts at December 31, 2017	2017 contributions to trusts
Surry				
Unit 1	2032	$ 612	$ 680	$ —
Unit 2	2033	633	670	—
North Anna				
Unit 1(2)	2038	524	541	—
Unit 2(2)	2040	536	508	—
Total (Virginia Power)		2,305	2,399	—
Millstone				
Unit 1(3)	N/A	377	533	—
Unit 2	2035	575	700	—
Unit 3(4)	2045	698	688	—
Kewaunee				
Unit 1(5)	N/A	452	773	—
Total (Dominion Energy)		$ 4,407	$ 5,093	$ —

(1) The cost estimates shown above reflect reductions for the expected future recovery of certain spent fuel costs based on Dominion Energy's and Virginia Power's contracts with the DOE for disposal of spent nuclear fuel consistent with the reductions reflected in Dominion Energy's and Virginia Power's nuclear decommissioning AROs.

(2) North Anna is jointly owned by Virginia Power (88.4%) and ODEC (11.6%). However, Virginia Power is responsible for 89.26% of the decommissioning obligation. Amounts reflect 89.26% of the decommissioning cost for both of North Anna's units.

(3) Unit 1 permanently ceased operations in 1998, before Dominion Energy's acquisition of Millstone.

(4) Millstone Unit 3 is jointly owned by Dominion Energy Nuclear Connecticut, Inc., with a 6.53% undivided interest in Unit 3 owned by Massachusetts Municipal and Green Mountain. Decommissioning cost is shown at Dominion Energy's ownership percentage. At December 31, 2017, the minority owners held $42 million of trust funds related to Millstone Unit 3 that are not reflected in the table above.

(5) Permanently ceased operations in 2013.

Also see Notes 14 and 22 to the Consolidated Financial Statements for further information about AROs and nuclear decommissioning, respectively, and Note 9 to the Consolidated Financial Statements for information about nuclear decommissioning trust investments.

Gas Infrastructure

The Gas Infrastructure Operating Segment of Dominion Energy Gas includes certain of Dominion Energy's regulated natural gas operations. DETI, the gas transmission pipeline and storage business, serves gas distribution businesses and other customers in the Northeast, mid-Atlantic and Midwest. East Ohio, the primary gas distribution business of Dominion Energy Gas, serves residential, commercial and industrial gas sales, transportation and gathering service customers primarily in Ohio. DGP conducts gas gathering and processing activities, which include the sale of extracted products at market rates, primarily in West Virginia, Ohio and Pennsylvania. Dominion Iroquois holds a 24.07% noncontrolling partnership interest in Iroquois, which provides service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end users, through interconnecting pipelines and exchanges primarily in New York.

The Gas Infrastructure Operating Segment of Dominion Energy includes LNG operations, Dominion Energy Questar operations, Hope's gas distribution operations in West Virginia, and nonregulated retail natural gas marketing, as well as Dominion Energy's investments in the Blue Racer joint venture, Atlantic Coast Pipeline and Dominion Energy Midstream. See *Properties and Investments* below for additional information regarding the Blue Racer and Atlantic Coast Pipeline investments. Dominion Energy's LNG operations involve the import and storage of LNG at Cove Point and the transportation of regasified LNG to the interstate pipeline grid and mid-Atlantic and Northeast markets. Dominion Energy has received DOE and FERC approval to export LNG from Cove Point and, once the Liquefaction Project commences commercial operations, will be able to import LNG and regasify it as natural gas and liquefy natural gas and export it as LNG. See Note 22 to the Consolidated Financial Statements for more information.

In September 2016, Dominion Energy completed the Dominion Energy Questar Combination and Dominion Energy Questar, a Rockies-based integrated natural gas company, became a wholly-owned subsidiary of Dominion Energy. Dominion Energy Questar included Questar Gas, Wexpro and Dominion Energy Questar Pipeline at closing. Questar Gas' regulated gas distribution operations in Utah, southwestern Wyoming and southeastern Idaho includes 29,600 miles of gas distribution pipeline. Wexpro develops and produces natural gas from reserves supplied to Questar Gas under a cost-of-service framework. Dominion Energy Questar Pipeline provides FERC-regulated interstate natural gas transportation and storage services in Utah, Wyoming and western Colorado through 2,200 miles of gas transmission pipeline and 56 bcf of working gas storage. See *Acquisitions and Dispositions* above and Note 3 to the Consolidated Financial Statements for a description of the Dominion Energy Questar Combination.

In 2014, Dominion Energy formed Dominion Energy Midstream, an MLP initially consisting of a preferred equity interest in Cove Point. See *General* above for more information. Also see *Acquisitions and Dispositions* above and Note 3 to the Consolidated Financial Statements for a description of Dominion Energy's contribution of Dominion Energy Questar Pipeline to

Dominion Energy Midstream in December 2016 as well as Dominion Energy's acquisition of DECG, which Dominion Energy contributed to Dominion Energy Midstream in April 2015, and Dominion Energy Midstream's acquisition of a 25.93% noncontrolling partnership interest in Iroquois in September 2015. DECG provides FERC-regulated interstate natural gas transportation services in South Carolina and southeastern Georgia through 1,500 miles of gas transmission pipeline.

Gas Infrastructure's existing five-year investment plan includes spending approximately $8.3 billion from 2018 through 2022 to upgrade existing or add new infrastructure to meet growing energy needs within its service territory and maintain reliability. Demand for natural gas is expected to continue to grow as initiatives to transition to gas from more carbon-intensive fuels are implemented. This plan includes Dominion Energy's portion of spending for the Atlantic Coast Pipeline Project.

Earnings for the *Gas Infrastructure Operating Segment of Dominion Energy Gas* primarily result from rates established by FERC and the Ohio Commission. The profitability of this business is dependent on Dominion Energy Gas' ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability in earnings results from changes in operating and maintenance expenditures, as well as changes in rates and the demand for services, which are dependent on weather, changes in commodity prices and the economy.

Approximately 91% of DETI's transmission capacity is subscribed including 86% under long-term contracts (two years or greater) and 5% on a year-to-year basis. DETI's storage services are 100% subscribed with long-term contracts.

Revenue from processing and fractionation operations largely results from the sale of commodities at market prices. For DGP's processing plants, Dominion Energy Gas receives the wet gas product from producers and may retain the extracted NGLs as compensation for its services. This exposes Dominion Energy Gas to commodity price risk for the value of the spread between the NGL products and natural gas. In addition, Dominion Energy Gas has volumetric risk as the majority of customers receiving these services are not required to deliver minimum quantities of gas.

East Ohio utilizes a straight-fixed-variable rate design for a majority of its customers. Under this rate design, East Ohio recovers a large portion of its fixed operating costs through a flat monthly charge accompanied by a reduced volumetric base delivery rate. Accordingly, East Ohio's revenue is less impacted by weather-related fluctuations in natural gas consumption than under the traditional rate design.

Earnings for the *Gas Infrastructure Operating Segment of Dominion Energy* primarily include the results of rates established by FERC and the West Virginia, Utah, Wyoming and Idaho Commissions. Additionally, Dominion Energy receives revenue from firm fee-based contractual arrangements, including negotiated rates, for certain LNG storage and terminalling services. Dominion Energy Questar Pipeline's and DECG's revenues are primarily derived from reservation charges for firm transportation and storage services as provided for in their FERC-approved tariffs. Revenue provided by Questar Gas' operations is based primarily on rates established by the Utah and Wyoming Commissions. The Idaho Commission has contracted with the Utah Commission for rate oversight of Questar Gas operations in a small area of southeastern Idaho. Hope's gas distribution operations in West Virginia serve residential, commercial, sale for resale and industrial gas sales, transportation and gathering service customers. Revenue provided by Hope's operations is based primarily on rates established by the West Virginia Commission. The profitability of these businesses is dependent on their ability, through the rates they are permitted to charge, to recover costs and earn a reasonable return on their capital investments. Variability in earnings results from changes in operating and maintenance expenditures, as well as changes in rates and the demand for services, which are dependent on weather, changes in commodity prices and the economy.

COMPETITION

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Dominion Energy Gas' natural gas transmission operations compete with domestic and Canadian pipeline companies. Dominion Energy Gas also competes with gas marketers seeking to provide or arrange transportation, storage and other services. Alternative fuel sources, such as oil or coal, provide another level of competition. Although competition is based primarily on price, the array of services that can be provided to customers is also an important factor. The combination of capacity rights held on certain long-line pipelines, a large storage capability and the availability of numerous receipt and delivery points along its own pipeline system enable Dominion Energy to tailor its services to meet the needs of individual customers.

DGP's processing and fractionation operations face competition in obtaining natural gas supplies for its processing and related services. Numerous factors impact any given customer's choice of processing services provider, including the location of the facilities, efficiency and reliability of operations, and the pricing arrangements offered.

In Ohio, there has been no legislation enacted to require supplier choice for natural gas distribution consumers. However, East Ohio has offered an Energy Choice program to residential and commercial customers since October 2000. East Ohio has since taken various steps approved by the Ohio Commission toward exiting the merchant function, including restructuring its commodity service and placing Energy Choice-eligible customers in a direct retail relationship with participating suppliers. Further, in April 2013, East Ohio fully exited the merchant function for its nonresidential customers, which are now required to choose a retail supplier or be assigned to one at a monthly variable rate set by the supplier. At December 31, 2017, approximately 1 million of East Ohio's 1.2 million Ohio customers were participating in the Energy Choice program.

Gas Infrastructure Operating Segment—Dominion Energy

Questar Gas and Hope do not currently face direct competition from other distributors of natural gas for residential and commercial customers in their service territories as state regulations in Utah, Wyoming and Idaho for Questar Gas, and West Virginia for Hope, do not allow customers to choose their provider at this time. See *State Regulations* in *Regulation* for additional information.

Cove Point's gas transportation, LNG import and storage operations, as well as the Liquefaction Project's capacity are contracted primarily under long-term fixed reservation fee agreements. However, in the future Cove Point may compete with other independent terminal operators as well as major oil and gas companies on the basis of terminal location, services provided and price. Competition from terminal operators primarily comes from refiners and distribution companies with marketing and trading arms.

Dominion Energy Questar Pipeline's and DECG's pipeline systems generate a substantial portion of their revenue from long-term firm contracts for transportation services and are therefore insulated from competitive factors during the terms of the contracts. When these long-term contracts expire, Dominion Energy Questar Pipeline's pipeline system faces competitive pressures from similar facilities that serve the Rocky Mountain region and DECG's pipeline system faces competitive pressures from similar facilities that serve the South Carolina and southeastern Georgia area in terms of location, rates, terms of service, and flexibility and reliability of service.

Dominion Energy's retail energy marketing operations compete against incumbent utilities and other energy marketers in nonregulated energy markets for natural gas. In March 2014, Dominion Energy completed the sale of its electric retail energy marketing business. In October 2017, Dominion Energy entered into an agreement to sell certain assets associated with its nonregulated retail energy marketing operations. The sale is expected to be completed by the end of 2018. The remaining retail natural gas business consists of approximately 350,000 customer accounts in five states. The heaviest concentration of customers in these markets are located in states where utilities have the advantage of long-standing commitment to customer choice, primarily Ohio and Pennsylvania.

REGULATION

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Dominion Energy Gas' natural gas transmission and storage operations are regulated primarily by FERC. East Ohio's gas distribution operations, including the rates that it may charge to customers, are regulated by the Ohio Commission. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

Gas Infrastructure Operating Segment—Dominion Energy

Cove Point's, Dominion Energy Questar Pipeline's, and DECG's operations are regulated primarily by FERC. Questar Gas' distribution operations, including the rates it may charge customers, are regulated by the Utah, Wyoming and Idaho Commissions. Hope's gas distribution operations, including the rates that it may charge customers, are regulated by the West Virginia Commission. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

PROPERTIES AND INVESTMENTS

For a description of Dominion Energy's and Dominion Energy Gas' existing facilities see Item 2. Properties.

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Dominion Energy Gas has the following significant projects under construction or development to better serve customers or expand its service offerings within its service territory.

In January 2018, DETI filed an application to request FERC authorization to construct and operate certain facilities located in Ohio and Pennsylvania for the Sweden Valley project. The project is expected to cost approximately $50 million and provide 120,000 Dths per day of firm transportation service from Pennsylvania to Ohio for delivery to Tennessee Gas Pipeline Company, L.L.C. The project's capacity is fully subscribed pursuant to a precedent agreement with one customer and is expected to be placed into service in the fourth quarter of 2019.

In September 2014, DETI announced its intent to construct and operate the Supply Header project which is estimated to cost between $550 million and $600 million to construct, excluding financing costs, and provide 1,500,000 Dths per day of firm transportation service to various customers. In December 2014, DETI entered into a precedent agreement with Atlantic Coast Pipeline for the Supply Header project. In October 2017, DETI received FERC authorization to construct and operate the project facilities, with the facilities expected to be in service in late 2019.

In 2008, East Ohio began PIR, aimed at replacing approximately 4,100 miles of its pipeline system at a cost of $2.7 billion. In 2011, approval was obtained to include an additional 1,450 miles and to increase annual capital investment to meet the program goal. The program will replace approximately 25% of the pipeline system and is anticipated to take place over a total of 25 years. In March 2015, East Ohio filed an application with the Ohio Commission requesting approval to extend the PIR program for an additional five years and to increase the annual capital investment, with corresponding increases in the annual rate-increase caps. In September 2016, the Ohio Commission approved a stipulation filed jointly by East Ohio and the Staff of the Ohio Commission to settle East Ohio's pending application. As requested, the PIR program and associated cost recovery will continue for another five-year term, calendar years 2017 through 2021, and East Ohio will be permitted to increase its annual capital expenditures to $200 million by 2018 and 3% per year thereafter subject to the cost recovery rate increase caps proposed by East Ohio. Costs associated with calendar year 2016 investment will be recovered under the existing terms. In April 2017, the Ohio Commission approved East Ohio's application to adjust the PIR cost recovery rates for 2016 costs. The filing reflects gross plan investment for 2016 of $188 million, cumulative gross plant investment of $1.2 billion and a revenue requirement of $157 million.

Gas Infrastructure Operating Segment—Dominion Energy

Dominion Energy has the following significant projects under construction or development.

Cove Point—Dominion Energy expects the Liquefaction Project to commence commercial operations in March 2018, which will enable the Cove Point facility to liquefy domestically-produced natural gas and export it as LNG. The DOE previously authorized Dominion Energy to export LNG to countries with free trade agreements. In September 2013, the DOE authorized

Dominion Energy to export LNG from Cove Point to non-free trade agreement countries.

In September 2014, Cove Point received the FERC order authorizing the Liquefaction Project with certain conditions. The conditions regarding the Liquefaction Project set forth in the FERC order largely incorporate the mitigation measures proposed in the environmental assessment. In October 2014, Cove Point commenced construction of the Liquefaction Project, with an in-service date anticipated in March 2018 at a total estimated cost of approximately $4.1 billion, excluding financing costs. The Cove Point facility is authorized to export at a rate of 770 million cubic feet of natural gas per day for a period of 20 years.

In April 2013, Dominion Energy announced it had fully subscribed the capacity of the project with 20-year terminal service agreements. ST Cove Point, LLC, a joint venture of Sumitomo Corporation, a Japanese corporation that is one of the world's leading trading companies, and Tokyo Gas Co., Ltd., a Japanese corporation that is the largest natural gas utility in Japan, and GAIL Global (USA) LNG LLC, a wholly-owned indirect U.S. subsidiary of GAIL (India) Ltd., have each contracted for half of the capacity. Following completion of the front-end engineering and design work, Dominion Energy also announced it had awarded its engineering, procurement and construction contract for new liquefaction facilities to IHI/Kiewit Cove Point, a joint venture between IHI E&C International Corporation and Kiewit Energy Company.

Cove Point has historically operated as an LNG import facility under various long-term import contracts. Since 2010, Dominion Energy has renegotiated certain existing LNG import contracts in a manner that will result in a significant reduction in pipeline and storage capacity utilization and associated anticipated revenues during the period from 2017 through 2028. Such amendments created the opportunity for Dominion Energy to explore the Liquefaction Project, which, will extend the economic life of Cove Point and contribute to Dominion Energy's overall growth plan. In total, these renegotiations reduced Cove Point's expected annual revenues from the import-related contracts by approximately $150 million from 2017 through 2028, partially offset by approximately $50 million of additional revenues in the years 2013 through 2017.

In June 2015, Cove Point executed binding agreements with two customers for the approximately $150 million Eastern Market Access Project. In January 2018, Cove Point received FERC authorization to construct and operate the project facilities, which are expected to be placed into service in early 2019.

DECG—In 2014, DECG executed binding precedent agreements with three customers for the Charleston project. The project is expected to cost approximately $125 million, and provide 80,000 Dths per day of firm transportation service from an existing interconnect with Transcontinental Gas Pipe, LLC in Spartanburg County, South Carolina to customers in Dillon, Marlboro, Sumter, Charleston, Lexington and Remington counties, South Carolina. In February 2017, DECG received FERC approval to construct and operate the project facilities, which are expected to be placed into service in March 2018.

Questar Gas—In 2010, Questar Gas began replacing aging high pressure infrastructure under a cost-tracking mechanism that allows it to place into rate base and earn a return on capital expenditures associated with a multi-year natural gas infrastructure-replacement program upon the completion of each project. At that time, the commission-allowed annual spending in the replacement program was approximately $55 million.

In its 2014 Utah general rate case, Questar Gas received approval to include intermediate high pressure infrastructure in the replacement program and increase the annual spending limit to approximately $65 million, adjusted annually using a gross domestic product inflation factor. At that time, 420 miles of high pressure pipe and 70 miles of intermediate high pressure pipe were identified to be replaced in the program over a 17-year period. Questar Gas has spent about $65 million each year through 2017 under this program. The program is evaluated in each Utah general rate case. The next Utah general rate case is anticipated to occur in 2019.

Gas Infrastructure Equity Method Investments—In September 2015, Dominion Energy, through Dominion Energy Midstream, acquired an additional 25.93% interest in Iroquois. Dominion Energy Gas holds a 24.07% interest with TransCanada holding a 50% interest. Iroquois owns and operates a 416-mile FERC regulated interstate natural gas pipeline providing service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end-users, through interconnecting pipelines and exchanges. Iroquois' pipeline extends from the U.S.-Canadian border at Waddington, New York through the state of Connecticut to South Commack, Long Island, New York and continuing on from Northport, Long Island, New York through the Long Island Sound to Hunts Point, Bronx, New York. See Note 9 to the Consolidated Financial Statements for further information about Dominion Energy's equity method investment in Iroquois.

In September 2014, Dominion Energy, along with Duke and Southern Company Gas, announced the formation of Atlantic Coast Pipeline. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion Energy an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. In October 2016, Dominion Energy purchased an additional 3% membership interest in Atlantic Coast Pipeline from Duke for $14 million. The members hold the following membership interests: Dominion Energy, 48%; Duke, 47%; and Southern Company Gas, 5%. Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina, with development and construction costs estimated between $6.0 billion and $6.5 billion, excluding financing costs. In October 2014, Atlantic Coast Pipeline requested approval from FERC to utilize the pre-filing process under which environmental review for the natural gas pipeline project will commence. Atlantic Coast Pipeline filed its FERC application in September 2015 and expects to be in service in late 2019. In October 2017, Atlantic Coast Pipeline received the FERC order authorizing the construction and operation of the project. The FERC order has been appealed to the U.S. Court of Appeals for the Fourth Circuit and the project remains subject to other pending federal and state approvals. See Note 9 to the Consolidated Financial Statements for further information about Dominion Energy's equity method investment in Atlantic Coast Pipeline.

In December 2012, Dominion Energy formed Blue Racer with Caiman to provide midstream services to natural gas producers operating in the Utica Shale region in Ohio and portions of Pennsylvania. Blue Racer is an equal partnership between Dominion Energy and Caiman, with Dominion Energy contributing midstream assets and Caiman contributing private equity capital. Midstream services offered by Blue Racer include gathering, processing, fractionation, and natural gas liquids transportation and marketing. Blue Racer is expected to develop additional new capacity designed to meet producer needs as the development of the Utica Shale formation increases. See Note 9 to the Consolidated Financial Statements for further information about Dominion Energy's equity method investment in Blue Racer.

SOURCES OF ENERGY SUPPLY

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Dominion Energy's and Dominion Energy Gas' natural gas supply is obtained from various sources including purchases from major and independent producers in the Mid-Continent and Gulf Coast regions, local producers in the Appalachian area, gas marketers and, for Questar Gas specifically, from Wexpro and other producers in the Rocky Mountain region. Wexpro's gas development and production operations serve the majority of Questar Gas' gas supply requirements in accordance with the Wexpro Agreement and the Wexpro II Agreement, comprehensive agreements with the states of Utah and Wyoming. Dominion Energy's and Dominion Energy Gas' large underground natural gas storage network and the location of their pipeline systems are a significant link between the country's major interstate gas pipelines and large markets in the Northeast, mid-Atlantic and Rocky Mountain regions. Dominion Energy's and Dominion Energy Gas' pipelines are part of an interconnected gas transmission system, which provides access to supplies nationwide for local distribution companies, marketers, power generators and industrial and commercial customers.

Dominion Energy's and Dominion Energy Gas' underground storage facilities play an important part in balancing gas supply with consumer demand and are essential to serving the Northeast, mid-Atlantic, Midwest and Rocky Mountain regions. In addition, storage capacity is an important element in the effective management of both gas supply and pipeline transmission capacity.

The supply of gas to serve Dominion Energy's retail energy marketing customers is procured through Dominion Energy's energy marketing group and market wholesalers.

SEASONALITY

Gas Infrastructure Operating Segment—Dominion Energy and Dominion Energy Gas

Gas Infrastructure's natural gas distribution business earnings vary seasonally, as a result of the impact of changes in temperature on demand by residential and commercial customers for gas to meet heating needs. Historically, the majority of these earnings have been generated during the heating season, which is generally from November to March; however, implementation of rate mechanisms in Ohio for East Ohio, and Utah, Wyoming and Idaho for Questar Gas, have reduced the earnings impact of weather-related fluctuations. Demand for services at Dominion Energy's gas transmission and storage business can also be weather sensitive. Earnings are also impacted by changes in commodity prices driven by seasonal weather changes, the effects of unusual weather events on operations and the economy.

The earnings of Dominion Energy's retail energy marketing operations also vary seasonally. Generally, the demand for gas peaks during the winter months to meet heating needs.

Corporate and Other

Corporate and Other Segment-Virginia Power and Dominion Energy Gas

Virginia Power's and Dominion Energy Gas' Corporate and Other segments primarily include certain specific items attributable to their operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Corporate and Other Segment-Dominion Energy

Dominion Energy's Corporate and Other segment includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

REGULATION

The Companies are subject to regulation by various federal, state and local authorities, including the state commissions of Virginia, North Carolina, Ohio, West Virginia, Utah, Wyoming and Idaho, SEC, FERC, EPA, DOE, NRC, Army Corps of Engineers, and the Department of Transportation.

State Regulations

ELECTRIC

Virginia Power's electric utility retail service is subject to regulation by the Virginia Commission and the North Carolina Commission.

Virginia Power holds CPCNs which authorize it to maintain and operate its electric facilities now in operation and to sell electricity to customers. However, Virginia Power may not construct generating facilities or large capacity transmission lines without the prior approval of various state and federal government agencies. In addition, the Virginia Commission and the North Carolina Commission regulate Virginia Power's transactions with affiliates and transfers of certain facilities. The Virginia Commission also regulates the issuance of certain securities.

Electric Regulation in Virginia

The Regulation Act instituted a cost-of-service rate model, ending Virginia's planned transition to retail competition for electric supply service to most classes of customers.

The Regulation Act authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, FERC-approved transmission costs, underground distribution lines, environmental compliance, conservation and energy efficiency programs and renewable energy programs, and also contains statutory provisions directing Virginia Power to file annual fuel cost recovery cases with the Virginia Commission. As amended, it provides for enhanced returns on capital expenditures on specific newly-proposed generation projects.

In February 2015, the Virginia Governor signed legislation into law which will keep Virginia Power's base rates unchanged until at least December 1, 2022. In addition, no biennial reviews will be conducted by the Virginia Commission for the five successive 12-month test periods beginning January 1, 2015, and ending December 31, 2019. The legislation states that Virginia Power's 2015 biennial review, filed in March 2015, would proceed for the sole purpose of reviewing and determining whether any refunds are due to customers based on earnings performance for generation and distribution services during the 2013 and 2014 test periods. In addition the legislation requires the Virginia Commission to conduct proceedings in 2017 and 2019 to determine the utility's ROE for use in connection with rate adjustment clauses and requires utilities to file integrated resource plans annually rather than biennially. In November 2017, the Virginia Commission approved an ROE of 9.2% for rate adjustment clauses.

In February 2017, the Governor of Virginia signed legislation into law that allows utilities to file a rate adjustment clause to recover costs of pumped hydroelectricity generation and storage facilities that are located in the coalfield region of Virginia. In March 2017, the Governor of Virginia signed legislation into law that allows utilities to file a rate adjustment clause to recover, beginning in 2020, reasonably appropriate costs for extending the operating licenses, or the operating lives, of nuclear power generation facilities.

In March 2017, the Governor of Virginia signed legislation into law stating that it is in the public interest for utilities to replace existing overhead tap lines having nine or more total unplanned outage events-per-mile with new underground facilities, and that utilities can seek cost recovery for such new underground facilities through a rate adjustment clause.

If the Virginia Commission's future rate decisions, including actions relating to Virginia Power's rate adjustment clause filings, differ materially from Virginia Power's expectations, it may adversely affect its results of operations, financial condition and cash flows.

See *Futures Issues and Other Matters* in Item 7. MD&A and Note 13 to the Consolidated Financial Statements for additional information, which is incorporated herein by reference.

Electric Regulation in North Carolina

Virginia Power's retail electric base rates in North Carolina are regulated on a cost-of-service/rate-of-return basis subject to North Carolina statutes and the rules and procedures of the North Carolina Commission. North Carolina base rates are set by a process that allows Virginia Power to recover its operating costs and an ROIC. If retail electric earnings exceed the authorized ROE established by the North Carolina Commission, retail electric rates may be subject to review and possible reduction by the North Carolina Commission, which may decrease Virginia Power's future earnings. Additionally, if the North Carolina Commission does not allow recovery of costs incurred in providing service on a timely basis, Virginia Power's future earnings could be negatively impacted. Fuel rates are subject to revision under annual fuel cost adjustment proceedings.

Virginia Power's transmission service rates in North Carolina are regulated by the North Carolina Commission as part of Virginia Power's bundled retail service to North Carolina customers.

See Note 13 to the Consolidated Financial Statements for additional information, which is incorporated herein by reference.

Gas

Dominion Energy Questar's natural gas development, production, transportation, and distribution services, including the rates it may charge its customers, are regulated by the state commissions of Utah, Wyoming and Idaho. East Ohio's natural gas distribution services, including the rates it may charge its customers, are regulated by the Ohio Commission. Hope's natural gas distribution services are regulated by the West Virginia Commission.

Gas Regulation in Utah, Wyoming and Idaho

Questar Gas is subject to regulation of rates and other aspects of its business by the Utah, Wyoming and Idaho Commissions. The Idaho Commission has contracted with the Utah Commission for rate oversight of Questar Gas' operations in a small area of southeastern Idaho. When necessary, Questar Gas seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. Base rates for Questar Gas are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges.

In addition to general rate increases, Questar Gas makes routine separate filings with the Utah and Wyoming Commissions to reflect changes in the costs of purchased gas. The majority of these purchased gas costs are subject to rate recovery through the Wexpro Agreement and Wexpro II Agreement. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The purchased gas recovery filings generally cover a prospective twelve-month period. Approved increases or decreases in gas cost recovery rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

In connection with the Dominion Energy Questar Combination, Questar Gas withdrew its general rate case filed in July 2016 with the Utah Commission and agreed not to file a general rate case with the Utah Commission to adjust its base distribution non-gas rates prior to July 2019, unless otherwise ordered by the Utah Commission. In addition Questar Gas agreed not to file a general rate case with the Wyoming Commission with a requested rate effective date earlier than January 2020. This does not impact Questar Gas' ability to adjust rates through various riders. See Note 3 to the Consolidated Financial Statements for additional information.

Gas Regulation in Ohio

East Ohio is subject to regulation of rates and other aspects of its business by the Ohio Commission. When necessary, East Ohio seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. A straight-fixed-variable rate design, in which the majority of operating costs are recovered through a monthly charge rather than a volumetric charge, is utilized to establish rates for a majority of East Ohio's customers pursuant to a 2008 rate case settlement.

In addition to general base rate increases, East Ohio makes routine filings with the Ohio Commission to reflect changes in the costs of gas purchased for operational balancing on its system. These purchased gas costs are subject to rate recovery through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The rider filings cover unrecovered gas costs plus prospective annual demand costs. Increases or decreases in gas cost rider rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

The Ohio Commission has also approved several stand-alone cost recovery mechanisms to recover specified costs and a return for infrastructure projects and certain other costs that vary widely over time; such costs are excluded from general base rates. See Note 13 to the Consolidated Financial Statements for additional information.

Gas Regulation in West Virginia

Hope is subject to regulation of rates and other aspects of its business by the West Virginia Commission. When necessary, Hope seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. Base rates for Hope are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges.

In addition to general rate increases, Hope makes routine separate filings with the West Virginia Commission to reflect changes in the costs of purchased gas. The majority of these purchased gas costs are subject to rate recovery through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The purchased gas cost recovery filings generally cover a prospective twelve-month period. Approved increases or decreases in gas cost recovery rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

Legislation was passed in West Virginia authorizing a stand-alone cost recovery mechanism to recover specified costs and a return for infrastructure upgrades, replacements and expansions between general base rate cases. See Note 13 to the Consolidated Financial Statements for additional information.

Status of Competitive Retail Gas Services

The states of Ohio and West Virginia, in which Dominion Energy and Dominion Energy Gas have gas distribution operations, have considered legislation regarding a competitive deregulation of natural gas sales at the retail level.

Ohio—Since October 2000, East Ohio has offered the Energy Choice program, under which residential and commercial customers are encouraged to purchase gas directly from retail suppliers or through a community aggregation program. In October 2006, East Ohio restructured its commodity service by entering into gas purchase contracts with selected suppliers at a fixed price above the New York Mercantile Exchange month-end settlement and passing that gas cost to customers under the Standard Service Offer program. Starting in April 2009, East Ohio buys natural gas under the Standard Service Offer program only for customers not eligible to participate in the Energy Choice program and places Energy Choice-eligible customers in a direct retail relationship with selected suppliers, which is designated on the customers' bills.

In January 2013, the Ohio Commission granted East Ohio's motion to fully exit the merchant function for its nonresidential customers, beginning in April 2013, which requires those customers to choose a retail supplier or be assigned to one at a monthly variable rate set by the supplier. At December 31, 2017, approximately 1.0 million of Dominion Energy Gas' 1.2 million Ohio customers were participating in the Energy Choice program. Subject to the Ohio Commission's approval, East Ohio may eventually exit the gas merchant function in Ohio entirely and have all customers select an alternate gas supplier. East Ohio continues to be the provider of last resort in the event of default by a supplier. Large industrial customers in Ohio also source their own natural gas supplies.

West Virginia—At this time, West Virginia has not enacted legislation allowing customers to choose providers in the retail natural gas markets served by Hope. However, the West Virginia Commission has issued regulations to govern pooling services, one of the tools that natural gas suppliers may utilize to provide retail customers a choice in the future and has issued rules requiring competitive gas service providers to be licensed in West Virginia.

Federal Regulations

FEDERAL ENERGY REGULATORY COMMISSION

Electric

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. Virginia Power purchases and sells electricity in the PJM wholesale market and Dominion Energy's merchant generators sell electricity in the PJM, MISO, CAISO and ISO-NE wholesale markets, and to wholesale purchasers in the states of Virginia, North Carolina, Indiana, Connecticut, Tennessee, Georgia, California, South Carolina and Utah, under Dominion Energy's market-based sales tariffs authorized by FERC or pursuant to FERC authority to sell as a qualified facility. In addition, Virginia Power has FERC approval of a tariff to sell wholesale power at capped rates based on its embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside Virginia Power's service territory. Any such sales would be voluntary.

Dominion Energy and Virginia Power are subject to FERC's Standards of Conduct that govern conduct between transmission function employees of interstate gas and electricity transmission providers and the marketing function employees of their affiliates. The rule defines the scope of transmission and marketing-related functions that are covered by the standards and is designed to prevent transmission providers from giving their affiliates undue preferences.

Dominion Energy and Virginia Power are also subject to FERC's affiliate restrictions that (1) prohibit power sales between Virginia Power and Dominion Energy's merchant plants without first receiving FERC authorization, (2) require the merchant plants and Virginia Power to conduct their wholesale power sales operations separately, and (3) prohibit Virginia Power from sharing market information with merchant plant operating personnel. The rules are designed to prohibit Virginia Power from giving the merchant plants a competitive advantage.

EPACT included provisions to create an ERO. The ERO is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. FERC has certified NERC as the ERO and also issued an initial order approving many reliability standards that went into effect in 2007. Entities that violate standards will be subject to fines of up to $1.2 million per day, per violation and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation.

Dominion Energy and Virginia Power plan and operate their facilities in compliance with approved NERC reliability requirements. Dominion Energy and Virginia Power employees participate on various NERC committees, track the development and implementation of standards, and maintain proper compliance registration with NERC's regional organizations. Dominion Energy and Virginia Power anticipate incurring additional compliance expenditures over the next several years as a result of the implementation of new cybersecurity programs. In addition, NERC has redefined critical assets which expanded the number of assets subject to NERC reliability standards, including cybersecurity assets. NERC continues to develop additional requirements specifically regarding supply chain standards and control centers that impact the bulk electric system. While Dominion Energy and Virginia Power expect to incur additional compliance costs in connection with NERC requirements and initiatives, such expenses are not expected to significantly affect results of operations.

In April 2008, FERC granted an application for Virginia Power's electric transmission operations to establish a forward-looking formula rate mechanism that updates transmission rates on an annual basis and approved an ROE of 11.4%, effective as of January 1, 2008. The formula rate is designed to recover the expected revenue requirement for each calendar year and is updated based on actual costs. The FERC-approved formula method, which is based on projected costs, allows Virginia Power to earn a current return on its growing investment in electric transmission infrastructure.

Gas

FERC regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, as amended. Under the Natural Gas Act, FERC has authority over rates, terms and conditions of services performed by Dominion Energy Questar Pipeline, DETI, DECG, Iroquois and certain services performed by Cove Point. The design, construction and operation of Cove Point's LNG facility, including associated natural gas pipelines, the Liquefaction Project and the import and export of LNG are also regulated by FERC.

Dominion Energy's and Dominion Energy Gas' interstate gas transmission and storage activities are conducted on an open access basis, in accordance with certificates, tariffs and service agreements on file with FERC and FERC regulations.

Dominion Energy and Dominion Energy Gas operate in compliance with FERC standards of conduct, which prohibit the sharing of certain non-public transmission information or customer specific data by its interstate gas transmission and storage companies with non-transmission function employees. Pursuant to these standards of conduct, Dominion Energy and Dominion Energy Gas also make certain informational postings available on Dominion Energy's website.

See Note 13 to the Consolidated Financial Statements for additional information.

Safety Regulations

Dominion Energy and Dominion Energy Gas are also subject to the Pipeline Safety Improvement Act of 2002 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which mandate inspections of interstate and intrastate natural gas transmission and storage pipelines, particularly those located in areas of high-density population. Dominion Energy and Dominion Energy Gas have evaluated their natural gas transmission and storage properties, as required by the Department of Transportation regulations under these Acts, and has implemented a program of identification, testing and potential remediation activities. These activities are ongoing.

The Companies are subject to a number of federal and state laws and regulations, including Occupational Safety and Health Administration, and comparable state statutes, whose purpose is to protect the health and safety of workers. The Companies have an internal safety, health and security program designed to monitor and enforce compliance with worker safety requirements, which is routinely reviewed and considered for improvement. The Companies believe that they are in material compliance with all applicable laws and regulations related to worker health and safety. Notwithstanding these preventive measures, incidents may occur that are outside of the Companies' control.

Environmental Regulations

Each of the Companies' operating segments faces substantial laws, regulations and compliance costs with respect to environmental matters. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the Companies. If compliance expenditures and associated operating costs are not recoverable from customers through regulated rates (in regulated businesses) or market prices (in unregulated businesses), those costs could adversely affect future results of operations and cash flows. The Companies have applied for or obtained the necessary environmental permits for the construction and operation of their facilities. Many of these permits are subject to reissuance and continuing review. For a discussion of significant aspects of these matters, including current and planned capital expenditures relating to environmental compliance required to be discussed in this Item, see *Environmental Matters* in *Future Issues and Other Matters* in Item 7. MD&A, which information is incorporated herein by reference. Additional information can also be found in Item 3. Legal Proceedings and Note 22 to the Consolidated Financial Statements, which information is incorporated herein by reference.

AIR

The CAA is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. Regulated emissions include, but are not limited to, carbon, methane, VOC, other GHGs, mercury, other toxic metals, hydrogen chloride, NOX, SO2, and particulate matter. At a minimum, delegated states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

GLOBAL CLIMATE CHANGE

The national and international attention to GHG emissions and their relationship to climate change has resulted in federal, regional and state legislative and regulatory action in this area. See, for example, the discussion of the Clean Power Plan and the United Nation's Paris Agreement in *Environmental Matters* in *Future Issues and Other* Matters in Item 7. MD&A.

The Companies support national climate change legislation that would provide a consistent, economy-wide approach to addressing this issue and are currently taking action to protect the environment and reduce GHG emissions while meeting the growing needs of their customers. Dominion Energy's CEO and operating segment CEOs are responsible for compliance with the laws and regulations governing environmental matters, including GHG emissions, and Dominion Energy's Board of Directors receives periodic updates on these matters. See *Environmental Strategy* below, *Environmental Matters* in *Future Issues and Other Matters* in Item 7. MD&A and Note 22 to the Consolidated Financial Statements for information on climate change legislation and regulation, which information is incorporated herein by reference.

WATER

The CWA is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. The CWA and analogous state laws impose restrictions and strict controls regarding discharges of effluent into surface waters and require permits to be obtained from the EPA or the analogous state agency for those discharges. Containment berms and similar structures may be required to help prevent accidental releases. Dominion Energy must comply with applicable CWA requirements at its current and former operating facilities. Stormwater related to construction activities is also regulated under the CWA and by state and local stormwater management and erosion and sediment control laws. From time to time, Dominion Energy's projects and operations may impact tidal and non-tidal wetlands. In these instances, Dominion Energy must obtain authorization from the appropriate federal, state and local agencies prior to impacting wetlands. The authorizing agency may impose significant direct or indirect mitigation costs to compensate for such impacts to wetlands.

WASTE AND CHEMICAL MANAGEMENT

Dominion Energy is subject to various federal and state laws and implementing regulations governing the management, storage, treatment, reuse and disposal of waste materials and hazardous substances, including the Resources Conservation and Recovery Act of 1976, CERCLA, the Emergency Planning and Community Right-to-Know Act of 1986 and the Toxic Substance Control Act of 1976. Dominion Energy's operations and construction activities, including activities associated with oil and gas production and gas storage wells, generate waste. Across Dominion Energy, completion water is disposed at commercial disposal facilities. Produced water is either hauled for disposal, evaporated or injected into company and third-party owned underground injection wells. Wells drilled in tight-gas-sand and shale reservoirs require hydraulic-fracture stimulation to achieve economic production rates and recoverable reserves. The majority of Wexpro's current and future production and reserve potential is derived from reservoirs that require hydraulic-fracture stimulation to be commercially viable. Currently, all well construction activities, including hydraulic-fracture stimulation and management and disposal of hydraulic fracturing fluids, are regulated by federal and state agencies that review and approve all aspects of gas- and oil-well design and operation.

PROTECTED SPECIES

The ESA and analogous state laws prohibit activities that can result in harm to specific species of plants and animals, as well as impacts to the habitat on which those species depend. In addition to ESA programs, the MBTA and the BGEPA establish broader prohibitions on harm to protected birds. Many of the Companies' facilities are subject to requirements of the ESA, MBTA and BGEPA. The ESA and BGEPA require potentially lengthy coordination with the state and federal agencies to ensure potentially affected species are protected. Ultimately, the suite of species protections may restrict company activities to certain times of year, project modifications may be necessary to avoid harm, or a permit may be needed to allow for unavoidable taking of the species. The authorizing agency may impose mitigation requirements and costs to compensate for harm of a protected species or habitat loss. These requirements and time of year restrictions can result in adverse impacts on project plans and schedules such that the Companies' businesses may be materially affected.

OTHER REGULATIONS

Other significant environmental regulations to which the Companies are subject include federal and state laws protecting graves, sacred sites, historic sites and cultural resources, including those of American Indian populations. These can result in compliance and mitigation costs, and potential adverse effects on project plans and schedules such that the Companies' businesses may be materially affected.

Nuclear Regulatory Commission

All aspects of the operation and maintenance of Dominion Energy's and Virginia Power's nuclear power stations are regulated by the NRC. Operating licenses issued by the NRC are subject to revocation, suspension or modification, and the operation of a nuclear unit may be suspended if the NRC determines that the public interest, health or safety so requires.

From time to time, the NRC adopts new requirements for the operation and maintenance of nuclear facilities. In many cases, these new regulations require changes in the design, operation and maintenance of existing nuclear facilities. If the NRC adopts such requirements in the future, it could result in substantial increases in the cost of operating and maintaining Dominion Energy's and Virginia Power's nuclear generating units. See Note 22 to the Consolidated Financial Statements for further information.

The NRC also requires Dominion Energy and Virginia Power to decontaminate their nuclear facilities once operations cease.

This process is referred to as decommissioning, and Dominion Energy and Virginia Power are required by the NRC to be financially prepared. For information on decommissioning trusts, see *Power Generation-Nuclear Decommissioning* above and Note 9 to the Consolidated Financial Statements. See Note 22 to the Consolidated Financial Statements for information on spent nuclear fuel.

ENVIRONMENTAL STRATEGY

As part of the Companies' overall long term strategic planning overseen by the Board of Directors, we have a well formed environmental strategy. The Companies are committed to continuing to be an industry leader, delivering safe, reliable, clean and affordable energy while fully complying with all applicable environmental laws and regulations. Additionally, we seek to build partnerships and engage with local communities, stakeholders and customers on environmental issues important to them. The Companies are dedicated to meeting their customers' growing energy needs with innovative, sustainable solutions. It is the Companies' belief that sustainable solutions should strive to balance the interdependent goals of environmental stewardship and economic effects. The integrated strategy to meet these objectives consists of three major elements:

- Reduction of GHG emissions;
- Energy infrastructure modernization, including natural gas and electric operations; and
- Conservation and energy efficiency.

Reduction of GHG Emissions

The Companies integrated strategy has resulted in a reduction in GHG emission intensity. Over the past two decades, the Companies have made changes to the generation mix and to natural gas operations which have significantly improved environmental performance. For example, Power Generation has significantly reduced both its carbon emissions and its carbon intensity while generating electricity with an increasingly clean portfolio. From 2000 through 2016, our carbon intensity decreased by 43%. This strategy has also resulted in significant reductions of other air pollutants such as NOX, SO_2 and mercury and also reduced the amount of coal ash generated and the amount of water withdrawn. The principal components of the strategy, which include initiatives that address electric energy production and delivery, natural gas storage, transmission and delivery and energy management, are as follows:

- Expand Dominion Energy's and Virginia Power's renewable energy portfolio, including solar, wind power, and biomass, to further diversify Dominion Energy's and Virginia Power's fleet, meet state renewable energy targets and lower the carbon footprint;
- Pursue the extension of operating licenses of existing nuclear units which provide carbon-free generation;
- Evaluate effective battery solutions, such as hydroelectric pumped storage, which help support a grid with increased renewables;
- Enhance conservation and energy efficiency programs on both the electric and gas side of our businesses to help customers use energy wisely and reduce environmental impacts;
- Sell, close, place in cold reserve or convert to cleaner fuels a number of coal-fired generation units owned by Dominion Energy and Virginia Power;
- Evaluate behind-the-meter and rate design solutions and other business opportunities;
- Construct new electric and gas transmission infrastructure to modernize the grid, to expand availability of cleaner fuel, to reduce emissions, to promote energy and economic security and help deliver more green energy to population centers where it is needed most;
- Replace older distribution pipeline mains and services; and
- Implement and enhance voluntary methane mitigation measures through participation in the EPA's Natural Gas Star and Methane Challenge programs; and continue to evaluate business opportunities presented by a lower carbon economy and innovative technologies.

See *Operating Segments* for more information on certain of the projects described above.

CLEANER GENERATION

Renewable energy is an important component of a diverse and reliable energy mix that helps to mitigate the environmental aspects of energy production. Nationally, Dominion Energy has nearly 2,400 MW of renewable generating capacity in operation or under development in nine states, including offtake agreements for Virginia Power's utility customers. Both Virginia and North Carolina have passed legislation setting targets for renewable power. Dominion Energy is committed to meeting Virginia's goals of 12% of base year electric energy sales from renewable power sources by 2022, and 15% by 2025, and North Carolina's Renewable Portfolio Standard of 12.5% by 2021 and continues to add utility-scale solar capacity. Backed by a $1 billion investment, Dominion Energy has grown its solar fleet in Virginia and North Carolina over the past two years from near zero to about 1,350 megawatts in service, in construction or under development.

See *Operating Segments* and Item 2. Properties for additional information, including Dominion Energy's merchant solar properties.

GHG EMISSIONS

Since 2000, Dominion Energy and Virginia Power have tracked the emissions of their electric generation fleet, which employs a mix of fuel and renewable energy sources. Comparing annual year 2016 to annual year 2000, the entire electric generating fleet (based on ownership percentage) reduced its average CO_2 emissions rate per MWh of energy produced from electric generation by approximately 43%. Comparing annual year 2016 to annual year 2000, the regulated electric generating fleet (based on ownership percentage) reduced its average CO_2 emissions rate per MWh of energy produced from electric generation by approximately 26%.

Dominion Energy also develops a comprehensive GHG inventory annually. For Power Generation, Dominion Energy and Virginia Power's direct CO_2 equivalent emissions, based on ownership percentage, were 37.2 million metric tons and 33.1 million metric tons, respectively, in 2016, compared to 34.3 million metric tons and 30.9 million metric tons, respectively, in 2015. The corresponding carbon intensity rates for Dominion Energy were 0.339 metric tons CO_2 equivalent emissions per net MWh in 2016 and 0.348 metric tons CO_2 equivalent emissions per net MWh in 2015.

For Power Delivery's regulated electric transmission and distribution operations, direct CO_2 equivalent emissions for 2016 were 42,856 metric tons, compared to 53,819 metric tons in 2015.

Dominion Energy's natural gas companies have been reporting GHG emissions to the EPA since 2011 under the GHG Reporting Program. In January 2016, the GHG Reporting Program was expanded to also include GHG inputs and emissions associated with natural gas gathering and boosting sources and transmission pipeline blowdowns for facilities that exceed 25,000 metric tons per year of CO_2 equivalent emissions. The sources within these new facilities were not previously covered under the rule and the first reports for these new sources were submitted to EPA on March 31, 2017.

Hope and East Ohio direct CO_2 equivalent emissions together decreased from 0.90 million metric tons in 2015 to 0.86 million metric tons in 2016. DETI's and Cove Point's direct CO_2 equivalent emissions together were 1.3 million metric tons in 2016, increasing from 1.1 million metric tons in 2015 attributable to new EPA reporting of transmission pipeline blowdowns.

The Companies' GHG inventory follows all methodologies specified in the EPA Mandatory Greenhouse Gas Reporting Rule, 40 Code of Federal Regulations Part 98 for calculating emissions. Total CO_2 equivalent emissions reported for our natural gas assets, as estimated in Dominion Energy's corporate inventory, were 2.3 million metric tons in 2016. This estimate includes emissions reported under the GHG Reporting Program, as well as other emissions not required to be reported under the federal program. The 2016 corporate GHG inventory emission estimate includes Dominion Energy Questar Pipeline, Questar Gas and Wexpro for the entire calendar year.

Energy Infrastructure Modernization

Dominion Energy's existing five-year investment plan includes significant capital expenditures to upgrade or add new electric transmission and distribution lines, substations and other facilities to meet growing electricity demand within its service territory, maintain reliability, implement a strategic underground program to minimize outage duration and address environmental requirements. These enhancements are primarily aimed at meeting Dominion Energy's continued goal of providing reliable service, and are intended to address both continued population growth and increases in electricity consumption. An additional benefit will be added capacity to efficiently deliver electricity from the renewable projects now being developed, or to be developed in the future, to meet our customers' preference for cleaner energy. See *Operating Segments* for additional information.

The Companies have also implemented infrastructure improvements and improved operational practices to reduce the GHG emissions from our natural gas facilities. Dominion Energy and Dominion Energy Gas, in connection with their existing five-year investment plans, are also pursuing the construction or upgrade of regulated infrastructure in their natural gas businesses. The Companies have made voluntary commitments as part of the EPA Methane Challenge Program to continue to reduce methane emissions as part of these improvements. See *Operating Segments* for additional information, including natural gas infrastructure projects.

Conservation and Energy Efficiency

Conservation and load management play a significant role in meeting the growing demand for electricity and natural gas, while also helping to reduce the environmental footprint of our customers.

The Regulation Act provides incentives for energy conservation through the implementation of conservation programs. Additional legislation in 2009 added definitions of peak-shaving and energy efficiency programs, and allowed for a margin on operating expenses and recovery of revenue reductions related to energy efficiency programs.

Virginia Power's DSM programs, implemented with Virginia Commission and North Carolina Commission approval, provide important incremental steps in assisting customers to reduce energy consumption through programs that include energy audits and incentives for customers to upgrade or install certain energy efficient measures and/or systems. The DSM programs began in Virginia in 2010 and in North Carolina in 2011. Currently, there are residential and non-residential DSM programs active in the two states. Virginia Power continues to evaluate opportunities to redesign current DSM programs and develop new DSM initiatives in Virginia and North Carolina.

Virginia Power continues to upgrade meters throughout Virginia to AMI, also referred to as smart meters. The AMI meter upgrades are part of an ongoing demonstration effort to help Virginia Power further evaluate the effectiveness of AMI meters to monitor voltage stability, remotely turn off and on electric service, increase detection and reporting capabilities with respect to power outages and restorations, obtain remote daily meter readings and offer dynamic rates.

East Ohio offers two DSM programs, approved by the Ohio Commission, designed to help customers reduce their energy consumption. One program provides weatherization assistance to help income-eligible customers reduce their energy usage. Another program has been designed to help East Ohio's residential customers improve their homes' energy efficiency, starting with a home energy assessment. Following the assessment, customers receive a report with recommendations on how to save energy and improve their home's comfort. This program includes rebates and free installation of several energy-efficient products such as, high-efficiency showerheads, kitchen and bathroom faucet aerators, programmable thermostat or carbon monoxide detector and water heater pipe wrap.

Questar Gas offers an energy-efficiency program, approved by the Utah and Wyoming Commissions, designed to help customers reduce their energy consumption. This program promotes the use of energy-efficient appliances and practices to reduce natural gas usage. The program provides home energy planning, which provides homeowners with a step-by-step roadmap to efficiency improvements to reduce gas usage. In addition to the recommendations, the program provides home owners with energy-saving devices such as pipe insulation and low-flow shower heads as well as rebates on appliances and weatherization items. The program also offers new construction builders with rebates for installing high-efficiency equipment and offers commercial businesses with rebates on energy efficient equipment and retrofits.

CYBERSECURITY

In an effort to reduce the likelihood and severity of cyber intrusions, the Companies have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of data and systems. In addition, the Companies are subject to mandatory cybersecurity regulatory requirements, interface regularly with a wide range of external organizations, and participate in classified briefings to maintain an awareness of current cybersecurity threats and vulnerabilities. The Companies' current security posture and regulatory compliance efforts are intended to address the evolving and changing cyber threats. See Item 1A. Risk Factors for additional information.

Item 1A. Risk Factors

The Companies' businesses are influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond their control. A number of these factors have been identified below. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in Item 7. MD&A.

The Companies' results of operations can be affected by changes in the weather. Fluctuations in weather can affect demand for the Companies' services. For example, milder than normal weather can reduce demand for electricity and gas transmission and distribution services. In addition, severe weather, including hurricanes, winter storms, earthquakes, floods and other natural disasters can disrupt operation of the Companies' facilities and cause service outages, production delays and property damage that require incurring additional expenses. Changes in weather conditions can result in reduced water levels or changes in water temperatures that could adversely affect operations at some of the Companies' power stations. Furthermore, the Companies' operations could be adversely affected and their physical plant placed at greater risk of damage should changes in global climate produce, among other possible conditions, unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, abnormal levels of precipitation and, for operations located on or near coastlines, a change in sea level or sea temperatures.

The rates of Dominion Energy's and Dominion Energy Gas' gas transmission and distribution operations and Virginia Power's electric transmission, distribution and generation operations are subject to regulatory review. Revenue provided by Virginia Power's electric transmission, distribution and generation operations and Dominion Energy's and Dominion Energy Gas' gas transmission and distribution operations is based primarily on rates approved by state and federal regulatory agencies. However, certain large scale customers are able to enter into negotiated-rate contracts rather than pay cost-of-service rates which are subject to regulatory review. The profitability of these businesses is dependent on their ability, through the rates that they are permitted to charge, to recover costs and earn a reasonable rate of return on their capital investment.

Virginia Power's wholesale rates for electric transmission service are updated on an annual basis through operation of a FERC-approved formula rate mechanism. Through this mechanism, Virginia Power's wholesale rates for electric transmission reflect the estimated cost-of-service for each calendar year. The difference in the estimated cost-of-service and actual cost-of-service for each calendar year is included as an adjustment to the wholesale rates for electric transmission service in a subsequent calendar year. These wholesale rates are subject to FERC review and prospective adjustment in the event that customers and/or interested state commissions file a complaint with FERC and are able to demonstrate that Virginia Power's wholesale revenue requirement is no longer just and reasonable. They are also subject to retroactive corrections to the extent that the formula rate was not properly populated with the actual costs.

Similarly, various rates and charges assessed by Dominion Energy's and Dominion Energy Gas' gas transmission businesses are subject to review by FERC. In addition, the rates of Dominion Energy's and Dominion Energy Gas' gas distribution businesses are subject to state regulatory review in the jurisdictions in which they operate. A failure by Dominion Energy or Dominion Energy Gas to support these rates could result in rate decreases from current rate levels, which could adversely affect Dominion Energy's and Dominion Energy Gas' results of operations, cash flows and financial condition.

Virginia Power's base rates, terms and conditions for generation and distribution services to customers in Virginia are reviewed by the Virginia Commission on a biennial basis in a proceeding that involves the determination of Virginia Power's actual earned ROE during a combined two-year historic test period, and the determination of Virginia Power's authorized ROE prospectively. Under certain circumstances described in the Regulation Act, Virginia Power may be required to share a portion of its earnings with customers through a refund process.

Legislation signed by the Virginia Governor in February 2015 suspends biennial reviews for the five successive 12-month test periods beginning January 1, 2015 and ending December 31, 2019, and no changes will be made to Virginia Power's existing base rates until at least December 1, 2022. During this period, Virginia Power bears the risk of any severe weather events and natural disasters, the risk of asset impairments related to the early retirement of any generation facilities due to the implementation of environmental regulations, as well as an increase in general operating and financing costs, and Virginia Power may not recover its associated costs through increases to base rates. If Virginia Power incurs any such significant additional expenses during this period, Virginia Power may not be able to recover its costs and/or earn a reasonable return on capital investment, which could negatively affect Virginia Power's future earnings.

Virginia Power's retail electric base rates for bundled generation, transmission, and distribution services to customers in North Carolina are regulated on a cost-of-service/rate-of-return basis subject to North Carolina statutes, and the rules and procedures of the North Carolina Commission. If retail electric earnings exceed the returns established by the North Carolina Commission, retail electric rates may be subject to review and possible reduction by the North Carolina Commission, which may decrease Virginia Power's future earnings. Additionally, if the North Carolina Commission does not allow recovery through base rates, on a timely basis, of costs incurred in providing service, Virginia Power's future earnings could be negatively impacted.

Governmental officials, stakeholders and advocacy groups may challenge these regulatory reviews. Such challenges may lengthen the time, complexity and costs associated with such regulatory reviews.

The Companies are subject to complex governmental regulation, including tax regulation, that could adversely affect their results of operations and subject the Companies to monetary penalties. The Companies' operations are subject to extensive federal, state and local regulation and require numerous permits, approvals and certificates from various governmental agencies. Such laws and regulations govern the terms and conditions of the services we offer, our relationships with affiliates, protection of our critical electric infrastructure assets and pipeline safety, among other matters. These operations are also subject to legislation governing taxation at the federal, state and local level. They must also comply with environmental legislation and associated regulations. Management believes that the necessary approvals have been obtained for existing operations and that the business is conducted in accordance with applicable laws. The Companies' businesses are subject to regulatory regimes which could result in substantial monetary penalties if any of the Companies is found not to be in compliance, including mandatory reliability standards and interaction in the wholesale markets. New laws or regulations, the revision or reinterpretation of existing laws or regulations, changes in enforcement practices of regulators, or penalties imposed for non-compliance with existing laws or regulations may result in substantial additional expense. Recent legislative and regulatory changes that are impacting the Companies include the 2017 Tax Reform Act and tariffs imposed on imported solar panels by the U.S. government in 2018.

The 2017 Tax Reform Act could have a material impact on our operations, cash flows, and financial results. Reductions in the estimated annual cost-of-service effect (commonly referred to as the gross-up factor) due to the reduction in the corporate income tax rates to 21% under the provisions of the 2017 Tax Reform Act could result in amounts currently collected from utility customers to be refundable to such customers, generally through reductions in rates. In addition, the Companies' regulators may require the reduction in accumulated deferred income tax balances under the provisions of the 2017 Tax Reform Act to be shared with customers, generally through reductions in future rates. The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes may be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred taxes may be determined by our federal and state regulators.

The 2017 Tax Reform Act could have a material impact on Dominion Energy and Dominion Energy Gas' FERC-regulated gas operations including rates charged to customers. In light of the reduction in the income tax rate in the 2017 Tax Reform Act, our FERC-regulated gas subsidiaries are subject to an increased risk of FERC initiating industry-wide proceedings under Section 5 of the Natural Gas Act to have interstate pipelines substantiate rates charged for transportation and storage of natural gas in interstate commerce, when viewed holistically, are "just and reasonable" taking into account the effects of tax reform and all other drivers. It is unclear if FERC will mandate a one-time rate reset or Section 5 rate case for Dominion Energy and Dominion Energy Gas' regulated subsidiaries; however, states as well as customers have petitioned FERC to request changes in rates as a result of tax reform.

The interpretation of provisions of the 2017 Tax Reform Act that take effect in 2018 may significantly impact our operations. The 2017 Tax Reform Act contains provisions that limit the deductibility of interest expense. The new provision generally limits the interest deduction on business interest to (1) business interest income, plus (2) 30 percent of the taxpayer's adjusted taxable income. Business interest and business interest income is defined as that allocable to a trade or business and not investment interest and income. Regulated public utilities are not subject to this interest limitation; however Dominion Energy is a consolidated group with both regulated and merchant lines of businesses. The U.S. Department of Treasury has been tasked with providing guidance on applying the interest limitation to consolidated groups, such as Dominion Energy, but it is unclear when that guidance may be issued, or whether that guidance could result in a disallowance of a portion of our interest deductions in the future.

Dominion Energy and Virginia Power's generation business may be negatively affected by possible FERC actions that could change market design in the wholesale markets or affect pricing rules or revenue calculations in the RTO markets. Dominion Energy and Virginia Power's generation stations operating in RTO markets sell capacity, energy and ancillary services into wholesale electricity markets regulated by FERC. The wholesale markets allow these generation stations to take advantage of market price opportunities, but also expose them to market risk. Properly functioning competitive wholesale markets depend upon FERC's continuation of clearly identified market rules. From time to time FERC may investigate and authorize RTOs to make changes in market design. FERC also periodically reviews Dominion Energy's authority to sell at market-based rates. Material changes by FERC to the design of the wholesale markets or its interpretation of market rules, Dominion Energy or Virginia Power's authority to sell power at market-based rates, or changes to pricing rules or rules involving revenue calculations, could adversely impact the future results of Dominion Energy or Virginia Power's generation business. For example, in July 2015, FERC approved changes to PJM's Reliability Pricing Model capacity market establishing a new Capacity Performance Resource product. This product offers the potential for higher capacity prices but can also impose significant economic penalties on generator owners such as Virginia Power for failure to perform during periods when electricity is in high demand. In addition, there have been changes to the interpretation and application of FERC's market manipulation rules. A failure to comply with these rules could lead to civil and criminal penalties.

The Companies' infrastructure build and expansion plans often require regulatory approval before construction can commence. The Companies may not complete facility construction, pipeline, conversion or other infrastructure projects that they commence, or they may complete projects on materially different terms or timing than initially anticipated, and they may not be able to achieve the intended benefits of any such project, if completed. Several facility construction, pipeline, electric transmission line, expansion, conversion and other infrastructure projects have been announced and additional projects may be considered in the future. The Companies compete for projects with companies of varying size and financial capabilities, including some that may have competitive advantages. Commencing construction on announced and future projects may require approvals from applicable state and federal agencies, and such approvals could include mitigation costs which may be material to the Companies. Projects may not be able to be completed on time as a result of weather conditions, delays in obtaining or failure to obtain regulatory approvals, delays in obtaining key materials, labor difficulties, difficulties with partners or potential partners, a decline in the credit strength of counterparties or vendors, or other factors beyond the Companies' control. Even if facility construction, pipeline, expansion, electric transmission line, conversion and other infrastructure projects are completed, the total costs of the projects may be higher than anticipated and the performance of the business of the Companies following completion of the projects may not meet expectations. Start-up and operational issues can arise in connection with the commencement of commercial operations at our facilities, including but not limited to commencement of commercial operations at our power generation facilities following expansions and the Liquefaction Project. Such issues may include failure to meet specific operating parameters, which may require adjustments to meet or amend these operating parameters. Additionally, the Companies may not be able to timely and effectively integrate the projects into their operations and such integration may result in unforeseen operating difficulties or unanticipated costs. Further, regulators may disallow recovery of some of the costs of a project if they are deemed not to be prudently incurred. Any of these or other factors could adversely affect the Companies' ability to realize the anticipated benefits from the facility construction, pipeline, electric transmission line, expansion, conversion and other infrastructure projects.

The development, construction and commissioning of several large-scale infrastructure projects simultaneously involves significant execution risk. The Companies are currently simultaneously developing, constructing or commissioning several major projects, including the Liquefaction Project, the Atlantic Coast Pipeline Project, the Supply Header project, Greensville County and multiple DETI projects, which together help contribute to the over $25 billion in capital expenditures planned by the Companies through 2022. Several of the Companies' key projects are increasingly large-scale, complex and being constructed in constrained geographic areas or in difficult terrain, for example, the Atlantic Coast Pipeline Project. The advancement of the Companies' ventures is also affected by the interventions, litigation or other activities of stakeholder and advocacy groups, some of which oppose natural gas-related and energy infrastructure projects. For example, certain landowners and stakeholder groups oppose the Atlantic Coast Pipeline Project, which could impede construction activities or the acquisition of rights-of-way and other land rights on a timely basis or on acceptable terms. Given that these projects provide the foundation for the Companies' strategic growth plan, if the Companies are unable to obtain or maintain the required approvals, develop the necessary technical expertise, allocate and coordinate sufficient resources, adhere to budgets and timelines, effectively handle public outreach efforts, or otherwise fail to successfully execute the projects, there could be an adverse impact to the Companies' financial position, results of operations and cash flows. For example, while Dominion Energy has received the required approvals to commence construction of the Liquefaction Project from the DOE, all DOE export licenses are subject to review and possible withdrawal should the DOE conclude that such export authorization is no longer in the public interest. Failure to comply with regulatory approval conditions or an adverse ruling in any future litigation could adversely affect the Companies' ability to execute their business plan.

The Companies are dependent on their contractors for the successful and timely completion of large-scale infrastructure projects. The construction of such projects is expected to take several years, is typically confined within a limited geographic area or difficult terrain and could be subject to delays, cost overruns, labor disputes and other factors that could cause the total cost of the project to exceed the anticipated amount and adversely affect the Companies' financial performance and/or impair the Companies' ability to execute the business plan for the project as scheduled.

Further, an inability to obtain financing or otherwise provide liquidity for the projects on acceptable terms could negatively affect the Companies' financial condition, cash flows, the projects' anticipated financial results and/or impair the Companies' ability to execute the business plan for the projects as scheduled.

The Companies' operations and construction activities are subject to a number of environmental laws and regulations which impose significant compliance costs to the Companies. The Companies' operations and construction activities are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources, and health and safety. Compliance with these legal requirements requires the Companies to commit significant capital toward permitting, emission fees, environmental monitoring, installation and operation of environmental control equipment and purchase of allowances and/or offsets. Additionally, the Companies could be responsible for expenses relating to remediation and containment obligations, including at sites where they have been identified by a regulatory agency as a potentially responsible party. Expenditures relating to environmental compliance have been significant in the past, and the Companies expect that they will remain significant in the future. Certain facilities have become uneconomical to operate and have been shut down, converted to new fuel types or sold. These types of events could occur again in the future.

We expect that existing environmental laws and regulations may be revised and/or new laws may be adopted including regulation of GHG emissions which could have an impact on the Companies' business. Risks relating to expected regulation of GHG emissions from existing fossil fuel-fired electric generating units are discussed below. In addition, further regulation of air quality and GHG emissions under the CAA have been imposed on the natural gas sector, including rules to limit methane leakage. The Companies are also subject to federal water and waste regulations, including regulations concerning cooling water intake structures, coal combustion by-product handling and disposal practices, wastewater discharges from steam electric generating stations, management and disposal of hydraulic fracturing fluids and the potential further regulation of polychlorinated biphenyls.

Compliance costs cannot be estimated with certainty due to the inability to predict the requirements and timing of implementation of any new environmental rules or regulations. Other factors which affect the ability to predict future environmental expenditures with certainty include the difficulty in estimating clean-up costs and quantifying liabilities under environmental laws that impose joint and several liabilities on all responsible parties. However, such expenditures, if material, could make the Companies' facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect the Companies' results of operations, financial performance or liquidity.

Any additional federal and/or state requirements imposed on energy companies mandating limitations on GHG emissions or requiring efficiency improvements may result in compliance costs that alone or in combination could make some of the Companies' electric generation units or natural gas facilities uneconomical to maintain or operate. The Clean Power Plan, targeted at reducing CO_2 emissions from existing fossil fuel-fired power generation facilities, has been stayed and is being reviewed by the EPA. Compliance with a replacement rule for the Clean Power Plan, or similar regulations, are expected to require increasing the energy efficiency of equipment at facilities, committing significant capital toward carbon reduction programs, purchase of allowances and/or emission rate credits, fuel switching, and/or retirement of high-emitting generation facilities and potential replacement with lower emitting generation facilities. In the absence of federal legislation, states are also contemplating regulations regarding GHG emissions. For example, the Virginia General Assembly has considered legislation which would authorize the state to directly join the RGGI program as a full participant. Given these developments and uncertainties, Dominion Energy and Virginia Power cannot estimate the aggregate effect of such requirements on their results of operations, financial condition or their customers. However, such expenditures, if material, could make Dominion Energy's and Virginia Power's generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect Dominion Energy's or Virginia Power's results of operations, financial performance or liquidity.

There are also potential impacts on Dominion Energy's and Dominion Energy Gas' natural gas businesses as federal or state GHG regulations may require GHG emission reductions from the natural gas sector which, in addition to resulting in increased costs, could affect demand for natural gas. Additionally, GHG requirements could result in increased demand for energy conservation and renewable products, which could impact the natural gas businesses.

Virginia Power is subject to risks associated with the disposal and storage of coal ash. Virginia Power historically produced and continues to produce coal ash, or CCRs, as a by-product of its coal-fired generation operations. The ash is stored and managed in impoundments (ash ponds) and landfills located at eight different facilities.

Virginia Power is facing litigation regarding alleged CWA violations at Chesapeake power station, and may face litigation concerning its coal ash facilities at other stations. Depending on the final outcome of any such litigation, Virginia Power could incur expenses and other costs, including costs associated with closing, corrective action and ongoing monitoring of certain ash ponds. In addition, the EPA has issued regulations concerning the management and storage of CCRs, which Virginia has adopted. These CCR regulations require Virginia Power to make additional capital expenditures and increase its operating and maintenance expenses.

Further, while Virginia Power operates its ash ponds and landfills in compliance with applicable state safety regulations, a release of coal ash with a significant environmental impact, such as the Dan River ash basin release by a neighboring utility, could result in remediation costs, civil and/or criminal penalties, claims, litigation, increased regulation and compliance costs, and reputational damage, and could impact the financial condition of Virginia Power.

The Companies' operations are subject to operational hazards, equipment failures, supply chain disruptions and personnel issues which could negatively affect the Companies. Operation of the Companies' facilities involves risk, including the risk of potential breakdown or failure of equipment or processes due to aging infrastructure, fuel supply, pipeline integrity or transportation disruptions, accidents, labor disputes or work stoppages by employees, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, and performance below expected levels. The Companies' businesses are dependent upon sophisticated information technology systems and network infrastructure, the failure of which could prevent them from accomplishing critical business functions. Because the Companies' transmission facilities, pipelines and other facilities are interconnected with those of third parties, the operation of their facilities and pipelines could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of the Companies' facilities below expected capacity levels could result in lost revenues and increased expenses, including higher maintenance costs. Unplanned outages of the Companies' facilities and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of the Companies' business. Unplanned outages typically increase the Companies' operation and maintenance expenses and may reduce their revenues as a result of selling less output or may require the Companies to incur significant costs as a result of operating higher cost units or obtaining replacement output from third parties in the open market to satisfy forward energy and capacity or other contractual obligations. Moreover, if the Companies are unable to perform their contractual obligations, penalties or liability for damages could result.

In addition, there are many risks associated with the Companies' operations and the transportation, storage and processing of natural gas and NGLs, including nuclear accidents, fires, explosions, uncontrolled release of natural gas and other environmental hazards, pole strikes, electric contact cases, the collision of third party equipment with pipelines and avian and other wildlife impacts. Such incidents could result in loss of human life or injuries among employees, customers or the public in general, environmental pollution, damage or destruction of facilities or business interruptions and associated public or employee safety impacts, loss of revenues, increased liabilities, heightened regulatory scrutiny and reputational risk. Further, the location of pipelines and storage facilities, or generation, transmission, substations and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks.

Dominion Energy and Virginia Power have substantial ownership interests in and operate nuclear generating units; as a result, each may incur substantial costs and liabilities. Dominion Energy's and Virginia Power's nuclear facilities are subject to operational, environmental, health and financial risks such as the on-site storage of spent nuclear fuel, the ability to dispose of such spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, limitations on the amounts and types of insurance available, potential operational liabilities and extended outages, the costs of replacement power, the costs of maintenance and the costs of securing the facilities against possible terrorist attacks. Dominion Energy and Virginia Power maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that future decommissioning costs could exceed amounts in the decommissioning trusts and/or damages could exceed the amount of insurance coverage. If Dominion Energy's and Virginia Power's decommissioning trust funds are insufficient, and they are not allowed to recover the additional costs incurred through insurance, or in the case of Virginia Power through regulatory mechanisms, their results of operations could be negatively impacted.

Dominion Energy's and Virginia Power's nuclear facilities are also subject to complex government regulation which could negatively impact their results of operations. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generating facilities. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or take some combination of these actions, depending on its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could require Dominion Energy and Virginia Power to make substantial expenditures at their nuclear plants. In addition, although the Companies have no reason to anticipate a serious nuclear incident at their plants, if an incident did occur, it could materially and adversely affect their results of operations and/or financial condition. A major incident at a nuclear facility anywhere in the world, such as the nuclear events in Japan in 2011, could cause the NRC to adopt increased safety regulations or otherwise limit or restrict the operation or licensing of domestic nuclear units.

Sustained declines in natural gas and NGL prices have resulted in, and could result in further, curtailments of third-party producers' drilling programs, delaying the production of volumes of natural gas and NGLs that Dominion Energy and Dominion Energy Gas gather, process, and transport and reducing the value of NGLs retained by Dominion Energy Gas, which may adversely affect Dominion Energy and Dominion Energy Gas' revenues and earnings. Dominion Energy and Dominion Energy Gas obtain their supply of natural gas and NGLs from numerous third-party producers. Most producers are under no obligation to deliver a specific quantity of natural gas or NGLs to Dominion Energy's and Dominion Energy Gas' facilities. A number of other factors could reduce the volumes of natural gas and NGLs available to Dominion Energy's and Dominion Energy Gas' pipelines and other assets. Increased regulation of energy extraction activities could result in reductions in drilling for new natural gas wells, which could decrease the volumes of natural gas supplied to Dominion Energy and Dominion Energy Gas. Producers with direct commodity price exposure face liquidity constraints, which could present a credit risk to Dominion Energy and Dominion Energy Gas. Producers could shift their production activities to regions outside Dominion Energy's and Dominion Energy Gas' footprint. In addition, the extent of natural gas reserves and the rate of production from such reserves may be less than anticipated. If producers were to decrease the supply of natural gas or NGLs to Dominion Energy's and Dominion Energy Gas' systems and facilities for any reason, Dominion Energy and Dominion Energy Gas could experience lower revenues to the extent they are unable to replace the lost volumes on similar terms. In addition, Dominion Energy Gas' revenue from processing and fractionation operations largely results from the sale of commodities at market prices. Dominion Energy Gas receives the wet gas product from producers and may retain the extracted NGLs as compensation for its services. This exposes Dominion Energy Gas to commodity price risk for the value of the spread between the NGL products and natural gas, and relative changes in these prices could adversely impact Dominion Energy Gas' results.

Dominion Energy's merchant power business operates in a challenging market, which could adversely affect its results of operations and future growth. The success of Dominion Energy's merchant power business depends upon favorable market conditions including the ability to sell power at prices sufficient to cover its operating costs. Dominion Energy operates in active wholesale markets that expose it to price volatility for electricity and fuel as well as the credit risk of counterparties. Dominion Energy attempts to manage its price risk by entering into hedging transactions, including short-term and long-term fixed price sales and purchase contracts.

In these wholesale markets, the spot market price of electricity for each hour is generally determined by the cost of supplying the next unit of electricity to the market during that hour. In many cases, the next unit of electricity supplied would be provided by generating stations that consume fossil fuels, primarily natural gas. Consequently, the open market wholesale price for electricity generally reflects the cost of natural gas plus the cost to convert the fuel to electricity. Therefore, changes in the price of natural gas generally affect the open market wholesale price of electricity. To the extent Dominion Energy does not enter into long-term power purchase agreements or otherwise effectively hedge its output, these changes in market prices could adversely affect its financial results.

Dominion Energy purchases fuel under a variety of terms, including long-term and short-term contracts and spot market purchases. Dominion Energy is exposed to fuel cost volatility for the portion of its fuel obtained through short-term contracts or on the spot market, including as a result of market supply shortages. Fuel prices can be volatile and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs, thus adversely impacting Dominion Energy's financial results.

In addition, in the event that any of the merchant generation facilities experience a forced outage, Dominion Energy may not receive the level of revenue it anticipated.

The Companies' financial results can be adversely affected by various factors driving supply and demand for electricity and gas and related services. Technological advances required by federal laws mandate new levels of energy efficiency in end-use devices, including lighting, furnaces and electric heat pumps and could lead to declines in per capita energy consumption. Additionally, certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by a fixed date. Further, Virginia Power's business model is premised upon the cost efficiency of the production, transmission and distribution of large-scale centralized utility generation. However, advances in distributed generation technologies, such as solar cells, gas microturbines and fuel cells, may make these alternative generation methods competitive with large-scale utility generation, and change how customers acquire or use our services. Virginia Power has an exclusive franchise to serve retail electric customers in Virginia. However, Virginia's Retail Access Statutes allow certain Power Generation customers exceptions to this franchise. As market conditions change, Virginia Power's customers may further pursue exceptions and Virginia Power's exclusive franchise may erode.

Reduced energy demand or significantly slowed growth in demand due to customer adoption of energy efficient technology, conservation, distributed generation, regional economic conditions, or the impact of additional compliance obligations, unless substantially offset through regulatory cost allocations, could adversely impact the value of the Companies' business activities.

Dominion Energy Gas has experienced a decline in demand for certain of its processing services due to competing facilities operating in nearby areas.

Dominion Energy and Dominion Energy Gas may not be able to maintain, renew or replace their existing portfolio of customer contracts successfully, or on favorable terms. Upon contract expiration, customers may not elect to re-contract with Dominion Energy and Dominion Energy Gas as a result of a variety of factors, including the amount of competition in the industry, changes in the price of natural gas, their level of satisfaction with Dominion Energy's and Dominion Energy Gas' services, the extent to which Dominion Energy and Dominion Energy Gas are able to successfully execute their business plans and the effect of the regulatory framework on customer demand. The failure to replace any such customer contracts on similar terms could result in a loss of revenue for Dominion Energy and Dominion Energy Gas and related decreases in their earnings and cash flows.

Certain of Dominion Energy and Dominion Energy Gas' gas pipeline services are subject to long-term, fixed-price "negotiated rate" contracts that are not subject to adjustment, even if the cost to perform such services exceeds the revenues received from such contracts. Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a "negotiated rate" which may be above or below the FERC regulated, cost-based recourse rate for that service. These "negotiated rate" contracts are not generally subject to adjustment for increased costs which could be produced by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue as a result of these "negotiated rate" contracts could decrease Dominion Energy and Dominion Energy Gas' earnings and cash flows.

Exposure to counterparty performance may adversely affect the Companies' financial results of operations. The Companies are exposed to credit risks of their counterparties and the risk that one or more counterparties may fail or delay the performance of their contractual obligations, including but not limited to payment for services. Some of Dominion Energy's operations are conducted through less than wholly-owned subsidiaries. In such arrangements, Dominion Energy is dependent on third parties to fund their required share of capital expenditures. Counterparties could fail or delay the performance of their contractual obligations for a number of reasons, including the effect of regulations on their operations. Defaults or failure to perform by customers, suppliers, contractors, joint venture partners, financial institutions or other third parties may adversely affect the Companies' financial results.

Dominion Energy will also be exposed to counterparty credit risk relating to the terminal services agreements for the Liquefaction Project. While the counterparties' obligations are supported by parental guarantees and letters of credit, there is no assurance that such credit support would be sufficient to satisfy the obligations in the event of a counterparty default. In addition, if a controversy arises under either agreement resulting in a judgment in Dominion Energy's favor, Dominion Energy may need to seek to enforce a final U.S. court judgment in a foreign tribunal, which could involve a lengthy process.

Market performance and other changes may decrease the value of Dominion Energy's and Virginia Power's decommissioning trust funds and Dominion Energy's and Dominion Energy Gas' benefit plan assets or increase Dominion Energy's and Dominion Energy Gas' liabilities, which could then require significant additional funding. The performance of the capital markets affects the value of the assets that are held in trusts to satisfy future obligations to decommission Dominion Energy's and Virginia Power's nuclear plants and under Dominion Energy's and Dominion Energy Gas' pension and other postretirement benefit plans. The Companies have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuation and will yield uncertain returns, which may fall below expected return rates.

With respect to decommissioning trust funds, a decline in the market value of these assets may increase the funding requirements of the obligations to decommission Dominion Energy's and Virginia Power's nuclear plants or require additional NRC-approved funding assurance.

A decline in the market value of the assets held in trusts to satisfy future obligations under Dominion Energy's and Dominion Energy Gas' pension and other postretirement benefit plans may increase the funding requirements under such plans. Additionally, changes in interest rates will affect the liabilities under Dominion Energy's and Dominion Energy Gas' pension and other postretirement benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including increased numbers of retirements or changes in mortality assumptions, may also increase the funding requirements of the obligations related to the pension and other postretirement benefit plans.

If the decommissioning trust funds and benefit plan assets are negatively impacted by market fluctuations or other factors, the Companies' results of operations, financial condition and/or cash flows could be negatively affected.

The use of derivative instruments could result in financial losses and liquidity constraints. The Companies use derivative instruments, including futures, swaps, forwards, options and FTRs, to manage commodity, currency and financial market risks. In addition, Dominion Energy and Dominion Energy Gas purchase and sell commodity-based contracts for hedging purposes.

The Dodd-Frank Act was enacted into law in July 2010 in an effort to improve regulation of financial markets. The Dodd-Frank Act includes provisions that will require certain over-the-counter derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end users, can choose to exempt their hedging transactions from these clearing and exchange trading requirements. Final rules for the over-the-counter derivative-related provisions of the Dodd-Frank Act will continue to be established through the ongoing rulemaking process of the applicable regulators, including rules regarding margin requirements for non-cleared swaps. If, as a result of changes to the rulemaking process, the Companies' derivative activities are not exempted from the clearing, exchange trading or margin requirements, the Companies could be subject to higher costs, including from higher margin requirements, for their derivative activities. In addition, changes to or the elimination of rulemaking that implements Title VII of the Dodd-Frank Act by the Companies' counterparties could result in increased costs related to the Companies' derivative activities.

Changing rating agency requirements could negatively affect the Companies' growth and business strategy. In order to maintain appropriate credit ratings to obtain needed credit at a reasonable cost in light of existing or future rating agency requirements, the Companies may find it necessary to take steps or change their business plans in ways that may adversely affect their growth and earnings. A reduction in the Companies' credit ratings could result in an increase in borrowing costs, loss of access to certain markets, or both, thus adversely affecting operating results and could require the Companies to post additional collateral in connection with some of its price risk management activities.

An inability to access financial markets could adversely affect the execution of the Companies' business plans. The Companies rely on access to short-term money markets and longer-term capital markets as significant sources of funding and liquidity for business plans with increasing capital expenditure needs, normal working capital and collateral requirements related to hedges of future sales and purchases of energy-related commodities. Deterioration in the Companies' creditworthiness, as evaluated by credit rating agencies or otherwise, or declines in market reputation either for the Companies or their industry in general, or general financial market disruptions outside of the Companies' control could increase their cost of borrowing or restrict their ability to access one or more financial markets. Further market disruptions could stem from delays in the current economic recovery, the bankruptcy of an unrelated company, general market disruption due to general credit market or political events, or the failure of financial institutions on which the Companies rely. Increased costs and restrictions on the Companies' ability to access financial markets may be severe enough to affect their ability to execute their business plans as scheduled.

Potential changes in accounting practices may adversely affect the Companies' financial results. The Companies cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry or their operations specifically. New accounting standards could be issued that could change the way they record revenues, expenses, assets and liabilities. These changes in accounting standards could adversely affect earnings or could increase liabilities.

War, acts and threats of terrorism, intentional acts and other significant events could adversely affect the Companies' operations. The Companies cannot predict the impact that any future terrorist attacks may have on the energy industry in general, or on the Companies' business in particular. Any retaliatory military strikes or sustained military campaign may affect the Companies' operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets. In addition, the Companies' infrastructure facilities, including projects under construction, could be direct targets of, or indirect casualties of, an act of terror. For example, a physical attack on a critical substation in California resulted in serious impacts to the power grid. Furthermore, the physical compromise of the Companies' facilities could adversely affect the Companies' ability to manage these facilities effectively. Instability in financial markets as a result of terrorism, war, intentional acts, pandemic, credit crises, recession or other factors could result in a significant decline in the U.S. economy and increase the cost of insurance coverage. This could negatively impact the Companies' results of operations and financial condition.

Hostile cyber intrusions could severely impair the Companies' operations, lead to the disclosure of confidential information, damage the reputation of the Companies and otherwise have an adverse effect on the Companies' business. The Companies own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run the Companies' facilities are not completely isolated from external networks. There appears to be an increasing level of activity, sophistication and maturity of threat actors, in particular nation state actors, that wish to disrupt the U.S. bulk power system and the U.S. gas transmission or distribution system. Such parties could view the Companies' computer systems, software or networks as attractive targets for cyber attack. For example, malware has been designed to target software that runs the nation's critical infrastructure such as power transmission grids and gas pipelines. In addition, the Companies' businesses require that they and their vendors collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A successful cyber attack on the systems that control the Companies' electric generation, electric or gas transmission or distribution assets could severely disrupt business operations, preventing the Companies from serving customers or collecting revenues. The breach of certain business systems could affect the Companies' ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to the Companies' reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. The Companies maintain property and casualty insurance that may cover certain damage caused by potential cyber incidents; however, other damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available. For these reasons, a significant cyber incident could materially and adversely affect the Companies' business, financial condition and results of operations.

Failure to attract and retain key executive officers and an appropriately qualified workforce could have an adverse effect on the Companies' operations. The Companies' business strategy is dependent on their ability to recruit, retain and motivate employees. The Companies' key executive officers are the CEO, CFO and presidents and those responsible for financial, operational, legal, regulatory and accounting functions. Competition for skilled management employees in these areas of the Companies' business operations is high. Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the length of time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labor may adversely affect the ability to manage and operate the Companies' business. In addition, certain specialized knowledge is required of the Companies' technical employees for transmission, generation and distribution operations. The Companies' inability to attract and retain these employees could adversely affect their business and future operating results.

The completion of the merger with SCANA is subject to the receipt of consents, approvals and/or findings from governmental entities, which may impose conditions that could have an adverse effect on Dominion Energy or SCANA or could cause either Dominion Energy or SCANA to abandon the merger. The completion of the merger is also subject to there not having been substantive changes in certain South Carolina laws that have or would reasonably be expected to have an adverse effect on SCANA or its subsidiaries or orders of governmental entities or changes in law that impose any condition that would reasonably be expected to result in specified changes to the South Carolina Commission petition. Dominion Energy and SCANA are not required to complete the merger until after the applicable waiting period under the Hart-Scott-Rodino Act expires or terminates and the requisite authorizations, approvals, consents and/or permits are received from the FERC, NRC, South Carolina Commission, North Carolina Commission and Georgia Public Service Commission. Any of the relevant governmental entities may oppose the merger, fail to approve the merger, fail to make required findings in favor of the merger, or impose certain requirements or obligations as conditions for their consent, approval or findings or in connection with their review. Regulatory approvals of the merger or findings with respect to the merger may not be obtained on a timely basis or at all, and such approvals or findings may include conditions that could have an adverse effect on Dominion Energy and/or SCANA, or result in the abandonment of the merger. Dominion Energy cannot provide any assurance that Dominion Energy and SCANA will obtain the necessary approvals or findings or that any required conditions will not have an adverse effect on Dominion Energy following the merger.

Subject to the terms and conditions set forth in the merger agreement, the merger agreement may require Dominion Energy to accept conditions from regulators that could adversely impact Dominion Energy after the merger without either of Dominion Energy or SCANA having the right to refuse to close the merger on the basis of those regulatory conditions, except that Dominion Energy is generally not required, and SCANA is generally not permitted without Dominion Energy's prior approval, to take any action or accept any condition that results in a burdensome condition for Dominion Energy or SCANA as more fully described in the SCANA Merger Agreement.

In addition, the SCANA Merger Agreement provides that Dominion Energy (but not SCANA) will have the right to refuse to complete the merger if, since the date of the SCANA Merger Agreement, any governmental entity shall have enacted any order, or there shall have been any change in law (including the Base Load Review Act and the other laws governing South Carolina public utilities), which imposes any material change to the terms, conditions or undertakings set forth in the South Carolina Commission petition, or any significant changes to the economic value of the proposed terms set forth in the South Carolina Commission petition, in each case as determined by Dominion Energy in good faith.

The SCANA Merger Agreement further provides that Dominion Energy will have the right to refuse to close the merger if there shall have occurred any substantive change in the Base Load Review Act or other laws governing South Carolina public utilities which has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries. There is currently pending before the South Carolina Senate a bill that would make substantive changes to the Base Load Review Act. This bill has passed the South Carolina House of Representatives. If this bill becomes law, Dominion Energy would not be obligated to complete the merger if it is determined that the bill has or would reasonably be expected to have an adverse effect on SCANA or any of its subsidiaries.

Certain lawsuits and regulatory actions have been filed against SCANA and SCE&G in connection with the abandonment of the V.C. Summer Units 2 and 3 new nuclear development project. If the relief requested in these matters (including a request for declaratory judgment that the Base Load Review Act is unconstitutional) is granted, Dominion Energy might not be obligated to complete the merger.

Dominion Energy and SCANA can provide no assurance that these risks will not materialize and either adversely impact Dominion Energy after the completion of the merger or, if such conditions rise to the thresholds discussed above, some of which, as described above, are in the subjective determination of Dominion Energy acting in good faith, or if the required authorizations, approvals, consents and/or permits are not obtained or received, result in the abandonment of the merger.

Dominion Energy expects to incur substantial expenses related to the merger with SCANA. Dominion Energy expects to incur relatively significant expenses in connection with completing the merger. While Dominion Energy has assumed that a certain level of transaction and integration expenses would be incurred, there are a number of factors beyond its control that could affect the total amount or the timing of its integration expenses. Many of the expenses that will be incurred, by their nature, are difficult to estimate accurately at the present time.

Following the merger with SCANA, Dominion Energy may be unable to successfully integrate SCANA's businesses. Dominion Energy and SCANA currently operate as independent public companies. After the merger, Dominion Energy will be required to devote significant management attention and resources to integrating SCANA's business. Potential difficulties Dominion Energy may encounter in the integration process include the following:

- The complexities associated with integrating SCANA and its utility businesses, while at the same time continuing to provide consistent, high quality services;
- The complexities of integrating a company with different core services, markets and customers;
- The inability to attract and retain key employees;
- Potential unknown liabilities and unforeseen increased expenses, delays or regulatory conditions associated with the merger;
- Difficulties in managing political and regulatory conditions related to SCANA's utility businesses after the merger;
- The cost recovery plan includes a moratorium on filing requests for adjustments in SCE&G's base electric rates until 2021 if the merger is approved by the South Carolina Commission, which would limit Dominion Energy's ability to recover increases in non-fuel related costs of electric operations for SCE&G's customers; and
- Performance shortfalls as a result of the diversion of Dominion Energy management's attention caused by completing the merger and integrating SCANA's utility businesses.

For these reasons, it is possible that the integration process following the merger could result in the distraction of Dominion Energy's management, the disruption of Dominion Energy's ongoing business or inconsistencies in its services, standards, controls, procedures and policies, any of which could adversely affect the ability of Dominion Energy to maintain or establish relationships with current and prospective customers, vendors and employees or could otherwise adversely affect the business and financial results of Dominion Energy.

Dominion Energy and SCANA may be materially adversely affected by negative publicity related to the merger and in connection with other related matters, including the abandonment of the V.C. Summer Units 2 and 3 new nuclear development project. From time to time, political and public sentiment in connection with the merger and in connection with other matters, including the abandonment of the V.C. Summer Units 2 and 3 new nuclear development project may result in a significant amount of adverse press coverage and other adverse public statements affecting Dominion Energy and SCANA. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceedings, as well as responding to and addressing adverse press coverage and other adverse public statements, can divert the time and effort of senior management from the management of Dominion Energy's and SCANA's respective businesses.

Addressing any adverse publicity, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of Dominion Energy and SCANA, on the morale and performance of their employees and on their relationships with their respective regulators, customers and commercial counterparties. It may also have a negative impact on their ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have a material adverse effect on Dominion Energy's and SCANA's respective business, financial condition, results of operations and prospects.

The market value of Dominion Energy common stock could decline if large amounts of its common stock are sold following the merger with SCANA. Following the merger, shareholders of Dominion Energy and former SCANA shareholders will own interests in a combined company operating an expanded business with more assets and a different mix of liabilities. Current shareholders of Dominion Energy and SCANA may not wish to continue to invest in the combined company, or may wish to reduce their investment in the combined company, in order to comply with institutional investing guidelines, to increase diversification or to track any rebalancing of stock indices in which Dominion Energy common stock or SCANA common stock is or was included. If, following the merger, large amounts of Dominion Energy common stock are sold, the price of its common stock could decline.

The merger with SCANA may not be accretive to operating earnings and may cause dilution to Dominion Energy's earnings per share, which may negatively affect the market price of Dominion Energy common stock. Dominion Energy currently anticipates that the merger will be immediately accretive to Dominion Energy's forecasted operating earnings per share on a standalone basis. This expectation is based on preliminary estimates, which may materially change. Dominion Energy may encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates or its ability to realize operational efficiencies. Any of these factors could cause a decrease in Dominion Energy's operating earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Dominion Energy's common stock. Dominion Energy expects the initial effect of the merger on its GAAP earnings will be a decrease in such earnings due to the anticipated charges for refunds to SCE&G customers, write-offs of regulatory assets and transaction costs.

Litigation against SCANA and Dominion Energy could result in an injunction preventing the completion of the merger with SCANA or may adversely affect the combined company's business, financial condition or results of operations following the merger with SCANA. Following the announcement of the SCANA Merger Agreement, lawsuits have been filed asserting claims relating to the merger. Among other things, the lawsuits allege breaches of various fiduciary duties by the members of the SCANA board in connection with the merger and allegations that Dominion Energy and/or SCANA aided and abetted such alleged breaches. Among other remedies, the plaintiffs seek to enjoin the merger, rescind the merger agreement or be awarded monetary damages should the merger be completed. While Dominion Energy believes that dismissal of these lawsuits is warranted, the outcome of any such litigation is inherently uncertain. The defense or settlement of any lawsuit or any claim that remains unresolved at the time the merger closes may adversely affect the combined company's business, financial condition or results of operation. Additionally, other lawsuits may be filed in the future making similar or new claims and seeking similar or new remedies.

Dominion Energy has goodwill and other intangible assets on its balance sheet, and these amounts will increase as a result of the merger with SCANA. If its goodwill or other intangible assets become impaired in the future, Dominion Energy may be required to record a significant, non-cash charge to earnings and reduce its shareholders' equity. Upon the completion of the merger, Dominion Energy will record as goodwill the excess of the purchase price paid by Dominion Energy over the fair value of SCANA's assets and liabilities as determined for financial accounting purposes. Under GAAP, intangible assets are reviewed for impairment on an annual basis or more frequently whenever events or circumstances indicate that its carrying value may not be recoverable. If Dominion Energy's intangible assets, including goodwill as a result of the merger, are determined to be impaired in the future, Dominion Energy may be required to record a significant, non-cash charge to earnings during the period in which the impairment is determined.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2017, Dominion Energy owned its principal executive office and three other corporate offices, all located in Richmond, Virginia. Dominion Energy also leases corporate offices in other cities in which its subsidiaries operate. Virginia Power and Dominion Energy Gas share Dominion Energy's principal office in Richmond, Virginia, which is owned by Dominion Energy. In addition, Virginia Power's Power Delivery and Power Generation segments share certain leased buildings and equipment. See Item 1. Business for additional information about each segment's principal properties, which information is incorporated herein by reference.

Dominion Energy's assets consist primarily of its investments in its subsidiaries, the principal properties of which are described here and in Item 1. Business.

Certain of Virginia Power's property is subject to the lien of the Indenture of Mortgage securing its First and Refunding Mortgage Bonds. There were no bonds outstanding as of December 31, 2017; however, by leaving the indenture open, Virginia Power expects to retain the flexibility to issue mortgage bonds in the future. Certain of Dominion Energy's merchant generation facilities are also subject to liens.

GAS INFRASTRUCTURE

Dominion Energy and Dominion Energy Gas

East Ohio's gas distribution network is located in Ohio. This network involves approximately 18,900 miles of pipe, exclusive of service lines. The right-of-way grants for many natural gas pipelines have been obtained from the actual owners of real estate, as underlying titles have been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many natural gas pipelines are on publicly-owned property, where company rights and actions are determined on a case-by-case basis, with results that range from reimbursed relocation to revocation of permission to operate.

Dominion Energy Gas has approximately 10,400 miles, excluding interests held by others, of gas transmission, gathering and storage pipelines located in the states of Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. Dominion Energy Gas also owns NGL processing plants capable of processing over 270,000 mcf per day of natural gas. Hastings is the largest plant and is capable of processing over 180,000 mcf per day of natural gas. Hastings can also fractionate over 580,000 Gals per day of NGLs into marketable products, including propane, isobutane, butane and natural gasoline. NGL operations have storage capacity of 1,226,500 Gals of propane, 109,000 Gals of isobutane, 442,000 Gals of butane, 2,000,000 Gals of natural gasoline and 1,012,500 Gals of mixed NGLs. Dominion Energy Gas also operates 20 underground gas storage fields located in New York, Ohio, Pennsylvania and West Virginia, with approximately 2,000 storage wells and approximately 399,000 acres of operated leaseholds.

The total designed capacity of the underground storage fields operated by Dominion Energy Gas is approximately 926 bcf. Certain storage fields are jointly-owned and operated by Dominion Energy Gas. The capacity of those fields owned by Dominion Energy Gas' partners totals approximately 223 bcf.

Dominion Energy

Cove Point's LNG facility has an operational peak regasification daily send-out capacity of approximately 1.8 million Dths and an aggregate LNG storage capacity of approximately 14.6 bcfe. In addition, Cove Point has a liquefier that has the potential to create approximately 15,000 Dths/day.

The Cove Point pipeline is a 36-inch diameter underground, interstate natural gas pipeline that extends approximately 88 miles from Cove Point to interconnections with Transcontinental Gas Pipe Line Company, LLC in Fairfax County, Virginia, and with Columbia Gas Transmission, LLC and DETI in Loudoun County, Virginia. In 2009, the original pipeline was expanded to include a 36-inch diameter expansion that extends approximately 48 miles, roughly 75% of which is parallel to the original pipeline.

Questar Gas distributes gas to customers in Utah, Wyoming and Idaho. Questar Gas owns and operates distribution systems and has a total of 29,600 miles of street mains, service lines and interconnecting pipelines. Questar Gas has a major operations center in Salt Lake City, and has operations centers, field offices and service-center facilities in other parts of its service area.

Dominion Energy Questar Pipeline operates 2,200 miles of natural gas transportation pipelines that interconnect with other pipelines in Utah, Wyoming and western Colorado. Dominion Energy Questar Pipeline's system ranges in diameter from lines that are less than four inches to 36-inches. Dominion Energy Questar Pipeline owns the Clay Basin storage facility in northeastern Utah, which has a certificated capacity of 120 bcf, including 54 bcf of working gas.

DECG's interstate natural gas pipeline system in South Carolina and southeastern Georgia is comprised of nearly 1,500 miles of transmission pipeline.

Hope's gas distribution network located in West Virginia is comprised of 3,200 miles of pipe, exclusive of service lines.

In total, Dominion Energy has 171 compressor stations with approximately 1,190,000 installed compressor horsepower.

POWER DELIVERY

See Item 1. Business, *General* for details regarding Power Delivery's principal properties, which primarily include transmission and distribution lines.

POWER GENERATION

Dominion Energy and Virginia Power generate electricity for sale on a wholesale and a retail level. Dominion Energy and Virginia Power supply electricity demand either from their generation facilities or through purchased power contracts. As of December 31, 2017, Power Generation's total utility and merchant generating capacity was approximately 26,000 MW. The following tables list Power Generation's utility and merchant generating units and capability, as of December 31, 2017.

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VIRGINIA POWER UTILITY GENERATION(1)

Plant	Location	Net Summer Capability (MW)	Percentage Net Summer Capability
Gas			
Brunswick County (CC)	Brunswick County, VA	1,376	
Warren County (CC)	Warren County, VA	1,350	
Ladysmith (CT)	Ladysmith, VA	784	
Bear Garden (CC)	Buckingham County, VA	622	
Remington (CT)	Remington, VA	608	
Possum Point (CC)	Dumfries, VA	573	
Chesterfield (CC)	Chester, VA	397	
Elizabeth River (CT)	Chesapeake, VA	348	
Possum Point(6)	Dumfries, VA	316	
Bellemeade (CC)(6)	Richmond, VA	267	
Bremo(6)	Bremo Bluff, VA	227	
Gordonsville Energy (CC)	Gordonsville, VA	218	
Gravel Neck (CT)	Surry, VA	170	
Darbytown (CT)	Richmond, VA	168	
Rosemary (CC)	Roanoke Rapids, NC	165	
Total Gas		7,589	37%
Coal			
Mt. Storm	Mt. Storm, WV	1,624	
Chesterfield(6)	Chester, VA	1,268	
Virginia City Hybrid Energy Center	Wise County, VA	610	
Clover	Clover, VA	439(2)	
Yorktown(3)	Yorktown, VA	323	
Mecklenburg(6)	Clarksville, VA	138	
Total Coal		4,402	21
Nuclear			
Surry	Surry, VA	1,676	
North Anna	Mineral, VA	1,672(4)	
Total Nuclear		3,348	16
Oil			
Yorktown	Yorktown, VA	790	
Possum Point	Dumfries, VA	783	
Gravel Neck (CT)	Surry, VA	198	
Darbytown (CT)	Richmond, VA	168	
Possum Point (CT)	Dumfries, VA	72	
Chesapeake (CT)	Chesapeake, VA	51	
Low Moor (CT)	Covington, VA	48	
Northern Neck (CT)	Lively, VA	47	
Total Oil		2,157	11
Hydro			
Bath County	Warm Springs, VA	1,808(5)	
Gaston	Roanoke Rapids, NC	220	
Roanoke Rapids	Roanoke Rapids, NC	95	
Other	Various	3	
Total Hydro		2,126	10
Biomass			
Pittsylvania	Hurt, VA	83	
Altavista	Altavista, VA	51	
Polyester	Hopewell, VA	51	
Southampton	Southampton, VA	51	
Total Biomass		236	1
Solar			
Whitehouse Solar	Louisa County, VA	20	
Woodland Solar	Isle of Wight County, VA	19	
Scott Solar	Powhatan County, VA	17	
Total Solar		56	—
Various			
Mt. Storm (CT)	Mt. Storm, WV	11	—
		19,925	
Power Purchase Agreements		854	4
Total Utility Generation		20,779	100%

Note: (CT) denotes combustion turbine and (CC) denotes combined cycle.

(1) The table excludes Virginia Power's Morgans Corner solar facility located in Pasquotank County, NC, Remington solar facility located in Remington, VA and Oceana solar facility located in Virginia Beach, VA which have a net summer capacity of 20 MW, 20 MW and 18 MW, respectively as these facilities are dedicated to serving non-jurisdictional customers.

(2) Excludes 50% undivided interest owned by ODEC.

(3) Coal-fired units are expected to be retired at Yorktown power station as early as 2018 as a result of the issuance of MATS.

(4) Excludes 11.6% undivided interest owned by ODEC.

(5) Excludes 40% undivided interest owned by Allegheny Generating Company, a subsidiary of FirstEnergy Corp.

(6) In January 2018, Virginia Power announced it would place certain units at this facility in cold storage.

DOMINION MERCHANT GENERATION

Plant	Location	Net Summer Capability (MW)	Percentage Net Summer Capability
Nuclear			
Millstone	Waterford, CT	2,001(1)	
Total Nuclear		2,001	39%
Gas			
Fairless (CC)	Fairless Hills, PA	1,240	
Manchester (CC)	Providence, RI	468	
Total Gas		1,708	33
Solar(2)			
Escalante I, II and III	Beaver County, UT	120(3)	
Amazon Solar Farm Virginia—Southampton	Newsoms, VA	100	
Amazon Solar Farm Virginia—Accomack	Oak Hall, VA	80	
Innovative Solar 37	Morven, NC	79	
Moffett Solar 1	Ridgeland, SC	71	
Granite Mountain East and West	Iron County, UT	65(3)	
Summit Farms Solar	Moyock, NC	60	
Enterprise	Iron County, UT	40(3)	
Iron Springs	Iron County, UT	40(3)	
Pavant Solar	Holden, UT	34(4)	
Camelot Solar	Mojave, CA	30(4)	
Midway II	Calipatria, CA	30	
Indy I, II and III	Indianapolis, IN	20(4)	
Amazon Solar Farm Virginia—Buckingham	Cumberland, VA	20	
Amazon Solar Farm Virginia—Correctional	Barhamsville, VA	20	
Hecate Cherrydale	Cape Charles, VA	20	
Amazon Solar Farm Virginia—Sappony	Soney Creek, VA	20	
Amazon Solar Farm Virginia—Scott II	Powhatan, VA	20	
Cottonwood Solar	Kings and Kern counties, CA	16(4)	
Alamo Solar	San Bernardino, CA	13(4)	
Maricopa West Solar	Kern County, CA	13(4)	
Imperial Valley Solar	Imperial, CA	13(4)	
Richland Solar	Jeffersonville, GA	13(4)	
CID Solar	Corcoran, CA	13(4)	
Kansas Solar	Lenmore, CA	13(4)	
Kent South Solar	Lenmore, CA	13(4)	
Old River One Solar	Bakersfield, CA	13(4)	
West Antelope Solar	Lancaster, CA	13(4)	
Adams East Solar	Tranquility, CA	13(4)	
Catalina 2 Solar	Kern County, CA	12(4)	
Mulberry Solar	Selmer, TN	11(4)	
Selmer Solar	Selmer, TN	11(4)	
Columbia 2 Solar	Mojave, CA	10(4)	
Hecate Energy Clarke County	White Post, VA	10	
Ridgeland Solar Farm I	Ridgeland, SC	10	
Azalea Solar	Davisboro, GA	5(4)	
Clipperton	Clinton, NC	5	
Fremont Solar	Fremont, NC	5	
Moorings 2	Lagrange, NC	5	
Pikeville Solar	Pikeville, NC	5	
Wakefield	Zebulon, NC	5	
Somers Solar	Somers, CT	3(4)	
Total Solar		1,112	22
Wind			
Fowler Ridge(5)	Benton County, IN	150(6)	
NedPower(5)	Grant County, WV	132(7)	
Total Wind		282	6
Fuel Cell			
Bridgeport Fuel Cell	Bridgeport, CT	15	
Total Fuel Cell		15	—
Total Merchant Generation		5,118	100%

Note: (CC) denotes combined cycle.
(1) Excludes 6.53% undivided interest in Unit 3 owned by Massachusetts Municipal and Green Mountain.
(2) All solar facilities are alternating current.
(3) Excludes 50% noncontrolling interest owned by NRG. Dominion Energy's interest is subject to a lien securing Dominion Solar Projects III, Inc.'s debt.
(4) Excludes 33% noncontrolling interest owned by Terra Nova Renewable Partners. Dominion Energy's interest is subject to a lien securing SBL Holdco's debt.
(5) Subject to a lien securing the facility's debt.
(6) Excludes 50% membership interest owned by BP.
(7) Excludes 50% membership interest owned by Shell.

Item 3. Legal Proceedings

From time to time, the Companies are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by the Companies, or permits issued by various local, state and/or federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, the Companies and their subsidiaries are involved in various legal proceedings.

In January 2016, Virginia Power self-reported a release of mineral oil from the Crystal City substation and began extensive cleanup. Virginia Power assumed the role of responsible party and has continued to cooperate with ongoing requirements for investigative and corrective action. In December 2016, the Virginia State Water Control Board approved a consent order between the VDEQ and Virginia Power related to this matter, which included a penalty in excess of $100,000. In May 2017, the VDEQ formally terminated the consent order, finding that all requirements had been completed. Also in May 2017, the U.S. Department of the Interior, on behalf of several federal and state agencies, proposed a settlement to resolve the agencies' claims for natural resource damages related to the mineral oil release. In January 2018, Virginia Power and the natural resource trustee agencies executed a settlement agreement that would require Virginia Power to pay approximately $400,000 to fund wetland restoration and related projects in the location of the release. Final approval of the settlement is pending completion of a 30-day public comment period which is expected during the first quarter of 2018.

See Notes 13 and 22 to the Consolidated Financial Statements and *Future Issues and Other Matters* in Item 7. MD&A, which information is incorporated herein by reference, for discussion of various environmental and other regulatory proceedings to which the Companies are a party.

Item 4. Mine Safety Disclosures

Not applicable.

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Information concerning the executive officers of Dominion Energy, each of whom is elected annually, is as follows:

Name and Age	Business Experience Past Five Years(1)
Thomas F. Farrell, II (63)	Chairman of the Board of Directors, President and CEO of Dominion Energy from April 2007 to date; Chairman and CEO of Dominion Energy Midstream GP, LLC (the general partner of Dominion Energy Midstream) from March 2014 to date and President from February 2015 to date; CEO of Dominion Energy Gas from September 2013 to date and Chairman from March 2014 to date; Chairman and CEO of Virginia Power from February 2006 to date and Questar Gas from September 2016 to date.
Mark F. McGettrick (60)	Executive Vice President and CFO of Dominion Energy from June 2009 to date, Dominion Energy Midstream GP, LLC from March 2014 to date, Virginia Power from June 2009 to date, Dominion Energy Gas from September 2013 to date, and Questar Gas from September 2016 to date.
Robert M. Blue (50)	Executive Vice President and President & CEO—Power Delivery Group of Dominion Energy from May 2017 to date; President and COO—Power Delivery Group of Virginia Power from May 2017 to date; Senior Vice President and President & CEO—Dominion Virginia Power of Dominion Energy from January 2017 to May 2017; President and COO of Virginia Power from January 2017 to May 2017; Senior Vice President—Law, Regulation & Policy of Dominion Energy, Dominion Energy Gas and Dominion Energy Midstream GP, LLC from February 2016 to December 2016 and Questar Gas from September 2016 to December 2016; President of Virginia Power from January 2016 to December 2016; Senior Vice President—Regulation, Law, Energy Solutions and Policy of Dominion Energy and Dominion Energy Gas from May 2015 to January 2016 and Dominion Energy Midstream GP, LLC from July 2015 to January 2016; Senior Vice President—Regulation, Law, Energy Solutions and Policy of Virginia Power from May 2015 to December 2015; President of Virginia Power from January 2014 to May 2015; Senior Vice President—Law, Public Policy and Environment of Dominion Energy from January 2011 to December 2013.
Paul D. Koonce (58)	Executive Vice President and President & CEO—Power Generation Group of Dominion Energy from January 2017 to date; President and COO—Power Generation Group of Virginia Power from May 2017 to date; Executive Vice President and CEO—Dominion Generation Group of Dominion Energy from January 2016 to December 2016; Executive Vice President and CEO—Energy Infrastructure Group of Dominion Energy from February 2013 to December 2015; Executive Vice President of Dominion Energy from April 2006 to February 2013; Executive Vice President of Dominion Energy Midstream GP, LLC from March 2014 to December 2015; President and COO of Virginia Power from June 2009 to May 2017; President of Dominion Energy Gas from September 2013 to December 2015.
Diane Leopold (51)	Executive Vice President and President & CEO—Gas Infrastructure Group of Dominion Energy and Dominion Energy Midstream GP, LLC from May 2017 to date; President of Dominion Energy Gas from January 2017 to date and Questar Gas from August 2017 to date; Senior Vice President and President & CEO—Dominion Energy of Dominion Energy and Dominion Energy Midstream GP, LLC from January 2017 to May 2017; President of DETI, East Ohio and Dominion Cove Point, Inc. from January 2014 to date; Senior Vice President of DETI from April 2012 to December 2013.
Mark O. Webb (53)	Senior Vice President—Corporate Affairs and Chief Legal Officer of Dominion Energy, Virginia Power, Dominion Energy Gas, Dominion Energy Midstream GP, LLC, and Questar Gas from January 2017 to date; Senior Vice President, General Counsel and Chief Risk Officer of Dominion Energy, Virginia Power and Dominion Energy Gas from May 2016 to December 2016; Senior Vice President and General Counsel of Dominion Energy Midstream GP, LLC from May 2016 to December 2016 and Questar Gas from September 2016 to December 2016; Vice President, General Counsel and Chief Risk Officer of Dominion Energy, Virginia Power and Dominion Energy Gas from January 2014 to May 2016; Vice President and General Counsel of Dominion Energy Midstream GP, LLC from March 2014 to May 2016; Vice President and General Counsel of Dominion Energy and Virginia Power from January 2013 to December 2013 and Dominion Energy Gas from September 2013 to December 2013.
Michele L. Cardiff (50)	Vice President, Controller and CAO of Dominion Energy and Virginia Power from April 2014 to date, Dominion Energy Gas and Dominion Energy Midstream GP, LLC from March 2014 to date and Questar Gas from September 2016 to date; Vice President—Accounting of DES from January 2014 to March 2014; Vice President and General Auditor of DES from September 2012 to December 2013.

(1) Any service listed for Virginia Power, Dominion Energy Midstream GP, LLC, Dominion Energy Gas, DETI, East Ohio, Dominion Cove Point, Inc., Questar Gas and DES reflects service at a subsidiary of Dominion Energy.

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Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Dominion Energy

Dominion Energy's common stock is listed on the NYSE. At February 15, 2018, there were approximately 123,000 record holders of Dominion Energy's common stock. The number of record holders is comprised of individual shareholder accounts maintained on Dominion Energy's transfer agent records and includes accounts with shares held in (1) certificate form, (2) book-entry in the Direct Registration System and (3) book-entry under Dominion Energy Direct®. Discussions of expected dividend payments and restrictions on Dominion Energy's payment of dividends required by this Item are contained in *Liquidity and Capital Resources* in Item 7. MD&A and Notes 17 and 20 to the Consolidated Financial Statements. Cash dividends were paid quarterly in 2017 and 2016. Quarterly information concerning stock prices and dividends is disclosed in Note 26 to the Consolidated Financial Statements, which information is incorporated herein by reference.

The following table presents certain information with respect to Dominion Energy's common stock repurchases during the fourth quarter of 2017:

DOMINION ENERGY PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share(2)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased under the Plans or Programs(3)
10/1/2017-10/31/17	29,305	$76.93	N/A	19,629,059 shares/$1.18 billion
11/1/2017-11/30/17	8	80.49	N/A	19,629,059 shares/$1.18 billion
12/1/2017-12/31/17	4	83.57	N/A	19,629,059 shares/$1.18 billion
Total	29,317	$76.93	N/A	19,629,059 shares/$1.18 billion

(1) 29,305, 8 and 4 shares were tendered by employees to satisfy tax withholding obligations on vested restricted stock in October, November and December 2017, respectively.
(2) Represents the weighted-average price paid per share.
(3) The remaining repurchase authorization is pursuant to repurchase authority granted by the Dominion Energy Board of Directors in February 2005, as modified in June 2007. The aggregate authorization granted by the Dominion Energy Board of Directors was 86 million shares (as adjusted to reflect a two-for-one stock split distributed in November 2007) not to exceed $4 billion.

Virginia Power

There is no established public trading market for Virginia Power's common stock, all of which is owned by Dominion Energy. Potential restrictions on Virginia Power's payment of dividends are discussed in Note 20 to the Consolidated Financial Statements. In 2016, no dividends were declared or paid given the sufficiency of operating and other cash flows at Dominion Energy. In 2017, Virginia Power declared and paid quarterly cash dividends of $445 million, $409 million and $345 million during the first three quarters of 2017, respectively. Virginia Power intends to pay quarterly cash dividends in 2018 but is neither required to nor restricted, except as described above, from making such payments.

Dominion Energy Gas

All of Dominion Energy Gas' membership interests are owned by Dominion Energy. Potential restrictions on Dominion Energy Gas' payment of distributions are discussed in Note 20 to the Consolidated Financial Statements. Dominion Energy Gas declared and paid cash distributions of $150 million in the second quarter of 2016. Dominion Energy Gas declared and paid cash distributions of $7 million and $8 million in the first and second quarters of 2017, respectively. Dominion Energy Gas intends to pay quarterly cash dividends in 2018 but is neither required to nor restricted, except as described above, from making such payments.

Item 6. Selected Financial Data

The following table should be read in conjunction with the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

DOMINION ENERGY

Year Ended December 31, (millions, except per share amounts)	2017(1)	2016(2)	2015	2014(3)	2013(4)
Operating revenue	**$12,586**	$11,737	$11,683	$12,436	$13,120
Income from continuing operations, net of tax(5)	**2,999**	2,123	1,899	1,310	1,789
Loss from discontinued operations, net of tax(5)	**—**	—	—	—	(92)
Net income attributable to Dominion Energy	**2,999**	2,123	1,899	1,310	1,697
Income from continuing operations before loss from discontinued operations per common share-basic	**4.72**	3.44	3.21	2.25	3.09
Net income attributable to Dominion Energy per common share-basic	**4.72**	3.44	3.21	2.25	2.93
Income from continuing operations before loss from discontinued operations per common share-diluted	**4.72**	3.44	3.20	2.24	3.09
Net income attributable to Dominion Energy per common share-diluted	**4.72**	3.44	3.20	2.24	2.93
Dividends declared per common share	**3.035**	2.80	2.59	2.40	2.25
Total assets	**76,585**	71,610	58,648	54,186	49,963
Long-term debt	**30,948**	30,231	23,468	21,665	19,199

(1) Includes $851 million of tax benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate, partially offset by $96 million of after-tax charges associated with equity method investments in wind-powered generation facilities.

(2) Includes a $122 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

(3) Includes $248 million of after-tax charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities, a $193 million after-tax charge related to Dominion Energy's restructuring of its producer services business and a $174 million after-tax charge associated with the Liability Management Exercise.

(4) Includes a $109 million after-tax charge related to Dominion Energy's restructuring of its producer services business ($76 million) and an impairment of certain natural gas infrastructure assets ($33 million). Also in 2013, Dominion Energy recorded a $92 million after-tax net loss from the discontinued operations of Brayton Point and Kincaid.

(5) Amounts attributable to Dominion Energy's common shareholders.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

MD&A discusses Dominion Energy's results of operations and general financial condition and Virginia Power's and Dominion Energy Gas' results of operations. MD&A should be read in conjunction with Item 1. Business and the Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. Virginia Power and Dominion Energy Gas meet the conditions to file under the reduced disclosure format, and therefore have omitted certain sections of MD&A.

CONTENTS OF MD&A

MD&A consists of the following information:

FORWARD-LOOKING STATEMENTS

This report contains statements concerning the Companies' expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by such words as "anticipate," "estimate," "forecast," "expect," "believe," "should," "could," "plan," "may," "continue," "target" or other similar words.

The Companies make forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to differ materially from predicted results. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Additionally, other factors may cause actual results to differ materially from those indicated in any forward-looking statement. These factors include but are not limited to:

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events and other natural disasters, including, but not limited to, hurricanes, high winds, severe storms, earthquakes, flooding and changes in water temperatures and availability that can cause outages and property damage to facilities;
- Federal, state and local legislative and regulatory developments, including changes in federal and state tax laws and regulations, including provisions of the 2017 Tax Reform Act that take effect beginning in 2018;
- Changes to federal, state and local environmental laws and regulations, including those related to climate change, the tightening of emission or discharge limits for GHGs and other substances, more extensive permitting requirements and the regulation of additional substances;
- Cost of environmental compliance, including those costs related to climate change;
- Changes in implementation and enforcement practices of regulators relating to environmental standards and litigation exposure for remedial activities;
- Difficulty in anticipating mitigation requirements associated with environmental and other regulatory approvals or related appeals;
- Risks associated with the operation of nuclear facilities, including costs associated with the disposal of spent nuclear fuel, decommissioning, plant maintenance and changes in existing regulations governing such facilities;
- Unplanned outages at facilities in which the Companies have an ownership interest;
- Fluctuations in energy-related commodity prices and the effect these could have on Dominion Energy's and Dominion Energy Gas' earnings and the Companies' liquidity position and the underlying value of their assets;
- Counterparty credit and performance risk;
- Global capital market conditions, including the availability of credit and the ability to obtain financing on reasonable terms;
- Risks associated with Virginia Power's membership and participation in PJM, including risks related to obligations created by the default of other participants;
- Fluctuations in the value of investments held in nuclear decommissioning trusts by Dominion Energy and Virginia Power and in benefit plan trusts by Dominion Energy and Dominion Energy Gas;
- Fluctuations in interest rates or foreign currency exchange rates;
- Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- Risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- Impacts of acquisitions, divestitures, transfers of assets to joint ventures or Dominion Energy Midstream, and retirements of assets based on asset portfolio reviews;
- The expected timing and likelihood of completion of the proposed acquisition of SCANA, including the ability to obtain the requisite approvals of SCANA's shareholders and the terms and condition of any regulatory approvals;
- Receipt of approvals for, and timing of, closing dates for other acquisitions and divestitures;
- The timing and execution of Dominion Energy Midstream's growth strategy;
- Changes in rules for regional transmission organizations and independent system operators in which Dominion Energy and Virginia Power participate, including changes in rate designs, changes in FERC's interpretation of market rules and new and evolving capacity models;
- Political and economic conditions, including inflation and deflation;
- Domestic terrorism and other threats to the Companies' physical and intangible assets, as well as threats to cybersecurity;

- Changes in demand for the Companies' services, including industrial, commercial and residential growth or decline in the Companies' service areas, changes in supplies of natural gas delivered to Dominion Energy and Dominion Energy Gas' pipeline and processing systems, failure to maintain or replace customer contracts on favorable terms, changes in customer growth or usage patterns, including as a result of energy conservation programs, the availability of energy efficient devices and the use of distributed generation methods;
- Additional competition in industries in which the Companies operate, including in electric markets in which Dominion Energy's merchant generation facilities operate and potential competition from the development and deployment of alternative energy sources, such as self-generation and distributed generation technologies, and availability of market alternatives to large commercial and industrial customers;
- Competition in the development, construction and ownership of certain electric transmission facilities in Virginia Power's service territory in connection with FERC Order 1000;
- Changes in technology, particularly with respect to new, developing or alternative sources of generation and smart grid technologies;
- Changes to regulated electric rates collected by Virginia Power and regulated gas distribution, transportation and storage rates, including LNG storage, collected by Dominion Energy and Dominion Energy Gas;
- Changes in operating, maintenance and construction costs;
- Timing and receipt of regulatory approvals necessary for planned construction or growth projects and compliance with conditions associated with such regulatory approvals;
- The inability to complete planned construction, conversion or growth projects at all, or with the outcomes or within the terms and time frames initially anticipated, including as a result of increased public involvement or intervention in such projects;
- Adverse outcomes in litigation matters or regulatory proceedings; and
- The impact of operational hazards, including adverse developments with respect to pipeline and plant safety or integrity, equipment loss, malfunction or failure, operator error, and other catastrophic events.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors.

The Companies' forward-looking statements are based on beliefs and assumptions using information available at the time the statements are made. The Companies caution the reader not to place undue reliance on their forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. The Companies undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

ACCOUNTING MATTERS

Critical Accounting Policies and Estimates

Dominion Energy has identified the following accounting policies, including certain inherent estimates, that as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and operations involved, could result in material changes to its financial condition or results of operations under different conditions or using different assumptions. Dominion Energy has discussed the development, selection and disclosure of each of these policies with the Audit Committee of its Board of Directors.

ACCOUNTING FOR REGULATED OPERATIONS

The accounting for Dominion Energy's regulated electric and gas operations differs from the accounting for nonregulated operations in that Dominion Energy is required to reflect the effect of rate regulation in its Consolidated Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, these costs that otherwise would be expensed by nonregulated companies are deferred as regulatory assets. Likewise, regulatory liabilities are recognized when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator.

Dominion Energy evaluates whether or not recovery of its regulatory assets through future rates is probable and makes various assumptions in its analysis. The expectations of future recovery are generally based on orders issued by regulatory commissions, legislation or historical experience, as well as discussions with applicable regulatory authorities and legal counsel. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made. See Notes 12 and 13 to the Consolidated Financial Statements for additional information.

ASSET RETIREMENT OBLIGATIONS

Dominion Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists and the ARO can be reasonably estimated. These AROs are recognized at fair value as incurred or when sufficient information becomes available to determine fair value and are generally capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Dominion Energy estimates the fair value of its AROs using present value techniques, in which it makes various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. The impact on measurements of new AROs or remeasurements of existing AROs, using different cost escalation or credit-adjusted risk free rates in the future, may be significant. When Dominion Energy revises any assumptions used to calculate the fair value of existing AROs, it adjusts the carrying amount of both the ARO liability and the related long-lived asset for assets that are in service; for assets that have ceased operations, Dominion Energy adjusts the carrying amount of the ARO liability with such changes recognized in income. Dominion Energy accretes the ARO liability to reflect the passage of time.

In 2017, 2016 and 2015, Dominion Energy recognized $117 million, $104 million and $93 million, respectively, of accretion, and expects to recognize $117 million in 2018. Dominion Energy records accretion and depreciation associated with utility nuclear decommissioning AROs and regulated pipeline replacement AROs as an adjustment to the regulatory liabilities related to these items.

A significant portion of Dominion Energy's AROs relates to the future decommissioning of its merchant and utility nuclear facilities. These nuclear decommissioning AROs are reported in the Power Generation segment. At December 31, 2017, Dominion Energy's nuclear decommissioning AROs totaled $1.5 billion, representing approximately 62% of its total AROs. Based on their significance, the following discussion of critical assumptions inherent in determining the fair value of AROs relates to those associated with Dominion Energy's nuclear decommissioning obligations.

Dominion Energy obtains from third-party specialists periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for its nuclear plants. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. In addition, Dominion Energy's cost estimates include cost escalation rates that are applied to the base year costs. Dominion Energy determines cost escalation rates, which represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities, for each nuclear facility. The selection of these cost escalation rates is dependent on subjective factors which are considered to be critical assumptions.

INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws, including the provisions of the 2017 Tax Reform Act, involves uncertainty, since tax authorities may interpret the laws differently. In addition, the states in which we operate may or may not conform to some or all the provisions in the 2017 Tax Reform Act. Ultimate resolution or clarification of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

Given the uncertainty and judgment involved in the determination and filing of income taxes, there are standards for recognition and measurement in financial statements of positions taken or expected to be taken by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. At December 31, 2017, Dominion Energy had $38 million of unrecognized tax benefits. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations.

Deferred income tax assets and liabilities are recorded representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Dominion Energy evaluates quarterly the probability of realizing deferred tax assets by considering current and historical financial results, expectations for future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets. Dominion Energy establishes a valuation allowance when it is more-likely-than-not that all or a portion of a deferred tax asset will not be realized. At December 31, 2017, Dominion Energy had established $146 million of valuation allowances.

The 2017 Tax Reform Act includes a broad range of tax reform provisions affecting the Companies, including changes in corporate tax rates and business deductions. Many of these provisions differ significantly from prior U.S. tax law, resulting in pervasive financial reporting implications for the Companies. The 2017 Tax Reform Act includes significant changes to the Internal Revenue Code of 1986, including amendments which significantly change the taxation of individuals and business entities and includes specific provisions related to regulated public utilities including Dominion Energy subsidiaries Questar Gas, Wexpro, Hope, Virginia Power, and Dominion Energy Gas' subsidiaries DETI and East Ohio. The more significant changes that impact the Companies included in the 2017 Tax Reform Act are (i) reducing the corporate federal income tax rate from 35% to 21%; (ii) limiting the deductibility of interest expense to 30% of adjusted taxable income for certain businesses; (iii) permitting 100% expensing (100% bonus depreciation) for certain qualified property; (iv) eliminating the deduction for qualified domestic production activities; and (v) limiting the utilization of net operating losses arising after December 31, 2017 to 80% of taxable income with an indefinite carryforward. The specific provisions related to regulated public utilities in the 2017 Tax Reform Act generally allow for the continued deductibility of interest expense, the exclusion from full expensing for tax purposes of certain property acquired and placed in service after September 27, 2017 and continues certain rate normalization requirements for accelerated depreciation benefits.

At the date of enactment, the Companies' deferred taxes were remeasured based upon the new tax rate expected to apply when temporary differences are realized or settled. For regulated operations, many of the changes in deferred taxes represent amounts probable of collection from or refund to customers, and are recorded as either an increase to a regulatory asset or liability. The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes may be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred taxes may be determined by our state and federal regulators. For nonregulated operations, the changes in deferred taxes are recorded as an adjustment to deferred tax expense.

ACCOUNTING FOR DERIVATIVE CONTRACTS AND FINANCIAL INSTRUMENTS AT FAIR VALUE

Dominion Energy uses derivative contracts such as physical and financial forwards, futures, swaps, options and FTRs to manage commodity, interest rate and foreign currency exchange rate risks of its business operations. Derivative contracts, with certain exceptions, are reported in the Consolidated Balance Sheets at fair value. The majority of investments held in Dominion Energy's nuclear decommissioning and rabbi trusts and pension and other postretirement funds are also subject to fair value accounting. See Notes 6 and 21 to the Consolidated Financial Statements for further information on these fair value measurements.

Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, management seeks indicative price information from external sources, including broker quotes and industry publications. When evaluating pricing information provided by brokers and other pricing services, Dominion Energy considers whether the broker is willing and able to trade at the quoted price, if the broker quotes are based on an active market or an inactive market and the extent to which brokers are utilizing a particular model if pricing is not readily available. If pricing information from external sources is not available, or if Dominion Energy believes that observable pricing information is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases, Dominion Energy must estimate prices based on available historical and near-term future price information and use of statistical methods, including regression analysis, that reflect its market assumptions.

Dominion Energy maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair value.

USE OF ESTIMATES IN GOODWILL IMPAIRMENT TESTING

As of December 31, 2017, Dominion Energy reported $6.4 billion of goodwill in its Consolidated Balance Sheet. A significant portion resulted from the acquisition of the former CNG in 2000 and the Dominion Energy Questar Combination in 2016.

In April of each year, Dominion Energy tests its goodwill for potential impairment, and performs additional tests more frequently if an event occurs or circumstances change in the interim that would more-likely-than-not reduce the fair value of a reporting unit below its carrying amount. The 2017, 2016 and 2015 annual tests and any interim tests did not result in the recognition of any goodwill impairment.

In general, Dominion Energy estimates the fair value of its reporting units by using a combination of discounted cash flows and other valuation techniques that use multiples of earnings for peer group companies and analyses of recent business combinations involving peer group companies. Fair value estimates are dependent on subjective factors such as Dominion Energy's estimate of future cash flows, the selection of appropriate discount and growth rates, and the selection of peer group companies and recent transactions. These underlying assumptions and estimates are made as of a point in time; subsequent modifications, particularly changes in discount rates or growth rates inherent in Dominion Energy's estimates of future cash flows, could result in a future impairment of goodwill. Although Dominion Energy has consistently applied the same methods in developing the assumptions and estimates that underlie the fair value calculations, such as estimates of future cash flows, and based those estimates on relevant information available at the time, such cash flow estimates are highly uncertain by nature and may vary significantly from actual results. If the estimates of future cash flows used in the most recent tests had been 10% lower, the resulting fair values would have still been greater than the carrying values of each of those reporting units tested, indicating that no impairment was present.

See Note 11 to the Consolidated Financial Statements for additional information.

USE OF ESTIMATES IN LONG-LIVED ASSET AND EQUITY METHOD INVESTMENT IMPAIRMENT TESTING

Impairment testing for an individual or group of long-lived assets, including intangible assets with definite lives, and equity method investments is required when circumstances indicate those assets may be impaired. When a long-lived asset's carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset's fair value is less than its carrying amount. When an equity method investment's carrying amount exceeds its fair value, and the decline in value is deemed to be other-than-temporary, an impairment is recognized to the extent that the fair value is less than its carrying amount. Performing an impairment test on long-lived assets and equity method investments involves judgment in areas such as identifying if circumstances indicate an impairment may exist, identifying and grouping affected assets in the case of long-lived assets, and developing the undiscounted and discounted estimated future cash flows (used to estimate fair value in the absence of a market-based value) associated with the asset, including probability weighting such cash flows to reflect expectations about possible variations in their amounts or timing, expectations about the operations of the long-lived assets and equity method investments and the selection of an appropriate discount rate. When determining whether a long-lived asset or asset group has been impaired, management groups assets at the lowest level that has identifiable cash flows. Although cash flow estimates are based on relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. For example, estimates of future cash flows would contemplate factors which may change over time, such as the expected use of the asset or underlying assets of equity method investees, including future production and sales levels, expected fluctuations of prices of commodities sold and consumed and expected proceeds from dispositions. See Note 9 to the Consolidated Financial Statements for a discussion of impairments related to certain equity method investments.

EMPLOYEE BENEFIT PLANS

Dominion Energy sponsors noncontributory defined benefit pension plans and other postretirement benefit plans for eligible active employees, retirees and qualifying dependents. The projected costs of providing benefits under these plans are dependent, in part, on historical information such as employee demographics, the level of contributions made to the plans and earnings on plan assets. Assumptions about the future, including the expected long-term rate of return on plan assets, discount rates applied to benefit obligations, mortality rates and the anticipated rate of increase in healthcare costs and participant compensation, also have a significant impact on employee benefit costs. The impact of changes in these factors, as well as differences between Dominion Energy's assumptions and actual experience, is generally recognized in the Consolidated Statements of Income over the remaining average service period of plan participants, rather than immediately.

The expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates and mortality rates are critical assumptions. Dominion Energy determines the expected long-term rates of return on plan assets for pension plans and other postretirement benefit plans by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset volatilities and correlations;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major stock market indices; and
- Investment allocation of plan assets. The strategic target asset allocation for Dominion Energy's pension funds is 28% U.S. equity, 18% non-U.S. equity, 35% fixed income, 3% real estate and 16% other alternative investments, such as private equity investments.

Strategic investment policies are established for Dominion Energy's prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include those mentioned above such as employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of Dominion Energy's assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. Future asset/liability studies will focus on strategies to further reduce pension and other postretirement plan risk, while still achieving attractive levels of returns.

Dominion Energy develops non-investment related assumptions, which are then compared to the forecasts of an independent investment advisor to ensure reasonableness. An internal committee selects the final assumptions. Dominion Energy calculated its pension cost using an expected long-term rate of return on plan assets assumption of 8.75% for 2017, 2016 and 2015. For 2018, the expected long-term rate of return for pension cost assumption is 8.75%. Dominion Energy calculated its other postretirement benefit cost using an expected long-term rate of return on plan assets assumption of 8.50% for 2017, 2016 and 2015. For 2018, the expected long-term rate of return for other postretirement benefit cost assumption is 8.50%. The rate used in calculating other postretirement benefit cost is lower than the rate used in calculating pension cost because of differences in the relative amounts of various types of investments held as plan assets.

Dominion Energy determines discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under its plans. The discount rates used to calculate pension cost and other postretirement benefit cost ranged from 3.31% to 4.50% for pension plans and 3.92% to 4.47% for other postretirement benefit plans in 2017, ranged from 2.87% to 4.99% for pension plans and 3.56% to 4.94% for other postretirement benefit plans in 2016 and were 4.40% in 2015. Dominion Energy selected a discount rate ranging from 3.80% to 3.81% for pension plans and 3.76% for other postretirement benefit plans for determining its December 31, 2017 projected benefit obligations.

Dominion Energy establishes the healthcare cost trend rate assumption based on analyses of various factors including the specific provisions of its medical plans, actual cost trends experienced and projected, and demographics of plan participants. Dominion Energy's healthcare cost trend rate assumption as of December 31, 2017 was 7.00% and is expected to gradually decrease to 5.00% by 2022 and continue at that rate for years thereafter.

Mortality rates are developed from actual and projected plan experience for postretirement benefit plans. Dominion Energy's actuary conducts an experience study periodically as part of the process to select its best estimate of mortality. Dominion Energy considers both standard mortality tables and improvement factors as well as the plans' actual experience when selecting a best estimate. During 2016, Dominion Energy conducted a new experience study as scheduled and, as a result, updated its mortality assumptions.

The following table illustrates the effect on cost of changing the critical actuarial assumptions previously discussed, while holding all other assumptions constant:

		Increase in Net Periodic Cost	
(millions, except percentages)	Change in Actuarial Assumption	Pension Benefits	Other Postretirement Benefits
Discount rate	(0.25)%	$20	$ 3
Long-term rate of return on plan assets	(0.25)%	19	4
Healthcare cost trend rate	1 %	N/A	24

In addition to the effects on cost, at December 31, 2017, a 0.25% decrease in the discount rate would increase Dominion Energy's projected pension benefit obligation by $338 million and its accumulated postretirement benefit obligation by $44 million, while a 1.00% increase in the healthcare cost trend rate would increase its accumulated postretirement benefit obligation by $158 million.

See Note 21 to the Consolidated Financial Statements for additional information on Dominion Energy's employee benefit plans.

New Accounting Standards

See Note 2 to the Consolidated Financial Statements for a discussion of new accounting standards.

Dominion Energy

RESULTS OF OPERATIONS

Presented below is a summary of Dominion Energy's consolidated results:

Year Ended December 31, (millions, except EPS)	2017	$ Change	2016	$ Change	2015
Net income attributable to Dominion Energy	$2,999	$ 876	$2,123	$ 224	$1,899
Diluted EPS	4.72	1.28	3.44	0.24	3.20

Overview

2017 VS. 2016

Net income attributable to Dominion Energy increased 41%, primarily due to benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate, the Dominion Energy Questar Combination and an absence of charges related to future ash pond and landfill closures. These increases were partially offset by lower renewable energy investment tax credits and charges associated with equity method investments in wind-powered generation facilities.

2016 VS. 2015

Net income attributable to Dominion Energy increased 12%, primarily due to higher renewable energy investment tax credits and the new PJM capacity performance market effective June 2016. These increases were partially offset by a decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields and charges related to future ash pond and landfill closure costs at certain utility generation facilities.

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion Energy's results of operations:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Operating Revenue	$12,586	$ 849	$11,737	$ 54	$11,683
Electric fuel and other energy-related purchases	2,301	(32)	2,333	(392)	2,725
Purchased electric capacity	6	(93)	99	(231)	330
Purchased gas	701	242	459	(92)	551
Net Revenue	9,578	732	8,846	769	8,077
Other operations and maintenance	2,875	(189)	3,064	469	2,595
Depreciation, depletion and amortization	1,905	346	1,559	164	1,395
Other taxes	668	72	596	45	551
Other income	165	(85)	250	54	196
Interest and related charges	1,205	195	1,010	106	904
Income tax expense (benefit)	(30)	(685)	655	(250)	905

An analysis of Dominion Energy's results of operations follows:

2017 VS. 2016

Net revenue increased 8%, primarily reflecting:

- A $663 million increase from the operations acquired in the Dominion Energy Questar Combination being included for all of 2017;
- A $97 million electric capacity benefit related to non-utility generators ($133 million) and a benefit due to the annual PJM capacity performance market effective June 2016 ($123 million), partially offset by the annual PJM capacity performance market effective June 2017 ($159 million);
- An $86 million increase due to additional generation output from merchant solar generating projects;
- A $71 million increase in sales to electric utility retail customers due to the effect of changes in customer usage and other factors, including $25 million related to customer growth;
- A $63 million increase from regulated natural gas transmission growth projects placed in service;
- A $46 million increase from rate adjustment clauses associated with electric utility operations; and
- A $34 million increase in services performed for Atlantic Coast Pipeline.

These increases were partially offset by:

- A $144 million decrease from Cove Point import contracts;
- A $114 million decrease due to unfavorable pricing at merchant generation facilities; and
- A decrease in sales to electric utility retail customers from a decrease in cooling degree days during the cooling season of 2017 ($53 million) and a reduction in heating degree days during the heating season of 2017 ($28 million).

Other operations and maintenance decreased 6%, primarily reflecting:

- A $197 million absence of charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $115 million decrease in certain electric transmission-related expenditures. These expenses are primarily recovered through state and FERC rates and do not impact net income;
- A $78 million benefit from the sale of certain assets associated with nonregulated retail energy marketing operations;
- The absence of organizational design initiative costs ($64 million); and
- A $46 million decrease in storm damage and service restoration costs associated with electric utility operations, partially offset by
- A $162 million increase from the operations acquired in the Dominion Energy Questar Combination being included for all of 2017;
- A $92 million increase in salaries, wages and benefits;
- A $36 million increase in outage costs; and
- A $33 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income.

Depreciation, depletion and amortization increased 22%, primarily due to the operations acquired in the Dominion Energy Questar Combination being included for all of 2017 ($162 million) and various growth projects being placed into service ($151 million).

Other taxes increased 12%, primarily due to the operations acquired in the Dominion Energy Questar Combination being included for all of 2017 ($35 million) and increased property taxes related to growth projects placed into service ($27 million).

Other income decreased 34%, primarily due to charges associated with equity method investments in wind-powered generation facilities ($158 million), partially offset by an increase in earnings, excluding charges, from equity method investments ($29 million) and an increase in AFUDC associated with rate-regulated projects ($23 million).

Interest and related charges increased 19%, primarily due to higher long-term debt interest expense resulting from debt issuances in 2016 and 2017 ($171 million) and debt acquired in the Dominion Energy Questar Combination ($37 million).

Income tax expense decreased $685 million, primarily due to benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate ($851 million), partially offset by lower renewable energy investment tax credits ($133 million).

2016 VS. 2015

Net revenue increased 10%, primarily reflecting:

- A $544 million increase from electric utility operations, primarily reflecting:
  - A $225 million electric capacity benefit, primarily due to the new PJM capacity performance market effective June 2016 ($155 million) and the expiration of non-utility generator contracts in 2015 ($58 million);
  - An increase from rate adjustment clauses ($183 million); and
  - The absence of an $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015; and
- A $305 million increase due to the Dominion Energy Questar Combination.

These increases were partially offset by:

- A $47 million decrease from merchant generation operations, primarily due to lower realized prices at certain merchant generation facilities ($64 million) and an increase in planned and unplanned outage days in 2016 ($26 million), partially offset by additional solar generating facilities placed into service ($37 million);
- A $19 million decrease from regulated natural gas transmission operations, primarily due to:
  - A $14 million decrease in gas transportation and storage activities, primarily due to decreased demand charges ($28 million), increased fuel costs ($13 million), contract rate changes ($11 million) and decreased revenue from gathering and extraction services ($8 million), partially offset by expansion projects placed in service ($18 million) and increased regulated gas sales ($20 million); and
  - A $17 million decrease in NGL activities, due to decreased prices ($15 million) and volumes ($2 million); partially offset by
  - A $12 million increase in other revenues, primarily due to an increase in services performed for Atlantic Coast Pipeline ($21 million), partially offset by decreased amortization of deferred revenue associated with conveyed shale development rights ($4 million); and
- A $12 million decrease from regulated natural gas distribution operations, primarily due to a decrease in rate adjustment clause revenue related to low income assistance programs ($26 million) and a decrease in sales to customers due to a reduction in heating degree days ($6 million), partially offset by an increase in AMR and PIR program revenues ($18 million).

Other operations and maintenance increased 18%, primarily reflecting:

- A $148 million increase due to the Dominion Energy Questar Combination, including $58 million of transaction and transition costs;
- A $98 million increase in charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $78 million decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields;
- Organizational design initiative costs ($64 million);
- A $50 million increase in storm damage and service restoration costs, including $23 million for Hurricane Matthew;
- A $20 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income; and
- A $16 million increase due to labor contract renegotiations as well as costs resulting from a union workforce temporary work stoppage; partially offset by
- A $26 million decrease in bad debt expense at regulated natural gas distribution operations primarily related to low income assistance programs. These bad debt expenses are recovered through rates and do not impact net income.

Depreciation, depletion and amortization increased 12%, primarily due to various expansion projects being placed into service.

Other income increased 28%, primarily due to an increase in earnings from equity method investments ($55 million) and an increase in AFUDC associated with rate-regulated projects ($12 million), partially offset by lower realized gains (net of investment income) on nuclear decommissioning trust funds ($19 million).

Interest and related charges increased 12%, primarily due to higher long-term debt interest expense resulting from debt issuances in 2016 ($134 million), partially offset by an increase in capitalized interest associated with the Cove Point Liquefaction Project ($45 million).

Income tax expense decreased 28%, primarily due to higher renewable energy investment tax credits ($189 million) and the impact of a state legislative change ($14 million), partially offset by higher pre-tax income ($15 million).

Outlook

Dominion Energy's strategy is to continue focusing on its regulated and long-term contracted businesses while maintaining upside potential in well-positioned nonregulated businesses. The goals of this strategy are to provide EPS growth, a growing dividend and to maintain a stable credit profile. Dominion Energy expects approximately 90% of earnings from its primary operating segments to come from regulated and long-term contracted businesses.

Dominion Energy's 2018 net income is expected to decrease on a per share basis as compared to 2017 primarily from the following:

- Absence of a benefit from remeasurement of deferred income taxes from the 2017 Tax Reform Act;
- Reduction of solar investment tax credits;
- Increases in interest and related charges;
- An increase in depreciation, depletion, and amortization; and
- Share dilution.

These decreases are expected to be partially offset by the following:

- Revenues from the Liquefaction Project;
- A return to normal weather in its electric utility operations;
- Growth in weather-normalized electric utility sales of approximately 1.5%;
- Construction and operation of growth projects in electric utility operations and associated rate adjustment clause revenue;
- Construction and operation of growth projects in gas transmission and distribution;
- Absence of additional refueling outages at Millstone; and
- A lower effective tax rate, driven by the tax reform.

In addition, if the merger with SCANA is completed in 2018, it would result in a decrease to net income as the result of charges to be incurred for refunds to SCE&G electric customers, write-offs of regulatory assets and transaction costs.

SEGMENT RESULTS OF OPERATIONS

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit or loss. Presented below is a summary of contributions by Dominion Energy's operating segments to net income attributable to Dominion Energy:

Year Ended December 31,	2017		2016		2015	
	Net Income attributable to Dominion Energy	Diluted EPS	Net Income attributable to Dominion Energy	Diluted EPS	Net Income attributable to Dominion Energy	Diluted EPS
(millions, except EPS)						
Power Delivery	$ 531	$0.83	$ 484	$0.78	$ 490	$0.82
Power Generation	1,181	1.86	1,397	2.26	1,120	1.89
Gas Infrastructure	898	1.41	726	1.18	680	1.15
Primary operating segments	2,610	4.10	2,607	4.22	2,290	3.86
Corporate and Other	389	0.62	(484)	(0.78)	(391)	(0.66)
Consolidated	$2,999	$4.72	$2,123	$3.44	$1,899	$3.20

Power Delivery

Presented below are operating statistics related to Power Delivery's operations:

Year Ended December 31,	2017	% Change	2016	% Change	2015
Electricity delivered (million MWh)	83.4	—%	83.7	—%	83.9
Degree days:					
Cooling	1,801	(2)	1,830	(1)	1,849
Heating	3,104	(10)	3,446	1	3,416
Average electric distribution customer accounts (thousands)(1)	2,574	1	2,549	1	2,525

(1) Period average.

Presented below, on an after-tax basis, are the key factors impacting Power Delivery's net income contribution:

2017 VS. 2016

	Increase (Decrease) Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$(14)	$(0.02)
Other	15	0.02
FERC transmission equity return	14	0.02
Storm damage and service restoration	14	0.02
Other	18	0.03
Share dilution	—	(0.02)
Change in net income contribution	$47	$0.05

2016 VS. 2015

	Increase (Decrease) Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$ (1)	$ —
Other	1	—
FERC transmission equity return	41	0.07
Storm damage and service restoration	(16)	(0.03)
Depreciation and amortization	(10)	(0.02)
AFUDC return	(8)	(0.01)
Interest expense	(5)	(0.01)
Other	(8)	(0.01)
Share dilution	—	(0.03)
Change in net income contribution	$ (6)	$(0.04)

Power Generation

Presented below are operating statistics related to Power Generation's operations:

Year Ended December 31,	2017	% Change	2016	% Change	2015
Electricity supplied (million MWh):					
Utility	85.0	(3)%	87.9	3%	85.2
Merchant	28.9	—	28.9	7	26.9
Degree days (electric utility service area):					
Cooling	1,801	(2)	1,830	(1)	1,849
Heating	3,104	(10)	3,446	1	3,416

Presented below, on an after-tax basis, are the key factors impacting Power Generation's net income contribution:

2017 VS. 2016

	Increase (Decrease) Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$ (36)	$(0.06)
Other	32	0.05
Electric capacity	58	0.09
Depreciation and amortization	(46)	(0.07)
Renewable energy investment tax credits	(133)	(0.21)
Merchant generation margin	(28)	(0.04)
Interest expense	(25)	(0.04)
Outage costs	(22)	(0.03)
Other	(16)	(0.03)
Share dilution	—	(0.06)
Change in net income contribution	$(216)	$(0.40)

2016 VS. 2015

	Increase (Decrease) Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$ 2	$ —
Other	13	0.02
Renewable energy investment tax credits	186	0.31
Electric capacity	137	0.23
Merchant generation margin	(34)	(0.06)
Rate adjustment clause equity return	24	0.04
Noncontrolling interest(1)	(28)	(0.05)
Depreciation and amortization	(25)	(0.04)
Other	2	0.01
Share dilution	—	(0.09)
Change in net income contribution	$277	$ 0.37

(1) Represents noncontrolling interest related to merchant solar partnerships.

Gas Infrastructure

Presented below are selected operating statistics related to Gas Infrastructure's operations.

Year Ended December 31,	2017	% Change	2016	% Change	2015
Gas distribution throughput (bcf)(1):					
Sales	130	113%	61	126%	27
Transportation	654	22	537	14	470
Heating degree days (gas distribution service area):					
Eastern region	4,930	(6)	5,235	(8)	5,666
Western region(1)	4,892	161	1,876	100	—
Average gas distribution customer accounts (thousands)(1)(2):					
Sales	1,240	—	1,234(3)	414	240
Transportation	1,086	1	1,071	1	1,057
Average retail energy marketing customer accounts (thousands)(2)	1,405	2	1,376	6	1,296

(1) Includes Dominion Energy Questar effective September 2016.
(2) Period average.
(3) Includes Dominion Energy Questar customer accounts for the entire year.

Presented below, on an after-tax basis, are the key factors impacting Gas Infrastructure's net income contribution:

2017 VS. 2016

	Increase (Decrease) Amount	EPS
(millions, except EPS)		
Dominion Energy Questar Combination	$184	$ 0.30
Sale of certain retail energy marketing assets	48	0.08
Assignment of shale development rights	13	0.02
Noncontrolling interest(1)	(30)	(0.05)
Cove Point import contracts	(86)	(0.14)
Transportation and storage growth projects	29	0.04
Other	14	0.02
Share dilution	—	(0.04)
	$172	$ 0.23

(1) Represents the portion of earnings attributable to Dominion Energy Midstream's public unitholders.

2016 VS. 2015

	Increase (Decrease) Amount	EPS
(millions, except EPS)		
Gas distribution margin:		
Weather	$ (4)	$(0.01)
Rate adjustment clauses	11	0.02
Other	6	0.01
Assignment of shale development rights	(48)	(0.08)
Dominion Energy Questar Combination	78	0.13
Other	3	0.01
Share dilution	—	(0.05)
Change in net income contribution	$ 46	$ 0.03

Corporate and Other

Presented below are the Corporate and Other segment's after-tax results:

Year Ended December 31,	2017	2016	2015
(millions, except EPS amounts)			
Specific items attributable to operating segments	$ 861	$ (180)	$ (136)
Specific items attributable to Corporate and Other segment	(151)	(44)	(5)
Total specific items	710	(224)	(141)
Other corporate operations	(321)	(260)	(250)
Total net expense	$ 389	$ (484)	$ (391)
EPS impact	$0.62	$(0.78)	$(0.66)

TOTAL SPECIFIC ITEMS

Corporate and Other includes specific items attributable to Dominion Energy's primary operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources. See Note 25 to the Consolidated Financial Statements for discussion of these items in more detail. Corporate and Other also includes specific items attributable to the Corporate and Other segment. In 2017, this primarily included $124 million of tax benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate. In 2016, this primarily included $53 million of after-tax transaction and transition costs associated with the Dominion Energy Questar Combination.

VIRGINIA POWER

RESULTS OF OPERATIONS

Presented below is a summary of Virginia Power's consolidated results:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Net Income	$1,540	$322	$1,218	$131	$1,087

Overview

2017 VS. 2016

Net income increased 26%, primarily due to the absence of charges related to future ash pond and landfill closures costs, a benefit from the remeasurement of deferred income taxes to the new corporate income tax rate and an electric capacity benefit.

2016 VS. 2015

Net income increased 12%, primarily due to the new PJM capacity performance market effective June 2016, an increase in rate adjustment clause revenue and the absence of a write-off of deferred fuel costs associated with the Virginia legislation enacted in February 2015. These increases were partially offset by charges related to future ash pond and landfill closure costs at certain utility generation facilities.

Analysis of Consolidated Operations

Presented below are selected amounts related to Virginia Power's results of operations:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Operating Revenue	$7,556	$ (32)	$7,588	$ (34)	$7,622
Electric fuel and other energy-related purchases	1,909	(64)	1,973	(347)	2,320
Purchased electric capacity	6	(93)	99	(231)	330
Net Revenue	5,641	125	5,516	544	4,972
Other operations and maintenance	1,478	(379)	1,857	223	1,634
Depreciation and amortization	1,141	116	1,025	72	953
Other taxes	290	6	284	20	264
Other income	76	20	56	(12)	68
Interest and related charges	494	33	461	18	443
Income tax expense	774	47	727	68	659

An analysis of Virginia Power's results of operations follows:

2017 VS. 2016

Net revenue increased 2%, primarily reflecting:

- A $97 million electric capacity benefit related to non-utility generators ($133 million) and a benefit due to the annual PJM capacity performance market effective June 2016 ($123 million), partially offset by the annual PJM capacity performance market effective June 2017 ($159 million);
- A $71 million increase in sales to retail customers due to the effect of changes in customer usage and other factors, including $25 million related to customer growth; and
- A $46 million increase from rate adjustment clauses; partially offset by
- A decrease in sales to retail customers from a decrease in cooling degree days during the cooling season of 2017 ($53 million) and a reduction in heating degree days during the heating season of 2017 ($28 million).

Other operations and maintenance decreased 20%, primarily reflecting:

- A $197 million decrease due to the absence of charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $115 million decrease in certain electric transmission-related expenditures. These expenses are primarily recovered through state and FERC rates and do not impact net income;
- A $46 million decrease in storm damage and service restoration costs; and
- The absence of organizational design initiative costs ($32 million); partially offset by
- A $37 million increase in salaries, wages and benefits and general administrative expenses.

Depreciation and amortization increased 11%, primarily due to various growth projects being placed into service ($58 million) and revised depreciation rates ($40 million).

Other income increased 36%, primarily reflecting:

- An $11 million increase in interest income associated with the settlement of state income tax refund claims;
- An $11 million increase from the assignment of Virginia Power's electric transmission tower rental portfolio; and
- An $8 million increase in AFUDC associated with rate-regulated projects; partially offset by
- A $16 million charge associated with a customer settlement.

Income tax expense increased 6% primarily due to higher pre-tax income ($139 million), partially offset by benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate ($93 million).

2016 VS. 2015

Net revenue increased 11%, primarily reflecting:

- A $225 million electric capacity benefit, primarily due to the new PJM capacity performance market effective June 2016 ($155 million) and the expiration of non-utility generator contracts in 2015 ($58 million);
- An increase from rate adjustment clauses ($183 million); and
- The absence of an $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015.

Other operations and maintenance increased 14%, primarily reflecting:

- A $98 million increase in charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $50 million increase in storm damage and service restoration costs, including $23 million for Hurricane Matthew;
- A $37 million increase in salaries, wages and benefits and general administrative expenses; and
- Organizational design initiative costs ($32 million).

Income tax expense increased 10%, primarily reflecting higher pre-tax income.

DOMINION ENERGY GAS

RESULTS OF OPERATIONS

Presented below is a summary of Dominion Energy Gas' consolidated results:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Net Income	$615	$223	$392	$(65)	$457

Overview

2017 VS. 2016

Net income increased 57%, primarily due to a benefit from the remeasurement of deferred income taxes to the new corporate income tax rate and gas transportation and storage activities from growth projects placed into service.

2016 VS. 2015

Net income decreased 14%, primarily due a decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields.

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion Energy Gas' results of operations:

Year Ended December 31, (millions)	2017	$ Change	2016	$ Change	2015
Operating Revenue	$1,814	$ 176	$1,638	$(78)	$1,716
Purchased gas	132	23	109	(24)	133
Other energy-related purchases	21	9	12	(9)	21
Net Revenue	1,661	144	1,517	(45)	1,562
Other operations and maintenance	527	53	474	84	390
Depreciation and amortization	227	23	204	(13)	217
Other taxes	185	15	170	4	166
Earnings from equity method investee	21	—	21	(2)	23
Other income	20	9	11	10	1
Interest and related charges	97	3	94	21	73
Income tax expense	51	(164)	215	(68)	283

An analysis of Dominion Energy Gas' results of operations follows:

2017 VS. 2016

Net revenue increased 9%, primarily reflecting:

- A $55 million increase due to regulated natural gas transmission growth projects placed in service;
- A $34 million increase in services performed for Atlantic Coast Pipeline;
- A $24 million increase in PIR program revenues; and
- A $16 million increase in rate recovery for low income assistance programs associated with regulated natural gas distribution operations.

Other operations and maintenance increased 11%, primarily reflecting:

- A $33 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income;
- A $16 million increase in bad debt expense at regulated natural gas distribution operations primarily related to low income assistance programs. These bad debt expenses are recovered through rates and do not impact net income;
- A $15 million increase due to a charge to write-off the balance of a regulatory asset no longer considered probable of recovery; and
- A $13 million increase in salaries, wages and benefits and general administrative expenses; partially offset by
- A $25 million increase in gains from agreements to convey shale development rights underneath several natural gas storage fields.

Depreciation and amortization increased 11%, primarily due to growth projects being placed into service.

Other income increased 82%, primarily due to a $12 million increase in AFUDC associated with rate-regulated projects, partially offset by the absence of the 2016 sale of a portion of Dominion Energy Gas' interest in Iroquois ($5 million).

Income tax expense decreased 76%, primarily due to benefits resulting from the remeasurement of deferred income taxes to the new corporate income tax rate ($197 million), partially offset by higher pre-tax income ($22 million).

2016 VS. 2015

Net revenue decreased 3%, primarily reflecting:

- A $34 million decrease from regulated natural gas transmission operations, primarily reflecting:
  - A $36 million decrease in gas transportation and storage activities, primarily due to decreased demand charges ($28 million), increased fuel costs ($13 million), contract rate changes ($11 million) and decreased revenue from gathering and extraction services ($8 million), partially offset by increased regulated gas sales ($16 million) and expansion projects placed in service ($9 million); and
  - An $18 million decrease from NGL activities, due to decreased prices ($16 million) and volumes ($2 million); partially offset by
  - A $21 million increase in services performed for Atlantic Coast Pipeline; and
- A $12 million decrease from regulated natural gas distribution operations, primarily reflecting:
  - A decrease in rate adjustment clause revenue related to low income assistance programs ($26 million); and
  - A $9 million decrease in other revenue primarily due to a decrease in pooling and metering activities ($3 million), a decrease in Blue Racer management fees ($3 million) and a decrease in gathering activities ($2 million); partially offset by
  - An $18 million increase in AMR and PIR program revenues; and
  - An $8 million increase in off-system sales.

Other operations and maintenance increased 22%, primarily reflecting:
- A $78 million decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields; and
- A $20 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income; partially offset by
- A $26 million decrease in bad debt expense at regulated natural gas distribution operations primarily related to low income assistance programs. These bad debt expenses are recovered through rates and do not impact net income.

Other income increased $10 million, primarily due to a gain on the sale of 0.65% of the noncontrolling partnership interest in Iroquois ($5 million) and an increase in AFUDC associated with rate-regulated projects ($5 million).

Interest and related charges increased 29%, primarily due to higher interest expense resulting from the issuances of senior notes in November 2015 and the second quarter of 2016 ($28 million), partially offset by an increase in deferred rate adjustment clause interest expense ($7 million).

Income tax expense decreased 24% primarily reflecting lower pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

Dominion Energy depends on both internal and external sources of liquidity to provide working capital and as a bridge to long-term debt financings. Short-term cash requirements not met by cash provided by operations are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through issuances of debt and/or equity securities.

At December 31, 2017, Dominion Energy had $2.1 billion of unused capacity under its credit facilities. See additional discussion below under *Credit Facilities and Short-Term Debt*.

A summary of Dominion Energy's cash flows is presented below:

Year Ended December 31,	2017	2016	2015
(millions)			
Cash and cash equivalents at beginning of year	$ 261	$ 607	$ 318
Cash flows provided by (used in):			
Operating activities	4,549	4,127	4,475
Investing activities	(5,993)	(10,703)	(6,503)
Financing activities	1,303	6,230	2,317
Net increase (decrease) in cash and cash equivalents	(141)	(346)	289
Cash and cash equivalents at end of year	$ 120	$ 261	$ 607

Operating Cash Flows

Net cash provided by Dominion Energy's operating activities increased $422 million, primarily due to the operations acquired in the Dominion Energy Questar combination being included for all of 2017, derivative activities, and lower income tax payments, partially offset by lower deferred fuel cost recoveries in the Virginia jurisdiction, higher interest expense, lower revenue from Cove Point's import contracts and higher pension and postretirement benefit payments and funding.

Dominion Energy believes that its operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and maintain or grow the dividend on common shares. In December 2017, Dominion Energy's Board of Directors established an annual dividend rate for 2018 of $3.34 per share of common stock, a 10.0% increase over the 2017 rate. Dividends are subject to declaration by the Board of Directors. In January 2018, Dominion Energy's Board of Directors declared dividends payable in March 2018 of 83.5 cents per share of common stock.

Beginning in 2018, the 2017 Tax Reform Act is expected to reduce customer rates due to lower income tax expense recoveries and the settlement of income taxes refundable through future rates. The Companies' regulated utilities continue to work with their respective regulatory commissions to determine the amount and timing of the 2017 Tax Reform Act benefits to customers. FERC has not yet issued guidance on the 2017 Tax Reform Act. The ultimate resolution of the amount and timing of these rate reductions with the Companies' regulators could be material to the Companies' operating cash flows.

Dominion Energy's operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows, and which are discussed in Item 1A. Risk Factors.

CREDIT RISK

Dominion Energy's exposure to potential concentrations of credit risk results primarily from its energy marketing and price risk management activities. Presented below is a summary of Dominion Energy's credit exposure as of December 31, 2017 for these activities. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights.

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
(millions)			
Investment grade(1)	$19	$—	$19
Non-investment grade(2)	8	—	8
No external ratings:			
Internally rated-investment grade(3)	5	—	5
Internally rated-non-investment grade(4)	63	—	63
Total	$95	$—	$95

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody's and Standard & Poor's. The five largest counterparty exposures, combined, for this category represented approximately 14% of the total net credit exposure.

(2) The five largest counterparty exposures, combined, for this category represented approximately 7% of the total net credit exposure.

(3) The five largest counterparty exposures, combined, for this category represented approximately 5% of the total net credit exposure.

(4) The five largest counterparty exposures, combined, for this category represented approximately 38% of the total net credit exposure.

Investing Cash Flows

Net cash used in Dominion Energy's investing activities decreased $4.7 billion, primarily due to the absence of the acquisition of Dominion Energy Questar and decreases in plant construction and other property additions, partially offset by an increase in acquisitions of solar development projects and increased contributions to Atlantic Coast Pipeline.

Financing Cash Flows and Liquidity

Dominion Energy relies on capital markets as significant sources of funding for capital requirements not satisfied by cash provided by its operations. As discussed in *Credit Ratings*, Dominion Energy's ability to borrow funds or issue securities and the return demanded by investors are affected by credit ratings. In addition, the raising of external capital is subject to certain regulatory requirements, including registration with the SEC for certain issuances.

Dominion Energy currently meets the definition of a well-known seasoned issuer under SEC rules governing the registration, communications and offering processes under the Securities Act of 1933. The rules provide for a streamlined shelf registration process to provide registrants with timely access to capital. This allows Dominion Energy to use automatic shelf registration statements to register any offering of securities, other than those for exchange offers or business combination transactions.

From time to time, Dominion Energy may reduce its outstanding debt and level of interest expense through redemption of debt securities prior to maturity and repurchases in the open market, in privately negotiated transactions, through tender offers or otherwise.

Net cash provided by Dominion Energy's financing activities decreased $4.9 billion, primarily due to the absence of issuances of debt, common stock, and Dominion Energy Midstream common and convertible preferred units utilized to finance the Dominion Energy Questar Combination in 2016.

CREDIT FACILITIES AND SHORT-TERM DEBT

Dominion Energy uses short-term debt to fund working capital requirements and as a bridge to long-term debt financings. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, Dominion Energy utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion Energy's credit ratings and the credit quality of its counterparties.

In connection with commodity hedging activities, Dominion Energy is required to provide collateral to counterparties under some circumstances. Under certain collateral arrangements, Dominion Energy may satisfy these requirements by electing to either deposit cash, post letters of credit or, in some cases, utilize other forms of security. From time to time, Dominion Energy may vary the form of collateral provided to counterparties after weighing the costs and benefits of various factors associated with the different forms of collateral. These factors include short-term borrowing and short-term investment rates, the spread over these short-term rates at which Dominion Energy can issue commercial paper, balance sheet impacts, the costs and fees of alternative collateral postings with these and other counterparties and overall liquidity management objectives.

Dominion Energy's commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

December 31, 2017	Facility Limit	Outstanding Commercial Paper(2)	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
Joint revolving credit facility(1)	**$5,000**	**$3,298**	**$—**	**$1,702**
Joint revolving credit facility(1)	500	—	76	424
Total	$5,500	$3,298	$76	$2,126

(1) These credit facilities mature in April 2020 and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to a combined $2.0 billion of letters of credit.

(2) The weighted-average interest rate of the outstanding commercial paper supported by Dominion Energy's credit facilities was 1.61% at December 31, 2017.

Dominion Energy has indicated its intention to replace the existing two joint revolving credit facilities with a $6.0 billion joint revolving credit facility in the first quarter of 2018. Terms and covenants of the new credit facility are expected to be similar to the existing credit facilities, including that Virginia Power, Dominion Energy Gas and Questar Gas will remain as co-borrowers, except that the maturity will be in five years and the maximum allowed total debt to total capital ratio, with respect to Dominion Energy only, will be increased from 65% to 67.5%. In February 2018, Virginia Power, as co-borrower, filed with the Virginia Commission for approval.

In February 2018, Dominion Energy borrowed $950 million under a 364-Day Term Loan Agreement that bears interest at a variable rate. In addition, the agreement contains a maximum allowed total debt to total capital ratio of 67.5%. The proceeds were used for general corporate purposes and to repay debt.

In July 2017, Dominion Energy Questar repaid a $250 million variable rate term loan due in August 2017 at the amount of principal then outstanding plus accrued interest.

In November 2017, Dominion Energy filed an SEC shelf registration for the sale of up to $3.0 billion of variable denomination floating rate demand notes, called Dominion Energy Reliability Investment℠. The registration limits the principal amount that may be outstanding at any one time to $1.0 billion. The notes are offered on a continuous basis and bear interest at a floating rate per annum determined by the Dominion Energy Reliability Investment Committee, or its designee, on a weekly basis. The notes have no stated maturity date, are non-transferable and may be redeemed in whole or in part by Dominion Energy or at the investor's option at any time. The balance as of December 31, 2017 was less than $0.1 million. The notes are short-term debt obligations of Dominion Energy and are reflected as short-term debt on Dominion Energy's Consolidated Balance Sheets. The proceeds will be used for general corporate purposes and to repay debt.

LONG-TERM DEBT

During 2017, Dominion Energy issued the following long-term public debt:

Type	Principal (millions)	Rate	Maturity
Senior notes	$ 400	1.875%	2019
Senior notes	400	2.750%	2022
Senior notes	100	3.900%	2025
Senior notes	750	3.500%	2027
Senior notes	550	3.800%	2047
Senior notes	200	2.750%	2023
Total notes issued	$2,400		

During 2017, Dominion Energy also issued the following long-term private debt:

- In March 2017, Dominion Energy issued through private placement $300 million of 3.496% senior notes that mature in 2024. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.
- In June 2017, Dominion Energy issued through private placement $500 million of variable rate senior notes that mature in 2019. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.
- In November 2017, Questar Gas issued through private placement $100 million of 3.38% senior notes that mature in 2032. The proceeds were used for general corporate purposes and to repay short-term debt.
- In December 2017, Dominion Energy issued through private placement $300 million of variable rate senior notes that mature in 2020. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.

During 2017, Dominion Energy also remarketed the following long-term debt:

- In May 2017, Dominion Energy successfully remarketed the $1.0 billion 2014 Series A 1.50% RSNs due in 2020 pursuant to the terms of the 2014 Equity Units. In connection with the remarketing, the interest rate on the junior subordinated notes was reset to 2.579%. Dominion Energy did not receive any proceeds from the remarketing. See Note 17 to the Consolidated Financial Statements for more information.

During 2017, Dominion Energy also borrowed the following under a term loan agreement:

- In May 2017, Dominion Solar Projects III, Inc. borrowed $280 million under a term loan agreement that bears interest at a variable rate. The term loan amortizes over an 18-year period and matures in May 2024. The debt is nonrecourse to Dominion Energy and is secured by Dominion Solar Projects III, Inc.'s interest in certain solar facilities. The proceeds were used for general corporate purposes.

During 2017, Dominion Energy repaid the following long-term debt:

- In August 2017, Dominion Energy retired its $75 million variable rate Massachusetts Development Finance Agency Solid Waste Disposal Revenue Bonds, Series 2010B, due in 2041 at the amount of principal then outstanding plus accrued interest.

During 2017, Dominion Energy repaid and repurchased $1.6 billion of long-term debt.

In October 2017, Questar Gas entered into an agreement with certain investors to issue through private placements in April 2018, $50 million of 3.30% 12-year senior notes and $100 million of 3.97% 30-year senior notes. The proceeds will be used for general corporate purposes and to repay short-term debt.

In January 2018, Dominion Energy Questar Pipeline issued through private placement $100 million of 3.53% senior notes and $150 million of 3.91% senior notes that mature in 2028 and 2038, respectively. The proceeds were used for general corporate purposes and to pay maturing long-term debt.

ISSUANCE OF COMMON STOCK AND OTHER EQUITY SECURITIES

Dominion Energy maintains Dominion Energy Direct® and a number of employee savings plans through which contributions may be invested in Dominion Energy's common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans. In January 2014, Dominion Energy began purchasing its common stock on the open market for these plans. In April 2014, Dominion Energy began issuing new common shares for these direct stock purchase plans.

During 2017, Dominion Energy issued 4.3 million shares of common stock totaling $335 million through employee savings plans, direct stock purchase and dividend reinvestment plans and other employee and director benefit plans. Dominion Energy received cash proceeds of $302 million from the issuance of 3.8 million of such shares through Dominion Energy Direct® and employee savings plans. In July 2017, Dominion Energy issued 12.5 million shares under the related stock purchase contracts entered into as part of Dominion Energy's 2014 Equity Units and received proceeds of $1.0 billion.

In January 2018, Dominion Energy issued 6.6 million shares and received cash proceeds of $495 million, net of fees and commissions paid of $5 million through its at-the-market program. See Note 19 to the Consolidated Financial Statements for a description of the at-the-market program.

During 2018, Dominion Energy plans to issue shares for employee savings plans and direct stock purchase and dividend reinvestment plans. In addition, if the merger with SCANA is realized, Dominion Energy would issue 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock outstanding at closing.

REPURCHASE OF COMMON STOCK

Dominion Energy did not repurchase any shares in 2017 and does not plan to repurchase shares during 2018, except for shares tendered by employees to satisfy tax withholding obligations on vested restricted stock, which does not count against its stock repurchase authorization.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. Dominion Energy believes that its current credit ratings provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to Dominion Energy may affect its ability to access these funding sources or cause an increase in the return required by investors. Dominion Energy's credit ratings affect its liquidity, cost of borrowing under credit facilities and collateral posting requirements under commodity contracts, as well as the rates at which it is able to offer its debt securities.

Both quantitative (financial strength) and qualitative (business or operating characteristics) factors are considered by the credit rating agencies in establishing an individual company's credit rating. Credit ratings should be evaluated independently and are subject to revision or withdrawal at any time by the assigning rating organization. The credit ratings for Dominion Energy are affected by its financial profile, mix of regulated and nonregulated businesses and respective cash flows, changes in methodologies used by the rating agencies and event risk, if applicable, such as major acquisitions or dispositions.

In January 2018, Moody's affirmed Dominion Energy's senior unsecured debt and commercial paper ratings of Baa2 and P-2, respectively, and Standard & Poor's affirmed Dominion Energy's senior unsecured debt and commercial paper ratings of BBB and A-2, respectively. Moody's and Standard & Poor's each changed Dominion Energy's rating outlook to negative from stable. Dominion Energy cannot predict the potential impact the negative outlook at Moody's and Standard & Poor's could have on its cost of borrowing.

In January 2018, Fitch affirmed Dominion Energy's senior unsecured debt and commercial paper ratings of BBB+ and F2, respectively, and maintained its stable outlook for both ratings.

Credit ratings as of February 23, 2018 follow:

	Fitch	Moody's	Standard & Poor's
Dominion Energy			
Issuer	BBB+	Baa2	BBB+
Senior unsecured debt securities	BBB+	Baa2	BBB
Junior subordinated notes(1)	BBB	Baa3	BBB
Enhanced junior subordinated notes(2)	BBB-	Baa3	BBB-
Junior/ remarketable subordinated notes(2)	BBB-	Baa3	BBB-
Commercial paper	F2	P-2	A-2

(1) Securities do not have an interest deferral feature.
(2) Securities have an interest deferral feature.

As of February 23, 2018, Fitch maintained a stable outlook for its respective ratings of Dominion Energy and Moody's and Standard & Poor's maintained a negative outlook for their respective ratings of Dominion Energy.

A downgrade in an individual company's credit rating does not necessarily restrict its ability to raise short-term and long-term financing as long as its credit rating remains investment grade, but it could result in an increase in the cost of borrowing. Dominion Energy works closely with Fitch, Moody's and Standard & Poor's with the objective of achieving its targeted credit ratings. Dominion Energy may find it necessary to modify its business plan to maintain or achieve appropriate credit ratings and such changes may adversely affect growth and EPS.

Debt Covenants

As part of borrowing funds and issuing debt (both short-term and long-term) or preferred securities, Dominion Energy must enter into enabling agreements. These agreements contain covenants that, in the event of default, could result in the acceleration of principal and interest payments; restrictions on distributions related to capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments; and in some cases, the termination of credit commitments unless a waiver of such requirements is agreed to by the lenders/security holders. These provisions are customary, with each agreement specifying which covenants apply. These provisions are not necessarily unique to Dominion Energy.

Some of the typical covenants include:

- The timely payment of principal and interest;
- Information requirements, including submitting financial reports filed with the SEC and information about changes in Dominion Energy's credit ratings to lenders;
- Performance obligations, audits/inspections, continuation of the basic nature of business, restrictions on certain matters related to merger or consolidation and restrictions on disposition of all or substantially all assets;
- Compliance with collateral minimums or requirements related to mortgage bonds; and
- Limitations on liens.

Dominion Energy is required to pay annual commitment fees to maintain its credit facilities. In addition, Dominion Energy's credit agreements contain various terms and conditions that could affect its ability to borrow under these facilities. They include maximum debt to total capital ratios and cross-default provisions.

As of December 31, 2017, the calculated total debt to total capital ratio, pursuant to the terms of the agreements, was as follows:

Company	Maximum Allowed Ratio(1)	Actual Ratio(2)
Dominion Energy	65%	62%

(1) The $950 million 364-Day Term Loan Credit Agreement, borrowed in February 2018, has a maximum allowed total debt to total capital ratio of 67.5%. In addition, the $6.0 billion replacement joint revolving credit facility, expected to be executed in the first quarter of 2018, is expected to increase the maximum allowed total debt to total capital ratio from 65% to 67.5%.
(2) Indebtedness as defined by the bank agreements excludes certain junior subordinated and remarketable subordinated notes reflected as long-term debt as well as AOCI reflected as equity in the Consolidated Balance Sheets.

If Dominion Energy or any of its material subsidiaries fails to make payment on various debt obligations in excess of $100 million, the lenders could require the defaulting company, if it is a borrower under Dominion Energy's credit facilities, to accelerate its repayment of any outstanding borrowings and the lenders could terminate their commitments, if any, to lend funds to that company under the credit facilities. In addition, if the defaulting company is Virginia Power, Dominion Energy's obligations to repay any outstanding borrowing under the credit facilities could also be accelerated and the lenders' commitments to Dominion Energy could terminate.

Dominion Energy executed RCCs in connection with its issuance of the June 2006 hybrids and September 2006 hybrids. See Note 17 to the Consolidated Financial Statements for additional information, including terms of the RCCs.

At December 31, 2017, the termination dates and covered debt under the RCCs associated with Dominion Energy's hybrids were as follows:

Hybrid	RCC Termination Date	Designated Covered Debt Under RCC
June 2006 hybrids	6/30/2036	September 2006 hybrids
September 2006 hybrids	9/30/2036	June 2006 hybrids

Dominion Energy monitors these debt covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2017, there have been no events of default under Dominion Energy's debt covenants.

Dividend Restrictions

Certain agreements associated with Dominion Energy's credit facilities contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict Dominion Energy's ability to pay dividends or receive dividends from its subsidiaries at December 31, 2017.

See Note 17 to the Consolidated Financial Statements for a description of potential restrictions on dividend payments by Dominion Energy in connection with the deferral of interest payments and contract adjustment payments on certain junior subordinated notes and equity units, initially in the form of corporate units, which information is incorporated herein by reference.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

CONTRACTUAL OBLIGATIONS

Dominion Energy is party to numerous contracts and arrangements obligating it to make cash payments in future years. These contracts include financing arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services and financial derivatives. Presented below is a table summarizing cash payments that may result from contracts to which Dominion Energy is a party as of December 31, 2017. For purchase obligations and other liabilities, amounts are based upon contract terms, including fixed and minimum quantities to be purchased at fixed or market-based prices. Actual cash payments will be based upon actual quantities purchased and prices paid and will likely differ from amounts presented below. The table excludes all amounts classified as current liabilities in the Consolidated Balance Sheets, other than current maturities of long-term debt, interest payable and certain derivative instruments. The majority of Dominion Energy's current liabilities will be paid in cash in 2018.

(millions)	2018	2019-2020	2021-2022	2023 and thereafter	Total
Long-term debt(1)	$3,311	$ 6,321	$3,719	$20,942	$34,293
Interest payments(2)	1,349	2,341	1,969	14,556	20,215
Leases(3)	68	119	87	361	635
Purchase obligations(4):					
Purchased electric capacity for utility operations	93	113	46	—	252
Fuel commitments for utility operations	1,019	820	364	1,362	3,565
Fuel commitments for nonregulated operations	115	97	110	165	487
Pipeline transportation and storage	389	712	549	2,190	3,840
Other(5)	330	107	28	45	510
Other long-term liabilities(6):					
Other contractual obligations(7)	151	107	31	153	442
Total cash payments	$6,825	$10,737	$6,903	$39,774	$64,239

(1) Based on stated maturity dates rather than the earlier redemption dates that could be elected by instrument holders. In February 2018, $250 million of Dominion Energy Questar Pipeline's senior notes were repaid using proceeds from the January 2018 issuance, through private placements, of $100 million and $150 million of senior notes that mature in 2028 and 2038, respectively. As a result, at December 31, 2017, $250 million of senior notes with a 2018 maturity were included in long-term debt in the Consolidated Balance Sheets.

(2) Includes interest payments over the terms of the debt and payments on related stock purchase contracts. Interest is calculated using the applicable interest rate or forward interest rate curve at December 31, 2017 and outstanding principal for each instrument with the terms ending at each instrument's stated maturity. See Note 17 to the Consolidated Financial Statements. Does not reflect Dominion Energy's ability to defer interest and stock purchase contract payments on certain junior subordinated notes or RSNs and equity units, initially in the form of Corporate Units.

(3) Primarily consists of operating leases.

(4) Amounts exclude open purchase orders for services that are provided on demand, the timing of which cannot be determined.

(5) Includes capital, operations, and maintenance commitments.

(6) Excludes regulatory liabilities, AROs and employee benefit plan obligations, which are not contractually fixed as to timing and amount. See Notes 12, 14 and 21 to the Consolidated Financial Statements. Due to uncertainty about the timing and amounts that will ultimately be paid, $27 million of income taxes payable associated with unrecognized tax benefits are excluded. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year. See Note 5 to the Consolidated Financial Statements.

(7) Includes interest rate and foreign currency swap agreements.

PLANNED CAPITAL EXPENDITURES

Dominion Energy's planned capital expenditures are expected to total approximately $5.5 billion, $5.2 billion and $4.8 billion in 2018, 2019 and 2020, respectively. Dominion Energy's planned expenditures are expected to include construction and expansion of electric generation and natural gas transmission and storage facilities, construction improvements and expansion of electric transmission and distribution assets, purchases of nuclear fuel, maintenance and Dominion Energy's portion of the Atlantic Coast Pipeline.

Dominion Energy expects to fund its capital expenditures with cash from operations and a combination of securities issuances and short-term borrowings. Planned capital expenditures include capital projects that are subject to approval by regulators and the Board of Directors.

See *Power Delivery, Power Generation* and *Gas Infrastructure - Properties* in Item 1. Business for a discussion of Dominion Energy's expansion plans.

These estimates are based on a capital expenditures plan reviewed and endorsed by Dominion Energy's Board of Directors in late 2017 and are subject to continuing review and adjustment and actual capital expenditures may vary from these estimates. Dominion Energy may also choose to postpone or cancel certain planned capital expenditures in order to mitigate the need for future debt financings and equity issuances.

Use of Off-Balance Sheet Arrangements

LEASING ARRANGEMENT

In July 2016, Dominion Energy signed an agreement with a lessor to construct and lease a new corporate office property in Richmond, Virginia. The lessor is providing equity and has obtained financing commitments from debt investors, totaling $365 million, to fund the estimated project costs. The project is expected to be completed by mid-2019. Dominion Energy has been appointed to act as the construction agent for the lessor, during which time Dominion Energy will request cash draws from the lessor and debt investors to fund all project costs, which totaled $139 million as of December 31, 2017. If the project is terminated under certain events of default, Dominion Energy could be required to pay up to 89.9% of the then funded amount. For specific full recourse events, Dominion Energy could be required to pay up to 100% of the then funded amount.

The five-year lease term will commence once construction is substantially complete and the facility is able to be occupied. At the end of the initial lease term, Dominion Energy can (i) extend the term of the lease for an additional five years, subject to the approval of the participants, at current market terms, (ii) purchase the property for an amount equal to the project costs or, (iii) subject to certain terms and conditions, sell the property on behalf of the lessor to a third party using commercially reasonable efforts to obtain the highest cash purchase price for the property. If the project is sold and the proceeds from the sale are insufficient to repay the investors for the project costs, Dominion Energy may be required to make a payment to the lessor, up to 87% of project costs, for the difference between the project costs and sale proceeds.

The respective transactions have been structured so that Dominion Energy is not considered the owner during construction for financial accounting purposes and, therefore, will not reflect the construction activity in its consolidated financial statements. The financial accounting treatment of the lease agreement will be impacted by the new accounting standard issued in February 2016. See Note 2 to the Consolidated Financial Statements for additional information. Dominion Energy will be considered the owner of the leased property for tax purposes, and as a result, will be entitled to tax deductions for depreciation and interest expense.

GUARANTEES

Dominion Energy primarily enters into guarantee arrangements on behalf of its consolidated subsidiaries. These arrangements are not subject to the provisions of FASB guidance that dictate a guarantor's accounting and disclosure requirements for guarantees, including indirect guarantees of indebtedness of others. In addition, Dominion Energy has provided a guarantee to support a portion of Atlantic Coast Pipeline's obligation under a $3.4 billion revolving credit facility. See Note 22 to the Consolidated Financial Statements for additional information, which information is incorporated herein by reference.

FUTURE ISSUES AND OTHER MATTERS

See Item 1. Business and Notes 13 and 22 to the Consolidated Financial Statements for additional information on various environmental, regulatory, legal and other matters that may impact future results of operations, financial condition and/or cash flows.

Environmental Matters

Dominion Energy is subject to costs resulting from a number of federal, state, tribal and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

ENVIRONMENTAL PROTECTION AND MONITORING EXPENDITURES

Dominion Energy incurred $200 million, $394 million and $298 million of expenses (including accretion and depreciation) during, 2017, 2016 and 2015 respectively, in connection with environmental protection and monitoring activities and expects these expenses to be approximately $190 million and $185 million in 2018 and 2019, respectively. In addition, capital expenditures related to environmental controls were $201 million, $191 million, and $94 million for 2017, 2016 and 2015, respectively. These expenditures are expected to be approximately $205 million and $135 million for 2018 and 2019, respectively.

FUTURE ENVIRONMENTAL REGULATIONS

Air

The CAA is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. At a minimum, delegated states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

In August 2015, the EPA issued final carbon standards for existing fossil fuel power plants. Known as the Clean Power Plan, the rule uses a set of measures for reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units and expanding renewable resources. The final rule has been challenged in the U.S. Court of Appeals for the D.C. Circuit. In February 2016, the U.S. Supreme Court issued a stay of the Clean Power Plan until the disposition of the petitions challenging the rule now before the Court of Appeals, and, if such petitions are filed in the future, before the U.S. Supreme Court. Pursuant to an Executive Order directing the EPA to undertake a review of the Clean Power Plan, the EPA issued a proposed rule in October 2017 to repeal the Clean Power Plan on the basis that the rule promulgated in 2015 exceeds the

EPA's authority under the CAA. In December 2017, the EPA issued an Advanced Notice of Proposed Rulemaking to solicit input on whether it should proceed with a rule to replace the Clean Power Plan, and if so, what the scope of such a rule should be. Given these developments and associated federal and state regulatory and legal uncertainties, Dominion Energy cannot predict the potential financial statement impacts but believes the potential expenditures to comply could be material.

Climate Change

In December 2015, the Paris Agreement was formally adopted under the United Nations Framework Convention on Climate Change. A key element of the initial U.S. commitment to the agreement was the implementation of the Clean Power Plan, which the EPA has proposed to repeal. In June 2017, the Administration announced that the U.S. intends to file to withdraw from the Paris Agreement in 2019. Several states, including Virginia, subsequently announced a commitment to achieving the carbon reduction goals of the Paris Agreement. It is not possible at this time to predict the timing and impact of this withdrawal, or how any legal requirements in the U.S. at the federal, state or local levels pursuant to the Paris Agreement could impact the Companies' customers or the business.

In March 2016, the EPA began development of regulations for reducing methane emissions from existing sources in the oil and natural gas sectors. In November 2016, the EPA issued an Information Collection Request to collect information on existing sources upstream of local distribution companies in this sector. In March 2017, the EPA withdrew the information collection request and it remains unclear whether the EPA may propose new regulations on existing sources. Dominion Energy cannot currently estimate the potential impacts on results of operations, financial condition and/or cash flows related to this matter.

State Actions Related to Air and GHG Emissions

In August 2017, the Ozone Transport Commission released a draft model rule for control of NO_x emissions from natural gas pipeline compressor fuel-fire prime movers. States within the ozone transport region, including states in which Dominion Energy has natural gas operations, are expected to develop reasonably achievable control technology rules for existing sources based on the Ozone Transport Commission model rule. States outside of the Ozone Transport Commission may also consider the model rules in setting new reasonably achievable control technology standards. Several states in which Dominion Energy operates, including Pennsylvania, New York and Maryland, are developing state-specific regulations to control GHG emissions, including methane. In January 2018, the VDEQ published for comment a proposed state carbon regulation program linked to RGGI. Dominion Energy cannot currently estimate the potential financial statements impacts on results of operations, financial condition and/or cash flows related to these matters.

PHMSA Regulation

The most recent reauthorization of PHMSA included new provisions on historical records research, maximum-allowed operating pressure validation, use of automated or remote-controlled valves on new or replaced lines, increased civil penalties and evaluation of expanding integrity management beyond high-consequence areas. PHMSA has not yet issued new rulemaking on most of these items.

Dodd-Frank Act

The Dodd-Frank Act was enacted into law in July 2010 in an effort to improve regulation of financial markets. The CEA, as amended by Title VII of the Dodd-Frank Act, requires certain over-the counter derivatives, or swaps, to be cleared through a derivatives clearing organization and, if the swap is subject to a clearing requirement, to be executed on a designated contract market or swap execution facility. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end users, may elect the end-user exception to the CEA's clearing requirements. Dominion Energy has elected to exempt its swaps from the CEA's clearing requirements. If, as a result of changes to the rulemaking process, Dominion Energy's derivative activities are not exempted from clearing, exchange trading or margin requirements, it could be subject to higher costs due to decreased market liquidity or increased margin payments. In addition, Dominion Energy's swap dealer counterparties may attempt to pass-through additional trading costs in connection with changes to or the elimination of rulemaking that implements Title VII of the Dodd-Frank Act. Due to the evolving rulemaking process, Dominion Energy is currently unable to assess the potential impact of the Dodd-Frank Act's derivative-related provisions on its financial condition, results of operations or cash flows.

Virginia Legislation

PROPOSED GRID TRANSFORMATION AND SECURITY ACT OF 2018

In January 2018, legislation was introduced in the Virginia General Assembly to reinstate base rate reviews on a triennial basis other than the first review, which will be a quadrennial review, occurring for Virginia Power in 2021 for the four successive 12-month test periods beginning January 1, 2017 and ending December 31, 2020. This review for Virginia Power will occur one year earlier than under the Regulation Act legislation enacted in February 2015.

In the triennial review proceedings, earnings that are more than 70 basis points above the utility's authorized return on equity that might have been refunded to customers may be reduced by any prior investment amounts for new solar or wind generation facilities or up to 5,000 MW of new solar or wind generation facilities and electric distribution grid transformation projects that Virginia Power elects to include in a customer credit reinvestment offset. The legislation declares that electric distribution grid transformation projects are in the public interest and provides that the costs of such projects may be recovered through a rate adjustment clause if not the subject of a customer credit reinvestment offset. Any costs that are the subject of a customer credit reinvestment offset may not be recovered in base rates for the service life of the projects and may not be included in base rates in future triennial review proceedings.

The legislation also includes provisions requiring Virginia Power to provide current customers a one-time bill credit of

$200 million and to reduce base rates to reflect reductions in federal tax liability resulting from the enactment of the 2017 Tax Reform Act. The legislation is pending.

Other Matters

While management currently has no plans which may affect the carrying value of Millstone, based on potential future economic and other factors, including, but not limited to, market power prices, results of capacity auctions, legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free generation, and the impact of potential EPA carbon rules; there is risk that Millstone may be evaluated for an early retirement date. Should management make any decision on a potential early retirement date, the precise date and the resulting financial statement impacts, which could be material to Dominion Energy, may be affected by a number of factors, including any potential regulatory or legislative solutions, results of any transmission system reliability study assessments, and decommissioning requirements, among other factors.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The matters discussed in this Item may contain "forward-looking statements" as described in the introductory paragraphs of Item 7. MD&A. The reader's attention is directed to those paragraphs and Item 1A. Risk Factors for discussion of various risks and uncertainties that may impact the Companies.

MARKET RISK SENSITIVE INSTRUMENTS AND RISK MANAGEMENT

The Companies' financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices as described below. Commodity price risk is present in Dominion Energy's and Virginia Power's electric operations and Dominion Energy's and Dominion Energy Gas' natural gas procurement and marketing operations due to the exposure to market shifts in prices received and paid for electricity, natural gas and other commodities. The Companies use commodity derivative contracts to manage price risk exposures for these operations. Interest rate risk is generally related to their outstanding debt and future issuances of debt. In addition, the Companies are exposed to investment price risk through various portfolios of equity and debt securities.

The following sensitivity analysis estimates the potential loss of future earnings or fair value from market risk sensitive instruments over a selected time period due to a 10% change in commodity prices or interest rates.

Commodity Price Risk

To manage price risk, Dominion Energy and Virginia Power hold commodity-based derivative instruments held for non-trading purposes associated with purchases and sales of electricity, natural gas and other energy-related products and Dominion Energy Gas primarily holds commodity-based financial derivative instruments held for non-trading purposes associated with purchases and sales of natural gas and other energy-related products.

The derivatives used to manage commodity price risk are executed within established policies and procedures and may include instruments such as futures, forwards, swaps, options and FTRs that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the hypothetical change in market prices of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on observable market prices.

A hypothetical 10% decrease in commodity prices would have resulted in a decrease in fair value of $5 million and $27 million of Dominion Energy's commodity-based derivative instruments as of December 31, 2017 and December 31, 2016, respectively. The decrease in sensitivity is largely due to a decrease in commodity derivative activity and changes in commodity prices.

A hypothetical 10% decrease in commodity prices would have resulted in a decrease in the fair value of $51 million and $62 million of Virginia Power's commodity-based derivative instruments as of December 31, 2017 and December 31, 2016, respectively. The decrease in sensitivity is largely due to a decrease in commodity derivative activity and lower commodity prices.

A hypothetical 10% increase in commodity prices of Dominion Energy Gas' commodity-based financial derivative instruments would have resulted in a decrease in fair value of $4 million as of both December 31, 2017 and 2016.

The impact of a change in energy commodity prices on the Companies' commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from physical sales of the commodity.

Interest Rate Risk

The Companies manage their interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. They also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For variable rate debt and interest rate swaps designated under fair value hedging and outstanding for the Companies, a hypothetical 10% increase in market interest rates would not have resulted in a material change in annual earnings at December 31, 2017 or 2016.

The Companies also use interest rate derivatives, including forward-starting swaps, as cash flow hedges of forecasted interest payments. As of December 31, 2017, Dominion Energy and Virginia Power had $3.5 billion and $1.5 billion, respectively, in aggregate notional amounts of these interest rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of $86 million and $67 million, respectively, in the fair value of Dominion Energy's and Virginia Power's interest rate derivatives at December 31, 2017. As of December 31, 2016, Dominion Energy and Virginia Power had

$2.9 billion and $1.7 billion, respectively, in aggregate notional amounts of these interest rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of $58 million and $45 million, respectively, in the fair value of Dominion Energy's and Virginia Power's interest rate derivatives at December 31, 2016.

During 2016, Dominion Energy Gas entered into foreign currency swaps with the purpose of hedging the foreign currency exchange risk associated with Euro denominated debt. As of December 31, 2017, Dominion Energy and Dominion Energy Gas had $280 million (€ 250 million) in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% increase in market interest rates would have resulted in a $6 million decrease in the fair value of Dominion Energy's and Dominion Energy Gas' foreign currency swaps at December 31, 2017. As of December 31, 2016, Dominion Energy and Dominion Energy Gas had $280 million (€ 250 million) in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% increase in market interest rates would have resulted in a $5 million decrease in the fair value of Dominion Energy's and Dominion Energy Gas's foreign currency swaps at December 31, 2016.

The impact of a change in interest rates on the Companies' interest rate-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net gains and/or losses from interest rate derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction.

Investment Price Risk

Dominion Energy and Virginia Power are subject to investment price risk due to securities held as investments in nuclear decommissioning and rabbi trust funds that are managed by third-party investment managers. These trust funds primarily hold marketable securities that are reported in the Consolidated Balance Sheets at fair value.

Dominion Energy recognized net realized gains (including investment income) on nuclear decommissioning and rabbi trust investments of $167 million and $144 million in 2017 and 2016, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. Dominion Energy recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains of $462 million and $183 million in 2017 and 2016, respectively.

Virginia Power recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $76 million and $67 million in 2017 and 2016, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. Virginia Power recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains of $216 million and $93 million in 2017 and 2016, respectively.

Dominion Energy sponsors pension and other postretirement employee benefit plans that hold investments in trusts to fund employee benefit payments. Virginia Power and Dominion Energy Gas employees participate in these plans. Dominion Energy's pension and other postretirement plan assets experienced aggregate actual returns of $1.6 billion and $534 million in 2017 and 2016, respectively, versus expected returns of $767 million and $691 million, respectively. Dominion Energy Gas' pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual returns of $335 million and $130 million in 2017 and 2016, respectively, versus expected returns of $165 million and $157 million, respectively. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans. A hypothetical 0.25% decrease in the assumed long-term rates of return on Dominion Energy's plan assets would result in an increase in net periodic cost of $19 million and $18 million as of December 31, 2017 and 2016, respectively, for pension benefits and $4 million as of both December 31, 2017 and 2016, for other postretirement benefits. A hypothetical 0.25% decrease in the assumed long-term rates of return on Dominion Energy Gas' plan assets, for employees represented by collective bargaining units, would result in an increase in net periodic cost of $4 million as of both December 31, 2017 and 2016, for pension benefits and $1 million as of both December 31, 2017 and 2016, for other postretirement benefits.

Risk Management Policies

The Companies have established operating procedures with corporate management to ensure that proper internal controls are maintained. In addition, Dominion Energy has established an independent function at the corporate level to monitor compliance with the credit and commodity risk management policies of all subsidiaries, including Virginia Power and Dominion Energy Gas. Dominion Energy maintains credit policies that include the evaluation of a prospective counterparty's financial condition, collateral requirements where deemed necessary and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, Dominion Energy also monitors the financial condition of existing counterparties on an ongoing basis. Based on these credit policies and the Companies' December 31, 2017 provision for credit losses, management believes that it is unlikely that a material adverse effect on the Companies' financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Dominion Energy, Inc.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Dominion Energy, Inc. and subsidiaries ("Dominion Energy") at December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Dominion Energy at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), Dominion Energy's internal control over financial reporting at December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2018, expressed an unqualified opinion on Dominion Energy's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of Dominion Energy's management. Our responsibility is to express an opinion on Dominion Energy's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to Dominion Energy in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2018

We have served as Dominion Energy's auditor since 1988.

Table of Contents

Dominion Energy, Inc.
Consolidated Statements of Income

Year Ended December 31, (millions, except per share amounts)	2017	2016	2015
Operating Revenue(1)	**$12,586**	$11,737	$11,683
Operating Expenses			
Electric fuel and other energy-related purchases	**2,301**	2,333	2,725
Purchased electric capacity	**6**	99	330
Purchased gas	**701**	459	551
Other operations and maintenance	**2,875**	3,064	2,595
Depreciation, depletion and amortization	**1,905**	1,559	1,395
Other taxes	**668**	596	551
Total operating expenses	**8,456**	8,110	8,147
Income from operations	**4,130**	3,627	3,536
Other income(1)	**165**	250	196
Interest and related charges	**1,205**	1,010	904
Income from operations including noncontrolling interests before income tax expense (benefit)	**3,090**	2,867	2,828
Income tax expense (benefit)	**(30)**	655	905
Net Income Including Noncontrolling Interests	**3,120**	2,212	1,923
Noncontrolling Interests	**121**	89	24
Net Income Attributable to Dominion Energy	**2,999**	2,123	1,899
Earnings Per Common Share			
Net income attributable to Dominion Energy—Basic	**$ 4.72**	$ 3.44	$ 3.21
Net income attributable to Dominion Energy—Diluted	**$ 4.72**	$ 3.44	$ 3.20
Dividends Declared Per Common Share	**$ 3.035**	$ 2.80	$ 2.59

(1) See Note 9 for amounts attributable to related parties.

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements.

Dominion Energy, Inc.
Consolidated Statements of Comprehensive Income

Year Ended December 31, (millions)	2017	2016	2015
Net income including noncontrolling interests	**$3,120**	$2,212	$1,923
Other comprehensive income (loss), net of taxes:			
Net deferred gains on derivatives-hedging activities, net of $(3), $(37) and $(74) tax	**8**	55	110
Changes in unrealized net gains on investment securities, net of $(121), $(53) and $23 tax	**215**	93	6
Changes in net unrecognized pension and other postretirement benefit costs, net of $32, $189 and $29 tax	**(69)**	(319)	(66)
Amounts reclassified to net income:			
Net derivative gains-hedging activities, net of $18, $100 and $68 tax	**(29)**	(159)	(108)
Net realized gains on investment securities, net of $21, $15 and $29 tax	**(37)**	(28)	(50)
Net pension and other postretirement benefit costs, net of $(32), $(22) and $(35) tax	**50**	34	51
Changes in other comprehensive income (loss) from equity method investees, net of $(2), $— and $1 tax	**3**	(1)	(1)
Total other comprehensive income (loss)	**141**	(325)	(58)
Comprehensive income including noncontrolling interests	**3,261**	1,887	1,865
Comprehensive income attributable to noncontrolling interests	**122**	89	24
Comprehensive income attributable to Dominion Energy	**$3,139**	$1,798	$1,841

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements.

Dominion Energy, Inc.
Consolidated Balance Sheets

At December 31, (millions)	2017	2016
ASSETS		
Current Assets		
Cash and cash equivalents	$ 120	$ 261
Customer receivables (less allowance for doubtful accounts of $17 and $18)	1,660	1,523
Other receivables (less allowance for doubtful accounts of $2 at both dates)(1)	126	183
Inventories		
Materials and supplies	1,049	1,087
Fossil fuel	328	341
Gas Stored	100	96
Prepayments	260	194
Regulatory assets	294	244
Other	397	319
Total current assets	4,334	4,248
Investments		
Nuclear decommissioning trust funds	5,093	4,484
Investment in equity method affiliates	1,544	1,561
Other	327	298
Total investments	6,964	6,343
Property, Plant and Equipment		
Property, plant and equipment	74,823	69,556
Accumulated depreciation, depletion and amortization	(21,065)	(19,592)
Total property, plant and equipment, net	53,758	49,964
Deferred Charges and Other Assets		
Goodwill	6,405	6,399
Pension and other postretirement benefit assets	1,378	1,078
Intangible assets, net	685	618
Regulatory assets	2,480	2,473
Other	581	487
Total deferred charges and other assets	11,529	11,055
Total assets	$ 76,585	$ 71,610

(1) See Note 9 for amounts attributable to related parties.

At December 31, (millions)	2017	2016
LIABILITIES AND EQUITY		
Current Liabilities		
Securities due within one year	$ 3,078	$ 1,709
Short-term debt	3,298	3,155
Accounts payable	875	1,000
Accrued interest, payroll and taxes	848	798
Other(1)	1,537	1,453
Total current liabilities	9,636	8,115
Long-Term Debt		
Long-term debt	25,588	24,878
Junior subordinated notes	3,981	2,980
Remarketable subordinated notes	1,379	2,373
Total long-term debt	30,948	30,231
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	4,523	8,602
Regulatory liabilities	6,916	2,622
Asset retirement obligations	2,169	2,236
Pension and other postretirement benefit liability	2,160	2,112
Other(1)	863	852
Total deferred credits and other liabilities	16,631	16,424
Total liabilities	57,215	54,770
Commitments and Contingencies (see Note 22)		
Equity		
Common stock-no par(2)	9,865	8,550
Retained earnings	7,936	6,854
Accumulated other comprehensive loss	(659)	(799)
Total common shareholders' equity	17,142	14,605
Noncontrolling interests	2,228	2,235
Total equity	19,370	16,840
Total liabilities and equity	$76,585	$71,610

(1) See Notes 3 and 9 for amounts attributable to related parties.
(2) 1 billion shares authorized; 645 million shares and 628 million shares outstanding at December 31, 2017 and 2016, respectively.

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements.

Dominion Energy, Inc.
Consolidated Statements of Equity

(millions)	Common Stock Shares	Common Stock Amount	Retained Earnings	Dominion Energy Shareholders Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Noncontrolling Interests	Total Equity
December 31, 2014	585	$5,876	$ 6,095	$(416)	$11,555	$ 402	$11,957
Net income including noncontrolling interests			1,899		1,899	24	1,923
Dominion Energy Midstream's acquisition of interest in Iroquois					—	216	216
Acquisition of Four Brothers and Three Cedars					—	47	47
Contributions from SunEdison to Four Brothers and Three Cedars					—	103	103
Sale of interest in merchant solar projects		26			26	179	205
Purchase of Dominion Energy Midstream common units		(6)			(6)	(19)	(25)
Issuance of common stock	11	786			786		786
Stock awards (net of change in unearned compensation)		13			13		13
Dividends			(1,536)		(1,536)		(1,536)
Dominion Energy Midstream distributions					—	(16)	(16)
Other comprehensive loss, net of tax				(58)	(58)		(58)
Other		(15)			(15)	2	(13)
December 31, 2015	596	6,680	6,458	(474)	12,664	938	13,602
Net income including noncontrolling interests			2,123		2,123	89	2,212
Contributions from SunEdison to Four Brothers and Three Cedars					—	189	189
Sale of interest in merchant solar projects		22			22	117	139
Sale of Dominion Energy Midstream common units—net of offering costs					—	482	482
Sale of Dominion Energy Midstream convertible preferred units—net of offering costs					—	490	490
Purchase of Dominion Energy Midstream common units		(3)			(3)	(14)	(17)
Issuance of common stock	32	2,152			2,152		2,152
Stock awards (net of change in unearned compensation)		14			14		14
Present value of stock purchase contract payments related to RSNs(1)		(191)			(191)		(191)
Tax effect of Dominion Energy Questar Pipeline contribution to Dominion Energy Midstream		(116)			(116)		(116)
Dividends and distributions			(1,727)		(1,727)	(62)	(1,789)
Other comprehensive loss, net of tax				(325)	(325)		(325)
Other		(8)			(8)	6	(2)
December 31, 2016	628	8,550	6,854	(799)	14,605	2,235	16,840
Net income including noncontrolling interests			**2,999**		**2,999**	**121**	**3,120**
Contributions from NRG to Four Brothers and Three Cedars					**—**	**9**	**9**
Issuance of common stock	**17**	**1,302**			**1,302**		**1,302**
Sale of Dominion Energy Midstream common units—net of offering costs					**—**	**18**	**18**
Stock awards (net of change in unearned compensation)		**22**			**22**		**22**
Dividends and distributions			**(1,931)**		**(1,931)**	**(156)**	**(2,087)**
Other comprehensive income, net of tax				**140**	**140**	**1**	**141**
Other		**(9)**	**14**		**5**		**5**
December 31, 2017	**645**	**$9,865**	**$ 7,936**	**$(659)**	**$17,142**	**$2,228**	**$19,370**

(1) See Note 17 for further information.

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements

Dominion Energy, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	2017	2016	2015
Operating Activities			
Net income including noncontrolling interests	$ 3,120	$ 2,212	$ 1,923
Adjustments to reconcile net income including noncontrolling interests to net cash provided by operating activities:			
Depreciation, depletion and amortization (including nuclear fuel)	2,202	1,849	1,669
Deferred income taxes and investment tax credits	(3)	725	854
Current income tax for Dominion Energy Questar Pipeline contribution to Dominion Energy Midstream	—	(212)	—
Proceeds from assignment of tower rental portfolio	91	—	—
Gains on the sales of assets	(148)	(50)	(123)
Charges associated with equity method investments	158	—	—
Charges associated with future ash pond and landfill closure costs	—	197	99
Contribution to pension plan	(75)	—	—
Other adjustments	(37)	(108)	(42)
Changes in:			
Accounts receivable	(103)	(286)	294
Inventories	15	1	(26)
Deferred fuel and purchased gas costs, net	(71)	54	94
Prepayments	(62)	21	(25)
Accounts payable	(89)	97	(199)
Accrued interest, payroll and taxes	64	203	(52)
Margin deposit assets and liabilities	(10)	(66)	237
Net realized and unrealized changes related to derivative activities	44	(335)	(176)
Asset retirement obligations	(94)	(61)	(4)
Pension and other postretirement benefits	(177)	(152)	(51)
Other operating assets and liabilities	(276)	38	3
Net cash provided by operating activities	4,549	4,127	4,475
Investing Activities			
Plant construction and other property additions (including nuclear fuel)	(5,504)	(6,085)	(5,575)
Acquisition of Dominion Energy Questar, net of cash acquired	—	(4,381)	—
Acquisition of solar development projects	(405)	(40)	(418)
Acquisition of DECG	—	—	(497)
Proceeds from sales of securities	1,831	1,422	1,340
Purchases of securities	(1,940)	(1,504)	(1,326)
Sale of certain retail energy marketing assets	68	—	—
Proceeds from assignment of shale development rights	70	10	79
Contributions to equity method affiliates	(370)	(198)	(51)
Distributions from equity method affiliates	228	26	16
Other	29	47	(71)
Net cash used in investing activities	(5,993)	(10,703)	(6,503)
Financing Activities			
Issuance (repayment) of short-term debt, net	143	(654)	734
Issuance of short-term notes	—	1,200	600
Repayment and repurchase of short-term notes	(250)	(1,800)	(400)
Issuance and remarketing of long-term debt	3,880	7,722	2,962
Repayment and repurchase of long-term debt	(1,572)	(1,610)	(892)
Net proceeds from issuance of Dominion Energy Midstream common units	18	482	—
Net proceeds from issuance of Dominion Energy Midstream preferred units	—	490	—
Proceeds from sale of interest in merchant solar projects	—	117	184
Contributions from NRG and SunEdison to Four Brothers and Three Cedars	9	189	103
Issuance of common stock	1,302	2,152	786
Common dividend payments	(1,931)	(1,727)	(1,536)
Other	(296)	(331)	(224)
Net cash provided by financing activities	1,303	6,230	2,317
Increase (decrease) in cash and cash equivalents	(141)	(346)	289
Cash and cash equivalents at beginning of year	261	607	318
Cash and cash equivalents at end of year	$ 120	$ 261	$ 607
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	$ 1,083	$ 905	$ 843
Income taxes	9	145	75
Significant noncash investing and financing activities:(1)(2)			
Accrued capital expenditures	343	427	478
Guarantee provided to equity method affiliate	30	—	—
Dominion Energy Midstream's acquisition of a noncontrolling partnership interest in Iroquois in exchange for issuance of Dominion Energy Midstream common units	—	—	216

(1) See Note 3 for noncash activities related to the acquisition of Four Brothers and Three Cedars.
(2) See Note 17 for noncash activities related to the remarketing of RSNs in 2017 and 2016.

The accompanying notes are an integral part of Dominion Energy's Consolidated Financial Statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Virginia Electric and Power Company

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Energy, Inc.) and subsidiaries ("Virginia Power") at December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, common shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Virginia Power at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of Virginia Power's management. Our responsibility is to express an opinion on Virginia Power's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to Virginia Power in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Virginia Power is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Virginia Power's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2018

We have served as Virginia Power's auditor since 1988.

Virginia Electric and Power Company
Consolidated Statements of Income

Year Ended December 31, (millions)	2017	2016	2015
Operating Revenue(1)	**$7,556**	$7,588	$7,622
Operating Expenses			
Electric fuel and other energy-related purchases(1)	**1,909**	1,973	2,320
Purchased electric capacity	**6**	99	330
Other operations and maintenance:			
Affiliated suppliers	**309**	310	279
Other	**1,169**	1,547	1,355
Depreciation and amortization	**1,141**	1,025	953
Other taxes	**290**	284	264
Total operating expenses	**4,824**	5,238	5,501
Income from operations	**2,732**	2,350	2,121
Other income	**76**	56	68
Interest and related charges(1)	**494**	461	443
Income from operations before income tax expense	**2,314**	1,945	1,746
Income tax expense	**774**	727	659
Net Income	**$1,540**	$1,218	$1,087

(1) See Note 24 for amounts attributable to affiliates.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Comprehensive Income

Year Ended December 31, (millions)	2017	2016	2015
Net income	**$1,540**	$1,218	$1,087
Other comprehensive income (loss), net of taxes:			
Net deferred losses on derivatives-hedging activities, net of $3, $1 and $2 tax	**(5)**	(2)	(1)
Changes in unrealized net gains (losses) on nuclear decommissioning trust funds, net of $(16), $(7) and $1 tax	**24**	11	(4)
Amounts reclassified to net income:			
Net derivative losses on derivative-hedging activities, net of $—, $— and $— tax	**1**	1	1
Net realized gains on nuclear decommissioning trust funds, net of $3, $2 and $4 tax	**(4)**	(4)	(6)
Total other comprehensive income (loss)	**16**	6	(10)
Comprehensive income	**$1,556**	$1,224	$1,077

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Balance Sheets

At December 31, (millions)	2017	2016
ASSETS		
Current Assets		
Cash and cash equivalents	$ 14	$ 11
Customer receivables (less allowance for doubtful accounts of $10 at both dates)	951	892
Other receivables (less allowance for doubtful accounts of $1 at both dates)	64	99
Affiliated receivables	3	112
Inventories (average cost method)		
Materials and supplies	531	525
Fossil fuel	319	328
Prepayments	27	30
Regulatory assets	205	179
Other(1)	110	72
Total current assets	2,224	2,248
Investments		
Nuclear decommissioning trust funds	2,399	2,106
Other	3	3
Total investments	2,402	2,109
Property, Plant and Equipment		
Property, plant and equipment	42,329	40,030
Accumulated depreciation and amortization	(13,277)	(12,436)
Total property, plant and equipment, net	29,052	27,594
Deferred Charges and Other Assets		
Pension and other postretirement benefit assets(1)	199	130
Intangible assets, net	233	225
Regulatory assets	810	770
Derivative assets(1)	91	128
Other	128	104
Total deferred charges and other assets	1,461	1,357
Total assets	$ 35,139	$ 33,308

(1) See Note 24 for amounts attributable to affiliates.

At December 31, (millions)	2017	2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	**$ 850**	$ 678
Short-term debt	**542**	65
Accounts payable	**361**	444
Payables to affiliates	**125**	109
Affiliated current borrowings	**33**	262
Accrued interest, payroll and taxes	**256**	239
Asset retirement obligations	**216**	181
Other(1)	**537**	544
Total current liabilities	**2,920**	2,522
Long-Term Debt	**10,496**	9,852
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,728**	5,103
Asset retirement obligations	**1,149**	1,262
Regulatory liabilities	**4,760**	1,962
Pension and other postretirement benefit liabilities(1)	**505**	396
Other	**357**	346
Total deferred credits and other liabilities	**9,499**	9,069
Total liabilities	**22,915**	21,443
Commitments and Contingencies (see Note 22)		
Common Shareholder's Equity		
Common stock – no par(2)	**5,738**	5,738
Other paid-in capital	**1,113**	1,113
Retained earnings	**5,311**	4,968
Accumulated other comprehensive income	**62**	46
Total common shareholder's equity	**12,224**	11,865
Total liabilities and shareholder's equity	**$35,139**	$33,308

(1) See Note 24 for amounts attributable to affiliates.
(2) 500,000 shares authorized; 274,723 shares outstanding at December 31, 2017 and 2016.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Common Shareholder's Equity

	Common Stock		Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
(millions, except for shares)	Shares (thousands)	Amount				
Balance at December 31, 2014	275	$5,738	$1,113	$ 3,154	$ 50	$10,055
Net income				1,087		1,087
Dividends				(491)		(491)
Other comprehensive loss, net of tax					(10)	(10)
Balance at December 31, 2015	275	5,738	1,113	3,750	40	10,641
Net income				1,218		1,218
Other comprehensive income, net of tax					6	6
Balance at December 31, 2016	275	5,738	1,113	4,968	46	11,865
Net income				**1,540**		**1,540**
Dividends				**(1,199)**		**(1,199)**
Other comprehensive income, net of tax					**16**	**16**
Other				**2**		**2**
Balance at December 31, 2017	**275**	**$5,738**	**$1,113**	**$ 5,311**	**$ 62**	**$12,224**

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Cash Flows

Year Ended December 31, (millions)	2017	2016	2015
Operating Activities			
Net income	$ 1,540	$ 1,218	$ 1,087
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (including nuclear fuel)	1,333	1,210	1,121
Deferred income taxes and investment tax credits	269	469	251
Proceeds from assignment of rental portfolio	91	—	—
Charges associated with future ash pond and landfill closure costs	—	197	99
Other adjustments	(36)	(16)	(27)
Changes in:			
Accounts receivable	(27)	(65)	128
Affiliated accounts receivable and payable	125	220	(314)
Inventories	3	20	(20)
Prepayments	3	8	214
Deferred fuel expenses, net	(59)	69	64
Accounts payable	(42)	25	(75)
Accrued interest, payroll and taxes	17	49	(9)
Net realized and unrealized changes related to derivative activities	13	(153)	(67)
Asset retirement obligations	(88)	(59)	10
Other operating assets and liabilities	(181)	77	93
Net cash provided by operating activities	2,961	3,269	2,555
Investing Activities			
Plant construction and other property additions	(2,496)	(2,489)	(2,474)
Purchases of nuclear fuel	(192)	(153)	(172)
Acquisition of solar development projects	(41)	(7)	(43)
Purchases of securities	(884)	(775)	(651)
Proceeds from sales of securities	849	733	639
Other	(51)	(33)	(87)
Net cash used in investing activities	(2,815)	(2,724)	(2,788)
Financing Activities			
Issuance (repayment) of short-term debt, net	477	(1,591)	295
Repayment of affiliated current borrowings, net	(229)	(114)	(51)
Issuance and remarketing of long-term debt	1,500	1,688	1,112
Repayment of long-term debt	(681)	(517)	(625)
Common dividend payments to parent	(1,199)	—	(491)
Other	(11)	(18)	(4)
Net cash provided by (used in) financing activities	(143)	(552)	236
Increase (decrease) in cash and cash equivalents	3	(7)	3
Cash and cash equivalents at beginning of year	11	18	15
Cash and cash equivalents at end of year	$ 14	$ 11	$ 18
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	$ 458	$ 435	$ 422
Income taxes	362	79	517
Significant noncash investing activities:			
Accrued capital expenditures	169	256	169

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Dominion Energy Gas Holdings, LLC

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Dominion Energy Gas Holdings, LLC (a wholly-owned subsidiary of Dominion Energy, Inc.) and subsidiaries ("Dominion Energy Gas") at December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Dominion Energy Gas at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of Dominion Energy Gas' management. Our responsibility is to express an opinion on Dominion Energy Gas' consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to Dominion Energy Gas in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Dominion Energy Gas is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of Dominion Energy Gas' internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2018

We have served as Dominion Energy Gas' auditor since 2012.

Dominion Energy Gas Holdings, LLC
Consolidated Statements of Income

Year Ended December 31, (millions)	2017	2016	2015
Operating Revenue(1)	**$1,814**	$1,638	$1,716
Operating Expenses			
Purchased gas(1)	**132**	109	133
Other energy-related purchases(1)	**21**	12	21
Other operations and maintenance:			
Affiliated suppliers	**87**	81	64
Other(1)	**440**	393	326
Depreciation and amortization	**227**	204	217
Other taxes	**185**	170	166
Total operating expenses	**1,092**	969	927
Income from operations	**722**	669	789
Earnings from equity method investee	**21**	21	23
Other income	**20**	11	1
Interest and related charges(1)	**97**	94	73
Income from operations before income tax expense	**666**	607	740
Income tax expense	**51**	215	283
Net Income	**$ 615**	$ 392	$ 457

(1) See Note 24 for amounts attributable to related parties.

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

Dominion Energy Gas Holdings, LLC
Consolidated Statements of Comprehensive Income

Year Ended December 31, (millions)	2017	2016	2015
Net income	**$615**	$392	$457
Other comprehensive income (loss), net of taxes:			
Net deferred gains (losses) on derivatives-hedging activities, net of $(3), $10, and $(4) tax	**5**	(16)	6
Changes in unrecognized pension benefit (costs), net of $(8), $14, and $13 tax	**20**	(20)	(20)
Amounts reclassified to net income:			
Net derivative (gains) losses, net of $3, $(6), and $3 tax	**(4)**	9	(3)
Net pension and other postretirement benefit costs, net of $(2), $(2), and $(3) tax	**4**	3	4
Other comprehensive income (loss)	**25**	(24)	(13)
Comprehensive income	**$640**	$368	$444

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

Table of Contents

Dominion Energy Gas Holdings, LLC
Consolidated Balance Sheets

At December 31, (millions)	2017	2016
ASSETS		
Current Assets		
Cash and cash equivalents	$ 4	$ 23
Customer receivables (less allowance for doubtful accounts of $1 at both dates)(1)	297	281
Other receivables (less allowance for doubtful accounts of $1 at both dates)(1)	15	13
Affiliated receivables	10	17
Inventories:		
Materials and supplies	55	57
Gas stored	9	13
Prepayments	112	94
Gas imbalances(1)	46	37
Other	52	47
Total current assets	600	582
Investments	97	99
Property, Plant and Equipment		
Property, plant and equipment	11,173	10,475
Accumulated depreciation and amortization	(3,018)	(2,851)
Total property, plant and equipment, net	8,155	7,624
Deferred Charges and Other Assets		
Goodwill	542	542
Intangible assets, net	109	98
Regulatory assets	511	577
Pension and other postretirement benefit assets(1)	1,828	1,557
Other(1)	98	63
Total deferred charges and other assets	3,088	2,837
Total assets	$11,940	$11,142

(1) See Note 24 for amounts attributable to related parties.

At December 31, (millions)	2017	2016
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term debt	**$ 629**	$ 460
Accounts payable	**193**	221
Payables to affiliates	**62**	29
Affiliated current borrowings	**18**	118
Accrued interest, payroll and taxes	**250**	225
Other(1)	**189**	162
Total current liabilities	**1,341**	1,215
Long-Term Debt	**3,570**	3,528
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**1,454**	2,438
Regulatory liabilities	**1,227**	219
Other(1)	**185**	206
Total deferred credits and other liabilities	**2,866**	2,863
Total liabilities	**7,777**	7,606
Commitments and Contingencies (see Note 22)		
Equity		
Membership interests	**4,261**	3,659
Accumulated other comprehensive loss	**(98)**	(123)
Total equity	**4,163**	3,536
Total liabilities and equity	**$11,940**	$11,142

(1) See Note 24 for amounts attributable to related parties.

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

Dominion Energy Gas Holdings, LLC
Consolidated Statements of Equity

(millions)	Membership Interests	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2014	$3,652	$ (86)	$3,566
Net income	457		457
Distributions	(692)		(692)
Other comprehensive loss, net of tax		(13)	(13)
Balance at December 31, 2015	3,417	(99)	3,318
Net income	392		392
Distributions	(150)		(150)
Other comprehensive loss, net of tax		(24)	(24)
Balance at December 31, 2016	3,659	(123)	3,536
Net income	**615**		**615**
Distributions	**(15)**		**(15)**
Other comprehensive income, net of tax		**25**	**25**
Other	**2**		**2**
Balance at December 31, 2017	**$4,261**	**$ (98)**	**$4,163**

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

Dominion Energy Gas Holdings, LLC
Consolidated Statements of Cash Flows

Year Ended December 31,	2017	2016	2015
(millions)			
Operating Activities			
Net income	**$ 615**	$ 392	$ 457
Adjustments to reconcile net income to net cash provided by operating activities:			
Gains on sales of assets	**(70)**	(50)	(123)
Depreciation and amortization	**227**	204	217
Deferred income taxes and investment tax credits	**27**	238	163
Other adjustments	**(9)**	(6)	16
Changes in:			
Accounts receivable	**(17)**	(68)	115
Affiliated receivables and payables	**40**	88	(105)
Inventories	**6**	8	(13)
Prepayments	**(18)**	(6)	99
Accounts payable	**(17)**	15	(51)
Accrued interest, payroll and taxes	**24**	42	(11)
Pension and other postretirement benefits	**(143)**	(141)	(119)
Other operating assets and liabilities	**(1)**	(68)	(17)
Net cash provided by operating activities	**664**	648	628
Investing Activities			
Plant construction and other property additions	**(778)**	(854)	(795)
Proceeds from sale of equity method investment in Iroquois	**—**	7	—
Proceeds from assignments of shale development rights	**70**	10	79
Other	**(23)**	(18)	(11)
Net cash used in investing activities	**(731)**	(855)	(727)
Financing Activities			
Issuance of short-term debt, net	**169**	69	391
Issuance (repayment) of affiliated current borrowings, net	**(100)**	23	(289)
Repayment of long-term debt	**—**	(400)	—
Issuance of long-term debt	**—**	680	700
Distribution payments to parent	**(15)**	(150)	(692)
Other	**(6)**	(5)	(7)
Net cash provided by financing activities	**48**	217	103
Increase (decrease) in cash and cash equivalents	**(19)**	10	4
Cash and cash equivalents at beginning of year	**23**	13	9
Cash and cash equivalents at end of year	**$ 4**	$ 23	$ 13
Supplemental Cash Flow Information			
Cash paid (received) during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 89**	$ 81	$ 70
Income taxes	**9**	(92)	98
Significant noncash investing and financing activities:			
Accrued capital expenditures	**38**	59	57

The accompanying notes are an integral part of Dominion Energy Gas' Consolidated Financial Statements.

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Combined Notes to Consolidated Financial Statements

NOTE 1. NATURE OF OPERATIONS

Dominion Energy, headquartered in Richmond, Virginia, is one of the nation's largest producers and transporters of energy. Dominion Energy's operations are conducted through various subsidiaries, including Virginia Power and Dominion Energy Gas. Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. Virginia Power is a member of PJM, an RTO, and its electric transmission facilities are integrated into the PJM wholesale electricity markets. All of Virginia Power's stock is owned by Dominion Energy. Dominion Energy Gas is a holding company that conducts business activities through a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states, regulated gas transportation and distribution operations in Ohio, and gas gathering and processing activities primarily in West Virginia, Ohio and Pennsylvania. All of Dominion Energy Gas' membership interests are held by Dominion Energy. The Dominion Energy Questar Combination was completed in September 2016. See Note 3 for a description of operations acquired in the Dominion Energy Questar Combination.

Dominion Energy's operations also include the Cove Point LNG import, transport and storage facility in Maryland, an equity investment in Atlantic Coast Pipeline and regulated gas transportation and distribution operations in West Virginia. Dominion Energy's nonregulated operations include merchant generation, energy marketing and price risk management activities, retail energy marketing operations and an equity investment in Blue Racer.

In October 2014, Dominion Energy Midstream launched its initial public offering of 20,125,000 common units representing limited partner interests. At December 31, 2017, Dominion Energy owns the general partner, 50.6% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Energy Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DECG, Dominion Energy Questar Pipeline and a 25.93% noncontrolling partnership interest in Iroquois. The public's ownership interest in Dominion Energy Midstream is reflected as noncontrolling interest in Dominion Energy's Consolidated Financial Statements.

Dominion Energy manages its daily operations through three primary operating segments: Power Delivery, Power Generation and Gas Infrastructure. Dominion Energy also reports a Corporate and Other segment, which includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Virginia Power manages its daily operations through two primary operating segments: Power Delivery and Power Generation. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Dominion Energy Gas manages its daily operations through one primary operating segment: Gas Infrastructure. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Energy Gas as a result of Dominion Energy's basis in the net assets contributed.

See Note 25 for further discussion of the Companies' operating segments.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

General

The Companies make certain estimates and assumptions in preparing their Consolidated Financial Statements in accordance with GAAP. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses and cash flows for the periods presented. Actual results may differ from those estimates.

The Companies' Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of their respective majority-owned subsidiaries and non-wholly-owned entities in which they have a controlling financial interest. For certain partnership structures, income is allocated based on the liquidation value of the underlying contractual arrangements. NRG's ownership interest in Four Brothers and Three Cedars, as well as Terra Nova Renewable Partners' 33% interest in certain of Dominion Energy's merchant solar projects, is reflected as noncontrolling interest in Dominion Energy's Consolidated Financial Statements. See Note 3 for further information on these transactions.

The Companies report certain contracts, instruments and investments at fair value. See Note 6 for further information on fair value measurements.

Dominion Energy maintains pension and other postretirement benefit plans. Virginia Power and Dominion Energy Gas participate in certain of these plans. See Note 21 for further information on these plans.

Certain amounts in the 2016 and 2015 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2017 presentation for comparative purposes. The reclassifications did not affect the Companies' net income, total assets, liabilities, equity or cash flows, except for the reclassification of debt issuance costs.

Amounts disclosed for Dominion Energy are inclusive of Virginia Power and/or Dominion Energy Gas, where applicable.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Dominion Energy and Virginia Power collect sales, consumption and consumer utility taxes and Dominion Energy Gas collects sales taxes; however, these amounts are excluded from revenue. Dominion Energy's customer receivables at December 31, 2017 and 2016 included $661 million and $631 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity and natural gas delivered but not yet billed to its utility customers. Virginia Power's customer receivables at December 31, 2017 and 2016 included \$400 million and \$349 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity delivered but not yet billed to its customers. Dominion Energy Gas' customer receivables at December 31, 2017 and 2016 included \$121 million and \$134 million, respectively, of accrued unbilled revenue based on estimated amounts of natural gas delivered but not yet billed to its customers. See Note 9 for amounts attributable to related parties.

The primary types of sales and service activities reported as operating revenue for Dominion Energy are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, and federally-regulated wholesale electric sales and electric transmission services;
- **Nonregulated electric sales** consist primarily of sales of electricity at market-based rates and contracted fixed rates, and associated derivative activity;
- **Regulated gas sales** consist primarily of state- and FERC-regulated natural gas sales and related distribution services and associated derivative activity;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices, sales of gas purchased from third parties, gas trading and marketing revenue and associated derivative activity;
- **Gas transportation and storage** consists primarily of FERC-regulated sales of transmission and storage services. Also included are state-regulated gas distribution charges to retail distribution service customers opting for alternate suppliers and sales of gathering services; and
- **Other revenue** consists primarily of sales of NGL production and condensate, extracted products and associated derivative activity. Other revenue also includes miscellaneous service revenue from electric and gas distribution operations, sales of energy-related products and services from Dominion Energy's retail energy marketing operations and gas processing and handling revenue.

The primary types of sales and service activities reported as operating revenue for Virginia Power are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales and federally-regulated wholesale electric sales and electric transmission services; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric distribution operations and miscellaneous revenue from generation operations, including sales of capacity and other commodities.

The primary types of sales and service activities reported as operating revenue for Dominion Energy Gas are as follows:

- **Regulated gas sales** consist primarily of state- and FERC-regulated natural gas sales and related distribution services;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices and sales of gas purchased from third parties. Revenue from sales of gas production is recognized based on actual volumes of gas sold to purchasers and is reported net of royalties;
- **Gas transportation and storage** consists primarily of FERC-regulated sales of transmission and storage services. Also included are state-regulated gas distribution charges to retail distribution service customers opting for alternate suppliers and sales of gathering services;
- **NGL revenue** consists primarily of sales of NGL production and condensate, extracted products and associated derivative activity; and
- **Other revenue** consists primarily of miscellaneous service revenue, gas processing and handling revenue.

Electric Fuel, Purchased Energy and Purchased Gas-Deferred Costs

Where permitted by regulatory authorities, the differences between Dominion Energy's and Virginia Power's actual electric fuel and purchased energy expenses and Dominion Energy's and Dominion Energy Gas' purchased gas expenses and the related levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while rate recovery in excess of current period fuel expenses is recognized as a regulatory liability.

Of the cost of fuel used in electric generation and energy purchases to serve utility customers, approximately 84% is currently subject to deferred fuel accounting, while substantially all of the remaining amount is subject to recovery through similar mechanisms.

Virtually all of Dominion Energy Gas', Cove Point's, Questar Gas' and Hope's natural gas purchases are either subject to deferral accounting or are recovered from the customer in the same accounting period as the sale.

Income Taxes

A consolidated federal income tax return is filed for Dominion Energy and its subsidiaries, including Virginia Power and Dominion Energy Gas' subsidiaries. In addition, where applicable, combined income tax returns for Dominion Energy and its subsidiaries are filed in various states; otherwise, separate state income tax returns are filed.

Although Dominion Energy Gas is disregarded for income tax purposes, a provision for income taxes is recognized to reflect the inclusion of its business activities in the tax returns of its parent, Dominion Energy. Virginia Power and Dominion Energy Gas participate in intercompany tax sharing agreements with Dominion Energy and its subsidiaries. Current income taxes are based on taxable income or loss and credits determined on a separate company basis.

Under the agreements, if a subsidiary incurs a tax loss or earns a credit, recognition of current income tax benefits is limited to refunds of prior year taxes obtained by the carryback of the net operating loss or credit or to the extent the tax loss or credit is absorbed by the taxable income of other Dominion Energy consolidated group members. Otherwise, the net operating loss or credit is carried forward and is recognized as a deferred tax asset until realized.

The 2017 Tax Reform Act includes a broad range of tax reform provisions affecting the Companies, including changes in corporate tax rates and business deductions. The 2017 Tax Reform Act reduces the corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017. Deferred tax assets and liabilities are classified as noncurrent in the Consolidated Balance

Sheets and measured at the enacted tax rate expected to apply when temporary differences are realized or settled. Thus, at the date of enactment, federal deferred taxes were remeasured based upon the new 21% tax rate. The total effect of tax rate changes on deferred tax balances is recorded as a component of the income tax provision related to continuing operations for the period in which the law is enacted, even if the assets and liabilities relate to other components of the financial statements, such as items of accumulated other comprehensive income. For Dominion Energy subsidiaries that are not rate-regulated utilities, existing deferred income tax assets or liabilities were adjusted for the reduction in the corporate income tax rate and allocated to continuing operations. Dominion Energy's rate-regulated utility subsidiaries likewise are required to adjust deferred income tax assets and liabilities for the change in income tax rates. However, if it is probable that the effect of the change in income tax rates will be recovered or refunded in future rates, the regulated utility recorded a regulatory asset or liability instead of an increase or decrease to deferred income tax expense.

Accounting for income taxes involves an asset and liability approach. Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Accordingly, deferred taxes are recognized for the future consequences of different treatments used for the reporting of transactions in financial accounting and income tax returns. The Companies establish a valuation allowance when it is more-likely-than-not that all, or a portion, of a deferred tax asset will not be realized. Where the treatment of temporary differences is different for rate-regulated operations, a regulatory asset is recognized if it is probable that future revenues will be provided for the payment of deferred tax liabilities.

The Companies recognize positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information.

If it is not more-likely-than-not that a tax position, or some portion thereof, will be sustained, the related tax benefits are not recognized in the financial statements. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of income tax refunds receivable or changes in deferred taxes. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in income taxes payable (or reduction in tax refunds receivable) is accompanied by a decrease in deferred tax liabilities. Except when such amounts are presented net with amounts receivable from or amounts prepaid to tax authorities, noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities on the Consolidated Balance Sheets and current payables are included in accrued interest, payroll and taxes on the Consolidated Balance Sheets.

The Companies recognize interest on underpayments and overpayments of income taxes in interest expense and other income, respectively. Penalties are also recognized in other income.

Dominion Energy and Virginia Power both recognized interest income of $11 million in 2017. Dominion Energy Gas' interest was immaterial in 2017. Interest for the Companies was immaterial in 2016 and 2015. Dominion Energy's, Virginia Power's and Dominion Energy Gas' penalties were immaterial in 2017, 2016 and 2015.

At December 31, 2017, Virginia Power had an income tax-related affiliated payable of $16 million, comprised of $16 million of federal income taxes due to Dominion Energy. Dominion Energy Gas also had an affiliated payable of $25 million due to Dominion Energy, representing $21 million of federal income taxes and $4 million of state income taxes. The net affiliated payables are expected to be paid to Dominion Energy.

In addition, Virginia Power's Consolidated Balance Sheet at December 31, 2017 included $1 million of noncurrent federal income taxes receivable, less than $1 million of state income taxes receivable and $1 million of noncurrent state income taxes receivable. Dominion Energy Gas' Consolidated Balance Sheet at December 31, 2017 included $14 million of state income taxes receivable.

At December 31, 2016, Virginia Power had an income tax-related affiliated receivable of $112 million, comprised of $122 million of federal income taxes due from Dominion Energy net of $10 million for state income taxes due to Dominion Energy. Dominion Energy Gas also had an affiliated receivable of $11 million due from Dominion Energy, representing $10 million of federal income taxes and $1 million of state income taxes. The net affiliated receivables were refunded by Dominion Energy.

In addition, Virginia Power's Consolidated Balance Sheet at December 31, 2016 included $2 million of noncurrent federal income taxes payable, $6 million of state income taxes receivable and $13 million of noncurrent state income taxes receivable. Dominion Energy Gas' Consolidated Balance Sheet at December 31, 2016 included $1 million of noncurrent federal income taxes payable, $1 million of state income taxes receivable and $7 million of noncurrent state income taxes payable.

Investment tax credits are recognized by nonregulated operations in the year qualifying property is placed in service. For regulated operations, investment tax credits are deferred and amortized over the service lives of the properties giving rise to the credits. Production tax credits are recognized as energy is generated and sold.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. The following table illustrates the checks outstanding but not yet presented for payment and recorded in accounts payable for the Companies:

Year Ended December 31,	2017	2016
(millions)		
Dominion Energy	**$30**	$24
Virginia Power	**17**	11
Dominion Energy Gas	**7**	9

The Companies hold restricted cash and cash equivalent balances that primarily consist of amounts held for customer deposits, future debt payments on Dominion Solar Projects III, Inc.'s term loan agreement and a distribution reserve at Cove Point. The amount of restricted cash held at each company is presented in the table below. These balances are presented in Other Current Assets and Other Investments in the Consolidated Balance Sheets.

Year Ended December 31,	2017	2016
(millions)		
Dominion Energy	$65	$61
Virginia Power	10	—
Dominion Energy Gas	26	20

For purposes of the Consolidated Statements of Cash Flows, cash and cash equivalents include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Derivative Instruments

Dominion Energy uses derivative instruments such as physical and financial forwards, futures, swaps, options and FTRs to manage the commodity, interest rate and foreign currency exchange rate risks of its business operations. Virginia Power uses derivative instruments such as physical and financial forwards, futures, swaps, options and FTRs to manage commodity and interest rate risks. Dominion Energy Gas uses derivative instruments such as physical and financial forwards, futures and swaps to manage commodity, interest rate and foreign currency exchange rate risks.

All derivatives, except those for which an exception applies, are required to be reported in the Consolidated Balance Sheets at fair value. Derivative contracts representing unrealized gain positions and purchased options are reported as derivative assets. Derivative contracts representing unrealized losses and options sold are reported as derivative liabilities. One of the exceptions to fair value accounting, normal purchases and normal sales, may be elected when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable. Expenses and revenues resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance.

The Companies do not offset amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. Dominion Energy had margin assets of $92 million and $82 million associated with cash collateral at December 31, 2017 and 2016, respectively. Dominion Energy's margin liabilities associated with cash collateral at December 31, 2017 or 2016 were immaterial. Virginia Power had margin assets of $23 million and $2 million associated with cash collateral at December 31, 2017 and 2016, respectively. Virginia Power's margin liabilities associated with cash collateral were immaterial at December 31, 2017 and 2016. Dominion Energy Gas' margin assets and liabilities associated with cash collateral were immaterial at December 31, 2017 and 2016. See Note 7 for further information about derivatives.

To manage price risk, the Companies hold certain derivative instruments that are not designated as hedges for accounting purposes. However, to the extent the Companies do not hold offsetting positions for such derivatives, they believe these instruments represent economic hedges that mitigate their exposure to fluctuations in commodity prices. All income statement activity, including amounts realized upon settlement, is presented in operating revenue, operating expenses, interest and related charges or other income based on the nature of the underlying risk.

Changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities for jurisdictions subject to cost-based rate regulation. Realized gains or losses on the derivative instruments are generally recognized when the related transactions impact earnings.

DERIVATIVE INSTRUMENTS DESIGNATED AS HEDGING INSTRUMENTS

The Companies designate a portion of their derivative instruments as either cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, the Companies formally document the relationship between the hedging instrument and the hedged item, as well as the risk management objective and the strategy for using the hedging instrument. The Companies assess whether the hedging relationship between the derivative and the hedged item is highly effective at offsetting changes in cash flows or fair values both at the inception of the hedging relationship and on an ongoing basis. Any change in the fair value of the derivative that is not effective at offsetting changes in the cash flows or fair values of the hedged item is recognized currently in earnings. Also, the Companies may elect to exclude certain gains or losses on hedging instruments from the assessment of hedge effectiveness, such as gains or losses attributable to changes in the time value of options or changes in the difference between spot prices and forward prices, thus requiring that such changes be recorded currently in earnings. Hedge accounting is discontinued prospectively for derivatives that cease to be highly effective hedges. For derivative instruments that are accounted for as fair value hedges or cash flow hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Cash Flow Hedges-A majority of the Companies' hedge strategies represents cash flow hedges of the variable price risk associated with the purchase and sale of electricity, natural gas and NGLs. The Companies also use interest rate swaps to hedge their exposure to variable interest rates on long-term debt as well as foreign currency swaps to hedge their exposure to interest payments denominated in Euros. For transactions in which the Companies are hedging the variability of cash flows, changes in the fair value of the derivatives are reported in AOCI, to the extent they are effective at offsetting changes in the hedged item. Any derivative gains or losses reported in AOCI are reclassified to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, hedge accounting is discontinued if the occurrence of the forecasted transaction is no longer probable.

Dominion Energy entered into interest rate derivative instruments to hedge its forecasted interest payments related to planned debt issuances in 2014. These interest rate derivatives were designated by Dominion Energy as cash flow hedges prior to the formation of Dominion Energy Gas. For the purposes of the Dominion Energy Gas financial statements, the derivative balances, AOCI balance, and any income statement impact related to these interest rate derivative instruments entered into by Dominion Energy have been, and will continue to be, included in the Dominion Energy Gas' Consolidated Financial Statements as the forecasted interest payments related to the debt issuances now occur at Dominion Energy Gas.

Fair Value Hedges-Dominion Energy also uses fair value hedges to mitigate the fixed price exposure inherent in commodity inventory. In addition, Dominion Energy has designated interest rate swaps as fair value hedges on certain fixed rate long-term debt to manage interest rate exposure. For fair value hedge transactions, changes in the fair value of the derivative are generally offset currently in earnings by the recognition of changes in the hedged item's fair value. Hedge accounting is discontinued if the hedged item no longer qualifies for hedge accounting. See Note 6 for further information about fair value measurements and associated valuation methods for derivatives. See Note 7 for further information on derivatives.

Property, Plant and Equipment

Property, plant and equipment is recorded at lower of original cost or fair value, if impaired. Capitalized costs include labor, materials and other direct and indirect costs such as asset retirement costs, capitalized interest and, for certain operations subject to cost-of-service rate regulation, AFUDC and overhead costs. The cost of repairs and maintenance, including minor additions and replacements, is generally charged to expense as it is incurred.

In 2017, 2016 and 2015, Dominion Energy capitalized interest costs and AFUDC to property, plant and equipment of $236 million, $159 million and $100 million, respectively. In 2017, 2016 and 2015, Virginia Power capitalized AFUDC to property, plant and equipment of $37 million, $21 million and $30 million, respectively. In 2017, 2016 and 2015, Dominion Energy Gas capitalized AFUDC to property, plant and equipment of $25 million, $8 million and $1 million, respectively.

Under Virginia law, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset and is not capitalized to property, plant and equipment. In 2017, 2016 and 2015, Virginia Power recorded $22 million, $31 million and $19 million of AFUDC related to these projects, respectively.

For property subject to cost-of-service rate regulation, including Virginia Power electric distribution, electric transmission, and generation property, Dominion Energy Gas natural gas distribution and transmission property, and for certain Dominion Energy natural gas property, the undepreciated cost of such property, less salvage value, is generally charged to accumulated depreciation at retirement. Cost of removal collections from utility customers not representing AROs are recorded as regulatory liabilities. For property subject to cost-of-service rate regulation that will be abandoned significantly before the end of its useful life, the net carrying value is reclassified from plant-in-service when it becomes probable it will be abandoned.

For property that is not subject to cost-of-service rate regulation, including nonutility property, cost of removal not associated with AROs is charged to expense as incurred. The Companies also record gains and losses upon retirement based upon the difference between the proceeds received, if any, and the property's net book value at the retirement date.

Depreciation of property, plant and equipment is computed on the straight-line method based on projected service lives. The Companies' average composite depreciation rates on utility property, plant and equipment are as follows:

Year Ended December 31, (percent)	2017	2016	2015
Dominion Energy			
Generation	**2.94**	2.83	2.78
Transmission	**2.55**	2.47	2.42
Distribution	**3.00**	3.02	3.11
Storage	**2.48**	2.29	2.42
Gas gathering and processing	**2.21**	2.66	3.19
General and other	**4.89**	4.12	3.67
Virginia Power			
Generation	**2.94**	2.83	2.78
Transmission	**2.54**	2.36	2.33
Distribution	**3.32**	3.32	3.33
General and other	**4.68**	3.49	3.40
Dominion Energy Gas			
Transmission	**2.40**	2.43	2.46
Distribution	**2.42**	2.55	2.45
Storage	**2.45**	2.19	2.44
Gas gathering and processing	**2.42**	2.58	3.20
General and other	**4.96**	4.54	4.72

In the first quarter of 2017, Virginia Power revised the depreciation rates for its assets to reflect the results of a new depreciation study. This change resulted in an increase in annual depreciation expense of $40 million ($25 million after-tax) for 2017. Additionally, Dominion Energy revised the depreciable lives for its merchant generation assets, excluding Millstone, which resulted in a decrease in annual depreciation expense of $26 million ($16 million after-tax) for 2017.

Capitalized costs of development wells and leaseholds are amortized on a field-by-field basis using the unit-of-production method and the estimated proved developed or total proved gas and oil reserves, at a rate of $2.11 per mcfe in 2017.

Dominion Energy's nonutility property, plant and equipment is depreciated using the straight-line method over the following estimated useful lives:

Asset	Estimated Useful Lives
Merchant generation-nuclear	**44 years**
Merchant generation-other	**15-40 years**
Nonutility gas gathering and processing	**3-50 years**
General and other	**5-59 years**

Depreciation and amortization related to Virginia Power's and Dominion Energy Gas' nonutility property, plant and equipment and exploration and production properties was immaterial for the years ended December 31, 2017, 2016 and 2015, except for Dominion Energy Gas' nonutility gas gathering and processing properties which are depreciated using the straight-line method over estimated useful lives between 10 and 50 years.

Nuclear fuel used in electric generation is amortized over its estimated service life on a units-of-production basis. Dominion Energy and Virginia Power report the amortization of nuclear fuel in electric fuel and other energy-related purchases expense in their Consolidated Statements of Income and in depreciation and amortization in their Consolidated Statements of Cash Flows.

Long-Lived and Intangible Assets

The Companies perform an evaluation for impairment whenever events or changes in circumstances indicate that the carrying amount of long-lived assets or intangible assets with finite lives may not be recoverable. A long-lived or intangible asset is written down to fair value if the sum of its expected future undiscounted cash flows is less than its carrying amount. Intangible assets with finite lives are amortized over their estimated useful lives.

Regulatory Assets and Liabilities

The accounting for Dominion Energy's and Dominion Energy Gas' regulated gas and Virginia Power's regulated electric operations differs from the accounting for nonregulated operations in that they are required to reflect the effect of rate regulation in their Consolidated Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, these costs that otherwise would be expensed by nonregulated companies are deferred as regulatory assets. Likewise, regulatory liabilities are recognized when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator.

The Companies evaluate whether or not recovery of their regulatory assets through future rates is probable and make various assumptions in their analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions, legislation or historical experience, as well as discussions with applicable regulatory authorities and legal counsel. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made.

Asset Retirement Obligations

The Companies recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed, for which a legal obligation exists. These amounts are generally capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, fair value is estimated using discounted cash flow analyses. Quarterly, the Companies assess their AROs to determine if circumstances indicate that estimates of the amounts or timing of future cash flows associated with retirement activities have changed. AROs are adjusted when significant changes in the amounts or timing of future cash flows are identified. Dominion Energy and Dominion Energy Gas report accretion of AROs and depreciation on asset retirement costs associated with their natural gas pipeline and storage well assets as an adjustment to the related regulatory liabilities when revenue is recoverable from customers for AROs. Virginia Power reports accretion of AROs and depreciation on asset retirement costs associated with decommissioning its nuclear power stations as an adjustment to the regulatory liability for certain jurisdictions. Additionally, Virginia Power reports accretion of AROs and depreciation on asset retirement costs associated with certain rider and prospective rider projects as an adjustment to the regulatory asset for certain jurisdictions. Accretion of all other AROs and depreciation of all other asset retirement costs are reported in other operations and maintenance expense and depreciation expense, respectively, in the Consolidated Statements of Income.

Debt Issuance Costs

The Companies defer and amortize debt issuance costs and debt premiums or discounts over the expected lives of the respective debt issues, considering maturity dates and, if applicable, redemption rights held by others. Deferred debt issuance costs are recorded as a reduction in long-term debt in the Consolidated Balance Sheets. Amortization of the issuance costs is reported as interest expense. Unamortized costs associated with redemptions of debt securities prior to stated maturity dates are generally recognized and recorded in interest expense immediately. As permitted by regulatory authorities, gains or losses resulting from the refinancing of debt allocable to utility operations subject to cost-based rate regulation are deferred and amortized over the lives of the new issuances.

Investments

MARKETABLE EQUITY AND DEBT SECURITIES

Dominion Energy accounts for and classifies investments in marketable equity and debt securities as trading or available-for-sale securities. Virginia Power classifies investments in marketable equity and debt securities as available-for-sale securities.

- *Trading securities* include marketable equity and debt securities held by Dominion Energy in rabbi trusts associated with certain deferred compensation plans. These securities are reported in other investments in the Consolidated Balance Sheets at fair value with net realized and unrealized gains and losses included in other income in the Consolidated Statements of Income.
- *Available-for-sale securities* include all other marketable equity and debt securities, primarily comprised of securities held in the nuclear decommissioning trusts. These investments are reported at fair value in nuclear decommissioning trust funds in the Consolidated Balance Sheets. Net realized and unrealized gains and losses (including any other-than-temporary impairments) on investments held in Virginia Power's nuclear decommissioning trusts are recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. For all other available-for-sale securities, including those held in Dominion Energy's merchant generation nuclear decommissioning trusts, net realized gains and losses (including any other-than-temporary impairments) are included in other income and unrealized gains and losses are reported as a component of AOCI, after-tax.

In determining realized gains and losses for marketable equity and debt securities, the cost basis of the security is based on the specific identification method.

NON-MARKETABLE INVESTMENTS

The Companies account for illiquid and privately held securities for which market prices or quotations are not readily available under either the equity or cost method. Non-marketable investments include:

- *Equity method investments* when the Companies have the ability to exercise significant influence, but not control, over the investee. Dominion Energy's investments are included in investments in equity method affiliates and Virginia Power's investments are included in other investments in their Consolidated Balance Sheets. The Companies record equity method adjustments in other income in the Consolidated Statements of Income including: their proportionate share of investee income or loss, gains or losses resulting from investee capital transactions, amortization of certain differences between the carrying value and the equity in the net assets of the investee at the date of investment and other adjustments required by the equity method.
- *Cost method investments* when Dominion Energy and Virginia Power do not have the ability to exercise significant influence over the investee. Dominion Energy's and Virginia Power's investments are included in other investments and nuclear decommissioning trust funds.

OTHER-THAN-TEMPORARY IMPAIRMENT

The Companies periodically review their investments to determine whether a decline in fair value should be considered other-than-temporary. If a decline in fair value of any security is determined to be other-than-temporary, the security is written down to its fair value at the end of the reporting period.

Decommissioning Trust Investments—Special Considerations

- The recognition provisions of the FASB's other-than-temporary impairment guidance apply only to debt securities classified as available-for-sale or held-to-maturity, while the presentation and disclosure requirements apply to both debt and equity securities.
- *Debt Securities*—Using information obtained from their nuclear decommissioning trust fixed-income investment managers, Dominion Energy and Virginia Power record in earnings any unrealized loss for a debt security when the manager intends to sell the debt security or it is more-likely-than-not that the manager will have to sell the debt security before recovery of its fair value up to its cost basis. If that is not the case, but the debt security is deemed to have experienced a credit loss, Dominion Energy and Virginia Power record the credit loss in earnings and any remaining portion of the unrealized loss in AOCI. Credit losses are evaluated primarily by considering the credit ratings of the issuer, prior instances of non-performance by the issuer and other factors.
- *Equity securities and other investments*—Dominion Energy's and Virginia Power's method of assessing other-than-temporary declines requires demonstrating the ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value prior to the consideration of the other criteria mentioned above. Since Dominion Energy and Virginia Power have limited ability to oversee the day-to-day management of nuclear decommissioning trust fund investments, they do not have the ability to ensure investments are held through an anticipated recovery period. Accordingly, they consider all equity and other securities as well as non-marketable investments held in nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired.

Inventories

Materials and supplies and fossil fuel inventories are valued primarily using the weighted-average cost method. Stored gas inventory is valued using the weighted-average cost method, except for East Ohio gas distribution operations, which are valued using the LIFO method. Under the LIFO method, current stored gas inventory was valued at $9 million and $13 million at December 31, 2017 and December 31, 2016, respectively. Based on the average price of gas purchased during 2017 and 2016, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by $79 million and $55 million, respectively.

Gas Imbalances

Natural gas imbalances occur when the physical amount of natural gas delivered from, or received by, a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. Dominion Energy and Dominion Energy Gas value these imbalances due to, or from, shippers and operators at an appropriate index price at period end, subject to the terms of its tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to Dominion Energy from other parties are reported in other current assets and imbalances that Dominion Energy and Dominion Energy Gas owe to other parties are reported in other current liabilities in the Consolidated Balance Sheets.

Goodwill

Dominion Energy and Dominion Energy Gas evaluate goodwill for impairment annually as of April 1 and whenever an event occurs or circumstances change in the interim that would more-likely-than-not reduce the fair value of a reporting unit below its carrying amount.

New Accounting Standards

REVENUE RECOGNITION

In May 2014, the FASB issued revised accounting guidance for revenue recognition from contracts with customers. The core principle of this revised accounting guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this update also require disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For the Companies, the revised accounting guidance is effective for interim and annual periods beginning January 1, 2018. The Companies have completed their evaluations of the impact of this guidance and expect no significant impact on their results of operations. However, the Companies will have offsetting increases in operating revenues and other energy-related purchases for noncash consideration related to NGLs received in consideration for performing processing and fractionation services and offsetting decreases in operating revenues and purchased gas for fuel retained to offset costs on certain transportation and storage arrangements. The Companies will apply the standard using the modified retrospective method as opposed to the full retrospective method.

Financial Instruments

In January 2016, the FASB issued revised accounting guidance for the recognition, measurement, presentation and disclosure of financial instruments. In accordance with the guidance effective January 2018, Dominion Energy and Virginia Power will no longer classify equity securities as trading or available-for-sale securities. All equity securities with a readily determinable fair value, or for which it is permitted to estimate fair value using NAV (or its equivalent), including those held in Dominion Energy's and Virginia Power's nuclear decommissioning trusts and Dominion Energy's rabbi trusts, will be reported at fair value in nuclear decommissioning trust funds and other investments, respectively, in the Consolidated Balance Sheets. However, Dominion Energy and Virginia Power may elect a measurement alternative for equity securities without a readily determinable fair value. Under the measurement alternative, equity securities will be reported at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or a similar investment of the same issuer. Net realized and unrealized gains and losses on equity securities held in Virginia Power's nuclear decommissioning trusts will be recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. For all other equity securities, including those held in Dominion Energy's merchant generation nuclear decommissioning trusts and rabbi trusts, net realized and unrealized gains and losses will be included in other income. Dominion Energy and Virginia Power will qualitatively assess equity securities reported using the measurement alternative to evaluate whether the investment is impaired on an ongoing basis.

Upon adoption of this guidance for equity securities held at January 1, 2018, Dominion Energy and Virginia Power recorded the cumulative-effect of a change in accounting principle to reclassify net unrealized gains from AOCI to retained earnings and to recognize equity securities previously categorized as cost method investments at fair value in nuclear decommissioning trust funds in the Consolidated Balance Sheets and a cumulative-effect adjustment to retained earnings. Dominion Energy and Virginia Power reclassified approximately \$1.1 billion (\$734 million after-tax) and \$119 million (\$73 million after-tax), respectively, of net unrealized gains from AOCI to retained earnings. Dominion Energy and Virginia Power also recorded approximately \$36 million (\$22 million after-tax) in net unrealized gains on equity securities previously classified as cost method investments of which \$4 million was recorded to retained earnings and \$32 million was recorded to regulatory liabilities for net unrealized gains subject to cost-based regulation. The potential impact to the Consolidated Statements of Income is subject to investment price risk and is therefore difficult to reasonably estimate. If this guidance had been effective January 1, 2017, Dominion Energy and Virginia Power would have recorded net unrealized gains of approximately \$275 million (\$176 million after-tax) and \$30 million (\$19 million after-tax), respectively, to other income in the Consolidated Statements of Income.

Leases

In February 2016, the FASB issued revised accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. The update requires that a liability and corresponding right-of-use asset are recorded on the balance sheet for all leases, including those leases currently classified as operating leases, while also refining the definition of a lease. In addition lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. Lessor accounting remains largely unchanged.

The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented for leases that commenced prior to the date of adoption. The Companies plan to elect the proposed transition expedient which would allow the Companies to maintain historical presentation for periods before January 1, 2019. The Companies expect to elect the other practical expedients, which would require no reassessment of whether existing contracts are or contain leases and no reassessment of lease classification for existing leases. The Companies have completed a preliminary assessment for evaluating the impact of this guidance and anticipate that its adoption will result in a significant amount of offsetting right-of-use assets and liabilities on their financial position for leases in effect at the adoption date. No material changes are expected on the Companies' results of operations. The Companies are beginning implementation activities that primarily include accumulating contracts and lease data points in formats compatible with a new lease management system that will assist with the initial adoption and on-going compliance with the standard.

Definition of a Business

In January 2017, the FASB issued revised accounting guidance to clarify the definition of a business. The revised guidance affects the evaluation of whether a transaction should be accounted for as an acquisition or disposition of an asset or a business, which may impact goodwill and related financial statement disclosures. The Companies have adopted this guidance on a prospective basis effective October 1, 2017. The adoption of the pronouncement will result in additional transactions being accounted for as asset acquisitions or dispositions.

Derecognition and Partial Sales of Nonfinancial Assets

In February 2017, the FASB issued revised accounting guidance clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2018, and the Companies have elected to apply the standard using the modified retrospective method. Upon adoption of the standard on January 1, 2018, Dominion Energy recorded the cumulative-effect of a change in accounting principle to reclassify $127 million from noncontrolling interests to common stock related to the sale of a noncontrolling interest in certain merchant solar projects completed in December 2015 and January 2016.

Net Periodic Pension and Other Postretirement Benefit Costs

In March 2017, the FASB issued revised accounting guidance for the presentation of net periodic pension and other postretirement benefit costs. The update requires that the service cost component of net periodic pension and other postretirement benefit costs be classified in the same line item as other compensation costs arising from services rendered by employees, while all other components of net periodic pension and other postretirement benefit costs would be classified outside of income from operations. In addition, only the service cost component will be eligible for capitalization during construction. However, these changes will not impact the accounting by participants in a multi-employer plan. The standard also recognized that in the event that a regulator continues to require capitalization of all net periodic benefit costs prospectively, the difference would result in recognition of a regulatory asset or liability. The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2018, with a retrospective adoption for income statement presentation and a prospective adoption for capitalization. For costs not capitalized for which regulators are expected to provide recovery, a regulatory asset will be established. As such, the amounts eligible for capitalization in the Consolidated Financial Statements of Virginia Power and Dominion Energy Gas, as subsidiary participants in Dominion Energy's multi-employer plans will differ from the amounts eligible for capitalization in the Consolidated Financial Statements of Dominion Energy, the plan administrator. These differences will result in a regulatory asset or liability recorded in the Consolidated Financial Statements of Dominion Energy.

Tax Reform

In December 2017, the staff of the SEC issued guidance which clarifies accounting for income taxes if information is not yet available or complete and provides for up to a one-year measurement period in which to complete the required analyses and accounting. The guidance describes three scenarios associated with a company's status of accounting for income tax reform: (1) a company is complete with its accounting for certain effects of tax reform, (2) a company is able to determine a reasonable estimate for certain effects of tax reform and records that estimate as a provisional amount, or (3) a company is not able to determine a reasonable estimate and therefore continues to apply accounting for income taxes based on the provisions of the tax laws that were in effect immediately prior to the 2017 Tax Reform Act being enacted. In addition, the guidance provides clarification related to disclosures for entities which are utilizing the measurement period. The Companies have recorded their best estimate of the impacts of the 2017 Tax Reform Act as discussed above and in Note 5. The amounts are considered to be provisional and may result in adjustments to be recognized during the measurement period.

In February 2018, the FASB issued revised accounting guidance to provide clarification on the application of the 2017 Tax Reform Act for balances recorded within AOCI. The revised guidance provides for stranded amounts within AOCI from the impacts of the 2017 Tax Reform Act to be reclassified to retained earnings. The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2019, with early adoption permitted, and may be applied prospectively or retrospectively upon adoption. If the Companies had adopted this guidance for the period ended December 31, 2017, Dominion Energy would have reclassified a benefit of $165 million from AOCI to retained earnings, Dominion Energy Gas would have reclassified a benefit of $26 million from AOCI to membership interests and Virginia Power would have reclassified an expense of $13 million from AOCI to retained earnings.

Note 3. Acquisitions and Dispositions

Dominion Energy

Proposed Acquisition of SCANA

Under the terms of the SCANA Merger Agreement announced in January 2018, Dominion Energy has agreed to issue 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock upon closing. In addition, Dominion Energy will provide the financial support for SCE&G to make a $1.3 billion up-front, one-time rate credit to all current electric service customers of SCE&G to be paid within 90 days of closing and a $575 million refund along with the benefit of the 2017 Tax Reform Act resulting in at least a 5% reduction to SCE&G electric service customers' bills over an eight-year period as well as the exclusions from rate recovery of approximately $1.7 billion of costs related to the V.C. Summer Units 2 and 3 new nuclear development project and approximately $180 million to purchase the Columbia Energy Center power station. In addition, SCANA's debt, which currently totals approximately $7.0 billion, is expected to remain outstanding.

The transaction requires approval of SCANA's shareholders, FERC and the NRC and clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act. In February 2018, the Federal Trade Commission granted early termination of the waiting period under the Hart-Scott-Rodino Act. In January 2018, SCANA and Dominion Energy filed for review and approval, as required, from the South Carolina Commission, the North Carolina Commission, the Georgia Public Service Commission and the NRC. Dominion Energy is not required to accept an order by the South Carolina Commission approving Dominion Energy's merger with SCANA if such order contains any material change to the terms, conditions or undertakings set forth in the cost recovery plan related to the V.C. Summer Units 2 and 3 new nuclear development project or any significant changes to the economic value of the cost recovery plan. In addition, the SCANA Merger Agreement provides that Dominion Energy will have the right to refuse to close the merger if there shall have occurred any substantive change in the Base Load Review Act or other laws governing South Carolina public utilities which has or would reasonably be expected to have an adverse effect on SCE&G. The SCANA Merger Agreement contains certain termination rights for both Dominion Energy and SCANA, and provides that, upon termination of the SCANA Combination under specified circumstances, Dominion Energy would be required to pay a termination fee of $280 million to SCANA and SCANA would be required to pay Dominion Energy a termination fee of $240 million. Subject to receipt of SCANA shareholder and any required regulatory approvals and meeting closing conditions, Dominion Energy targets closing by the end of 2018.

Acquisition of Dominion Energy Questar

In September 2016, Dominion Energy completed the Dominion Energy Questar Combination and Dominion Energy Questar, a Rockies-based integrated natural gas company, became a wholly-owned subsidiary of Dominion Energy. Dominion Energy Questar included Questar Gas, Wexpro and Dominion Energy Questar Pipeline at closing. Questar Gas has regulated gas distribution operations in Utah, southwestern Wyoming and southeastern Idaho. Wexpro develops and produces natural gas from reserves supplied to Questar Gas under a cost-of-service framework. Dominion Energy Questar Pipeline provides FERC-regulated interstate natural gas transportation and storage services in Utah, Wyoming and western Colorado. The Dominion Energy Questar Combination provides Dominion Energy with pipeline infrastructure that provides a principal source of gas supply to Western states. Dominion Energy Questar's regulated businesses also provide further balance between Dominion Energy's electric and gas operations.

In accordance with the terms of the Dominion Energy Questar Combination, at closing, each share of issued and outstanding Dominion Energy Questar common stock was converted into the right to receive $25.00 per share in cash. The total consideration was $4.4 billion based on 175.5 million shares of Dominion Energy Questar outstanding at closing.

Dominion Energy financed the Dominion Energy Questar Combination through the: (1) August 2016 issuance of $1.4 billion of 2016 Equity Units, (2) August 2016 issuance of $1.3 billion of senior notes, (3) September 2016 borrowing of $1.2 billion under a term loan agreement and (4) $500 million of the proceeds from the April 2016 issuance of common stock. See Notes 17 and 19 for more information.

PURCHASE PRICE ALLOCATION

Dominion Energy Questar's assets acquired and liabilities assumed were measured at estimated fair value at the closing date and are included in the Gas Infrastructure operating segment. The majority of operations acquired are subject to the rate-setting authority of FERC, as well as the Utah Commission and/or the Wyoming Commission and therefore are accounted for pursuant to ASC 980, *Regulated Operations*. The fair values of Dominion Energy Questar's assets and liabilities subject to rate-setting and cost recovery provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair values of these assets and liabilities equal their carrying values. Accordingly, neither the assets and liabilities acquired, nor the pro forma financial information, reflect any adjustments related to these amounts.

The fair value of Dominion Energy Questar's assets acquired and liabilities assumed that are not subject to the rate-setting provisions discussed above was determined using the income approach. In addition, the fair value of Dominion Energy Questar's 50% interest in White River Hub, accounted for under the equity method, was determined using the market approach and income approach. The valuations are considered Level 3 fair value measurements due to the use of significant judgmental and unobservable inputs, including projected timing and amount of future cash flows and discount rates reflecting risk inherent in the future cash flows and future market prices.

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill at the closing date. The goodwill reflects the value associated with enhancing Dominion Energy's regulated portfolio of businesses, including the expected increase in demand for low-carbon, natural gas-fired generation in the Western states and the expected continued growth of rate-regulated businesses located in a defined service area with a stable regulatory environment. The goodwill recognized is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to goodwill.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at closing which reflects the following adjustments from the preliminary valuation recognized during the measurement period. During the fourth quarter of 2016, certain modifications were made to preliminary valuation amounts for acquired property, plant and equipment, current liabilities, and deferred income taxes, resulting in a $6 million net decrease to goodwill, which related primarily to the sale of Questar Fueling Company in December 2016 as further described in the *Sale of Questar Fueling Company*. In the third quarter of 2017, certain modifications were made to the valuation amounts for regulatory liabilities, current liabilities and deferred income taxes, resulting in a $6 million net increase to goodwill recorded in Dominion Energy's Consolidated Balance Sheets. The modifications relate primarily to the finalization of Dominion Energy Questar's 2016 tax return for the period January 1, 2016 through the Dominion Energy Questar Combination, as well as certain regulatory adjustments.

(millions)	Amount
Total current assets	$ 224
Investments(1)	58
Property, plant and equipment(2)	4,131
Goodwill	3,111
Total deferred charges and other assets, excluding goodwill	75
Total Assets	7,599
Total current liabilities(3)	793
Long-term debt(4)	963
Deferred income taxes	807
Regulatory liabilities	259
Asset retirement obligations	160
Other deferred credits and other liabilities	220
Total Liabilities	3,202
Total purchase price	4,397

(1) Includes $40 million for an equity method investment in White River Hub. The fair value adjustment on the equity method investment in White River Hub is considered to be equity method goodwill and is not amortized.

(2) Nonregulated property, plant and equipment, excluding land, will be depreciated over remaining useful lives primarily ranging from 9 to 18 years.
(3) Includes $301 million of short-term debt, of which no amounts remain outstanding at December 31, 2017, as well as a $250 million variable interest rate term loan due in August 2017 that was paid in July 2017.
(4) Unsecured senior and medium-term notes with maturities which range from 2017 to 2048 and bear interest at rates from 2.98% to 7.20%.

REGULATORY MATTERS

The transaction required approval of Dominion Energy Questar's shareholders, clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act and approval from both the Utah Commission and the Wyoming Commission. In February 2016, the Federal Trade Commission granted antitrust approval of the Dominion Energy Questar Combination under the Hart-Scott-Rodino Act. In May 2016, Dominion Energy Questar's shareholders voted to approve the Dominion Energy Questar Combination. In August 2016 and September 2016, approvals were granted by the Utah Commission and the Wyoming Commission, respectively. Information regarding the transaction was also provided to the Idaho Commission, who acknowledged the Dominion Energy Questar Combination in October 2016, and directed Dominion Energy Questar to notify the Idaho Commission when it makes filings with the Utah Commission.

With the approval of the Dominion Energy Questar Combination in Utah and Wyoming, Dominion Energy agreed to the following:

- Contribution of $75 million to Dominion Energy Questar's qualified and non-qualified defined-benefit pension plans and its other post-employment benefit plans within six months of the closing date. This contribution was made in January 2017.
- Increasing Dominion Energy Questar's historical level of corporate contributions to charities by $1 million per year for at least five years.
- Withdrawal of Questar Gas' general rate case filed in July 2016 with the Utah Commission and agreement to not file a general rate case with the Utah Commission to adjust its base distribution non-gas rates prior to July 2019, unless otherwise ordered by the Utah Commission. In addition, Questar Gas agreed not to file a general rate case with the Wyoming Commission with a requested rate effective date earlier than January 2020. Questar Gas' ability to adjust rates through various riders is not affected.

RESULTS OF OPERATIONS AND PRO FORMA INFORMATION

The impact of the Dominion Energy Questar Combination on Dominion Energy's operating revenue and net income attributable to Dominion Energy in the Consolidated Statements of Income for the twelve months ended December 31, 2016 was an increase of $379 million and $73 million, respectively.

Dominion Energy incurred transaction and transition costs in 2017 and 2016, of which $26 million and $58 million was recorded in other operations and maintenance expense, respectively, and $16 million was recorded in interest and related charges in 2016 in Dominion Energy's Consolidated Statements of Income. These costs consist of the amortization of financing costs, the charitable contribution commitment described above, employee-related expenses, professional fees, and other miscellaneous costs.

The following unaudited pro forma financial information reflects the consolidated results of operations of Dominion Energy assuming the Dominion Energy Questar Combination had taken place on January 1, 2015. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of the combined company.

	Twelve Months Ended December 31,	
	2016(1)	2015
(millions, except EPS)		
Operating Revenue	$12,497	$12,818
Net income attributable to Dominion Energy	2,300	2,108
Earnings Per Common Share – Basic	$ 3.73	$ 3.56
Earnings Per Common Share – Diluted	$ 3.73	$ 3.55

(1) Amounts include adjustments for non-recurring costs directly related to the Dominion Energy Questar Combination.

CONTRIBUTION OF DOMINION ENERGY QUESTAR PIPELINE TO DOMINION ENERGY MIDSTREAM

In October 2016, Dominion Energy entered into the Contribution Agreement under which Dominion Energy contributed Dominion Energy Questar Pipeline to Dominion Energy Midstream. Upon closing of the agreement on December 1, 2016, Dominion Energy Midstream became the owner of all of the issued and outstanding membership interests of Dominion Energy Questar Pipeline in exchange for consideration consisting of Dominion Energy Midstream common and convertible preferred units with a combined value of $467 million and cash payment of $823 million, $300 million of which is considered a debt-financed distribution, for a total of $1.3 billion. In addition, under the terms of the Contribution Agreement, Dominion Energy Midstream repurchased 6,656,839 common units from Dominion Energy, and repaid its $301 million promissory note to Dominion Energy in December 2016. The cash proceeds from these transactions were utilized in December 2016 to repay the $1.2 billion term loan agreement borrowed in September 2016. Since Dominion Energy consolidates Dominion Energy Midstream for financial reporting purposes, the transactions associated with the Contribution Agreement were eliminated upon consolidation. See Note 5 for the tax impacts of the transactions.

SALE OF QUESTAR FUELING COMPANY

In December 2016, Dominion Energy completed the sale of Questar Fueling Company. The proceeds from the sale were $28 million, net of transaction costs. No gain or loss was recorded in Dominion Energy's Consolidated Statements of Income, as the sale resulted in measurement period adjustments to the net assets acquired of Dominion Energy Questar. See the *Purchase Price Allocation* section above for additional details on the measurement period adjustments recorded.

Combined Notes to Consolidated Financial Statements, Continued

Wholly-Owned Merchant Solar Projects

ACQUISITIONS

The following table presents significant completed acquisitions of wholly-owned merchant solar projects by Dominion Energy.

Completed Acquisition Date	Seller	Number of Projects	Project Location	Project Name(s)	Initial Acquisition (millions)(1)	Project Cost (millions)(2)	Date of Commercial Operations	MW Capacity
April 2015	EC&R NA Solar PV, LLC	1	California	Alamo	$ 66	$ 66	May 2015	20
April 2015	EDF Renewable Development, Inc.	3	California	Cottonwood(3)	106	106	May 2015	24
June 2015	EDF Renewable Development, Inc.	1	California	Catalina 2	68	68	July 2015	18
July 2015	SunPeak Solar, LLC	1	California	Imperial Valley 2	42	71	August 2015	20
November 2015	EC&R NA Solar PV, LLC	1	California	Maricopa West	65	65	December 2015	20
November 2015	Community Energy Solar, LLC	1	Virginia	Amazon Solar Farm U.S East	34	212	October 2016	80
February 2017	Community Energy Solar, LLC	1	Virginia	Amazon Solar Farm Virginia—Southampton	29	205	December 2017	100
March 2017	Solar Frontier Americas Holding LLC	1(4)	California	Midway II	77	78	June 2017	30
May 2017	Cypress Creek Renewables, LLC	1	North Carolina	IS37	154	160	June 2017	79
June 2017	Hecate Energy Virginia C&C LLC	1	Virginia	Clarke County	16	16	August 2017	10
June 2017	Strata Solar Development, LLC/Moorings Farm 2 Holdco, LLC	2	North Carolina	Fremont, Moorings 2	20	20	November 2017	10
September 2017	Hecate Energy Virginia C&C LLC	1	Virginia	Cherrydale	40	41	November 2017	20
October 2017	Strata Solar Development, LLC	2	North Carolina	Clipperton, Pikeville	20	21	November 2017	10

(1) The purchase price was primarily allocated to Property, Plant and Equipment.
(2) Includes acquisition cost.
(3) One of the projects, Marin Carport, began commercial operations in 2016.
(4) In April 2017, Dominion Energy discontinued efforts on the acquisition of the additional 20 MW solar project from Solar Frontier Americas Holding LLC.

In addition during 2016, Dominion Energy acquired 100% of the equity interests of seven solar projects in Virginia, North Carolina and South Carolina for an aggregate purchase price of $32 million, all of which was allocated to property, plant and equipment. The projects cost $421 million in total, including initial acquisition costs, and generate 221 MW combined. One of the projects commenced commercial operations in 2016 and the remaining projects commenced commercial operations in 2017.

Long-term power purchase, interconnection and operation and maintenance agreements have been executed for all of the projects described above. These projects are included in the Power Generation operating segment. Dominion Energy has claimed or will claim federal investment tax credits on these solar projects.

SALE OF INTEREST IN MERCHANT SOLAR PROJECTS

In September 2015, Dominion Energy signed an agreement to sell a noncontrolling interest (consisting of 33% of the equity interests) in all of its then-currently wholly-owned merchant solar projects, 24 solar projects totaling 425 MW, to SunEdison, including certain projects in the table above. In December 2015, the sale of interest in 15 of the solar projects closed for $184 million with the sale of interest in the remaining projects completed in January 2016 for $117 million. Upon closing, SunEdison sold its interest in these projects to Terra Nova Renewable Partners. Terra Nova Renewable Partners has a future option to buy all or a portion of Dominion Energy's remaining 67% ownership in the projects upon the occurrence of certain events, none of which are expected to occur in 2018.

Non-Wholly-Owned Merchant Solar Projects

ACQUISITIONS OF FOUR BROTHERS AND THREE CEDARS

In June 2015, Dominion Energy acquired 50% of the units in Four Brothers from SunEdison for $64 million of consideration, consisting of $2 million in cash and a $62 million payable. Dominion Energy had no remaining obligation related to this payable at December 31, 2016. Four Brothers operates four solar projects located in Utah, which produce and sell electricity and renewable energy credits. The facilities began commercial operations during the third quarter of 2016, generating 320 MW, at a cost of approximately $670 million.

In September 2015, Dominion Energy acquired 50% of the units in Three Cedars from SunEdison for $43 million of consideration, consisting of $6 million in cash and a $37 million payable. There was a $2 million payable included in other current liabilities in Dominion Energy's Consolidated Balance Sheets at December 31, 2016. Dominion has no remaining obligation related to this payable at December 31, 2017. Three Cedars operates three solar projects located in Utah, which produce and sell electricity and renewable energy credits. The facilities began commercial operations during the third quarter of 2016, generating 210 MW, at a cost of approximately $450 million.

The Four Brothers and Three Cedars facilities operate under long-term power purchase, interconnection and operation and maintenance agreements. Dominion Energy claimed 99% of the federal investment tax credits on the projects.

Dominion Energy owns 50% of the voting interests in Four Brothers and Three Cedars and has a controlling financial interest over the entities through its rights to control operations. The allocation of the $64 million purchase price for Four Brothers resulted in $89 million of property, plant and equipment and $25 million of noncontrolling interest. The allocation of the $43 million purchase price for Three Cedars resulted in $65 million of property, plant and equipment and $22 million of noncontrolling interest. The noncontrolling interest for each entity was measured at fair value using the discounted cash flow method, with the primary components of the valuation being future cash flows (both incoming and outgoing) and the discount rate. Dominion Energy determined its discount rate based on the cost of capital a utility-scale investor would expect, as well as the cost of capital an individual project developer could achieve via a combination of nonrecourse project financing and outside equity partners. The acquired assets of Four Brothers and Three Cedars are included in the Power Generation operating segment.

Dominion Energy has assumed the majority of the agreements to provide administrative and support services in connection with operations and maintenance of the facilities and technical management services of the solar facilities. Costs related to services to be provided under these agreements were immaterial for the years ended December 31, 2017, 2016 and 2015.

In November 2016, NRG acquired the 50% of units in Four Brothers and Three Cedars previously held by SunEdison. Subsequent to Dominion Energy's acquisition of Four Brothers and Three Cedars, SunEdison and NRG made contributions to Four Brothers and Three Cedars of $301 million in aggregate through December 31, 2017, which are reflected as noncontrolling interests in the Consolidated Balance Sheets.

Dominion Energy Midstream Acquisition of Interest in Iroquois

In September 2015, Dominion Energy Midstream acquired from NG and NJNR a 25.93% noncontrolling partnership interest in Iroquois, which owns and operates a 416-mile, FERC-regulated natural gas transmission pipeline in New York and Connecticut. In exchange for this partnership interest, Dominion Energy Midstream issued 8.6 million common units representing limited partnership interests in Dominion Energy Midstream (6.8 million common units to NG for its 20.4% interest and 1.8 million common units to NJNR for its 5.53% interest). The investment was recorded at $216 million based on the value of Dominion Energy Midstream's common units at closing. These common units are reflected as noncontrolling interest in Dominion Energy's Consolidated Financial Statements. Dominion Energy Midstream's noncontrolling partnership interest is reflected in the Gas Infrastructure operating segment. In addition to this acquisition, Dominion Energy Gas currently holds a 24.07% noncontrolling partnership interest in Iroquois. Dominion Energy Midstream and Dominion Energy Gas each account for their interest in Iroquois as an equity method investment. See Notes 9 and 15 for more information regarding Iroquois.

Acquisition of DECG

In January 2015, Dominion Energy completed the acquisition of 100% of the equity interests of DECG from SCANA for $497 million in cash, as adjusted for working capital. DECG owns and operates nearly 1,500 miles of FERC-regulated interstate natural gas pipeline in South Carolina and southeastern Georgia. This acquisition supports Dominion Energy's natural gas expansion into the southeastern U.S. The allocation of the purchase price resulted in $277 million of net property, plant and equipment, $250 million of goodwill, of which approximately $225 million is expected to be deductible for income tax purposes, and $38 million of regulatory liabilities. The goodwill reflects the value associated with enhancing Dominion Energy's regulated gas position, economic value attributable to future expansion projects as well as increased opportunities for synergies. The acquired assets of DECG are included in the Gas Infrastructure operating segment.

On March 24, 2015, DECG converted to a limited liability company under the laws of South Carolina and changed its name from Carolina Gas Transmission Corporation to DECG. On April 1, 2015, Dominion Energy contributed 100% of the issued and outstanding membership interests of DECG to Dominion Energy Midstream in exchange for total consideration of $501 million, as adjusted for working capital. Total consideration to Dominion Energy consisted of the issuance of a two-year, $301 million senior unsecured promissory note payable by Dominion Energy Midstream at an annual interest rate of 0.6%, and 5,112,139 common units, valued at $200 million, representing limited partner interests in Dominion Energy Midstream. The number of units was based on the volume weighted average trading price of Dominion Energy Midstream's common units for the ten trading days prior to April 1, 2015, or $39.12 per unit. Since Dominion Energy consolidates Dominion Energy Midstream for financial reporting purposes, this transaction was eliminated upon consolidation and did not impact Dominion Energy's financial position or cash flows.

VIRGINIA POWER

Acquisition of Solar Projects

In December 2015, Virginia Power completed the acquisition of 100% of a solar development project in North Carolina from Morgans Corner for $47 million, all of which was allocated to property, plant and equipment. The project was placed into service in December 2015 with a total cost of $49 million, including the initial acquisition cost. The project generates 20 MW. The output generated by the project is used to meet a ten-year non-jurisdictional supply agreement with the U.S. Navy, which has the unilateral option to extend for an additional ten years. In October 2015, the North Carolina Commission granted the transfer of the existing CPCN from Morgans Corner to Virginia Power. The acquired asset is included in the Power Generation operating segment.

DOMINION ENERGY AND DOMINION ENERGY GAS

Blue Racer

See Note 9 for a discussion of transactions related to Blue Racer.

NOTE 4. OPERATING REVENUE

The Companies' operating revenue consists of the following:

Year Ended December 31, (millions)	2017	2016	2015
Dominion Energy			
Electric sales:			
Regulated	$ 7,383	$ 7,348	$ 7,482
Nonregulated	1,429	1,519	1,488
Gas sales:			
Regulated	1,067	500	218
Nonregulated	457	354	471
Gas transportation and storage	1,786	1,636	1,616
Other	464	380	408
Total operating revenue	$12,586	$11,737	$11,683
Virginia Power			
Regulated electric sales	$ 7,383	$ 7,348	$ 7,482
Other	173	240	140
Total operating revenue	$ 7,556	$ 7,588	$ 7,622
Dominion Energy Gas			
Gas sales:			
Regulated	$ 87	$ 119	$ 122
Nonregulated	20	13	10
Gas transportation and storage	1,435	1,307	1,366
NGL revenue	91	62	93
Other	181	137	125
Total operating revenue	$ 1,814	$ 1,638	$ 1,716

NOTE 5. INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently. The Companies are routinely audited by federal and state tax authorities. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

The 2017 Tax Reform Act includes a broad range of tax reform provisions affecting the Companies as discussed in Note 2. The 2017 Tax Reform Act reduces the corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017. At the date of enactment, deferred tax assets and liabilities were remeasured based upon the new 21% enacted tax rate expected to apply when temporary differences are realized or settled. The specific provisions related to regulated public utilities in the 2017 Tax Reform Act generally allows for the continued deductibility of interest expense, changes the tax depreciation of certain property acquired after September 27, 2017, and continues certain rate normalization requirements for accelerated depreciation benefits.

In December 2015, U.S. federal legislation was enacted, providing an extension of the 50% bonus depreciation allowance for qualifying expenditures incurred in 2015, 2016 and 2017. In addition, the legislation extended the 30% investment tax credit for qualifying expenditures incurred through 2019 and provides a phase down of the credit to 26% in 2020, 22% in 2021 and 10% in 2022 and thereafter.

As indicated in Note 2, certain of the Companies' operations, including accounting for income taxes, is subject to regulatory accounting treatment. For regulated operations, many of the changes in deferred taxes represent amounts probable of collection from or refund to customers, and are recorded as either an increase to a regulatory asset or liability. The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes may be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred taxes may be determined by state and federal regulators. See Note 13 for more information.

The Companies have completed or have made a reasonable estimate for the measurement and accounting of certain effects of the 2017 Tax Reform Act which have been reflected in the Consolidated Financial Statements. The changes in deferred taxes were recorded as either an increase to a regulatory liability or as an adjustment to the deferred tax provision.

The items reflected as provisional amounts are related to accelerated depreciation for tax purposes of certain property acquired and placed into service after September 27, 2017 and the impact of accelerated depreciation on state income taxes to the extent there is uncertainty on conformity to the new federal tax system.

The determination of the income tax effects of the items reflected as provisional amounts represents a reasonable estimate, but will require additional analysis of historical records and further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Department of Treasury regulations, which will require more time, information and resources than currently available to the Companies.

Continuing Operations

Details of income tax expense for continuing operations including noncontrolling interests were as follows:

	Dominion Energy			Virginia Power			Dominion Energy Gas		
Year Ended December 31, (millions)	2017	2016	2015	2017	2016	2015	2017	2016	2015
Current:									
Federal	$ (1)	$ (155)	$ (24)	$432	$168	$316	$ 16	$ (27)	$ 90
State	(26)	85	75	73	90	92	8	4	30
Total current expense (benefit)	(27)	(70)	51	505	258	408	24	(23)	120
Deferred:									
Federal									
2017 Tax Reform Act impact	(851)	—	—	(93)	—	—	(197)	—	—
Taxes before operating loss carryforwards and investment tax credits	739	1,050	384	319	435	154	199	239	156
Tax utilization expense (benefit) of operating loss carryforwards	174	(161)	539	4	(2)	96	5	(2)	6
Investment tax credits	(200)	(248)	(134)	(23)	(25)	(11)	—	—	—
State	132	50	66	59	27	13	20	1	1
Total deferred expense (benefit)	(6)	691	855	266	435	252	27	238	163
Investment tax credit-gross deferral	5	35	—	5	35	—	—	—	—
Investment tax credit-amortization	(2)	(1)	(1)	(2)	(1)	(1)	—	—	—
Total income tax expense (benefit)	$ (30)	$ 655	$ 905	$774	$727	$659	$ 51	$215	$283

The accounting for the reduction in the corporate income tax rate decreased deferred income tax expense by $851 million at Dominion Energy, $93 million at Virginia Power, and $197 million for Dominion Energy Gas for the year ending December 31, 2017. The decrease in deferred income taxes at Dominion Energy primarily relates to the remeasurement of deferred taxes on merchant operations and includes the effects at Virginia Power and Dominion Energy Gas. Virginia Power and Dominion Energy Gas have certain regulatory assets and liabilities that have not yet been charged or returned to customers through rates, or on which they do not earn a return, including unrecognized pension and other postretirement benefits. The remeasurement of the deferred taxes on these regulatory balances was charged to continuing operations in 2017. For ratemaking purposes, Dominion Energy Gas' subsidiary DETI follows the cash method on pension contributions. Deferred taxes recorded on pension balances as required by GAAP are not included as a component of rates and therefore the remeasurement of these deferred taxes were charged to continuing operations in 2017.

In 2016, Dominion Energy realized a taxable gain resulting from the contribution of Dominion Energy Questar Pipeline to Dominion Energy Midstream. The contribution and related transactions resulted in increases in the tax basis of Dominion Energy Questar Pipeline's assets and the number of Dominion Energy Midstream's common and convertible preferred units held by noncontrolling interests. The direct tax effects of the transactions included a provision for current income taxes ($212 million) and an offsetting benefit for deferred income taxes ($96 million) and were charged to common shareholders' equity. The federal tax liability was reduced by $129 million of tax credits generated in 2016 that otherwise would have resulted in additional credit carryforwards and a $17 million benefit provided by the domestic production activities deduction. These benefits, as indirect effects of the contribution transaction, were reflected in Dominion Energy's 2016 current federal income tax expense.

In 2015, Dominion Energy's current federal income tax benefit includes the recognition of a $20 million benefit related to a carryback to be filed for nuclear decommissioning expenditures included in its 2014 net operating loss.

For continuing operations including noncontrolling interests, the statutory U.S. federal income tax rate reconciles to the Companies' effective income tax rate as follows:

	Dominion Energy			Virginia Power			Dominion Energy Gas		
Year Ended December 31,	2017	2016	2015	2017	2016	2015	2017	2016	2015
U.S. statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increases (reductions) resulting from:									
State taxes, net of federal benefit	2.0	2.4	3.7	3.7	3.8	3.9	2.4	0.5	2.7
Investment tax credits	(6.3)	(11.7)	(4.7)	(0.8)	—	(0.6)	—	—	—
Production tax credits	(0.7)	(0.8)	(0.8)	(0.4)	(0.5)	(0.6)	—	—	—
Valuation allowances	0.2	1.2	(0.3)	—	0.1	—	0.3	—	—
Federal legislative change	(27.5)	—	—	(4.0)	—	—	(29.5)	—	—
State legislative change	—	(0.6)	(0.1)	—	—	—	—	—	—
AFUDC—equity	(1.4)	(0.6)	(0.3)	(0.6)	(0.6)	(0.6)	(0.9)	(0.2)	0.2
Employee stock ownership plan deduction	(0.6)	(0.6)	(0.6)	—	—	—	—	—	—
Other, net	(1.7)	(1.4)	0.1	0.6	(0.4)	0.6	0.4	0.1	0.3
Effective tax rate	(1.0)%	22.9%	32.0%	33.5%	37.4%	37.7%	7.7%	35.4%	38.2%

In 2017, the Companies' effective tax rates reflect the net benefit of remeasurement of deferred taxes resulting from the lower corporate income tax rate promulgated by the 2017 Tax Reform Act, and the completion of audits by state tax authorities that resulted in the recognition of previously unrecognized tax benefits. At December 31, 2016, Virginia Power's unrecognized tax benefits included state refund claims for open tax years through 2011. Management believed settlement of the claims, including interest thereon, within the next twelve months was remote. In June 2017, Virginia Power received and accepted a cash offer to settle the refund claims. As a result of the settlement, Virginia Power decreased its unrecognized tax benefits by $8 million, and recognized a $2 million tax benefit, which impacted its effective tax rate. Also in connection with this settlement, Virginia Power realized interest income of $11 million, which is reflected in other income in the Consolidated Statements of Income.

In 2016, Dominion Energy's effective tax rate reflects a valuation allowance on a state credit not expected to be utilized by a Dominion Energy subsidiary which files a separate state return.

The Companies' deferred income taxes consist of the following:

	Dominion Energy		Virginia Power		Dominion Energy Gas	
At December 31,	2017	2016	2017	2016	2017	2016
(millions)						
Deferred income taxes:						
Total deferred income tax assets	$ 2,686	$ 1,827	$ 923	$ 268	$ 320	$ 126
Total deferred income tax liabilities	7,158	10,381	3,600	5,323	1,774	2,564
Total net deferred income tax liabilities	$ 4,472	$ 8,554	$2,677	$5,055	$1,454	$ 2,438
Total deferred income taxes:						
Plant and equipment, primarily depreciation method and basis differences	$ 5,056	$ 7,782	$2,969	$4,604	$1,132	$ 1,726
Excess deferred income taxes	(1,050)	—	(687)	—	(244)	—
Nuclear decommissioning	829	1,240	260	406	—	—
Deferred state income taxes	834	747	378	321	227	204
Federal benefit of deferred state income taxes	(175)	(261)	(79)	(112)	(48)	(71)
Deferred fuel, purchased energy and gas costs	1	(25)	(3)	(29)	2	4
Pension benefits	141	155	(104)	(138)	419	646
Other postretirement benefits	(51)	(68)	44	49	(2)	(6)
Loss and credit carryforwards	(1,536)	(1,547)	(111)	(88)	(4)	(5)
Valuation allowances	146	135	5	3	3	—
Partnership basis differences	473	688	—	—	26	43
Other	(196)	(292)	5	39	(57)	(103)
Total net deferred income tax liabilities	$ 4,472	$ 8,554	$2,677	$5,055	$1,454	$ 2,438
Deferred Investment Tax Credits – Regulated Operations	51	48	51	48	—	—
Total Deferred Taxes and Deferred Investment Tax Credits	$ 4,523	$ 8,602	$2,728	$5,103	$1,454	$ 2,438

The most significant impact reflected for the 2017 Tax Reform Act is the adjustment of the net accumulated deferred income tax liability for the reduction in the corporate income tax rate to 21%. In addition to amounts recognized in deferred income tax expense, the impacts of the 2017 Tax Reform Act decreased the accumulated deferred income tax liability by $3.1 billion at Dominion Energy, $1.9 billion at Virginia Power and $0.8 billion at Dominion Energy Gas at December 31, 2017. At Dominion Energy, the December 31, 2017 balance sheet reflects the impact of the 2017 Tax Reform Act on our regulatory liabilities which increased our regulatory liabilities by $4.2 billion, and created a corresponding deferred tax asset of $1.1 billion. At Virginia Power, our regulatory liabilities increased $2.6 billion, and created a deferred tax asset of $0.7 billion. At Dominion Energy Gas, our regulatory liabilities increased $1.0 billion, and created a deferred tax asset of $0.2 billion. These adjustments had no impact on 2017 cash flows.

At December 31, 2017, Dominion Energy had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	$ 560	$ 118	$ —	2034
Federal investment credits	—	938	—	2033-2037
Federal production credits	—	129	—	2031-2037
Other federal credits	—	58	—	2031-2037
State losses	1,366	103	(63)	2018-2037
State minimum tax credits	—	90	—	No expiration
State investment and other credits	—	100	(83)	2018-2027
Total	$1,926	$1,536	$(146)	

At December 31, 2017, Virginia Power had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	$ 1	$ —	$—	2034
Federal investment credits	—	51	—	2034-2037
Federal production and other credits	—	51	—	2031-2037
State investment credits	—	9	(5)	2024
Total	$ 1	$111	$(5)	

At December 31, 2017, Dominion Energy Gas had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Other federal credits	$—	$1	$—	2032-2036
State losses	33	3	(3)	2036-2037
Total	$33	$4	$ (3)	

A reconciliation of changes in the Companies' unrecognized tax benefits follows:

	Dominion Energy			Virginia Power			Dominion Energy Gas		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
(millions)									
Balance at January 1	$ 64	$103	$145	$13	$12	$ 36	$ 7	$ 29	$29
Increases-prior period positions	1	9	2	—	4	—	—	1	—
Decreases-prior period positions	(9)	(44)	(40)	(1)	(3)	(25)	—	(19)	—
Increases-current period positions	5	6	8	—	—	1	—	—	—
Settlements with tax authorities	(23)	(8)	(5)	(8)	—	—	(7)	(4)	—
Expiration of statutes of limitations	—	(2)	(7)	—	—	—	—	—	—
Balance at December 31	$ 38	$ 64	$103	$ 4	$13	$ 12	$—	$ 7	$29

Certain unrecognized tax benefits, or portions thereof, if recognized, would affect the effective tax rate. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations. For Dominion Energy and its subsidiaries, these unrecognized tax benefits were $31 million, $45 million and $69 million at December 31, 2017, 2016 and 2015, respectively. For Dominion Energy, the change in these unrecognized tax benefits decreased income tax expense by $9 million, $18 million and $6 million in 2017, 2016 and 2015, respectively. For Virginia Power, these unrecognized tax benefits were $3 million, $9 million, and $8 million at December 31, 2017, 2016 and 2015, respectively. For Virginia Power, the change in these unrecognized tax benefits decreased income tax expense by $6 million in 2017 and increased income tax expense by $1 million and less than $1 million in 2016 and 2015, respectively. For Dominion Energy Gas, these unrecognized tax benefits were less than $1 million, $5 million and $19 million at December 31, 2017, 2016 and 2015, respectively. For Dominion Energy Gas, the change in these unrecognized tax benefits decreased income tax expense by $5 million, $11 million and less than $1 million in 2017, 2016 and 2015, respectively.

Dominion Energy participates in the IRS Compliance Assurance Process which provides the opportunity to resolve complex tax matters with the IRS before filing its federal income tax returns, thus achieving certainty for such tax return filing positions agreed to by the IRS. In 2016 and 2017, the Companies submitted research credit claims for tax years 2012-2016. These claims are currently under IRS examination. With the exception of these research credit claims, the IRS has completed its audit of tax years through 2015. The statute of limitations has not yet expired for tax years after 2012. Although Dominion Energy has not received a final letter indicating no changes to its taxable income for tax year 2016, no material adjustments are expected. The IRS examination of tax year 2017 is ongoing.

It is reasonably possible that settlement negotiations and expiration of statutes of limitations could result in a decrease in unrecognized tax benefits in 2018 by up to $13 million for Dominion Energy, $2 million for Virginia Power and less than $1 million for Dominion Energy Gas. If such changes were to occur, other than revisions of the accrual for interest on tax underpayments and overpayments, earnings could increase by up to $12 million for Dominion Energy, $2 million for Virginia Power and less than $1 million for Dominion Energy Gas.

Otherwise, with regard to 2017 and prior years, Dominion Energy, Virginia Power and Dominion Energy Gas cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2018.

For each of the major states in which Dominion Energy operates, the earliest tax year remaining open for examination is as follows:

State	Earliest Open Tax Year
Pennsylvania(1)	2012
Connecticut	2014
Virginia(2)	2014
West Virginia(1)	2014
New York(1)	2011
Utah	2014

(1) Considered a major state for Dominion Energy Gas' operations.
(2) Considered a major state for Virginia Power's operations.

The Companies are also obligated to report adjustments resulting from IRS settlements to state tax authorities. In addition, if Dominion Energy utilizes operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

NOTE 6. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, the use of a mid-market pricing convention (the mid-point between bid and ask prices) is permitted. Fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of the Companies' own nonperformance risk on their liabilities. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). Dominion Energy applies fair value measurements to certain assets and liabilities including commodity, interest rate, and foreign currency derivative instruments, and other investments including those held in nuclear decommissioning, Dominion Energy's rabbi, and pension and other postretirement benefit plan trusts, in accordance with the requirements discussed above. Virginia Power applies fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments and other investments including those held in the nuclear decommissioning trust, in accordance with the requirements discussed above. Dominion Energy Gas applies fair value measurements to certain assets and liabilities including commodity, interest rate, and foreign currency derivative instruments and other investments including those held in pension and other postretirement benefit plan trusts, in accordance with the requirements described above. The Companies apply credit adjustments to their derivative fair values in accordance with the requirements described above.

Inputs and Assumptions

The Companies maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, price information is sought from external sources, including broker quotes and industry publications. When evaluating pricing information provided by brokers and other pricing services, the Companies consider whether the broker is willing and able to trade at the quoted price, if the broker quotes are based on an active market or an inactive market and the extent to which brokers are utilizing a particular model if pricing is not readily available. If pricing information from external sources is not available, or if the Companies believe that observable pricing is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases the Companies must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis, that reflect their market assumptions.

The Companies' commodity derivative valuations are prepared by Dominion Energy's ERM department. The ERM department creates daily mark-to-market valuations for the Companies' derivative transactions using computer-based statistical models. The inputs that go into the market valuations are transactional information stored in the systems of record and market pricing information that resides in data warehouse databases. The majority of forward prices are automatically uploaded into the data warehouse databases from various third-party sources. Inputs obtained from third-party sources are evaluated for reliability considering the reputation, independence, market presence, and methodology used by the third-party. If forward prices are not available from third-party sources, then the ERM department models the forward prices based on other available market data. A team consisting of risk management and risk quantitative analysts meets each business day to assess the validity of market prices and mark-to-market valuations. During this meeting, the changes in mark-to-market valuations from period to period are examined and qualified against historical expectations. If any discrepancies are identified during this process, the mark-to-market valuations or the market pricing information is evaluated further and adjusted, if necessary.

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, Dominion Energy and Virginia Power generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. Dominion Energy and Virginia Power use other option models under special circumstances, including a Spread Approximation Model when contracts include different commodities or commodity locations and a Swing Option Model when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, the Companies may estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. For individual contracts, the use of different valuation models or assumptions could have a significant effect on the contract's estimated fair value.

The inputs and assumptions used in measuring fair value include the following:

For commodity derivative contracts:

- Forward commodity prices
- Transaction prices
- Price volatility
- Price correlation
- Volumes
- Commodity location
- Interest rates
- Credit quality of counterparties and the Companies
- Credit enhancements
- Time value

For interest rate derivative contracts:

- Interest rate curves
- Credit quality of counterparties and the Companies
- Notional value
- Credit enhancements
- Time value

For foreign currency derivative contracts:

- Foreign currency forward exchange rates
- Interest rates
- Credit quality of counterparties and the Companies
- Notional value
- Credit enhancements
- Time value

For investments:

- Quoted securities prices and indices
- Securities trading information including volume and restrictions
- Maturity
- Interest rates
- Credit quality

The Companies regularly evaluate and validate the inputs used to estimate fair value by a number of methods, including review and verification of models, as well as various market price verification procedures such as the use of pricing services and multiple broker quotes to support the market price of the various commodities and investments in which the Companies transact.

Levels

The Companies also utilize the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- Level 1—Quoted prices (unadjusted) in active markets for identical assets and liabilities that they have the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as certain exchange-traded derivatives, and exchange-listed equities, U.S. and international equity securities, mutual funds and certain Treasury securities held in nuclear decommissioning trust funds for Dominion Energy and Virginia Power, benefit plan trust funds for Dominion Energy and Dominion Energy Gas, and rabbi trust funds for Dominion Energy.

- Level 2—Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include commodity forwards and swaps, interest rate swaps, foreign currency swaps and cash and cash equivalents, corporate debt instruments, government securities and other fixed income investments held in nuclear decommissioning trust funds for Dominion Energy and Virginia Power, benefit plan trust funds for Dominion Energy and Dominion Energy Gas and rabbi trust funds for Dominion Energy.
- Level 3—Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 for the Companies consist of long-dated commodity derivatives, FTRs, certain natural gas and power options and other modeled commodity derivatives.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. In these cases, the lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. Alternative investments, consisting of investments in partnerships, joint ventures and other alternative investments held in nuclear decommissioning and benefit plan trust funds, are generally valued using NAV based on the proportionate share of the fair value as determined by reference to the most recent audited fair value financial statements or fair value statements provided by the investment manager adjusted for any significant events occurring between the investment manager's and the Companies' measurement date. Alternative investments recorded at NAV are not classified in the fair value hierarchy.

For derivative contracts, the Companies recognize transfers among Level 1, Level 2 and Level 3 based on fair values as of the first day of the month in which the transfer occurs. Transfers out of Level 3 represent assets and liabilities that were previously classified as Level 3 for which the inputs became observable for classification in either Level 1 or Level 2. Because the activity and liquidity of commodity markets vary substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of the Companies' over-the-counter derivative contracts is subject to change.

Level 3 Valuations

Fair value measurements are categorized as Level 3 when price or other inputs that are considered to be unobservable are significant to their valuations. Long-dated commodity derivatives are generally based on unobservable inputs due to the length of time to settlement and the absence of market activity and are therefore categorized as Level 3. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from ISO auctions, which are generally not considered to be liquid markets. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

The Companies enter into certain physical and financial forwards, futures, options and swaps, which are considered Level 3 as they have one or more inputs that are not observable and are significant to the valuation. The discounted cash flow method is used to value Level 3 physical and financial forwards and futures contracts. An option model is used to value Level 3 physical and financial options. The discounted cash flow model for forwards and futures calculates mark-to-market valuations based on forward market prices, original transaction prices, volumes, risk-free rate of return, and credit spreads. The option model calculates mark-to-market valuations using variations of the Black-Scholes option model. The inputs into the models are the forward market prices, implied price volatilities, risk-free rate of return, the option expiration dates, the option strike prices, the original sales prices, and volumes. For Level 3 fair value measurements, certain forward market prices and implied price volatilities are considered unobservable. The unobservable inputs are developed and substantiated using historical information, available market data, third-party data, and statistical analysis. Periodically, inputs to valuation models are reviewed and revised as needed, based on historical information, updated market data, market liquidity and relationships, and changes in third-party pricing sources.

The following table presents Dominion Energy's quantitative information about Level 3 fair value measurements at December 31, 2017. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets					
Physical and financial forwards and futures:					
Natural gas(2)	$ 84	Discounted cash flow	Market price (per Dth)(4)	(2) - 14	—
FTRs	29	Discounted cash flow	Market price (per MWh)(4)	(1) - 7	2
Physical options:					
Natural gas	1	Option model	Market price (per Dth)(4)	2 - 7	3
			Price volatility (5)	26% - 54%	33%
Electricity	43	Option model	Market price (per MWh)(4)	22 - 74	37
			Price volatility (5)	13% - 63%	33%
Total assets	$157				
Liabilities					
Financial forwards:					
Liquids(3)	$ 2	Discounted cash flow	Market price (per Gal)(4)	0 - 2	1
FTRs	$ 5	Discounted cash flow	Market price (per MWh)(4)	(4) - 6	—
Total liabilities	$ 7				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Includes NGLs and oil.
(4) Represents market prices beyond defined terms for Levels 1 and 2.
(5) Represents volatilities unrepresented in published markets.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)
Price volatility	Buy	Increase (decrease)	Gain (loss)
Price volatility	Sell	Increase (decrease)	Loss (gain)

Nonrecurring Fair Value Measurements

DOMINION ENERGY

See Note 9 for information regarding an impairment charge recognized associated with Dominion Energy's equity method investment in Fowler Ridge.

ATLANTIC COAST PIPELINE GUARANTEE AGREEMENT

In October 2017, Dominion Energy entered into a guarantee agreement in connection with Atlantic Coast Pipeline's obligation under a $3.4 billion revolving credit facility. See Note 22 for more information about the guarantee agreement associated with Atlantic Coast Pipeline's revolving credit facility. Dominion Energy recorded a liability of $30 million, the fair value of the guarantee at inception, associated with the guarantee agreement. The fair value was estimated using a discounted cash flow method and is considered a Level 3 fair value measurement due to the use of a significant unobservable input related to the interest rate differential between the interest rate charged on the guaranteed revolving credit facility and the estimated interest rate that would have been charged had the loan not been guaranteed.

Recurring Fair Value Measurements

Fair value measurements are separately disclosed by level within the fair value hierarchy with a separate reconciliation of fair value measurements categorized as Level 3. Fair value disclosures for assets held in Dominion Energy's and Dominion Energy Gas' pension and other postretirement benefit plans are presented in Note 21.

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The following table presents Dominion Energy's assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
December 31, 2017				
Assets				
Derivatives:				
Commodity	$ —	$ 101	$157	$ 258
Interest rate	—	17	—	17
Foreign currency	—	32	—	32
Investments(1):				
Equity securities:				
U.S.	3,493	—	—	3,493
Fixed income:				
Corporate debt instruments	—	444	—	444
Government securities	307	794	—	1,101
Cash equivalents and other	34	—	—	34
Total assets	$3,834	$1,388	$157	$5,379
Liabilities				
Derivatives:				
Commodity	$ —	$ 190	$ 7	$ 197
Interest rate	—	85	—	85
Foreign currency	—	2	—	2
Total liabilities	$ —	$ 277	$ 7	$ 284
December 31, 2016				
Assets				
Derivatives:				
Commodity	$ —	$ 115	$147	$ 262
Interest rate	—	17	—	17
Investments(1):				
Equity securities:				
U.S.	2,913	—	—	2,913
Fixed income:				
Corporate debt instruments	—	487	—	487
Government securities	424	614	—	1,038
Cash equivalents and other	5	—	—	5
Total assets	$3,342	$1,233	$147	$4,722
Liabilities				
Derivatives:				
Commodity	$ —	$ 88	$ 8	$ 96
Interest rate	—	53	—	53
Foreign currency	—	6	—	6
Total liabilities	$ —	$ 147	$ 8	$ 155

(1) Includes investments held in the nuclear decommissioning and rabbi trusts. Excludes $88 million and $89 million of assets at December 31, 2017 and 2016, respectively, measured at fair value using NAV (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

The following table presents the net change in Dominion Energy's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	2017	2016	2015
Balance at January 1,	$139	$ 95	$107
Total realized and unrealized gains (losses):			
Included in earnings	(38)	(35)	(5)
Included in other comprehensive loss	(2)	—	(9)
Included in regulatory assets/liabilities	42	(39)	(4)
Settlements	6	38	9
Purchases	—	87	—
Transfers out of Level 3	3	(7)	(3)
Balance at December 31,	$150	$139	$ 95
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	$ 2	$ (1)	$ 2

The following table presents Dominion Energy's gains and losses included in earnings in the Level 3 fair value category:

(millions)	Operating Revenue	Electric Fuel and Other Energy-Related Purchases	Purchased Gas	Total
Year Ended December 31, 2017				
Total gains (losses) included in earnings	$ 3	$(42)	$ 1	$(38)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	2	—	—	2
Year Ended December 31, 2016				
Total gains (losses) included in earnings	$—	$(35)	$—	$(35)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	—	(1)	—	(1)
Year Ended December 31, 2015				
Total gains (losses) included in earnings	$ 6	$(11)	$—	$ (5)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	1	1	—	2

VIRGINIA POWER

The following table presents Virginia Power's quantitative information about Level 3 fair value measurements at December 31, 2017. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets					
Physical and financial forwards and futures:					
Natural gas(2)	$ 81	Discounted cash flow	Market price (per Dth)(3)	(2)-7	(1)
FTRs	27	Discounted cash flow	Market price (per MWh)(3)	(1)-7	2
Physical options:					
Natural gas	1	Option model	Market price (per Dth)(3)	2-7	3
			Price volatility (4)	26%-54%	33%
Electricity	43	Option model	Market price (per MWh)(3)	22-74	37
			Price volatility (4)	13%-63%	33%
Total assets	$152				
Liabilities:					
Financial forwards:					
FTRs	$ 5	Discounted cash flow	Market price (per MWh)(3)	(4)-6	—
Total liabilities	$ 5				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Represents market prices beyond defined terms for Levels 1 and 2.
(4) Represents volatilities unrepresented in published markets.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)
Price volatility	Buy	Increase (decrease)	Gain (loss)
Price volatility	Sell	Increase (decrease)	Loss (gain)

The following table presents Virginia Power's assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
December 31, 2017				
Assets				
Derivatives:				
Commodity	**$ —**	**$ 14**	**$152**	**$ 166**
Investments(1):				
Equity securities:				
U.S.	**1,566**	**—**	**—**	**1,566**
Fixed income:				
Corporate debt instruments	**—**	**224**	**—**	**224**
Government securities	**168**	**326**	**—**	**494**
Cash equivalents and other	**16**	**—**	**—**	**16**
Total assets	**$1,750**	**$564**	**$152**	**$2,466**
Liabilities				
Derivatives:				
Commodity	**$ —**	**$ 4**	**$ 5**	**$ 9**
Interest rate	**—**	**57**	**—**	**57**
Total liabilities	**$ —**	**$ 61**	**$ 5**	**$ 66**
December 31, 2016				
Assets				
Derivatives:				
Commodity	$ —	$ 43	$145	$ 188
Interest rate	—	6	—	6
Investments(1):				
Equity securities:				
U.S.	1,302	—	—	1,302
Fixed income:				
Corporate debt instruments	—	277	—	277
Government securities	136	291	—	427
Total assets	$1,438	$617	$145	$2,200
Liabilities				
Derivatives:				
Commodity	$ —	$ 8	$ 2	$ 10
Interest rate	—	21	—	21
Total liabilities	$ —	$ 29	$ 2	$ 31

(1) Includes investments held in the nuclear decommissioning trusts. Excludes $27 million and $26 million of assets at December 31, 2017 and 2016, respectively, measured at fair value using NAV (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

The following table presents the net change in Virginia Power's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	2017	2016	2015
Balance at January 1,	**$143**	$ 93	$102
Total realized and unrealized gains (losses):			
Included in earnings	**(43)**	(35)	(13)
Included in regulatory assets/liabilities	**40**	(37)	(5)
Settlements	**7**	35	13
Purchases	**—**	87	—
Transfers out of Level 3	**—**	—	(4)
Balance at December 31,	**$147**	$143	$ 93

The gains and losses included in earnings in the Level 3 fair value category were classified in electric fuel and other energy-related purchases expense in Virginia Power's Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the years ended December 31, 2017, 2016 and 2015.

DOMINION ENERGY GAS

The following table presents Dominion Energy Gas' quantitative information about Level 3 fair value measurements at December 31, 2017. The range and weighted average are presented in dollars for market price inputs.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Liabilities:					
Financial forwards:					
NGLs	**$2**	Discounted cash flow	Market price (per Dth)(2)	0 - 1	1
Total liabilities	**$2**				

(1) Averages weighted by volume.
(2) Represents market prices beyond defined terms for Levels 1 and 2.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

The following table presents Dominion Energy Gas' assets and liabilities for commodity and foreign currency derivatives that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

	Level 1	Level 2	Level 3	Total
(millions)				
December 31, 2017				
Assets				
Foreign currency	**$—**	**$32**	**$—**	**$32**
Total assets	**$—**	**$32**	**$—**	**$32**
Liabilities				
Commodity	**$—**	**$ 4**	**$ 2**	**$ 6**
Foreign currency	**—**	**2**	**—**	**2**
Total liabilities	**$—**	**$ 6**	**$ 2**	**$ 8**
December 31, 2016				
Liabilities				
Commodity	$—	$ 3	$ 2	$ 5
Foreign currency	—	6	—	6
Total liabilities	$—	$ 9	$ 2	$11

The following table presents the net change in Dominion Energy Gas' derivative assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

	2017	2016	2015
(millions)			
Balance at January 1,	**$ (2)**	$ 6	$ 2
Total realized and unrealized gains (losses):			
Included in earnings	**—**	—	1
Included in other comprehensive loss	**(3)**	—	(5)
Settlements	**—**	—	(1)
Transfers out of Level 3	**3**	(8)	9
Balance at December 31,	**$ (2)**	$ (2)	$ 6

The gains and losses included in earnings in the Level 3 fair value category were classified in operating revenue in Dominion Energy Gas' Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the years ended December 31, 2017, 2016 and 2015.

Fair Value of Financial Instruments

Substantially all of the Companies' financial instruments are recorded at fair value, with the exception of the instruments described below, which are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. The carrying amount of cash and cash equivalents, restricted cash (which is recorded in other current assets), customer and other receivables, affiliated receivables, short-term debt, affiliated current borrowings, payables to affiliates and accounts payable are representative of fair value because of the short-term nature of these instruments. For the Companies' financial instruments that are not recorded at fair value, the carrying amounts and estimated fair values are as follows:

December 31,	2017		2016	
	Carrying Amount	Estimated Fair Value(1)	Carrying Amount	Estimated Fair Value(1)
(millions)				
Dominion Energy				
Long-term debt, including securities due within one year(2)	**$28,666**	**$31,233**	$26,587	$28,273
Junior subordinated notes(3)	**3,981**	**4,102**	2,980	2,893
Remarketable subordinated notes(3)	**1,379**	**1,446**	2,373	2,418
Virginia Power				
Long-term debt, including securities due within one year(3)	**$11,346**	**$12,842**	$10,530	$11,584
Dominion Energy Gas				
Long-term debt, including securities due within one year(4)	**$ 3,570**	**$ 3,719**	$ 3,528	$ 3,603

(1) Fair value is estimated using market prices, where available, and interest rates currently available for issuance of debt with similar terms and remaining maturities. All fair value measurements are classified as Level 2. The carrying amount of debt issues with short-term maturities and variable rates refinanced at current market rates is a reasonable estimate of their fair value.

(2) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium, and foreign currency remeasurement adjustments. At December 31, 2017, and 2016, includes the valuation of certain fair value hedges associated with Dominion Energy's fixed rate debt of $(22) million and $(1) million, respectively.

(3) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium.

(4) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium, and foreign currency remeasurement adjustments.

NOTE 7. DERIVATIVES AND HEDGE ACCOUNTING ACTIVITIES

The Companies are exposed to the impact of market fluctuations in the price of electricity, natural gas and other energy-related products they market and purchase, as well as interest rate and foreign currency exchange rate risks of their business operations. The Companies use derivative instruments to manage exposure to these risks, and designate certain derivative instruments as fair value or cash flow hedges for accounting purposes. As discussed in Note 2, for jurisdictions subject to cost-based rate regulation, changes in the fair value of derivatives are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings. See Note 6 for further information about fair value measurements and associated valuation methods for derivatives.

Derivative assets and liabilities are presented gross on the Companies' Consolidated Balance Sheets. Dominion Energy's derivative contracts include both over-the-counter transactions and those that are executed on an exchange or other trading platform (exchange contracts) and centrally cleared. Virginia Power's and Dominion Energy Gas' derivative contracts include over-the-counter transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Exchange contracts utilize a financial intermediary, exchange, or clearinghouse to enter, execute, or clear the transactions. Certain over-the-counter and exchange contracts contain contractual rights of setoff through master netting arrangements, derivative clearing agreements, and contract default provisions. In addition, the contracts are subject to conditional rights of setoff through counterparty nonperformance, insolvency, or other conditions.

In general, most over-the-counter transactions and all exchange contracts are subject to collateral requirements. Types of collateral for over-the-counter and exchange contracts include cash, letters of credit, and, in some cases, other forms of security, none of which are subject to restrictions. Cash collateral is used in the table below to offset derivative assets and liabilities. Certain accounts receivable and accounts payable recognized on the Companies' Consolidated Balance Sheets, as well as letters of credit and other forms of security, all of which are not included in the tables below, are subject to offset under master netting or similar arrangements and would reduce the net exposure. See Note 23 for further information regarding credit-related contingent features for the Companies derivative instruments.

DOMINION ENERGY

Balance Sheet Presentation

The tables below present Dominion Energy's derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2017			December 31, 2016		
(millions)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$174	$—	$174	$211	$—	$211
Exchange	80	—	80	44	—	44
Interest rate contracts:						
Over-the-counter	17	—	17	17	—	17
Foreign currency contracts:						
Over-the-counter	32	—	32	—	—	—
Total derivatives, subject to a master netting or similar arrangement	303	—	303	272	—	272
Total derivatives, not subject to a master netting or similar arrangement	4	—	4	7	—	7
Total	$307	$—	$307	$279	$—	$279

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Commodity contracts:								
Over-the-counter	$174	$ 9	$—	$165	$211	$14	$—	$197
Exchange	80	80	—	—	44	44	—	—
Interest rate contracts:								
Over-the-counter	17	8	—	9	17	9	—	8
Foreign currency contracts:								
Over-the-counter	32	2	—	30	—	—	—	—
Total	$303	$99	$—	$204	$272	$67	$—	$205

	December 31, 2017			December 31, 2016		
(millions)	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$ 76	$—	$ 76	$ 23	$—	$ 23
Exchange	120	—	120	71	—	71
Interest rate contracts:						
Over-the-counter	85	—	85	53	—	53
Foreign currency contracts:						
Over-the-counter	2	—	2	6	—	6
Total derivatives, subject to a master netting or similar arrangement	283	—	283	153	—	153
Total derivatives, not subject to a master netting or similar arrangement	1	—	1	2	—	2
Total	$284	$—	$284	$155	$—	$155

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
(millions)								
Commodity contracts:								
Over-the-counter	$ 76	$ 9	$ 6	$ 61	$ 23	$14	$—	$ 9
Exchange	120	80	40	—	71	44	27	—
Interest rate contracts:								
Over-the-counter	85	8	—	77	53	9	—	44
Foreign currency contracts:								
Over-the-counter	2	2	—	—	6	—	—	6
Total	$283	$99	$46	$138	$153	$67	$27	$59

Volumes

The following table presents the volume of Dominion Energy's derivative activity as of December 31, 2017. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	77	19
Basis	163	600
Electricity (MWh):		
Fixed price	10,552,363	364,990
FTRs	46,494,865	—
Liquids (Gal)(2)	44,153,704	10,087,200
Interest rate(3)	$1,950,000,000	$4,192,517,177
Foreign currency(3)(4)	$ —	$ 280,000,000

(1) Includes options.
(2) Includes NGLs and oil.
(3) Maturity is determined based on final settlement period.
(4) Euro equivalent volumes are € 250,000,000.

Ineffectiveness and AOCI

For the years ended December 31, 2017, 2016 and 2015, gains or losses on hedging instruments determined to be ineffective and amounts excluded from the assessment of effectiveness were not material. Amounts excluded from the assessment of effectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion Energy's Consolidated Balance Sheet at December 31, 2017:

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
(millions)			
Commodities:			
Gas	$ (2)	$ (3)	34 months
Electricity	(55)	(55)	12 months
Other	(4)	(4)	15 months
Interest rate	(246)	(10)	384 months
Foreign currency	5	(1)	102 months
Total	$(302)	$(73)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates and foreign currency exchange rates.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion Energy's derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)	Fair Value – Derivatives under Hedge Accounting	Fair Value – Derivatives not under Hedge Accounting	Total Fair Value
At December 31, 2017			
ASSETS			
Current Assets			
Commodity	$ 5	$158	$163
Interest rate	6	—	6
Total current derivative assets(1)	11	158	169
Noncurrent Assets			
Commodity	—	95	95
Interest rate	11	—	11
Foreign currency	32	—	32
Total noncurrent derivative assets(2)	43	95	138
Total derivative assets	$ 54	$253	$307
LIABILITIES			
Current Liabilities			
Commodity	$103	$ 92	$195
Interest rate	53	—	53
Foreign currency	2	—	2
Total current derivative liabilities(3)	158	92	250
Noncurrent Liabilities			
Commodity	1	1	2
Interest rate	32	—	32
Total noncurrent derivative liabilities(4)	33	1	34
Total derivative liabilities	$191	$ 93	$284
At December 31, 2016			
ASSETS			
Current Assets			
Commodity	$ 29	$101	$130
Interest rate	10	—	10
Total current derivative assets(1)	39	101	140
Noncurrent Assets			
Commodity	—	132	132
Interest rate	7	—	7
Total noncurrent derivative assets(2)	7	132	139
Total derivative assets	$ 46	$233	$279
LIABILITIES			
Current Liabilities			
Commodity	$ 51	$ 41	$ 92
Interest rate	33	—	33
Foreign currency	3	—	3
Total current derivative liabilities(3)	87	41	128
Noncurrent Liabilities			
Commodity	1	3	4
Interest rate	20	—	20
Foreign currency	3	—	3
Total noncurrent derivative liabilities(4)	24	3	27
Total derivative liabilities	$111	$ 44	$155

(1) Current derivative assets are presented in other current assets in Dominion Energy's Consolidated Balance Sheets.

(2) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion Energy's Consolidated Balance Sheets.

(3) Current derivative liabilities are presented in other current liabilities in Dominion Energy's Consolidated Balance Sheets.

(4) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion Energy's Consolidated Balance Sheets.

The following table presents the gains and losses on Dominion Energy's derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships (millions)	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)	Amount of Gain (Loss) Reclassified From AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment(2)
Year Ended December 31, 2017			
Derivative type and location of gains (losses):			
Commodity:			
Operating revenue		$ 81	
Purchased gas		(2)	
Total commodity	$ 1	$ 79	$—
Interest rate(3)	(8)	(52)	(58)
Foreign currency(4)	18	20	—
Total	$ 11	$ 47	$(58)
Year Ended December 31, 2016			
Derivative type and location of gains (losses):			
Commodity:			
Operating revenue		$330	
Purchased gas		(13)	
Electric fuel and other energy-related purchases		(10)	
Total commodity	$164	$307	$—
Interest rate(3)	(66)	(31)	(26)
Foreign currency(4)	(6)	(17)	—
Total	$ 92	$259	$(26)
Year Ended December 31, 2015			
Derivative type and location of gains (losses):			
Commodity:			
Operating revenue		$203	
Purchased gas		(15)	
Electric fuel and other energy-related purchases		(1)	
Total commodity	$230	$187	$ 4
Interest rate(3)	(46)	(11)	(13)
Total	$184	$176	$ (9)

(1) Amounts deferred into AOCI have no associated effect in Dominion Energy's Consolidated Statements of Income.

(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion Energy's Consolidated Statements of Income.

(3) Amounts recorded in Dominion Energy's Consolidated Statements of Income are classified in interest and related charges.

(4) Amounts recorded in Dominion Energy's Consolidated Statements of Income are classified in other income.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives(1)		
Year Ended December 31,	2017	2016	2015
(millions)			
Derivative type and location of gains (losses):			
Commodity:			
Operating revenue	$ 18	$ 2	$ 24
Purchased gas	(3)	4	(14)
Electric fuel and other energy-related purchases	(59)	(70)	(14)
Other operations & maintenance	(1)	1	—
Interest rate(2)	—	—	(1)
Total	$(45)	$(63)	$ (5)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion Energy's Consolidated Statements of Income.

(2) Amounts recorded in Dominion Energy's Consolidated Statements of Income are classified in interest and related charges.

VIRGINIA POWER

Balance Sheet Presentation

The tables below present Virginia Power's derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2017			December 31, 2016		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
(millions)						
Commodity contracts:						
Over-the-counter	$155	$—	$155	$147	$—	$147
Interest rate contracts:						
Over-the-counter	—	—	—	6	—	6
Total derivatives, subject to a master netting or similar arrangement	155	—	155	153	—	153
Total derivatives, not subject to a master netting or similar arrangement	11	—	11	41	—	41
Total	$166	$—	$166	$194	$—	$194

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
(millions)								
Commodity contracts:								
Over-the-counter	$155	$ 4	$—	$151	$147	$ 2	$—	$145
Interest rate contracts:								
Over-the-counter	—	—	—	—	6	—	—	6
Total	$155	$ 4	$—	$151	$153	$ 2	$—	$151

Combined Notes to Consolidated Financial Statements, Continued

(millions)	December 31, 2017 Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	December 31, 2016 Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$ 4	$—	$ 4	$ 2	$—	$ 2
Interest rate contracts:						
Over-the-counter	57	—	57	21	—	21
Total derivatives, subject to a master netting or similar arrangement	61	—	61	23	—	23
Total derivatives, not subject to a master netting or similar arrangement	5	—	5	8	—	8
Total	$66	$—	$66	$31	$—	$31

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
Commodity contracts:								
Over-the-counter	$ 4	$ 4	$—	$—	$ 2	$ 2	$—	$—
Interest rate contracts:								
Over-the-counter	57	—	—	57	21	—	—	21
Total	$61	$ 4	$—	$57	$23	$ 2	$—	$21

Volumes

The following table presents the volume of Virginia Power's derivative activity at December 31, 2017. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	33	5
Basis	79	540
Electricity (MWh):		
Fixed price(1)	1,453,910	364,990
FTRs	42,582,981	—
Interest rate(2)	$1,150,000,000	$300,000,000

(1) Includes options.
(2) Maturity is determined based on final settlement period.

Ineffectiveness and AOCI

For the years ended December 31, 2017, 2016 and 2015, gains or losses on hedging instruments determined to be ineffective were not material.

The following table presents selected information related to losses on cash flow hedges included in AOCI in Virginia Power's Consolidated Balance Sheet at December 31, 2017:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$(12)	$(1)	384 months
Total	$(12)	$(1)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., interest payments) in earnings, thereby achieving the realization of interest rates contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in interest rates.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Virginia Power's derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)	Fair Value - Derivatives under Hedge Accounting	Fair Value - Derivatives not under Hedge Accounting	Total Fair Value
At December 31, 2017			
ASSETS			
Current Assets			
Commodity	$—	$ 75	$ 75
Total current derivative assets(1)	—	75	75
Noncurrent Assets			
Commodity	—	91	91
Total noncurrent derivative assets	—	91	91
Total derivative assets	$—	$166	$166
LIABILITIES			
Current Liabilities			
Commodity	$—	$ 9	$ 9
Interest rate	44	—	44
Total current derivative liabilities(2)	44	9	53
Noncurrent Liabilities			
Interest rate	13	—	13
Total noncurrent derivatives liabilities(3)	13	—	13
Total derivative liabilities	$57	$ 9	$ 66
At December 31, 2016			
ASSETS			
Current Assets			
Commodity	$—	$ 60	$ 60
Interest rate	6	—	6
Total current derivative assets(1)	6	60	66
Noncurrent Assets			
Commodity	—	128	128
Total noncurrent derivative assets	—	128	128
Total derivative assets	$6	$188	$194
LIABILITIES			
Current Liabilities			
Commodity	$—	$ 10	$ 10
Interest rate	8	—	8
Total current derivative liabilities(2)	8	10	18
Noncurrent Liabilities			
Interest rate	13	—	13
Total noncurrent derivative liabilities(3)	13	—	13
Total derivative liabilities	$21	$ 10	$ 31

(1) Current derivative assets are presented in other current assets in Virginia Power's Consolidated Balance Sheets.

(2) Current derivative liabilities are presented in other current liabilities in Virginia Power's Consolidated Balance Sheets.

(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Virginia Power's Consolidated Balance Sheets.

The following tables present the gains and losses on Virginia Power's derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships (millions)	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)	Amount of Gain (Loss) Reclassified From AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment(2)
Year Ended December 31, 2017			
Derivative type and location of gains (losses):			
Interest rate(3)	$(8)	$(1)	$(58)
Total	$(8)	$(1)	$(58)
Year Ended December 31, 2016			
Derivative type and location of gains (losses):			
Interest rate(3)	$(3)	$(1)	$(26)
Total	$(3)	$(1)	$(26)
Year Ended December 31, 2015			
Derivative type and location of gains (losses):			
Commodity:			
Electric fuel and other energy-related purchases		$(1)	
Total commodity	$—	$(1)	$ 4
Interest rate(3)	(3)	—	(13)
Total	$(3)	$(1)	$ (9)

(1) Amounts deferred into AOCI have no associated effect in Virginia Power's Consolidated Statements of Income.

(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power's Consolidated Statements of Income.

(3) Amounts recorded in Virginia Power's Consolidated Statements of Income are classified in interest and related charges.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives(1)		
Year Ended December 31, (millions)	2017	2016	2015
Derivative type and location of gains (losses):			
Commodity(2)	$(57)	$(70)	$(13)
Total	$(57)	$(70)	$(13)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power's Consolidated Statements of Income.

(2) Amounts recorded in Virginia Power's Consolidated Statements of Income are classified in electric fuel and other energy-related purchases.

Combined Notes to Consolidated Financial Statements, Continued

DOMINION ENERGY GAS

Balance Sheet Presentation

The tables below present Dominion Energy Gas' derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2017			December 31, 2016		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
(millions)						
Foreign currency contracts:						
Over-the-counter	$32	$—	$32	$—	$—	$—
Total derivatives, subject to a master netting or similar arrangement	$32	$—	$32	$—	$—	$—

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
(millions)								
Foreign currency contracts:								
Over-the-counter	$32	$2	$—	$30	$—	$—	$—	$—
Total	$32	$2	$—	$30	$—	$—	$—	$—

	December 31, 2017			December 31, 2016		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
(millions)						
Commodity contracts:						
Over-the-counter	$6	$—	$6	$ 5	$—	$ 5
Foreign currency contracts:						
Over-the-counter	2	—	2	6	—	6
Total derivatives, subject to a master netting or similar arrangement	$8	$—	$8	$11	$—	$11

	December 31, 2017				December 31, 2016			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
(millions)								
Commodity contracts								
Over-the-counter	$6	$—	$—	$ 6	$ 5	$—	$—	$ 5
Foreign currency contracts:								
Over-the-counter	2	2	—	—	6	—	—	6
Total	$8	$ 2	$—	$ 6	$11	$—	$—	$11

Volumes

The following table presents the volume of Dominion Energy Gas' derivative activity at December 31, 2017. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Basis	1	—
NGLs (Gal)	40,961,704	8,491,200
Foreign currency(1)	$ —	$280,000,000

(1) Maturity is determined based on final settlement period. Euro equivalent volumes are €250,000,000.

Ineffectiveness and AOCI

For the years ended December 31, 2017, 2016 and 2015, gains or losses on hedging instruments determined to be ineffective were not material.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion Energy Gas' Consolidated Balance Sheet at December 31, 2017:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Commodities:			
NGLs	$ (4)	$(4)	15 months
Interest rate	(25)	(3)	324 months
Foreign currency	6	(1)	102 months
Total	$(23)	$(8)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates, and foreign currency exchange rates.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion Energy Gas' derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)	Fair Value-Derivatives Under Hedge Accounting	Fair Value-Derivatives Not Under Hedge Accounting	Total Fair Value
At December 31, 2017			
ASSETS			
Noncurrent Assets			
Foreign currency	$32	$—	$32
Total noncurrent derivative assets(1)	32	—	32
Total derivative assets	$32	$—	$32
LIABILITIES			
Current Liabilities			
Commodity	$ 6	$—	$ 6
Foreign currency	2	—	2
Total current derivative liabilities(2)	8	—	8
Total derivative liabilities	$ 8	$—	$ 8
At December 31, 2016			
LIABILITIES			
Current Liabilities			
Commodity	$ 4	$—	$ 4
Foreign currency	3	—	3
Total current derivative liabilities(2)	7	—	7
Noncurrent Liabilities			
Commodity	1	—	1
Foreign currency	3	—	3
Total noncurrent derivative liabilities(3)	4	—	4
Total derivative liabilities	$11	$—	$11

(1) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion Energy Gas' Consolidated Balance Sheets.
(2) Current derivative liabilities are presented in other current liabilities in Dominion Energy Gas' Consolidated Balance Sheets.
(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion Energy Gas' Consolidated Balance Sheets.

The following tables present the gains and losses on Dominion Energy Gas' derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)	Amount of Gain (Loss) Reclassified From AOCI to Income
(millions)		
Year Ended December 31, 2017		
Derivative Type and Location of Gains (Losses):		
Commodity:		
Operating revenue		**$ (8)**
Total commodity	**$(10)**	**$ (8)**
Interest rate(2)	**—**	**(5)**
Foreign currency(3)	**18**	**20**
Total	**$ 8**	**$ 7**
Year Ended December 31, 2016		
Derivative Type and Location of Gains (Losses):		
Commodity:		
Operating revenue		$ 4
Total commodity	$(12)	$ 4
Interest rate(2)	(8)	(2)
Foreign currency(3)	(6)	(17)
Total	$(26)	$(15)
Year Ended December 31, 2015		
Derivative Type and Location of Gains (Losses):		
Commodity:		
Operating revenue		$ 6
Total commodity	$ 16	$ 6
Interest rate(2)	(6)	—
Total	$ 10	$ 6

(1) Amounts deferred into AOCI have no associated effect in Dominion Energy Gas' Consolidated Statements of Income.

(2) Amounts recorded in Dominion Energy Gas' Consolidated Statements of Income are classified in interest and related charges.

(3) Amounts recorded in Dominion Energy Gas' Consolidated Statements of Income are classified in other income.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives		
Year Ended December 31,	**2017**	2016	2015
(millions)			
Derivative type and location of gains (losses):			
Commodity			
Operating revenue	**$—**	$1	$6
Total	**$—**	$1	$6

NOTE 8. EARNINGS PER SHARE

The following table presents the calculation of Dominion Energy's basic and diluted EPS:

	2017	2016	2015
(millions, except EPS)			
Net income attributable to Dominion Energy	**$2,999**	$2,123	$1,899
Average shares of common stock outstanding – Basic	**636.0**	616.4	592.4
Net effect of dilutive securities(1)	**—**	0.7	1.3
Average shares of common stock outstanding – Diluted	**636.0**	617.1	593.7
Earnings Per Common Share – Basic	**$ 4.72**	$ 3.44	$ 3.21
Earnings Per Common Share – Diluted	**$ 4.72**	$ 3.44	$ 3.20

(1) Dilutive securities consist primarily of the 2013 Equity Units for 2016 and 2015. See Note 17 for more information.

The 2014 Equity Units were excluded from the calculation of diluted EPS for the years ended December 31, 2016 and 2015, as the dilutive stock price threshold was not met. The 2016 Equity Units were excluded from the calculation of diluted EPS for the year ended December 31, 2017 and 2016, as the dilutive stock price threshold was not met. See Note 17 for more information. The Dominion Energy Midstream convertible preferred units are potentially dilutive securities but had no effect on the calculation of diluted EPS for the years ended December 31, 2017 and 2016. See Note 19 for more information.

NOTE 9. INVESTMENTS

DOMINION ENERGY

Equity and Debt Securities

RABBI TRUST SECURITIES

Marketable equity and debt securities and cash equivalents held in Dominion Energy's rabbi trusts and classified as trading totaled $112 million and $104 million at December 31, 2017 and 2016, respectively.

DECOMMISSIONING TRUST SECURITIES

Dominion Energy holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Dominion Energy's decommissioning trust funds are summarized below:

(millions)	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
At December 31, 2017				
Marketable equity securities:				
U.S.	$1,569	$1,857	$ —	$3,426
Fixed income:				
Corporate debt instruments	430	15	(1)	444
Government securities	1,039	27	(5)	1,061
Common/collective trust funds	60	—	—	60
Cost method investments	68	—	—	68
Cash equivalents and other(2)	34	—	—	34
Total	$3,200	$1,899	$ (6)(3)	$5,093
At December 31, 2016				
Marketable equity securities:				
U.S.	$1,449	$1,408	$ —	$2,857
Fixed income:				
Corporate debt instruments	478	13	(4)	487
Government securities	978	22	(8)	992
Common/collective trust funds	67	—	—	67
Cost method investments	69	—	—	69
Cash equivalents and other(2)	12	—	—	12
Total	$3,053	$1,443	$(12)(3)	$4,484

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $5 million and $9 million at December 31, 2017 and 2016, respectively.
(3) The fair value of securities in an unrealized loss position was $565 million and $576 million at December 31, 2017 and 2016, respectively.

The fair value of Dominion Energy's marketable debt securities held in nuclear decommissioning trust funds at December 31, 2017 by contractual maturity is as follows:

(millions)	Amount
Due in one year or less	$ 151
Due after one year through five years	385
Due after five years through ten years	370
Due after ten years	659
Total	$1,565

Presented below is selected information regarding Dominion Energy's marketable equity and debt securities held in nuclear decommissioning trust funds:

Year Ended December 31, (millions)	2017	2016	2015
Proceeds from sales	$1,831	$1,422	$1,340
Realized gains(1)	166	128	219
Realized losses(1)	71	55	84

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

Dominion Energy recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31, (millions)	2017	2016	2015
Total other-than-temporary impairment losses(1)	$ 44	$ 51	$ 66
Losses recorded to the nuclear decomissioning trust regulatory liability	(16)	(16)	(26)
Losses recognized in other comprehensive income (before taxes)	(5)	(12)	(9)
Net impairment losses recognized in earnings	$ 23	$ 23	$ 31

(1) Amounts include other-than-temporary impairment losses for debt securities of $5 million, $13 million and $9 million at December 31, 2017, 2016 and 2015, respectively.

VIRGINIA POWER

Virginia Power holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Virginia Power's decommissioning trust funds are summarized below:

(millions)	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
At December 31, 2017				
Marketable equity securities:				
U.S.	$ 734	$831	$—	$1,565
Fixed income:				
Corporate debt instruments	216	8	—	224
Government securities	482	13	(2)	493
Common/collective trust funds	27	—	—	27
Cost method investments	68	—	—	68
Cash equivalents and other(2)	22	—	—	22
Total	$1,549	$852	$(2)(3)	$2,399
At December 31, 2016				
Marketable equity securities:				
U.S.	$ 677	$624	$—	$1,301
Fixed income:				
Corporate debt instruments	274	6	(4)	276
Government securities	420	9	(2)	427
Common/collective trust funds	26	—	—	26
Cost method investments	69	—	—	69
Cash equivalents and other(2)	7	—	—	7
Total	$1,473	$639	$(6)(3)	$2,106

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.

(2) Includes pending sales of securities of $6 million and $7 million at December 31, 2017 and 2016, respectively.

(3) The fair value of securities in an unrealized loss position was $234 million and $287 million at December 31, 2017 and 2016, respectively.

The fair value of Virginia Power's marketable debt securities at December 31, 2017, by contractual maturity is as follows:

(millions)	Amount
Due in one year or less	$ 32
Due after one year through five years	165
Due after five years through ten years	199
Due after ten years	348
Total	$744

Presented below is selected information regarding Virginia Power's marketable equity and debt securities held in nuclear decommissioning trust funds.

Year Ended December 31, (millions)	2017	2016	2015
Proceeds from sales	$849	$733	$639
Realized gains(1)	75	63	110
Realized losses(1)	30	27	43

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

Virginia Power recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31, (millions)	2017	2016	2015
Total other-than-temporary impairment losses(1)	$ 20	$ 26	$ 36
Losses recorded to the nuclear decomissioning trust regulatory liability	(16)	(16)	(26)
Losses recognized in other comprehensive income (before taxes)	(2)	(7)	(6)
Net impairment losses recognized in earnings	$ 2	$ 3	$ 4

(1) Amounts include other-than-temporary impairment losses for debt securities of $2 million, $8 million and $6 million at December 31, 2017, 2016 and 2015, respectively.

Equity Method Investments

DOMINION ENERGY AND DOMINION ENERGY GAS

Investments that Dominion Energy and Dominion Energy Gas account for under the equity method of accounting are as follows:

Company As of December 31, (millions)	Ownership %	Investment Balance 2017	Investment Balance 2016	Description
Dominion Energy				
Blue Racer	50%	$ 691	$ 677	Midstream gas and related services
Iroquois	50%(1)	311	316	Gas transmission system
Atlantic Coast Pipeline	48%	382	256	Gas transmission system
Fowler Ridge	50%	81	116	Wind-powered merchant generation facility
NedPower	50%	—(2)	112	Wind-powered merchant generation facility
Other	various	79	84	
Total		$1,544	$1,561	
Dominion Energy Gas				
Iroquois	24.07%	$ 95	$ 98	Gas transmission system
Total		$ 95	$ 98	

(1) Comprised of Dominion Energy Midstream's interest of 25.93% and Dominion Energy Gas' interest of 24.07%. See Note 15 for more information.

(2) Liability of $17 million associated with NedPower recorded to other deferred credits and other liabilities, on the Consolidated Balance Sheets as of December 31, 2017. See additional discussion of NedPower below.

Dominion Energy's equity earnings on its investments totaled $14 million, $111 million and $56 million in 2017, 2016 and 2015, respectively, included in other income in Dominion Energy's Consolidated Statements of Income. Dominion Energy received distributions from these investments of $419 million, $104 million and $83 million in 2017, 2016 and 2015, respectively. As of December 31, 2017 and 2016, the carrying amount of Dominion Energy's investments exceeded its share of underlying equity in net assets by $249 million and $260 million, respectively. These differences are comprised at both December 31, 2017 and 2016 of $176 million, reflecting equity method goodwill that is not being amortized and at December 31, 2017 and 2016, of $73 million and $84 million related to basis differences from Dominion Energy's investments in Blue Racer and wind projects, which are being amortized over the useful lives of the underlying assets, and in Atlantic Coast Pipeline, which is being amortized over the term of the credit facility.

Dominion Energy Gas' equity earnings on its investment totaled $21 million in 2017 and 2016 and $23 million in 2015. Dominion Energy Gas received distributions from its investment of $24 million, $22 million and $28 million in 2017, 2016 and 2015, respectively. As of December 31, 2017 and 2016, the carrying amount of Dominion Energy Gas' investment exceeded its share of underlying equity in net assets by $8 million. The difference reflects equity method goodwill and is not being amortized. In May 2016, Dominion Energy Gas sold 0.65% of the noncontrolling partnership interest in Iroquois to TransCanada for approximately $7 million, which resulted in a $5 million ($3 million after-tax) gain, included in other income in Dominion Energy Gas' Consolidated Statements of Income.

DOMINION ENERGY

BLUE RACER

In December 2012, Dominion Energy formed a joint venture with Caiman to provide midstream services to natural gas producers operating in the Utica Shale region in Ohio and portions of Pennsylvania. Blue Racer is an equal partnership between Dominion Energy and Caiman, with Dominion Energy contributing midstream assets and Caiman contributing private equity capital.

In December 2016, Dominion Energy Gas repurchased a portion of the Western System from Blue Racer for $10 million, which is included in property, plant and equipment in Dominion Energy Gas' Consolidated Balance Sheets.

ATLANTIC COAST PIPELINE

In September 2014, Dominion Energy, along with Duke and Southern Company Gas, announced the formation of Atlantic Coast Pipeline. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion Energy an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. In October 2016, Dominion Energy purchased an additional 3% membership interest in Atlantic Coast Pipeline from Duke for $14 million. As of December 31, 2017, the members hold the following membership interests: Dominion Energy, 48%; Duke, 47%; and Southern Company Gas, 5%.

Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina. Subsidiaries and affiliates of all three members plan to be customers of the pipeline under 20-year contracts. Public Service Company of North Carolina, Inc. also plans to be a customer of the pipeline under a 20-year contract. Atlantic Coast Pipeline is considered an equity method investment as Dominion Energy has the ability to exercise significant influence, but not control, over the investee. See Note 15 for more information.

DETI provides services to Atlantic Coast Pipeline which totaled $129 million, $95 million and $74 million in 2017, 2016 and 2015, respectively, included in operating revenue in Dominion Energy and Dominion Energy Gas' Consolidated Statements of Income. Amounts receivable related to these services were $12 million and $10 million at December 31, 2017 and 2016, respectively, composed entirely of accrued unbilled revenue, included in other receivables in Dominion Energy and Dominion Energy Gas' Consolidated Balance Sheets.

In October 2017, Dominion Energy entered into a guarantee agreement to support a portion of Atlantic Coast Pipeline's obligation under its credit facility. See Note 22 for more information.

Dominion Energy contributed $310 million, $184 million and $38 million during 2017, 2016 and 2015, respectively, to Atlantic Coast Pipeline.

Dominion Energy received distributions of $270 million in 2017 from Atlantic Coast Pipeline. No distributions were received in 2016 or 2015.

FOWLER RIDGE & NEDPOWER

In the fourth quarter of 2017, Dominion Energy recorded a charge of $126 million ($76 million after-tax) in other income in its Consolidated Statements of Income reflecting its share of a long-lived asset impairment of property, plant and equipment recorded by NedPower, which resulted in losses in excess of Dominion Energy's investment balance. Dominion Energy recorded the excess losses due to its commitment to provide further financial support for NedPower, resulting in a liability of $17 million recorded to other deferred credits and other liabilities, on the Consolidated Balance Sheets.

As a result of the impairment recorded by NedPower, Dominion Energy evaluated its equity method investment in Fowler Ridge, a similar wind-powered merchant generation facility, determined its fair value was other than-temporarily impaired and recorded an impairment charge of $32 million ($20 million after-tax) in other income in its Consolidated Statements of Income. The fair value of $81 million was estimated using a discounted cash flow method and is considered a Level 3 fair value measurement due to the use of significant unobservable inputs related to the timing and amount of future equity distributions based on the investee's future wind generation and operating costs.

NOTE 10. PROPERTY, PLANT AND EQUIPMENT

Major classes of property, plant and equipment and their respective balances for the Companies are as follows:

At December 31, (millions)	2017	2016
Dominion Energy		
Utility:		
Generation	$17,602	$17,147
Transmission	15,335	14,315
Distribution	17,408	16,381
Storage	2,887	2,814
Nuclear fuel	1,599	1,537
Gas gathering and processing	219	216
Oil and gas	1,720	1,652
General and other	1,514	1,450
Plant under construction	7,765	6,254
Total utility	66,049	61,766
Nonutility:		
Merchant generation-nuclear	1,452	1,419
Merchant generation-other	4,992	4,149
Nuclear fuel	968	897
Gas gathering and processing	630	619
Other-including plant under construction	732	706
Total nonutility	8,774	7,790
Total property, plant and equipment	$74,823	$69,556
Virginia Power		
Utility:		
Generation	$17,602	$17,147
Transmission	8,332	7,871
Distribution	11,151	10,573
Nuclear fuel	1,599	1,537
General and other	794	745
Plant under construction	2,840	2,146
Total utility	42,318	40,019
Nonutility-other	11	11
Total property, plant and equipment	$42,329	$40,030
Dominion Energy Gas		
Utility:		
Transmission	$ 4,732	$ 4,231
Distribution	3,267	3,019
Storage	1,688	1,627
Gas gathering and processing	202	198
General and other	216	184
Plant under construction	293	448
Total utility	10,398	9,707
Nonutility:		
Gas gathering and processing	630	$ 619
Other-including plant under construction	145	149
Total nonutility	775	768
Total property, plant and equipment	$11,173	$10,475

DOMINION ENERGY AND VIRGINIA POWER

Jointly-Owned Power Stations

Dominion Energy's and Virginia Power's proportionate share of jointly-owned power stations at December 31, 2017 is as follows:

(millions, except percentages)	Bath County Pumped Storage Station(1)	North Anna Units 1 and 2(1)	Clover Power Station(1)	Millstone Unit 3(2)
Ownership interest	60%	88.4%	50%	93.5%
Plant in service	$1,059	$ 2,504	$ 589	$1,217
Accumulated depreciation	(612)	(1,263)	(231)	(381)
Nuclear fuel	—	745	—	552
Accumulated amortization of nuclear fuel	—	(607)	—	(427)
Plant under construction	2	92	6	68

(1) Units jointly owned by Virginia Power.
(2) Unit jointly owned by Dominion Energy.

The co-owners are obligated to pay their share of all future construction expenditures and operating costs of the jointly-owned facilities in the same proportion as their respective ownership interest. Dominion Energy and Virginia Power report their share of operating costs in the appropriate operating expense (electric fuel and other energy-related purchases, other operations and maintenance, depreciation, depletion and amortization and other taxes, etc.) in the Consolidated Statements of Income.

Acquisition of Solar Projects

In September 2017, Virginia Power entered into agreements to acquire two solar development projects in North Carolina. The first acquisition is expected to close prior to the project commencing commercial operations, which is expected by the end of 2018, and cost approximately $140 million once constructed, including the initial acquisition cost. The second acquisition is expected to close prior to the project commencing commercial operations, which is expected by the end of 2019, and cost approximately $140 million once constructed, including the initial acquisition cost. The projects are expected to generate approximately 155 MW combined. Virginia Power anticipates claiming federal investment tax credits on these solar projects.

Assignment of Tower Rental Portfolio

Virginia Power rents space on certain of its electric transmission towers to various wireless carriers for communications antennas and other equipment. In March 2017, Virginia Power sold its rental portfolio to Vertical Bridge Towers II, LLC for $91 million in cash. The proceeds are subject to Virginia Power's FERC-regulated tariff, under which it is required to return half of the proceeds to customers. Virginia Power recognized $11 million during 2017, with the remaining $35 million to be recognized ratably through 2023.

DOMINION ENERGY AND DOMINION ENERGY GAS

Assignments of Shale Development Rights

In December 2013, Dominion Energy Gas closed on agreements with two natural gas producers to convey over time approximately 100,000 acres of Marcellus Shale development rights underneath several of its natural gas storage fields. The agreements provide for payments to Dominion Energy Gas, subject to customary adjustments, of approximately $200 million over a period of nine years, and an overriding royalty interest in gas produced from the acreage. In 2013, Dominion Energy Gas received approximately $100 million in cash proceeds. In 2014, Dominion Energy Gas received $16 million in additional cash proceeds resulting from post-closing adjustments. In March 2015, Dominion Energy Gas and one of the natural gas producers closed on an amendment to the agreement, which included the immediate conveyance of approximately 9,000 acres of Marcellus Shale development rights and a two-year extension of the term of the original agreement. The conveyance of development rights resulted in the recognition of $43 million ($27 million after-tax) of previously deferred revenue to operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income. In April 2016, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the immediate conveyance of a 32% partial interest in the remaining approximately 70,000 acres. This conveyance resulted in the recognition of the remaining $35 million ($21 million after-tax) of previously deferred revenue to operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income. In August 2017, Dominion Energy Gas and the natural gas producer signed an amendment to the agreement, which included the finalization of contractual matters on previous conveyances, the conveyance of Dominion Energy Gas' remaining 68% interest in approximately 70,000 acres and the elimination of Dominion Energy Gas' overriding royalty interest in gas produced from all acreage. Dominion Energy Gas will receive total consideration of $130 million, with $65 million received in 2017 and $65 million to be received by the end of the third quarter of 2018 in connection with the final conveyance. As a result of this amendment, in 2017, Dominion Energy Gas recognized a $56 million ($33 million after-tax) gain included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income associated with the finalization of the contractual matters on previous conveyances, a $9 million ($5 million after-tax) gain included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income associated with the elimination of its overriding royalty interest and expects to recognize an approximately $65 million ($47 million after-tax) gain associated with the final conveyance of acreage.

In November 2014, Dominion Energy Gas closed an agreement with a natural gas producer to convey over time approximately 24,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields. The agreement provided for payments to Dominion Energy Gas, subject to customary adjustments, of approximately $120 million over a period of four years, and an overriding royalty interest in gas produced from the acreage. In November 2014, Dominion Energy Gas closed on the agreement and received proceeds of $60 million associated with an initial conveyance of approximately 12,000 acres. In connection with that agreement, in 2016, Dominion Energy Gas conveyed a 50% interest in approximately 4,000 acres of Marcellus Shale development rights and received proceeds of $10 million and an overriding royalty interest in gas produced from the acreage. These transactions resulted in a $10 million ($6 million after-tax) gain. In July 2017, in connection with the existing agreement, Dominion Energy Gas conveyed an additional 50% interest in approximately 2,000 acres of Marcellus Shale development rights and received proceeds of $5 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in a $5 million ($3 million after-tax) gain. The gains are included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income. In January 2018, Dominion Energy Gas and the natural gas producer closed on an amendment to the agreement, which included the conveyance of Dominion Energy Gas' remaining 50% interest in approximately 18,000 acres and the elimination of Dominion Energy Gas' overriding royalty interest in gas produced from all acreage. Dominion Energy Gas received proceeds of $28 million, resulting in an approximately $28 million ($20 million after-tax) gain recorded in the first quarter of 2018.

In March 2015, Dominion Energy Gas conveyed to a natural gas producer approximately 11,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields and received proceeds of $27 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in a $27 million ($16 million after-tax) gain, included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income.

In September 2015, Dominion Energy Gas closed on an agreement with a natural gas producer to convey approximately 16,000 acres of Utica and Point Pleasant Shale development rights underneath one of its natural gas storage fields. The agreement provided for a payment to Dominion Energy Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage. In September 2015, Dominion Energy Gas received proceeds of $52 million associated with the conveyance of the acreage, resulting in a $52 million ($29 million after-tax) gain, included in other operations and maintenance expense in Dominion Energy Gas' Consolidated Statements of Income.

DOMINION ENERGY

Sale of Certain Retail Energy Marketing Assets

In October 2017, Dominion Energy entered into an agreement to sell certain assets associated with its nonregulated retail energy marketing operations for total consideration of $143 million, subject to customary approvals and certain adjustments. In December 2017, the first phase of the agreement closed for $79 million, which resulted in the recognition of a $78 million ($48 million after-tax) benefit, included in other operations and maintenance expense in Dominion Energy's Consolidated Statements of Income. Dominion Energy is expected to recognize a benefit of approximately $65 million ($48 million after-tax) in other operations and maintenance expense upon closing of the second phase of the agreement in 2018. Pursuant to the agreement, Dominion Energy entered into a commission agreement with the buyer upon the first closing in December 2017 under which the buyer will pay a commission in connection with the right to use Dominion Energy's brand in marketing materials and other services over a ten-year term.

NOTE 11. GOODWILL AND INTANGIBLE ASSETS

Goodwill

The changes in Dominion Energy's and Dominion Energy Gas' carrying amount and segment allocation of goodwill are presented below:

(millions)	Power Generation	Gas Infrastructure	Power Delivery	Corporate and Other(1)	Total
Dominion Energy					
Balance at December 31, 2015(2)	$1,422	$ 946	$926	$—	$3,294
Dominion Energy Questar Combination	—	3,105(3)	—	—	3,105
Balance at December 31, 2016(2)	$1,422	$4,051	$926	$—	$6,399
Dominion Energy Questar Combination	—	6(3)	—	—	6
Balance at December 31, 2017(2)	$1,422	$4,057	$926	$—	$6,405
Dominion Energy Gas					
Balance at December 31, 2015(2)	$ —	$ 542	$ —	$—	$ 542
No events affecting goodwill	—	—	—	—	—
Balance at December 31, 2016(2)	$ —	$ 542	$ —	$—	$ 542
No events affecting goodwill	—	—	—	—	—
Balance at December 31, 2017(2)	$ —	$ 542	$ —	$—	$ 542

(1) Goodwill recorded at the Corporate and Other segment is allocated to the primary operating segments for goodwill impairment testing purposes.
(2) Goodwill amounts do not contain any accumulated impairment losses.
(3) See Note 3.

Other Intangible Assets

The Companies' other intangible assets are subject to amortization over their estimated useful lives. Dominion Energy's amortization expense for intangible assets was $80 million, $73 million and $78 million for 2017, 2016 and 2015, respectively. In 2017, Dominion Energy acquired $147 million of intangible assets, primarily representing software and right-of-use assets, with an estimated weighted-average amortization period of approximately 14 years. Amortization expense for Virginia Power's intangible assets was $31 million, $29 million and $25 million for 2017, 2016 and 2015, respectively. In 2017, Virginia Power acquired $39 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of 7 years. Dominion Energy Gas' amortization expense for intangible assets was $14 million, $6 million and $18 million for 2017, 2016 and 2015, respectively. In 2017, Dominion Energy Gas acquired $25 million of intangible assets, primarily representing software and right-of-use assets, with an estimated weighted-average amortization period of approximately 14 years. The components of intangible assets are as follows:

	2017		2016	
At December 31, (millions)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Dominion Energy				
Software, licenses and other	$1,043	$358	$955	$337
Virginia Power				
Software, licenses and other	$ 347	$114	$326	$101
Dominion Energy Gas				
Software, licenses and other	$ 165	$ 56	$147	$ 49

Annual amortization expense for these intangible assets is estimated to be as follows:

(millions)	2018	2019	2020	2021	2022
Dominion Energy	$78	$68	$56	$43	$37
Virginia Power	$30	$26	$20	$13	$ 9
Dominion Energy Gas	$13	$13	$12	$11	$10

NOTE 12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities include the following:

At December 31, (millions)	2017	2016
Dominion Energy		
Regulatory assets:		
Deferred rate adjustment clause costs(1)	$ 70	$ 63
Deferred nuclear refueling outage costs(2)	54	71
Unrecovered gas costs(3)	38	19
Deferred cost of fuel used in electric generation(4)	23	—
Other	109	91
Regulatory assets-current	294	244
Unrecognized pension and other postretirement benefit costs(5)	1,336	1,401
Deferred rate adjustment clause costs(1)	401	329
Derivatives(6)	223	174
PJM transmission rates(7)	222	192
Utility reform legislation(8)	147	99
Income taxes recoverable through future rates(9)	32	123
Other	119	155
Regulatory assets-noncurrent	2,480	2,473
Total regulatory assets	$2,774	$2,717
Regulatory liabilities:		
Provision for future cost of removal and AROs(10)	$ 101	$ —
PIPP(11)	20	28
Deferred cost of fuel used in electric generation(4)	8	61
Other	64	74
Regulatory liabilities-current(12)	193	163
Income taxes refundable through future rates(13)	4,058	—
Provision for future cost of removal and AROs(10)	1,384	1,427
Nuclear decommissioning trust(14)	1,121	902
Derivatives(6)	69	69
Other	284	224
Regulatory liabilities-noncurrent	6,916	2,622
Total regulatory liabilities	$7,109	$2,785
Virginia Power		
Regulatory assets:		
Deferred rate adjustment clause costs(1)	$ 56	$ 51
Deferred nuclear refueling outage costs(2)	54	71
Deferred cost of fuel used in electric generation(4)	23	—
Other	72	57
Regulatory assets-current	205	179
Deferred rate adjustment clause costs(1)	312	246
PJM transmission rates(7)	222	192
Derivatives(6)	190	133
Income taxes recoverable through future rates(9)	—	76
Other	86	123
Regulatory assets-noncurrent	810	770
Total regulatory assets	$1,015	$ 949
Regulatory liabilities:		
Provision for future cost of removal(10)	$ 80	$ —
Deferred cost of fuel used in electric generation(4)	8	61
Other	39	54
Regulatory liabilities-current(12)	127	115
Income taxes refundable through future rates(13)	2,581	—
Nuclear decommissioning trust(14)	1,121	902
Provision for future cost of removal(10)	915	946
Derivatives(6)	69	69
Other	74	45
Regulatory liabilities-noncurrent	4,760	1,962
Total regulatory liabilities	$4,887	$2,077

At December 31, (millions)	2017	2016
Dominion Energy Gas		
Regulatory assets:		
Deferred rate adjustment clause costs(1)	$ 14	$ 12
Unrecovered gas costs(3)	8	12
Other	4	2
Regulatory assets-current(15)	26	26
Unrecognized pension and other postretirement benefit costs(5)	258	358
Utility reform legislation(8)	147	99
Deferred rate adjustment clause costs(1)	89	79
Income taxes recoverable through future rates(9)	—	23
Other	17	18
Regulatory assets-noncurrent	511	577
Total regulatory assets	$ 537	$603
Regulatory liabilities:		
PIPP(11)	$ 20	$ 28
Provision for future cost of removal and AROs(10)	13	—
Other	5	7
Regulatory liabilities-current(12)	38	35
Income taxes refundable through future rates(13)	998	—
Provision for future cost of removal and AROs(10)	160	174
Other	69	45
Regulatory liabilities-noncurrent	1,227	219
Total regulatory liabilities	$1,265	$254

(1) Primarily reflects deferrals under the electric transmission FERC formula rate and the deferral of costs associated with certain current and prospective rider projects for Virginia Power and deferrals of costs associated with certain current and prospective rider projects for Dominion Energy Gas. See Note 13 for more information.

(2) Legislation enacted in Virginia in April 2014 requires Virginia Power to defer operation and maintenance costs incurred in connection with the refueling of any nuclear-powered generating plant. These deferred costs will be amortized over the refueling cycle, not to exceed 18 months.

(3) Reflects unrecovered gas costs at regulated gas operations, which are recovered through filings with the applicable regulatory authority.

(4) Reflects deferred fuel expenses for the Virginia and North Carolina jurisdictions of Dominion Energy's and Virginia Power's generation operations. See Note 13 for more information.

(5) Represents unrecognized pension and other postretirement employee benefit costs expected to be recovered through future rates generally over the expected remaining service period of plan participants by certain of Dominion Energy's and Dominion Energy Gas' rate-regulated subsidiaries.

(6) As discussed under Derivative Instruments in Note 2, for jurisdictions subject to cost-based rate regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities as they are expected to be recovered from or refunded to customers.

(7) Reflects amount related to the PJM transmission cost allocation matter. See Note 13 for more information.

(8) Ohio legislation under House Bill 95, which became effective in September 2011. This law updates natural gas legislation by enabling gas companies to include more up-to-date cost levels when filing rate cases. It also allows gas companies to seek approval of capital expenditure plans under which gas companies can recognize carrying costs on associated capital investments placed in service and can defer the carrying costs plus depreciation and property tax expenses for recovery from ratepayers in the future.

(9) Amounts to be recovered through future rates to pay income taxes that become payable when rate revenue is provided to recover AFUDC-equity and depreciation of property, plant and equipment for which deferred income taxes were not recognized for ratemaking purposes, including amounts attributable to tax rate changes. See below for discussion of the 2017 Tax Reform Act.

(10) Rates charged to customers by the Companies' regulated businesses include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.
(11) Under PIPP, eligible customers can make reduced payments based on their ability to pay. The difference between the customer's total bill and the PIPP plan amount is deferred and collected or returned annually under the PIPP rate adjustment clause according to East Ohio tariff provisions. See Note 13 for more information.
(12) Current regulatory liabilities are presented in other current liabilities in the Consolidated Balance Sheets of the Companies.
(13) Amounts recorded to pass the effect of reduced income tax rates from the 2017 Tax Reform Act to customers in future periods, which will reverse at the weighted average tax rate that was used to build the reserves over the remaining book life of the property, net of amounts to be recovered through future rates to pay income taxes that become payable when rate revenue is provided to recover AFUDC-equity.
(14) Primarily reflects a regulatory liability representing amounts collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of Virginia Power's utility nuclear generation stations, in excess of the related AROs.
(15) Current regulatory assets are presented in other current assets in the Consolidated Balance Sheets of Dominion Energy Gas.

At December 31, 2017, $390 million of Dominion Energy's, $273 million of Virginia Power's and $11 million of Dominion Energy Gas' regulatory assets represented past expenditures on which they do not currently earn a return. With the exception of the $222 million PJM transmission cost allocation matter, the majority of these expenditures are expected to be recovered within the next two years.

NOTE 13. REGULATORY MATTERS

Regulatory Matters Involving Potential Loss Contingencies

As a result of issues generated in the ordinary course of business, the Companies are involved in various regulatory matters. Certain regulatory matters may ultimately result in a loss; however, as such matters are in an initial procedural phase, involve uncertainty as to the outcome of pending reviews or orders, and/or involve significant factual issues that need to be resolved, it is not possible for the Companies to estimate a range of possible loss. For matters for which the Companies cannot estimate a range of possible loss, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the regulatory process such that the Companies are able to estimate a range of possible loss. For regulatory matters for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any estimated range is based on currently available information, involves elements of judgment and significant uncertainties and may not represent the Companies' maximum possible loss exposure. The circumstances of such regulatory matters will change from time to time and actual results may vary significantly from the current estimate. For current matters not specifically reported below, management does not anticipate that the outcome from such matters would have a material effect on the Companies' financial position, liquidity or results of operations.

FERC—ELECTRIC

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. Dominion Energy's merchant generators sell electricity in the PJM, MISO, CAISO and ISO-NE wholesale markets, and to wholesale purchasers in the states of Virginia, North Carolina, Indiana, Connecticut, Tennessee, Georgia, California, South Carolina and Utah, under Dominion Energy's market-based sales tariffs authorized by FERC or pursuant to FERC authority to sell as a qualified facility. Virginia Power purchases and, under its FERC market-based rate authority, sells electricity in the wholesale market. In addition, Virginia Power has FERC approval of a tariff to sell wholesale power at capped rates based on its embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside Virginia Power's service territory. Any such sales would be voluntary.

Rates

In April 2008, FERC granted an application for Virginia Power's electric transmission operations to establish a forward-looking formula rate mechanism that updates transmission rates on an annual basis and approved an ROE of 11.4%, effective as of January 1, 2008. The formula rate is designed to recover the expected revenue requirement for each calendar year and is updated based on actual costs. The FERC-approved formula method, which is based on projected costs, allows Virginia Power to earn a current return on its growing investment in electric transmission infrastructure.

In March 2010, ODEC and North Carolina Electric Membership Corporation filed a complaint with FERC against Virginia Power claiming, among other issues, that the incremental costs of undergrounding certain transmission line projects were unjust, unreasonable and unduly discriminatory or preferential and should be excluded from Virginia Power's transmission formula rate. A settlement of the other issues raised in the complaint was approved by FERC in May 2012.

In March 2014, FERC issued an order excluding from Virginia Power's transmission rates for wholesale transmission customers located outside Virginia the incremental costs of undergrounding certain transmission line projects. FERC found it is not just and reasonable for non-Virginia wholesale transmission customers to be allocated the incremental costs of undergrounding the facilities because the projects are a direct result of Virginia legislation and Virginia Commission pilot programs intended to benefit the citizens of Virginia. The order is retroactively effective as of March 2010 and will cause the reallocation of the costs charged to wholesale transmission customers with loads outside Virginia to wholesale transmission customers with loads in Virginia. FERC determined that there was not sufficient evidence on the record to determine the magnitude of the underground increment and held a hearing to determine the appropriate amount of undergrounding cost to be allocated to each wholesale transmission customer in Virginia.

In October 2017, FERC issued an order determining the calculation of the incremental costs of undergrounding the transmission projects and affirming that the costs are to be recovered from the wholesale transmission customers with loads located in Virginia. FERC directed Virginia Power to rebill all wholesale transmission customers retroactively to March 2010 within 30 days of when the proceeding becomes final and no longer subject to rehearing. In November 2017, Virginia Power, North Carolina Electric Membership Corporation and the wholesale transmission customers filed petitions for rehearing. While Virginia Power cannot predict the outcome of the matter, it is not expected to have a material effect on results of operations.

PJM Transmission Rates

In April 2007, FERC issued an order regarding its transmission rate design for the allocation of costs among PJM transmission customers, including Virginia Power, for transmission service provided by PJM. For new PJM-planned transmission facilities that operate at or above 500 kV, FERC established a PJM regional rate design where customers pay according to each customer's share of the region's load. For recovery of costs of existing facilities, FERC approved the existing methodology whereby a customer pays the cost of facilities located in the same zone as the customer. A number of parties appealed the order to the U.S. Court of Appeals for the Seventh Circuit.

In August 2009, the court issued its decision affirming the FERC order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above for further consideration by FERC. On remand, FERC reaffirmed its earlier decision to allocate the costs of new facilities 500 kV and above according to the customer's share of the region's load. A number of parties filed appeals of the order to the U.S. Court of Appeals for the Seventh Circuit. In June 2014, the court again remanded the cost allocation issue to FERC. In December 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the cost allocation issue. The hearing only concerns the costs of new facilities approved by PJM prior to February 1, 2013. Transmission facilities approved after February 1, 2013 are allocated on a hybrid cost allocation method approved by FERC and not subject to any court review.

In June 2016, PJM, the PJM transmission owners and state commissions representing substantially all of the load in the PJM market submitted a settlement to FERC to resolve the outstanding issues regarding this matter. Under the terms of the settlement, Virginia Power would be required to pay approximately $200 million to PJM over the next 10 years. Although the settlement agreement has not been accepted by FERC, and the settlement is opposed by a small group of parties to the proceeding, Virginia Power believes it is probable it will be required to make payment as an outcome of the settlement. Accordingly, as of December 31, 2017, Virginia Power has a contingent liability of $231 million in other deferred credits and other liabilities, which is offset by a $222 million regulatory asset for the amount that will be recovered through retail rates in Virginia.

FERC—GAS

In July 2017, FERC audit staff communicated to DETI that it had substantially completed an audit of DETI's compliance with the accounting and reporting requirements of FERC's Uniform System of Accounts and provided a description of matters and preliminary recommendations. In November 2017, the FERC audit staff issued its audit report which could have the potential to result in adjustments which could be material to Dominion Energy and Dominion Energy Gas' results of operations. In December 2017, DETI provided its response to the audit report. DETI requested FERC review of contested findings and submitted its plan for compliance with the uncontested portions of the report. In connection with one uncontested issue, DETI recognized a charge of $15 million ($9 million after-tax) recorded within other operations and maintenance expense in Dominion Energy's and Dominion Energy Gas' Consolidated Statements of Income during 2017 to write-off the balance of a regulatory asset, originally established in 2008, that is no longer considered probable of recovery. Pending final resolution of the audit process and a determination by FERC, management is unable to estimate the potential impact of the other findings and no amounts have been recognized.

2017 TAX REFORM ACT

Subsequent to the enactment of the 2017 Tax Reform Act, the Companies' state regulators issued orders requesting that public utilities evaluate the total tax impact on the entity's cost of service and accrue a regulatory liability attributable to the benefits of the reduction in the corporate income tax rate. Certain of the orders requested that the public utilities submit a response to the state regulatory commissions detailing the total tax impact on the utility's cost of service.

Virginia Power submitted a response to the North Carolina Commission detailing the impact of the 2017 Tax Reform Act on base non-fuel cost of service and Virginia Power's excess deferred income taxes clarifying that the amounts have been deferred to a regulatory liability. Questar Gas submitted a response to the Utah Commission detailing the impact of the 2017 Tax Reform Act on base rates and the infrastructure rider, and proposing that the benefits be passed back to customers. These filings are pending. Dominion Energy plans to respond to the remaining state regulatory commissions in accordance with the due dates on the issued orders. The Companies will begin to reserve the impacts of the cost of service reduction as a regulatory liability beginning in 2018 until the rates are reset.

To date, the FERC has not issued guidance on how and when to reflect the impacts of the 2017 Tax Reform Act in customer rates.

The Companies have recorded a reasonable estimate of net income taxes refundable through future rates in the jurisdictions in which they operate. Through actions by FERC or state regulators the estimates may be subject to changes that could have a material impact on the Companies' results of operations, financial condition and/or cash flows.

Other Regulatory Matters

ELECTRIC REGULATION IN VIRGINIA

The Regulation Act enacted in 2007 instituted a cost-of-service rate model, ending Virginia's planned transition to retail competition for electric supply service to most classes of customers.

The Regulation Act authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, FERC-approved transmission costs, underground distribution lines, environmental compliance, conservation and energy efficiency programs and renewable energy programs, and also contains statutory provisions directing Virginia Power to file annual fuel cost recovery cases with the Virginia Commission. As amended, it provides for enhanced returns on capital expenditures on specific newly-proposed generation projects.

If the Virginia Commission's future rate decisions, including actions relating to Virginia Power's rate adjustment clause filings, differ materially from Virginia Power's expectations, it may adversely affect its results of operations, financial condition and cash flows.

Regulation Act Legislation

In February 2015, the Virginia Governor signed legislation into law which will keep Virginia Power's base rates unchanged until at least December 1, 2022. In addition, no biennial reviews will be conducted by the Virginia Commission for the five successive 12-month test periods beginning January 1, 2015, and ending December 31, 2019. The legislation states that Virginia Power's 2015 biennial review, filed in March 2015, would proceed for the sole purpose of reviewing and determining whether any refunds are due to customers based on earnings performance for generation and distribution services during the 2013 and 2014 test periods. In addition, the legislation requires the Virginia Commission to conduct proceedings in 2017 and 2019 to determine the utility's ROE for use in connection with rate adjustment clauses and requires utilities to file integrated resource plans annually rather than biennially. In November 2015, the Virginia Commission ordered testimony, briefs and a separate bifurcated hearing in Virginia Power's then-pending Rider B, R, S, and W cases on whether the Virginia Commission can adjust the ROE applicable to these rate adjustment clauses prior to 2017. In February 2016, the Virginia Commission issued final orders in these cases, stating that it could adjust the ROE for the projects. After separate, additional bifurcated hearings, the Virginia Commission issued final orders setting base ROEs for the Rider GV, C1A and C2A, BW, US-2 and U cases.

In February 2016, certain industrial customers of APCo petitioned the Virginia Commission to issue a declaratory judgment that Virginia legislation enacted in 2015 keeping APCo's base rates unchanged until at least 2020 (and Virginia Power's base rates unchanged until at least 2022) is unconstitutional, and to require APCo to make biennial review filings in 2016 and 2018. Virginia Power intervened to support the constitutionality of this legislation. In July 2016, the Virginia Commission held in a divided opinion that this legislation is constitutional, and the industrial customers appealed this order to the Supreme Court of Virginia. In November 2016, the Supreme Court of Virginia granted the appeal as a matter of right and consolidated it for oral argument with other similar appeals from the Virginia Commission's order. In September 2017, the Supreme Court of Virginia affirmed that the legislation is constitutional.

In March 2017, as required by Regulation Act legislation enacted in February 2015, Virginia Power filed an application for the Virginia Commission to determine the general ROE for Virginia Power's non-transmission rate adjustment clauses. The application supported a 10.5% ROE for these rate adjustment clauses. In November 2017, the Virginia Commission approved a general 9.2% ROE for these rate adjustment clauses.

2015 Biennial Review

In November 2015, the Virginia Commission issued the 2015 Biennial Review Order. After deciding several contested regulatory earnings adjustments, the Virginia Commission ruled that Virginia Power earned on average an ROE of approximately 10.89% on its generation and distribution services for the combined 2013 and 2014 test periods. Because this ROE was more than 70 basis points above Virginia Power's authorized ROE of 10.0%, the Virginia Commission ordered that approximately $20 million in excess earnings be credited to customer bills based on usage in 2013 and 2014 over a six-month period beginning within 60 days of the 2015 Biennial Review Order.

Virginia Fuel Expenses

In May 2017, Virginia Power submitted its annual fuel factor to the Virginia Commission to recover an estimated $1.6 billion in Virginia jurisdictional projected fuel expenses for the rate year beginning July 1, 2017. Virginia Power's proposed fuel rate represented a fuel revenue increase of $279 million when applied to projected kilowatt-hour sales for the period July 1, 2017 to June 30, 2018. In June 2017, the Virginia Commission approved Virginia Power's proposed fuel rate.

Solar Facility Projects

In February 2017, Virginia Power received approval from the Virginia Commission for a CPCN to construct and operate the Remington solar facility and related distribution interconnection facilities. The 20 MW facility began operations in October 2017 at a total cost of $45 million, excluding financing costs. The facility is the subject of a public-private partnership whereby the Commonwealth of Virginia, a non-jurisdictional customer, compensates Virginia Power for the facility's net electrical energy output, and Microsoft Corporation purchases all environmental attributes (including renewable energy certificates) generated by the facility. There is no rate adjustment clause associated with this CPCN, nor will any costs of the project be recovered from jurisdictional customers.

In March 2017, Virginia Power received Virginia Commission approval for a CPCN to construct and operate the Oceana solar facility and related distribution interconnection facilities. The 18 MW facility began operations in December 2017 at a total cost of $40 million, excluding financing costs. The facility is the subject of a public-private partnership whereby the Commonwealth of Virginia, a non-jurisdictional customer, compensates Virginia Power for the facility's net electrical energy output. Virginia Power will retire renewable energy certificates on the Commonwealth of Virginia's behalf in an amount equal to those generated by the facility. There is no rate adjustment clause associated with the facility, nor will any of its costs be recovered from jurisdictional customers.

Rate Adjustment Clauses

Below is a discussion of significant riders associated with various Virginia Power projects:

- The Virginia Commission previously approved Rider T1 concerning transmission rates. In May 2017, Virginia Power proposed a $625 million total revenue requirement consisting of $490 million for the transmission component of Virginia Power's base rates and $135 million for Rider T1. This total revenue requirement represents a $55 million decrease versus the revenues to be produced during the rate year under current rates. In July 2017, the Virginia Commission approved the proposed total revenue requirement, including Rider T1, subject to true-up, for the rate year beginning September 1, 2017.

- The Virginia Commission previously approved Rider S in conjunction with the Virginia City Hybrid Energy Center. In February 2017, the Virginia Commission approved a $243 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2017. It also established a 10.4% ROE effective April 1, 2017. In February 2018, the Virginia Commission approved a $218 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2018. It also established a 10.2% base ROE effective April 1, 2018.
- The Virginia Commission previously approved Rider W in conjunction with Warren County. In February 2017, the Virginia Commission approved a $121 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2017. It also established a 10.4% ROE effective April 1, 2017. In February 2018, the Virginia Commission approved a $109 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2018. It also established a 10.2% ROE for Rider W effective April 1, 2018.
- The Virginia Commission previously approved Rider R in conjunction with Bear Garden. In February 2017, the Virginia Commission approved a $72 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2017. It also established a 10.4% ROE effective April 1, 2017. In February 2018, the Virginia Commission approved a $66 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2018. It also established a 10.2% ROE for Rider R effective April 1, 2018.
- The Virginia Commission previously approved Rider B in conjunction with the conversion of three power stations to biomass. In February 2017, the Virginia Commission approved a $27 million revenue requirement for the rate year beginning April 1, 2017. It also established an 11.4% ROE effective April 1, 2017. In June 2017, Virginia Power proposed a $42 million revenue requirement for the rate year beginning April 1, 2018, which represents a $15 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider U in conjunction with cost recovery to move certain electric distribution facilities underground as authorized by prior Virginia legislation. In September 2017, the Virginia Commission approved a total $22 million annual revenue requirement effective October 1, 2017, using a 9.4% ROE, and a total capital investment of $40 million for second phase conversions.
- The Virginia Commission previously approved Riders C1A and C2A in connection with cost recovery for DSM programs. In June 2017, the Virginia Commission approved a $28 million revenue requirement, subject to true-up, for the rate year beginning July 1, 2017. It also established a 9.4% ROE for Riders C1A and C2A effective July 1, 2017. In October 2017, Virginia Power requested approval to extend one existing energy efficiency program for five years with a new $25 million cost cap, and proposed a total $31 million revenue requirement for the rate year beginning July 1, 2018, which represents a $3 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider BW in conjunction with Brunswick County. In April 2017, the Virginia Commission established a 10.4% ROE for Rider BW effective September 1, 2017. In June 2017, it approved a $127 million revenue requirement, subject to true-up, for the rate year beginning September 1, 2017. In October 2017, Virginia Power proposed a $132 million revenue requirement for the rate year beginning September 1, 2018, which represents a $5 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider US-2 in conjunction with the Scott Solar, Whitehouse, and Woodland solar facilities. In April 2017, the Virginia Commission established a 9.4% ROE for Rider US-2 effective September 1, 2017. In June 2017, the Virginia Commission approved a $10 million revenue requirement, subject to true-up, for the rate year beginning September 1, 2017. In October 2017, Virginia Power proposed a $15 million revenue requirement for the rate year beginning September 1, 2018, which represents a $5 million increase over the previous year. This case is pending.
- The Virginia Commission previously approved Rider GV in conjunction with Greensville County. In February 2017, the Virginia Commission approved an $82 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2017. It also established a 9.4% ROE effective April 1, 2017. In February 2018, the Virginia Commission approved an $82 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2018. It also established a 9.2% ROE effective April 1, 2018.

Electric Transmission Projects

In November 2013, the Virginia Commission issued an order granting Virginia Power a CPCN to construct approximately 7 miles of new overhead 500 kV transmission line from the existing Surry switching station in Surry County to a new Skiffes Creek switching station in James City County, and approximately 20 miles of new 230 kV transmission line in James City County, York County, and the City of Newport News from the proposed new Skiffes Creek switching station to Virginia Power's existing Whealton substation in the City of Hampton. As of July 2017, Virginia Power has received all major required permits and approvals and is proceeding with construction of the project. In connection with the receipt of the permit from the U.S. Army Corps of Engineers in July 2017, Virginia Power was required to make payments totaling approximately $90 million to fund improvements to historical and cultural resources near the project. Accordingly, in July 2017, Virginia Power recorded an increase to property, plant and equipment and a corresponding liability for these payment obligations. Through December 31, 2017, Virginia Power had made $90 million of such payments. Also in July 2017, the National Parks Conservation Association filed a lawsuit in U.S. District Court for the D.C. Circuit seeking to set aside the permit granted by the U.S. Army Corps of Engineers for the project and requested a preliminary injunction against the permit. In August 2017, the National Trust for Historic Preservation and Preservation Virginia filed a similar lawsuit in U.S. District Court for the D.C. Circuit. In October 2017, the preliminary injunction requests were denied. These lawsuits are pending.

In November 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to convert an existing transmission line to 230 kV in Prince William County, Virginia, and Loudoun County, Virginia, and to construct and operate a new approximately five mile overhead 230 kV double circuit transmission line between a tap point near the Gainesville substation and a new to-be-constructed Haymarket substation. The total estimated cost of the project is approximately $55 million. In April 2017, the Virginia Commission issued an interim order instructing Virginia Power to construct and operate the project along an approved route if Virginia Power could obtain all necessary rights-of-way. Otherwise, the Virginia Commission ruled that Virginia Power can construct and operate the project along an approved alternative route. In June 2017, the Virginia Commission issued a final order approving the alternative route for the project, and granted the necessary CPCN. In July 2017, the Virginia Commission retained jurisdiction over the case to evaluate two requests to reconsider its decisions. Also in July 2017, Virginia Power requested that the Virginia Commission stay the proceeding while Virginia Power discusses the proposed route with leaders of Prince William County. In December 2017, the Virginia Commission granted in part the two motions for reconsideration, retained jurisdiction for further proceedings in the case and stayed the effectiveness of its final order. This matter is pending.

In November 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate in multiple Virginia counties an approximately 38 mile overhead 230 kV transmission line between the Remington and Gordonsville substations, along with associated facilities. In August 2017, the Virginia Commission granted a CPCN for the project. The total estimated cost of the project is approximately $105 million.

In March 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in multiple Virginia counties approximately 33 miles of the existing 500 kV transmission line between the Cunningham switching station and the Dooms substation, along with associated station work. In May 2017, the Virginia Commission granted a CPCN to construct and operate the project. The total estimated cost of the project is approximately $60 million.

In August 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in multiple Virginia counties approximately 28 miles of the existing 500 kV transmission line between the Carson switching station and a terminus located near the Rogers Road switching station under construction in Greensville County, Virginia, along with associated work at the Carson switching station. In March 2017, the Virginia Commission granted a CPCN to construct and operate the project. The total estimated cost of the project is approximately $55 million.

In January 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and rearrange its Idylwood substation in Fairfax County, Virginia. In September 2017, the Virginia Commission granted a CPCN for the project. The total estimated cost of the project is approximately $110 million.

In June 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in Prince William County, Virginia, approximately 9 miles of existing 115 kV transmission lines between Possum Point Switching Station and NOVEC's Smoketown delivery point, utilizing 230 kV design on the majority of the route, for total estimated cost of approximately $20 million. In February 2018, the Virginia Commission granted a CPCN for the project.

In September 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in Augusta County, Virginia approximately 18 miles of the existing 500 kV transmission line between the Dooms substation and the Valley substation, along with associated substation work, for a total estimated cost of approximately $65 million. This case is pending.

In November 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to build and operate in Fairfax County, Virginia approximately 4 miles of 230 kV transmission line between the Idylwood and Tysons substations, along with associated substation work. The total estimated cost of the project is approximately $125 million. This case is pending.

In February 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in Lancaster County, Virginia and Middlesex County, Virginia and across the Rappahannock River, approximately 2 miles of existing 115 kV transmission lines between Harmony Village Substation and White Stone Substation. In December 2017, the Virginia Commission granted a CPCN for the project to be constructed under the Rappahannock River. The total estimated cost of the project is approximately $85 million.

North Anna

Virginia Power is considering the construction of a third nuclear unit at a site located at North Anna nuclear power station. If Virginia Power decides to build a new unit, it would require a COL from the NRC, approval of the Virginia Commission and certain environmental permits and other approvals. In June 2017, the NRC issued the COL. Virginia Power has not yet committed to building a new nuclear unit at North Anna nuclear power station.

Requests by BREDL for a contested NRC hearing on Virginia Power's COL application were dismissed, and in September 2016, the U.S. Court of Appeals for the D.C. Circuit dismissed with prejudice petitions for judicial review that BREDL and other organizations had filed challenging the NRC's reliance on a rule generically assessing the environmental impacts of continued onsite storage of spent nuclear fuel in various licensing proceedings, including Virginia Power's COL proceeding. This dismissal followed the Court's June 2016 decision in New York v. NRC, upholding the NRC's continued storage rule and August 2016 denial of requests for rehearing en banc. Therefore, the contested portion of the COL proceeding was closed. The NRC is required to conduct a hearing in all COL proceedings. This mandatory NRC hearing was held in March 2017, was uncontested and the resulting NRC decision authorized issuance of the COL.

In August 2016, Virginia Power received a 60-day notice of intent to sue from the Sierra Club alleging Endangered Species Act violations. The notice alleges that the U.S. Army Corps of Engineers failed to conduct adequate environmental and consultation reviews, related to a potential third nuclear unit located at North Anna, prior to issuing a CWA section 404 permit to Virginia Power in September 2011. No lawsuit was filed and in November 2016, the Army Corps of Engineers suspended the section 404 permit while it gathered additional information. The section 404 permit was reinstated in April 2017.

NORTH CAROLINA REGULATION

In August 2017, Virginia Power submitted its annual filing to the North Carolina Commission to adjust the fuel component of its electric rates. Virginia Power proposed a total $15 million increase to the fuel component of its electric rates for the rate year beginning January 1, 2018. In January 2018, the North Carolina Commission approved Virginia Power's proposed fuel charge adjustment.

Ohio Regulation

PIR Program

In 2008, East Ohio began PIR, aimed at replacing approximately 25% of its pipeline system. In March 2015, East Ohio filed an application with the Ohio Commission requesting approval to extend the PIR program for an additional five years and to increase the annual capital investment, with corresponding increases in the annual rate-increase caps. In September 2016, the Ohio Commission approved a stipulation filed jointly by East Ohio and the Staff of the Ohio Commission to settle East Ohio's pending application. As requested, the PIR program and associated cost recovery will continue for another five-year term, calendar years 2017 through 2021, and East Ohio will be permitted to increase its annual capital expenditures to $200 million by 2018 and 3% per year thereafter subject to the cost recovery rate increase caps proposed by East Ohio.

In April 2017, the Ohio Commission approved East Ohio's application to adjust the PIR cost recovery rates for 2016 costs. The filing reflects gross plant investment for 2016 of $188 million, cumulative gross plant investment of $1.2 billion and a revenue requirement of $157 million.

AMR Program

In 2007, East Ohio began installing automated meter reading technology for its 1.2 million customers in Ohio. The AMR program approved by the Ohio Commission was completed in 2012. Although no further capital investment will be added, East Ohio is approved to recover depreciation, property taxes, carrying charges and a return until East Ohio has another rate case.

In April 2017, the Ohio Commission approved East Ohio's application to adjust its AMR cost recovery rate for 2016 costs. The filing reflects a revenue requirement of approximately $6 million.

PIPP Plus Program

Under the Ohio PIPP Plus Program, eligible customers can make reduced payments based on their ability to pay their bill. The difference between the customer's total bill and the PIPP amount is deferred and collected under the PIPP Rider in accordance with the rules of the Ohio Commission. In July 2017, East Ohio's annual update of the PIPP Rider was automatically approved by the Ohio Commission after a 45-day waiting period from the date of the filing. The revised rider rate reflects the recovery over the twelve-month period from July 2017 through June 2018 of projected deferred program costs of approximately $19 million from April 2017 through June 2018, net of a refund for over-recovery of accumulated arrearages of approximately $20 million as of March 31, 2017.

UEX Rider

East Ohio has approval for a UEX Rider through which it recovers the bad debt expense of most customers not participating in the PIPP Plus Program. The UEX Rider is adjusted annually to achieve dollar for dollar recovery of East Ohio's actual write-offs of uncollectible amounts. In September 2017, the Ohio Commission approved East Ohio's application requesting approval of its UEX Rider to reflect a refund of over-recovered accumulated bad debt expense of approximately $12 million as of March 31, 2017, and recovery of prospective net bad debt expense projected to total approximately $22 million for the twelve-month period from April 2017 to March 2018.

Ohio Legislation

In March 2017, the Governor of Ohio signed legislation into law that allows utilities to file an application to recover infrastructure development costs associated with economic development projects. The new cost recovery provision allows for projects totaling up to $22 million for East Ohio subject to Ohio Commission approval.

DSM Rider

East Ohio has approval for a DSM rider through which it recovers expenditures related to its DSM programs. In December 2017, East Ohio filed an application with the Ohio Commission seeking approval of an adjustment to the DSM rider to recover a total of $5 million, which includes an under-recovery of costs during the preceding 12-month period. This application is pending.

West Virginia Regulation

In October 2017, the West Virginia Commission approved Hope's application for new PREP customer rates, for the year beginning November 1, 2017, that provide for projected revenue of $4 million related to capital investments of $21 million, $27 million and $31 million for 2016, 2017 and 2018, respectively.

Utah and Wyoming Regulation

In October 2017, Questar Gas submitted filings with both the Utah Commission and the Wyoming Commission for an approximately $25 million gas cost increase reflecting forecasted increases in commodity and transportation costs. The Utah Commission and the Wyoming Commission both approved the filings in October 2017 with rates effective November 2017.

FERC—Gas

Cove Point

In November 2016, pursuant to the terms of a previous settlement, Cove Point filed a general rate case for its FERC-jurisdictional services, with 23 proposed rates to be effective January 1, 2017. Cove Point proposed an annual cost-of-service of approximately $140 million. In December 2016, FERC accepted a January 1, 2017 effective date for all proposed rates but five which were suspended to be effective June 1, 2017. Under the terms of the settlement agreement filed by Cove Point in August 2017 and approved by FERC in November 2017, Cove Point's rates effective October 2017 result in decreases to annual revenues and depreciation expense of approximately $18 million and $3 million, respectively, compared to the rates in effect through December 2016.

DETI

In September 2017, DETI submitted its annual transportation cost rate adjustment to FERC requesting approval to recover $39 million. Also in September 2017, DETI submitted its annual electric power cost adjustment to FERC requesting approval to recover $6 million. In October 2017, FERC approved these adjustments.

NOTE 14. ASSET RETIREMENT OBLIGATIONS

AROs represent obligations that result from laws, statutes, contracts and regulations related to the eventual retirement of certain of the Companies' long-lived assets. Dominion Energy's and Virginia Power's AROs are primarily associated with the decommissioning of their nuclear generation facilities and ash pond and landfill closures. Dominion Energy Gas' AROs primarily include plugging and abandonment of gas and oil wells and the interim retirement of natural gas gathering, transmission, distribution and storage pipeline components.

The Companies have also identified, but not recognized, AROs related to the retirement of Dominion Energy's LNG facility, Dominion Energy's and Dominion Energy Gas' storage wells in their underground natural gas storage network, certain Virginia Power electric transmission and distribution assets located on property with easements, rights of way, franchises and lease agreements, Virginia Power's hydroelectric generation facilities and the abatement of certain asbestos not expected to be disturbed in Dominion Energy's and Virginia Power's generation facilities. The Companies currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets since the economic lives of these assets can be extended indefinitely through regular repair and maintenance and they currently have no plans to retire or dispose of any of these assets. As a result, a settlement date is not determinable for these assets and AROs for these assets will not be reflected in the Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. The Companies continue to monitor operational and strategic developments to identify if sufficient information exists to reasonably estimate a retirement date for these assets. The changes to AROs during 2016 and 2017 were as follows:

(millions)	Amount
Dominion Energy	
AROs at December 31, 2015	$2,103
Obligations incurred during the period(1)	204
Obligations settled during the period	(171)
Revisions in estimated cash flows(2)	245
Accretion	104
AROs at December 31, 2016(3)	$2,485
Obligations incurred during the period	**37**
Obligations settled during the period	**(214)**
Revisions in estimated cash flows	**7**
Accretion	**117**
AROs at December 31, 2017(3)	**$2,432**
Virginia Power	
AROs at December 31, 2015	$1,247
Obligations incurred during the period	9
Obligations settled during the period	(115)
Revisions in estimated cash flows(2)	245
Accretion	57
AROs at December 31, 2016	$1,443
Obligations incurred during the period	**11**
Obligations settled during the period	**(152)**
Revisions in estimated cash flows	**(1)**
Accretion	**64**
AROs at December 31, 2017	**$1,365**
Dominion Energy Gas	
AROs at December 31, 2015	$ 149
Obligations incurred during the period	6
Obligations settled during the period	(8)
Accretion	9
AROs at December 31, 2016(4)	$ 156
Obligations incurred during the period	**2**
Obligations settled during the period	**(7)**
Accretion	**9**
AROs at December 31, 2017(4)	**$ 160**

(1) Primarily reflects AROs assumed in the Dominion Energy Questar Combination. See Note 3 for further information.
(2) Primarily reflects future ash pond and landfill closure costs at certain utility generation facilities. See Note 22 for further information.
(3) Includes $249 million and $263 million reported in other current liabilities at December 31, 2016, and 2017, respectively.
(4) Includes $147 million and $146 million reported in other deferred credits and other liabilities, with the remainder recorded in other current liabilities, at December 31, 2016 and 2017, respectively.

Dominion Energy and Virginia Power have established trusts dedicated to funding the future decommissioning of their nuclear plants. At December 31, 2017 and 2016, the aggregate fair value of Dominion Energy's trusts, consisting primarily of equity and debt securities, totaled $5.1 billion and $4.5 billion, respectively. At December 31, 2017 and 2016, the aggregate fair value of Virginia Power's trusts, consisting primarily of debt and equity securities, totaled $2.4 billion and $2.1 billion, respectively.

NOTE 15. VARIABLE INTEREST ENTITIES

The primary beneficiary of a VIE is required to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that has both 1) the power to direct the activities that most significantly impact the entity's economic performance and 2) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

DOMINION ENERGY

At December 31, 2017, Dominion Energy owns the general partner, 50.6% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Energy Midstream, which owns a preferred equity interest and the general partner interest in Cove Point. Additionally, Dominion Energy owns the manager and 67% of the membership interest in certain merchant solar facilities, as discussed in Note 2. Dominion Energy has concluded that these entities are VIEs due to the limited partners or members lacking the characteristics of a controlling financial interest. In addition, in 2016 Dominion Energy created a wholly owned subsidiary, SBL Holdco, as a holding company of its interest in the VIE merchant solar facilities and accordingly SBL Holdco is a VIE. Dominion Energy is the primary beneficiary of Dominion Energy Midstream, SBL Holdco and the merchant solar facilities, and Dominion Energy Midstream is the primary beneficiary of Cove Point, as they have the power to direct the activities that most significantly impact their economic performance as well as the obligation to absorb losses and benefits which could be significant to them. Dominion Energy's securities due within one year and long-term debt include $30 million and $332 million, respectively, of debt issued in 2016 by SBL Holdco net of issuance costs that is nonrecourse to Dominion Energy and is secured by SBL Holdco's interest in the merchant solar facilities.

Dominion Energy owns a 48% membership interest in Atlantic Coast Pipeline. See Note 9 for more details regarding the nature of this entity. Dominion Energy concluded that Atlantic Coast Pipeline is a VIE because it has insufficient equity to finance its activities without additional subordinated financial support. Dominion Energy has concluded that it is not the primary beneficiary of Atlantic Coast Pipeline as it does not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impact its economic performance, as the power to direct is shared among multiple unrelated parties. Dominion Energy is obligated to provide capital contributions based on its ownership percentage. Dominion Energy's maximum exposure to loss is limited to its current and future investment as well as any obligations under a guarantee provided. See Note 22 for more information.

DOMINION ENERGY AND VIRGINIA POWER

Dominion Energy's and Virginia Power's nuclear decommissioning trust funds and Dominion Energy's rabbi trusts hold investments in limited partnerships or similar type entities (see Note 9 for further details). Dominion Energy and Virginia Power concluded that these partnership investments are VIEs due to the limited partners lacking the characteristics of a controlling financial interest. Dominion Energy and Virginia Power have concluded neither is the primary beneficiary as they do not have the power to direct the activities that most significantly impact these VIEs' economic performance. Dominion Energy and Virginia Power are obligated to provide capital contributions to the partnerships as required by each partnership agreement based on their ownership percentages. Dominion Energy and Virginia Power's maximum exposure to loss is limited to their current and future investments.

DOMINION ENERGY AND DOMINION ENERGY GAS

Dominion Energy previously concluded that Iroquois was a VIE because a non-affiliated Iroquois equity holder had the ability during a limited period of time to transfer its ownership interests to another Iroquois equity holder or its affiliate. At the end of the first quarter 2016, such right no longer existed and, as a result, Dominion Energy concluded that Iroquois is no longer a VIE.

VIRGINIA POWER

Virginia Power had long-term power and capacity contracts with five non-utility generators, which contain certain variable pricing mechanisms in the form of partial fuel reimbursement that Virginia Power considers to be variable interests. Contracts with two of these non-utility generators expired during 2015 and two additional contracts expired during 2017, leaving a remaining aggregate summer generation capacity of approximately 218 MW. After an evaluation of the information provided by these entities, Virginia Power was unable to determine whether they were VIEs. However, the information they provided, as well as Virginia Power's knowledge of generation facilities in Virginia, enabled Virginia Power to conclude that, if they were VIEs, it would not be the primary beneficiary. This conclusion reflects Virginia Power's determination that its variable interests do not convey the power to direct the most significant activities that impact the economic performance of the remaining entity during the remaining terms of Virginia Power's contract and for the years the entity is expected to operate after its contractual relationship expires. The remaining contract expires in 2021. Virginia Power is not subject to any risk of loss from this potential VIE other than its remaining purchase commitments which totaled $200 million as of December 31, 2017. Virginia Power paid $86 million, $144 million, and $200 million for electric capacity and $24 million, $31 million, and $83 million for electric energy to these entities for the years ended December 31, 2017, 2016 and 2015, respectively.

DOMINION ENERGY GAS

DETI has been engaged to oversee the construction of, and to subsequently operate and maintain, the projects undertaken by Atlantic Coast Pipeline based on the overall direction and oversight of Atlantic Coast Pipeline's members. An affiliate of DETI holds a membership interest in Atlantic Coast Pipeline, therefore DETI is considered to have a variable interest in Atlantic Coast Pipeline. The members of Atlantic Coast Pipeline hold the power to direct the construction, operations and maintenance activities of the entity. DETI has concluded it is not the primary beneficiary of Atlantic Coast Pipeline as it does not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impact its economic performance. DETI has no obligation to absorb any losses of the VIE. See Note 24 for information about associated related party receivable balances.

VIRGINIA POWER AND DOMINION ENERGY GAS

Virginia Power and Dominion Energy Gas purchased shared services from DES, an affiliated VIE, of $340 million and $126 million, $346 million and $123 million, and $318 million and $115 million for the years ended December 31, 2017, 2016 and 2015, respectively. Virginia Power and Dominion Energy Gas determined that neither is the primary beneficiary of DES as neither has both the power to direct the activities that most significantly impact its economic performance as well as the obligation to absorb losses and benefits which could be significant to it. DES provides accounting, legal, finance and certain administrative and technical services to all Dominion Energy subsidiaries, including Virginia Power and Dominion Energy Gas. Virginia Power and Dominion Energy Gas have no obligation to absorb more than their allocated shares of DES costs.

NOTE 16. SHORT-TERM DEBT AND CREDIT AGREEMENTS

The Companies use short-term debt to fund working capital requirements and as a bridge to long-term debt financings. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, Dominion Energy utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion Energy's credit ratings and the credit quality of its counterparties.

DOMINION ENERGY

Commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

	Facility Limit	Outstanding Commercial Paper(2)	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
At December 31, 2017				
Joint revolving credit facility(1)	**$5,000**	**$3,298**	**$—**	**$1,702**
Joint revolving credit facility(1)	**500**	**—**	**76**	**424**
Total	**$5,500**	**$3,298**	**$76**	**$2,126**
At December 31, 2016				
Joint revolving credit facility(1)	$5,000	$3,155	$—	$1,845
Joint revolving credit facility(1)	500	—	85	415
Total	$5,500	$3,155	$85	$2,260

(1) These credit facilities mature in April 2020 and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to a combined $2.0 billion of letters of credit.

(2) The weighted-average interest rates of the outstanding commercial paper supported by Dominion Energy's credit facilities were 1.61% and 1.05% at December 31, 2017 and 2016, respectively.

Questar Gas' short-term financing is supported through its access as co-borrower to the two joint revolving credit facilities discussed above with Dominion Energy, Virginia Power and Dominion Energy Gas. At December 31, 2017, the aggregate sub-limit for Questar Gas was $250 million. In December 2016, Questar Gas entered into a commercial paper program pursuant to which it began accessing the commercial paper markets.

Dominion Energy has indicated its intention to replace the existing two joint revolving credit facilities with a $6.0 billion joint revolving credit facility in the first quarter of 2018. Terms and covenants of the new credit facility are expected to be similar to the existing credit facilities, including that Virginia Power, Dominion Energy Gas and Questar Gas will remain as co-borrowers, except that the maturity will be in five years and the maximum allowed total debt to total capital ratio, with respect to Dominion Energy only, will be increased from 65% to 67.5%. In February 2018, Virginia Power, as co-borrower, filed with the Virginia Commission for approval.

In addition to the credit facilities mentioned above, SBL Holdco has $30 million of credit facilities which have an original stated maturity date of December 2017 with automatic one-year renewals through the maturity of the SBL Holdco term loan agreement in 2023. Dominion Solar Projects III, Inc. has $25 million of credit facilities which have an original stated maturity date of May 2018 with automatic one-year renewals through the maturity of the Dominion Solar Projects III, Inc. term loan agreement in 2024. At December 31, 2017, no amounts were outstanding under either of these facilities.

In February 2018, Dominion Energy borrowed $950 million under a 364-Day Term Loan Agreement that bears interest at a variable rate. In addition, the agreement contains a maximum allowed total debt to total capital ratio of 67.5%.

VIRGINIA POWER

Virginia Power's short-term financing is supported through its access as co-borrower to the two joint revolving credit facilities. These credit facilities can be used for working capital, as support for the combined commercial paper programs of the Companies and for other general corporate purposes.

Virginia Power's share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion Energy, Dominion Energy Gas and Questar Gas were as follows:

(millions)	Facility Limit(1)	Outstanding Commercial Paper(2)	Outstanding Letters of Credit
At December 31, 2017			
Joint revolving credit facility(1)	**$5,000**	**$542**	**$—**
Joint revolving credit facility(1)	**500**	**—**	**—**
Total	**$5,500**	**$542**	**$—**
At December 31, 2016			
Joint revolving credit facility(1)	$5,000	$ 65	$—
Joint revolving credit facility(1)	500	—	1
Total	$5,500	$ 65	$ 1

(1) The full amount of the facilities is available to Virginia Power, less any amounts outstanding to co-borrowers Dominion Energy, Dominion Energy Gas and Questar Gas. Sub-limits for Virginia Power are set within the facility limit but can be changed at the option of the Companies multiple times per year. At December 31, 2017, the sub-limit for Virginia Power was an aggregate $1.5 billion. If Virginia Power has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term intercompany borrowings from Dominion Energy. These facilities mature in April 2020 and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $2.0 billion (or the sub-limit, whichever is less) of letters of credit.

(2) The weighted-average interest rates of the outstanding commercial paper supported by these credit facilities were 1.65% and 0.97% at December 31, 2017 and 2016, respectively.

In addition to the credit facility commitments mentioned above, Virginia Power also has a $100 million credit facility with a maturity date of April 2020. As of December 31, 2017, this facility supports $100 million of certain variable rate tax-exempt financings of Virginia Power. In February 2018, Virginia Power provided notice to redeem all $100 million of outstanding variable rate tax-exempt financings supported by this credit facility.

DOMINION ENERGY GAS

Dominion Energy Gas' short-term financing is supported by its access as co-borrower to the two joint revolving credit facilities. These credit facilities can be used for working capital, as support for the combined commercial paper programs of the Companies and for other general corporate purposes.

Dominion Energy Gas' share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion Energy, Virginia Power and Questar Gas were as follows:

(millions)	Facility Limit(1)	Outstanding Commercial Paper(2)	Outstanding Letters of Credit
At December 31, 2017			
Joint revolving credit facility(1)	**$1,000**	**$629**	**$—**
Joint revolving credit facility(1)	**500**	**—**	**—**
Total	**$1,500**	**$629**	**$—**
At December 31, 2016			
Joint revolving credit facility(1)	$1,000	$460	$—
Joint revolving credit facility(1)	500	—	—
Total	$1,500	$460	$—

(1) A maximum of a combined $1.5 billion of the facilities is available to Dominion Energy Gas, assuming adequate capacity is available after giving effect to uses by co-borrowers Dominion Energy, Virginia Power and Questar Gas. Sub-limits for Dominion Energy Gas are set within the facility limit but can be changed at the option of the Companies multiple times per year. At December 31, 2017, the sub-limit for Dominion Energy Gas was an aggregate $750 million. If Dominion Energy Gas has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term intercompany borrowings from Dominion Energy. These credit facilities mature in April 2020 and can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion (or the sub-limit, whichever is less) of letters of credit.

(2) The weighted-average interest rate of the outstanding commercial paper supported by these credit facilities was 1.57% and 1.00% at December 31, 2017 and 2016, respectively.

NOTE 17. LONG-TERM DEBT

At December 31, (millions, except percentages)	2017 Weighted-average Coupon(1)	2017	2016
Dominion Energy Gas Holdings, LLC:			
Unsecured Senior Notes:			
2.5% and 2.8%, due 2019 and 2020	2.68%	$ 1,150	$ 1,150
2.875% to 4.8%, due 2023 to 2044(2)	3.90%	2,450	2,413
Dominion Energy Gas Holdings, LLC total principal		$ 3,600	$ 3,563
Unamortized discount and debt issuance costs		(30)	(35)
Dominion Energy Gas Holdings, LLC total long-term debt		$ 3,570	$ 3,528
Virginia Electric and Power Company:			
Unsecured Senior Notes:			
1.2% to 7.25%, due 2017 to 2022	3.92%	$ 1,950	$ 2,554
2.75% to 8.875%, due 2023 to 2047	4.53%	8,690	7,190
Tax-Exempt Financings(3):			
Variable rates, due 2017 to 2027	1.27%	100	175
1.75% to 5.6%, due 2023 to 2041	2.25%	678	678
Virginia Electric and Power Company total principal		$11,418	$10,597
Securities due within one year	4.17%	(850)	(678)
Unamortized discount, premium and debt issuances costs, net		(72)	(67)
Virginia Electric and Power Company total long-term debt		$10,496	$ 9,852
Dominion Energy, Inc.:			
Unsecured Senior Notes:			
Variable rates, due 2019 and 2020	1.99%	$ 800	$ —
1.25% to 6.4%, due 2017 to 2022	2.95%	5,800	5,750
2.85% to 7.0%, due 2024 to 2044	4.72%	5,049	4,649
Tax-Exempt Financing, variable rate, due 2041(4)		—	75
Unsecured Junior Subordinated Notes:			
2.579% to 4.104%, due 2019 to 2021	3.08%	2,100	1,100
Payable to Affiliated Trust, 8.4% due 2031	8.40%	10	10
Enhanced Junior Subordinated Notes:			
5.25% and 5.75%, due 2054 and 2076	5.48%	1,485	1,485
Variable rates, due 2066	4.15%	422	422
Remarketable Subordinated Notes, 1.5% and 2.0%, due 2020 to 2024	2.00%	1,400	2,400
Unsecured Debentures and Senior Notes(5):			
6.8% and 6.875%, due 2026 and 2027	6.81%	89	89
Term Loan, variable rate, due 2017(6)		—	250
Unsecured Senior and Medium-Term Notes(6):			
5.31% to 6.85%, due 2017 and 2018	5.72%	120	135
2.98% to 7.20%, due 2024 to 2051	4.37%	600	500
Term Loans, variable rates, due 2023 and 2024(7)	3.74%	638	405
Tax-Exempt Financing, 1.55%, due 2033(8)	1.55%	27	27
Dominion Energy Midstream Partners, LP:			
Term Loan, variable rate, due 2019	2.74%	300	300
Unsecured Senior and Medium-Term Notes, 5.83% and 6.48%, due 2018(9)	5.84%	255	255
Unsecured Senior Notes, 4.875%, due 2041(9)	4.88%	180	180
Dominion Energy Gas Holdings, LLC total principal (from above)		3,600	3,563
Virginia Electric and Power Company total principal (from above)		11,418	10,597
Dominion Energy, Inc. total principal		$34,293	$32,192
Fair value hedge valuation(10)		(22)	(1)
Securities due within one year(11) (12)	3.44%	(3,078)	(1,709)
Unamortized discount, premium and debt issuance costs, net		(245)	(251)
Dominion Energy, Inc. total long-term debt		$30,948	$30,231

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2017.

(2) Amount includes foreign currency remeasurement adjustments.

(3) These financings relate to certain pollution control equipment at Virginia Power's generating facilities. As of December 31, 2017, certain variable rate tax-exempt financings are supported by a $100 million credit facility that terminates in April 2020. In February 2018, Virginia Power provided notice to redeem three series of variable rate tax-exempt financings with an aggregate outstanding principal of $100 million. The financings would otherwise mature in 2024, 2026 and 2027.

(4) Represents variable rate Massachusetts Development Finance Agency Solid Waste Disposal Revenue Bonds due in 2041 repaid in August 2017.

Combined Notes to Consolidated Financial Statements, Continued

(5) *Represents debt assumed by Dominion Energy from the merger of its former CNG subsidiary.*
(6) *Represents debt obligations of Dominion Energy Questar or Questar Gas. See Note 3 for more information.*
(7) *Represents debt associated with SBL Holdco and Dominion Solar Projects III, Inc. The debt is nonrecourse to Dominion Energy and is secured by SBL Holdco's and Dominion Solar Projects III, Inc.'s interest in certain merchant solar facilities.*
(8) *Represents debt obligations of a DGI subsidiary.*
(9) *Represents debt obligations of Dominion Energy Questar Pipeline. See Note 3 for more information.*
(10) *Represents the valuation of certain fair value hedges associated with Dominion Energy's fixed rate debt.*
(11) *Excludes $250 million of Dominion Energy Questar Pipeline's senior notes that matured in February 2018 which were repaid using proceeds from the January 2018 issuance, through private placement, of $100 million of 3.53% senior notes and $150 million of 3.91% senior notes that mature in 2028 and 2038, respectively.*
(12) *Includes $20 million of estimated mandatory prepayments due within one year based on estimated cash flows in excess of debt service at SBL Holdco and Dominion Solar Projects III, Inc.*

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2017, were as follows:

(millions, except percentages)	2018	2019	2020	2021	2022	Thereafter	Total
Dominion Energy Gas	$ —	$ 450	$ 700	$ —	$ —	$ 2,450	$ 3,600
Weighted-average Coupon		2.50%	2.80%			3.90%	
Virginia Power							
Unsecured Senior Notes	$ 850	$ 350	$ —	$ —	$ 750	$ 8,690	$10,640
Tax-Exempt Financings	—	—	—	—	—	778	778
Total	$ 850	$ 350	$ —	$ —	$ 750	$ 9,468	$11,418
Weighted-average Coupon	4.17%	5.00%			3.15%	4.33%	
Dominion Energy							
Term Loans(1)	$ 36	$ 336	$ 35	$ 35	$ 34	$ 462	$ 938
Unsecured Senior Notes(2)	3,275	3,400	1,000	900	1,500	17,058	27,133
Tax-Exempt Financings	—	—	—	—	—	805	805
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts	—	—	—	—	—	10	10
Unsecured Junior Subordinated Notes	—	550	1,000	550	—	—	2,100
Enhanced Junior Subordinated Notes	—	—	—	—	—	1,907	1,907
Remarketable Subordinated Notes	—	—	—	700	—	700	1,400
Total	$3,311	$4,286	$2,035	$2,185	$1,534	$20,942	$34,293
Weighted-average Coupon	3.62%	2.89%	2.58%	3.12%	2.97%	4.38%	

(1) *Excludes mandatory prepayments associated with SBL Holdco and Dominion Solar Projects III, Inc. based on cash flows in excess of debt service. At December 31, 2017, $20 million of estimated mandatory prepayments due within one year were included in securities due within one year in Dominion Energy's Consolidated Balance Sheets.*
(2) *In February 2018, $250 million of Dominion Energy Questar Pipeline's senior notes were repaid using proceeds from the January 2018 issuance, through private placements, of $100 million of 3.53% senior notes and $150 million of 3.91% senior notes that mature in 2028 and 2038, respectively. As a result, at December 31, 2017, $250 million was included in long-term debt in the Consolidated Balance Sheets.*

The Companies short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2017, there were no events of default under these covenants.

Enhanced Junior Subordinated Notes

In June 2006 and September 2006, Dominion Energy issued $300 million of June 2006 hybrids and $500 million of September 2006 hybrids, respectively. Beginning June 30, 2016, the June 2006 hybrids bear interest at three-month LIBOR plus 2.825%, reset quarterly. Previously, interest was fixed at 7.5% per year. The September 2006 hybrids bear interest at the three-month LIBOR plus 2.3%, reset quarterly.

In October 2014, Dominion Energy issued $685 million of October 2014 hybrids that will bear interest at 5.75% per year until October 1, 2024. Thereafter, they will bear interest at the three-month LIBOR plus 3.057%, reset quarterly.

Dominion Energy may defer interest payments on the hybrids on one or more occasions for up to 10 consecutive years. If the interest payments on the hybrids are deferred, Dominion Energy may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments during the deferral period. Also, during the deferral period, Dominion Energy may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the hybrids.

Dominion Energy executed RCCs in connection with its issuance of the June 2006 hybrids and the September 2006 hybrids. Under the terms of the RCCs, Dominion Energy covenants to and for the benefit of designated covered debtholders, as may be designated from time to time, that Dominion Energy shall not redeem, repurchase, or defease all or any part of the hybrids, and shall not cause its majority owned subsidiaries to purchase all or any part of the hybrids, on or before their applicable RCC termination date, unless, subject to certain limitations, during the 180 days prior to such activity, Dominion Energy has received a specified amount of proceeds as set forth in the RCCs from the sale of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than the applicable characteristics of the hybrids at that time, as more fully described in the RCCs. In September 2011, Dominion Energy amended the RCCs of the June 2006 hybrids and September 2006 hybrids to expand the measurement period for consideration of proceeds from the sale of common stock issuances from 180 days to 365 days. The proceeds Dominion Energy receives from the replacement offering, adjusted by a predetermined factor, must equal or exceed the redemption or repurchase price.

In 2015, Dominion Energy purchased and cancelled $14 million and $3 million of the June 2006 hybrids and the September 2006 hybrids, respectively. In the first quarter of 2016, Dominion Energy purchased and cancelled $38 million and $4 million of the June 2006 hybrids and the September 2006 hybrids, respectively. In July 2016, Dominion Energy launched a tender offer to purchase up to $200 million in aggregate of additional June 2006 hybrids and September 2006 hybrids, which expired on August 1, 2016. In connection with the tender offer, Dominion Energy purchased and cancelled $125 million and $74 million of the June 2006 hybrids and the September 2006 hybrids, respectively. All purchases were conducted in compliance with the applicable RCC. Also in July 2016, Dominion Energy issued $800 million of 5.25% July 2016 hybrids. The proceeds were used for general corporate purposes, including to finance the tender offer. The July 2016 hybrids are listed on the NYSE under the symbol DRUA.

Remarketable Subordinated Notes

In June 2013, Dominion Energy issued $550 million of 2013 Series A 6.125% Equity Units and $550 million of 2013 Series B 6.0% Equity Units, initially in the form of Corporate Units. In July 2014, Dominion Energy issued $1.0 billion of 2014 Series A 6.375% Equity Units, initially in the form of Corporate Units. The Corporate Units were listed on the NYSE under the symbols DCUA, DCUB and DCUC respectively.

Each Corporate Unit consisted of a stock purchase contract and 1/20 interest in a RSN issued by Dominion Energy. The stock purchase contracts obligated the holders to purchase shares of Dominion Energy common stock at a future settlement date prior to the relevant RSN maturity date. The purchase price paid under the stock purchase contracts was $50 per Corporate Unit and the number of shares purchased was determined under a formula based upon the average closing price of Dominion Energy common stock near the settlement date. The RSNs were pledged as collateral to secure the purchase of common stock under the related stock purchase contracts.

In May 2017, Dominion Energy successfully remarketed the $1.0 billion 2014 Series A 1.50% RSNs due 2020 pursuant to the terms of the related 2014 Equity Units. In connection with the remarketing, the interest rate on the junior subordinated notes was reset to 2.579%, payable on a semi-annual basis and Dominion Energy ceased to have the ability to redeem the notes at its option or defer interest payments. In March 2016 and May 2016, Dominion Energy successfully remarketed the $550 million 2013 Series A 1.07% RSNs due 2021 and the $550 million 2013 Series B 1.18% RSNs due 2019, respectively, pursuant to the terms of the related 2013 Equity Units. In connection with the remarketings, the interest rate on the Series A and Series B junior subordinated notes was reset to 4.104% and 2.962%, respectively, payable on a semi-annual basis and Dominion Energy ceased to have the ability to redeem the notes at its option or defer interest payments. At December 31, 2017, the securities are included in junior subordinated notes in Dominion Energy's Consolidated Balance Sheets. Dominion Energy did not receive any proceeds from the remarketings. Remarketing proceeds belonged to the investors holding the related equity units and were temporarily used to purchase a portfolio of treasury securities. Upon maturity of each portfolio, the proceeds were applied on behalf of investors on the related stock purchase contract settlement date to pay the purchase price to Dominion Energy for issuance of 12.5 million shares of its common stock in July 2017 and 8.5 million shares of its common stock in both April 2016 and July 2016. See Issuance of Common Stock below for a description of common stock issued by Dominion Energy under the stock purchase contracts.

In August 2016, Dominion Energy issued $1.4 billion of 2016 Series A 6.75% Equity Units, initially in the form of Corporate Units. The Corporate Units are listed on the NYSE under the symbol DCUD. The net proceeds from the 2016 Equity Units were used to finance the Dominion Energy Questar Combination. See Note 3 for more information.

Each 2016 Series A Corporate Unit consists of a stock purchase contract, a 1/40 interest in a 2016 Series A-1 RSN issued by Dominion Energy and a 1/40 interest in a 2016 Series A-2 RSN issued by Dominion Energy. The stock purchase contracts obligate the holders to purchase shares of Dominion Energy common stock at a future settlement date prior to the relevant RSN maturity date. The purchase price to be paid under the stock purchase contracts is $50 per Corporate Unit and the number of shares to be purchased will be determined under a formula based upon the average closing price of Dominion Energy common stock near the settlement date. The RSNs are pledged as collateral to secure the purchase of common stock under the related stock purchase contracts.

Dominion Energy makes quarterly interest payments on the RSNs and quarterly contract adjustment payments on the stock purchase contracts, at the rates described below. Dominion Energy may defer payments on the stock purchase contracts and the RSNs for one or more consecutive periods but generally not beyond the purchase contract settlement date. If payments are deferred, Dominion Energy may not make any cash distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, Dominion Energy may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the RSNs.

Dominion Energy has recorded the present value of the stock purchase contract payments as a liability offset by a charge to equity. Interest payments on the RSNs are recorded as interest expense and stock purchase contract payments are charged against the liability. Accretion of the stock purchase contract liability is recorded as imputed interest expense. In calculating diluted EPS, Dominion Energy applies the treasury stock method to the equity units.

Pursuant to the terms of the 2016 Equity Units, Dominion Energy expects to remarket both the 2016 Series A-1 and 2016 Series A-2 RSNs during the third quarter of 2019. Following a successful remarketing, the interest rate on the RSNs will be reset, interest will be payable on a semi-annual basis and Dominion Energy will cease to have the ability to redeem the RSNs at its option or defer interest payments. Proceeds of each remarketing will belong to the investors in the related equity units and will be held and applied on their behalf at the settlement date of the related stock purchase contracts to pay the purchase price to Dominion Energy for issuance of its common stock.

Combined Notes to Consolidated Financial Statements, Continued

Under the terms of the stock purchase contracts, assuming no anti-dilution or other adjustments, Dominion Energy will issue between 15.0 million and 18.8 million shares in August 2019. A total of 23.1 million shares of Dominion Energy's common stock has been reserved for issuance in connection with the stock purchase contracts.

Selected information about Dominion Energy's equity units is presented below:

Issuance Date	Units Issued	Total Net Proceeds	Total Long-term Debt	RSN Annual Interest Rate	Stock Purchase Contract Annual Rate	Stock Purchase Contract Liability(1)	Stock Purchase Settlement Date
(millions, except interest rates)							
8/15/2016(2)	28	$1,374.8	$1,400.0	2.000%(3)	4.750%	$190.6	8/15/2019

(1) Payments of $101 million and $94 million were made in 2017 and 2016, respectively, including payments for the remarketed 2013 Series A and B notes and the remarketed 2014 Series A notes. The stock purchase contract liability was $111 million and $212 million at December 31, 2017 and 2016, respectively.

(2) The maturity dates of the $700 million Series A-1 RSNs and $700 million Series A-2 RSNs are August 15, 2021 and August 15, 2024, respectively.

(3) Annual interest rate applies to each of the Series A-1 RSNs and Series A-2 RSNs.

NOTE 18. PREFERRED STOCK

Dominion Energy is authorized to issue up to 20 million shares of preferred stock; however, none were issued and outstanding at December 31, 2017 or 2016.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference; however, none were issued and outstanding at December 31, 2017 or 2016.

NOTE 19. EQUITY

Issuance of Common Stock

DOMINION ENERGY

Dominion Energy maintains Dominion Energy Direct® and a number of employee savings plans through which contributions may be invested in Dominion Energy's common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans. In January 2014, Dominion Energy began purchasing its common stock on the open market for these plans. In April 2014, Dominion Energy began issuing new common shares for these direct stock purchase plans.

During 2017, Dominion Energy received cash proceeds, net of fees and commissions, of $1.3 billion from the issuance of approximately 17 million shares of common stock through various programs resulting in approximately 645 million shares of common stock outstanding at December 31, 2017. These proceeds include cash of $302 million received from the issuance of 3.8 million of such shares through Dominion Energy Direct® and employee savings plans.

In July 2017, Dominion Energy issued 12.5 million shares under the related stock purchase contracts entered into as part of Dominion Energy's 2014 Equity Units and received proceeds of $1.0 billion.

In both April 2016 and July 2016, Dominion Energy issued 8.5 million shares under the related stock purchase contracts entered into as part of Dominion Energy's 2013 Equity Units and received $1.1 billion of total proceeds. Additionally, Dominion Energy completed a market issuance of equity in April 2016 of 10.2 million shares and received proceeds of $756 million through a registered underwritten public offering. A portion of the net proceeds was used to finance the Dominion Energy Questar Combination. See Note 3 for more information.

In June 2017, Dominion Energy filed an SEC shelf registration for the sale of debt and equity securities including the ability to sell common stock through an at-the-market program. Also in June 2017, Dominion Energy entered into three separate sales agency agreements to effect sales under the program and pursuant to which it may offer from time to time up to $500 million aggregate amount of its common stock. Sales of common stock can be made by means of privately negotiated transactions, as transactions on the NYSE at market prices or in such other transactions as are agreed upon by Dominion Energy and the sales agents in conformance with applicable securities laws. In January 2018, Dominion Energy provided sales instructions to one of the sales agents and has issued 6.6 million shares through at-the-market issuances and received cash proceeds of $495 million, net of fees and commissions paid of $5 million.

Following these issuances, Dominion Energy has no remaining ability to issue stock under the 2017 sales agency agreements and has completed the program.

VIRGINIA POWER

In 2017, 2016 and 2015, Virginia Power did not issue any shares of its common stock to Dominion Energy.

Shares Reserved for Issuance

At December 31, 2017, Dominion Energy had approximately 67 million shares reserved and available for issuance for Dominion Energy Direct®, employee stock awards, employee savings plans, director stock compensation plans and issuance in connection with stock purchase contracts. See Note 17 for more information.

Repurchase of Common Stock

Dominion Energy did not repurchase any shares in 2017 or 2016 and does not plan to repurchase shares during 2018, except for shares tendered by employees to satisfy tax withholding obligations on vested restricted stock, which do not count against its stock repurchase authorization.

Purchase of Dominion Energy Midstream Units

In September 2015, Dominion Energy initiated a program to purchase from the market up to $50 million of common units representing limited partner interests in Dominion Energy Midstream, which expired in September 2016. Dominion Energy purchased approximately 658,000 common units for $17 million and 887,000 common units for $25 million for the years ended December 31, 2016 and 2015, respectively.

Issuance of Dominion Energy Midstream Units

In 2017, Dominion Energy Midstream received $18 million of proceeds from the issuance of common units through its at-the-market program.

In 2016, Dominion Energy Midstream received $482 million of proceeds from the issuance of common units and $490 million of proceeds from the issuance of convertible preferred units. The net proceeds were primarily used to finance a portion of the acquisition of Dominion Energy Questar Pipeline from Dominion Energy. See Note 3 for more information.

The holders of the convertible preferred units are entitled to receive cumulative quarterly distributions payable in cash or additional convertible preferred units, subject to certain conditions. The units are convertible into Dominion Energy Midstream common units on a one-for-one basis, subject to certain adjustments, (i) in whole or in part at the option of the unitholders any time after December 1, 2018 or, (ii) in whole or in part at Dominion Energy Midstream's option, subject to certain conditions, any time after December 1, 2019. The conversion of such units would result in a potential increase to Dominion Energy's net income attributable to noncontrolling interests.

Accumulated Other Comprehensive Income (Loss)

Presented in the table below is a summary of AOCI by component:

At December 31,	2017	2016
(millions)		
Dominion Energy		
Net deferred losses on derivatives-hedging activities, net of tax of $188 and $173	$ (301)	$ (280)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(419) and $(318)	747	569
Net unrecognized pension and other postretirement benefit costs, net of tax of $692 and $691	(1,101)	(1,082)
Other comprehensive loss from equity method investees, net of tax of $2 and $4	(3)	(6)
Total AOCI, including noncontrolling interest	$ (658)	$ (799)
Less other comprehensive income attributable to noncontrolling interest	1	—
Total AOCI, excluding noncontrolling interest	$ (659)	$ (799)
Virginia Power		
Net deferred losses on derivatives-hedging activities, net of tax of $8 and $5	$ (12)	$ (8)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(47) and $(35)	74	54
Total AOCI	$ 62	$ 46
Dominion Energy Gas		
Net deferred losses on derivatives-hedging activities, net of tax of $15 and $15	$ (23)	$ (24)
Net unrecognized pension costs, net of tax of $59 and $68	(75)	(99)
Total AOCI	$ (98)	$ (123)

DOMINION ENERGY

The following table presents Dominion Energy's changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrealized gains and losses on investment securities	Unrecognized pension and other postretirement benefit costs	Other comprehensive loss from equity method investees	Total
(millions)					
Year Ended December 31, 2017					
Beginning balance	$(280)	$569	$(1,082)	$(6)	$(799)
Other comprehensive income before reclassifications: gains (losses)	8	215	(69)	3	157
Amounts reclassified from AOCI: (gains) losses(1)	(29)	(37)	50	—	(16)
Net current period other comprehensive income (loss)	(21)	178	(19)	3	141
Less other comprehensive income attributable to noncontrolling interest	1	—	—	—	1
Ending balance	$(302)	$747	$(1,101)	$(3)	$(659)
Year Ended December 31, 2016					
Beginning balance	$(176)	$504	$ (797)	$(5)	$(474)
Other comprehensive income before reclassifications: gains (losses)	55	93	(319)	(1)	(172)
Amounts reclassified from AOCI: (gains) losses(1)	(159)	(28)	34	—	(153)
Net current period other comprehensive income (loss)	(104)	65	(285)	(1)	(325)
Ending balance	$(280)	$569	$(1,082)	$(6)	$(799)

(1) See table below for details about these reclassifications.

The following table presents Dominion Energy's reclassifications out of AOCI by component:

Details about AOCI components	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
(millions)		
Year Ended December 31, 2017		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$ (81)	Operating revenue
	2	Purchased gas
Interest rate contracts	52	Interest and related charges
Foreign currency contracts	(20)	Other Income
Total	(47)	
Tax	18	Income tax expense
Total, net of tax	$ (29)	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$ (81)	Other income
Impairment	23	Other income
Total	(58)	
Tax	21	Income tax expense
Total, net of tax	$ (37)	
Unrecognized pension and other postretirement benefit costs:		
Amortization of prior-service costs (credits)	$ (21)	Other operations and maintenance
Amortization of actuarial losses	103	Other operations and maintenance
Total	82	
Tax	(32)	Income tax expense
Total, net of tax	$ 50	
Year Ended December 31, 2016		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$(330)	Operating revenue
	13	Purchased gas
	10	Electric fuel and other energy-related purchases
Interest rate contracts	31	Interest and related charges
Foreign currency contracts	17	Other Income
Total	(259)	
Tax	100	Income tax expense
Total, net of tax	$(159)	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$ (66)	Other income
Impairment	23	Other income
Total	(43)	
Tax	15	Income tax expense
Total, net of tax	$ (28)	
Unrecognized pension and other postretirement benefit costs:		
Prior-service costs (credits)	$ (15)	Other operations and maintenance
Actuarial losses	71	Other operations and maintenance
Total	56	
Tax	(22)	Income tax expense
Total, net of tax	$ 34	

VIRGINIA POWER

The following table presents Virginia Power's changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrealized gains and losses on investment securities	Total
(millions)			
Year Ended December 31, 2017			
Beginning balance	$ (8)	$54	$46
Other comprehensive income before reclassifications: gains (losses)	(5)	24	19
Amounts reclassified from AOCI: (gains) losses(1)	1	(4)	(3)
Net current period other comprehensive income (loss)	(4)	20	16
Ending balance	$(12)	$74	$62
Year Ended December 31, 2016			
Beginning balance	$ (7)	$47	$40
Other comprehensive income before reclassifications: gains (losses)	(2)	11	9
Amounts reclassified from AOCI: (gains) losses(1)	1	(4)	(3)
Net current period other comprehensive income (loss)	(1)	7	6
Ending balance	$ (8)	$54	$46

(1) See table below for details about these reclassifications.

The following table presents Virginia Power's reclassifications out of AOCI by component:

Details about AOCI components	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
(millions)		
Year Ended December 31, 2017		
(Gains) losses on cash flow hedges:		
Interest rate contracts	$ 1	Interest and related charges
Total	1	
Tax	—	Income tax expense
Total, net of tax	$ 1	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$(9)	Other income
Impairment	2	Other income
Total	(7)	
Tax	3	Income tax expense
Total, net of tax	$(4)	
Year Ended December 31, 2016		
(Gains) losses on cash flow hedges:		
Interest rate contracts	$ 1	Interest and related charges
Total	1	
Tax	—	Income tax expense
Total, net of tax	$ 1	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$(9)	Other income
Impairment	3	Other income
Total	(6)	
Tax	2	Income tax expense
Total, net of tax	$(4)	

DOMINION ENERGY GAS

The following table presents Dominion Energy Gas' changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrecognized pension costs	Total
(millions)			
Year Ended December 31, 2017			
Beginning balance	$(24)	$(99)	$(123)
Other comprehensive income before reclassifications: losses	5	20	25
Amounts reclassified from AOCI(1): losses	(4)	4	—
Net current period other comprehensive loss	1	24	25
Ending balance	$(23)	$(75)	$ (98)
Year Ended December 31, 2016			
Beginning balance	$(17)	$(82)	$ (99)
Other comprehensive income before reclassifications: (losses)	(16)	(20)	(36)
Amounts reclassified from AOCI(1): losses	9	3	12
Net current period other comprehensive income (loss)	(7)	(17)	(24)
Ending balance	$(24)	$(99)	$(123)

(1) See table below for details about these reclassifications.

The following table presents Dominion Energy Gas' reclassifications out of AOCI by component:

Details about AOCI components (millions)	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
Year Ended December 31, 2017		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$ 8	Operating revenue
Interest rate contracts	5	Interest and related charges
Foreign currency contracts	(20)	Other income
Total	(7)	
Tax	3	Income tax expense
Total, net of tax	$ (4)	
Unrecognized pension costs:		
Actuarial losses	$ 6	Other operations and maintenance
Total	6	
Tax	(2)	Income tax expense
Total, net of tax	$ 4	
Year Ended December 31, 2016		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$ (4)	Operating revenue
Interest rate contracts	2	Interest and related charges
Foreign currency contracts	17	Other income
Total	15	
Tax	(6)	Income tax expense
Total, net of tax	$ 9	
Unrecognized pension costs:		
Actuarial losses	$ 5	Other operations and maintenance
Total	5	
Tax	(2)	Income tax expense
Total, net of tax	$ 3	

Stock-Based Awards

The 2005 and 2014 Incentive Compensation Plans permit stock-based awards that include restricted stock, performance grants, goal-based stock, stock options, and stock appreciation rights. The Non-Employee Directors Compensation Plan permits grants of restricted stock and stock options. Under provisions of these plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of the CGN Committee of the Board of Directors or the Board of Directors itself, as provided under each plan. At December 31, 2017, approximately 23 million shares were available for future grants under these plans.

Goal-based stock awards are granted in lieu of cash-based performance grants to certain officers who have not achieved a certain targeted level of share ownership. As of December 31, 2017, unrecognized compensation cost related to nonvested goal-based stock awards was immaterial.

Dominion Energy measures and recognizes compensation expense relating to share-based payment transactions over the vesting period based on the fair value of the equity or liability instruments issued. Dominion Energy's results for the years ended December 31, 2017, 2016 and 2015 include $45 million, $33 million, and $39 million, respectively, of compensation costs and $16 million, $11 million, and $14 million, respectively of income tax benefits related to Dominion Energy's stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in Dominion Energy's Consolidated Statements of Income. Excess Tax Benefits are classified as a financing cash flow.

Restricted Stock

Restricted stock grants are made to officers under Dominion Energy's LTIP and may also be granted to certain key non-officer employees from time to time. The fair value of Dominion Energy's restricted stock awards is equal to the closing price of Dominion Energy's stock on the date of grant. New shares are issued for restricted stock awards on the date of grant and generally vest over a three-year service period. The following table provides a summary of restricted stock activity for the years ended December 31, 2017, 2016 and 2015:

	Shares (thousands)	Weighted - average Grant Date Fair Value
Nonvested at December 31, 2014	1,065	$56.74
Granted	302	73.26
Vested	(510)	50.71
Cancelled and forfeited	(2)	62.62
Nonvested at December 31, 2015	855	$66.16
Granted	372	71.67
Vested	(301)	56.83
Cancelled and forfeited	(40)	71.75
Nonvested at December 31, 2016	886	$71.40
Granted	**454**	**74.24**
Vested	**(287)**	**68.90**
Cancelled and forfeited	**(10)**	**72.37**
Nonvested at December 31, 2017	**1,043**	**$73.32**

As of December 31, 2017, unrecognized compensation cost related to nonvested restricted stock awards totaled $42 million and is expected to be recognized over a weighted-average period of 2.0 years. The fair value of restricted stock awards that vested was $21 million, $21 million, and $37 million in 2017, 2016 and 2015, respectively. Employees may elect to have shares of restricted stock withheld upon vesting to satisfy tax withholding obligations. The number of shares withheld will vary for each employee depending on the vesting date fair market value of Dominion Energy stock and the applicable federal, state and local tax withholding rates.

Cash-Based Performance Grants

Cash-based performance grants are made to Dominion Energy's officers under Dominion Energy's LTIP. The actual payout of cash-based performance grants will vary between zero and 200%

of the targeted amount based on the level of performance metrics achieved.

In February 2015, a cash-based performance grant was made to officers. Payout of the performance grant occurred in January 2017 based on the achievement of two performance metrics during 2015 and 2016: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The total of the payout under the grant was $10 million.

In February 2016, a cash-based performance grant was made to officers. Payout of the performance grant occurred in January 2018 based on the achievement of two performance metrics during 2016 and 2017: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The total of the payout under the grant was $12 million.

In February 2017, two cash-based performance grants were made to officers as the Company transitioned from a two-year performance period to a three-year performance period. Payout of the two-year grant is expected to occur by March 15, 2019 based on the achievement of two performance metrics during 2017 and 2018: TSR relative to that of companies that are members of the Company's compensation peer group and ROIC. At December 31, 2017, the targeted amount of the two-year grant was $15 million and a liability of $7 million had been accrued for this award. Payout of the three-year cash-based performance grant is expected to occur by March 15, 2020 based on the achievement of two performance metrics during 2017, 2018 and 2019: TSR relative to that of companies that are members of the Company's compensation peer group and ROIC. At December 31, 2017, the targeted amount of the three-year grant was $15 million and a liability of $5 million had been accrued for the award.

NOTE 20. DIVIDEND RESTRICTIONS

The Virginia Commission may prohibit any public service company, including Virginia Power, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2017, the Virginia Commission had not restricted the payment of dividends by Virginia Power.

The Ohio Commission may prohibit any public service company, including East Ohio, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2017, the Ohio Commission had not restricted the payment of dividends by East Ohio.

The Utah Commission may prohibit any public service company, including Questar Gas, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2017, the Utah Commission had not restricted the payment of dividends by Questar Gas.

Certain agreements associated with the Companies' credit facilities contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict the Companies' ability to pay dividends or receive dividends from their subsidiaries at December 31, 2017.

As part of the SCANA Merger Agreement, Dominion Energy shall not declare, set aside or pay any dividends on, or make any other distributions (whether in cash, stock or property) in respect of, any of its capital stock, other than regular quarterly cash dividends.

See Note 17 for a description of potential restrictions on dividend payments by Dominion Energy in connection with the deferral of interest payments on certain junior subordinated notes and equity units, initially in the form of corporate units.

NOTE 21. EMPLOYEE BENEFIT PLANS

Dominion Energy and Dominion Energy Gas—Defined Benefit Plans

Dominion Energy provides certain retirement benefits to eligible active employees, retirees and qualifying dependents. Dominion Energy Gas participates in a number of the Dominion Energy-sponsored retirement plans. Under the terms of its benefit plans, Dominion Energy reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

Dominion Energy maintains qualified noncontributory defined benefit pension plans covering virtually all employees. Retirement benefits are based primarily on years of service, age and the employee's compensation. Dominion Energy's funding policy is to contribute annually an amount that is in accordance with the provisions of ERISA. The pension programs also provide benefits to certain retired executives under company-sponsored nonqualified employee benefit plans. The nonqualified plans are funded through contributions to grantor trusts. Dominion Energy also provides retiree healthcare and life insurance benefits with annual employee premiums based on several factors such as age, retirement date and years of service.

Pension benefits for Dominion Energy Gas employees not represented by collective bargaining units are covered by the Dominion Energy Pension Plan, a defined benefit pension plan sponsored by Dominion Energy that provides benefits to multiple Dominion Energy subsidiaries. Pension benefits for Dominion Energy Gas employees represented by collective bargaining units are covered by separate pension plans for East Ohio and, for DETI, a plan that provides benefits to employees of both DETI and Hope. Employee compensation is the basis for allocating pension costs and obligations between DETI and Hope and determining East Ohio's share of total pension costs.

Retiree healthcare and life insurance benefits for Dominion Energy Gas employees not represented by collective bargaining units are covered by the Dominion Retiree Health and Welfare Plan, a plan sponsored by Dominion Energy that provides certain retiree healthcare and life insurance benefits to multiple Dominion Energy subsidiaries. Retiree healthcare and life insurance benefits for Dominion Energy Gas employees represented by collective bargaining units are covered by separate other postretirement benefit plans for East Ohio and, for DETI, a plan that provides benefits to both DETI and Hope. Employee headcount is the basis for allocating other postretirement benefit costs and obligations between DETI and Hope and determining East Ohio's share of total other postretirement benefit costs.

Pension and other postretirement benefit costs are affected by employee demographics (including age, compensation levels and years of service), the level of contributions made to the plans and earnings on plan assets. These costs may also be affected by changes in key assumptions, including expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates, mortality rates and the rate of compensation increases.

Dominion Energy uses December 31 as the measurement date for all of its employee benefit plans, including those in which Dominion Energy Gas participates. Dominion Energy uses the market-related value of pension plan assets to determine the expected return on plan assets, a component of net periodic pension cost, for all pension plans, including those in which Dominion Energy Gas participates. The market-related value recognizes changes in fair value on a straight-line basis over a four-year period, which reduces year-to-year volatility. Changes in fair value are measured as the difference between the expected and actual plan asset returns, including dividends, interest and realized and unrealized investment gains and losses. Since the market-related value recognizes changes in fair value over a four-year period, the future market-related value of pension plan assets will be impacted as previously unrecognized changes in fair value are recognized.

Dominion Energy's pension and other postretirement benefit plans hold investments in trusts to fund employee benefit payments. Dominion Energy's pension and other postretirement plan assets experienced aggregate actual returns of $1.6 billion and $534 million in 2017 and 2016, respectively, versus expected returns of $767 million and $691 million, respectively. Dominion Energy Gas' pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual returns of $335 million and $130 million in 2017 and 2016, respectively, versus expected returns of $165 million and $157 million, respectively. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans.

In October 2014, the Society of Actuaries published new mortality tables and mortality improvement scales. Such tables and scales are used to develop mortality assumptions for use in determining pension and other postretirement benefit liabilities and expense. Following evaluation of the new tables, Dominion Energy changed its assumption for mortality rates to reflect a generational improvement scale. This change in assumption increased net periodic benefit cost for Dominion Energy and Dominion Energy Gas (for employees represented by collective bargaining units) by $25 million and $3 million, respectively, for 2015.

During 2016, Dominion Energy and Dominion Energy Gas (for employees represented by collective bargaining units) engaged their actuary to conduct an experience study of their employees demographics over a five-year period as compared to significant assumptions that were being used to determine pension and other postretirement benefit obligations and periodic costs. These assumptions primarily included mortality, retirement rates, termination rates, and salary increase rates. The changes in assumptions implemented as a result of the experience study resulted in increases of $290 million and $38 million in the pension and other postretirement benefits obligations, respectively, at December 31, 2016 for Dominion Energy and $24 million and $9 million in the pension and other postretirement benefits obligations, respectively, at December 31, 2016 for Dominion Energy Gas. In addition, these changes increased net periodic benefit costs $42 million for Dominion Energy during 2017. The increase in net periodic benefit costs for Dominion Energy Gas during 2017 was immaterial.

PLAN AMENDMENTS AND REMEASUREMENTS

In the fourth quarter of 2017, Dominion Energy remeasured its pension and other postretirement benefit plans as a result of voluntary and involuntary separation programs at Dominion Energy Questar. The settlement and related remeasurement resulted in a reduction in the pension benefit obligation of approximately $75 million and an increase in the accumulated postretirement benefit obligation of approximately $2 million. The discount rates used for the 2017 pension cost and related settlement were 4.46% as of December 31, 2016, 4.51% as of January 31, 2017 and 4.05% as of June 30 and September 30, 2017. All other assumptions used were consistent with the measurement as of December 31, 2016.

In the first quarter of 2017, Dominion Energy and Dominion Energy Gas remeasured an other postretirement benefit plan as a result of an amendment that changed post-65 retiree medical coverage for certain current and future Local 69 retirees effective July 1, 2017. The remeasurement resulted in a decrease in Dominion Energy's and Dominion Energy Gas' accumulated postretirement benefit obligation of $73 million and $61 million, respectively. As a result of regulatory accounting, the remeasurement had an immaterial impact on net income for both Dominion Energy and Dominion Energy Gas. The discount rate used for the remeasurement was 4.30%. All other assumptions used were consistent with the measurement as of December 31, 2016.

Also during the first quarter of 2017, Dominion Energy recorded a $7 million ($4 million after-tax) charge, including $6 million ($4 million after-tax) at Dominion Energy Gas, as a result of additional payments associated with the new collective bargaining agreement, which is reflected in other operations and maintenance expense in their Consolidated Statements of Income.

In the third quarter of 2016, Dominion Energy remeasured an other postretirement benefit plan as a result of an amendment that changed post-65 retiree medical coverage for certain current and future Local 50 retirees effective April 1, 2017. The remeasurement resulted in a decrease in Dominion Energy's accumulated postretirement benefit obligation of $37 million. The impact of the remeasurement on net periodic benefit credit was recognized prospectively from the remeasurement date and increased the net periodic benefit credit for 2016 by $9 million. The discount rate used for the remeasurement was 3.71% and the demographic and mortality assumptions were updated using plan-specific studies and mortality improvement scales. The expected long-term rate of return used was consistent with the measurement as of December 31, 2015.

FUNDED STATUS

The following table summarizes the changes in pension plan and other postretirement benefit plan obligations and plan assets and includes a statement of the plans' funded status for Dominion Energy and Dominion Energy Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
Year Ended December 31,	2017	2016	2017	2016
(millions, except percentages)				
Dominion Energy				
Changes in benefit obligation:				
Benefit obligation at beginning of year	$ 8,132	$ 6,391	$ 1,478	$ 1,430
Dominion Energy Questar Combination	—	817	—	85
Service cost	138	118	26	31
Interest cost	345	317	60	65
Benefits paid	(323)	(286)	(83)	(83)
Actuarial (gains) losses during the year	830	784	119	166
Plan amendments(1)	5	—	(73)	(216)
Settlements and curtailments(2)	(75)	(9)	2	—
Benefit obligation at end of year	$ 9,052	$ 8,132	$ 1,529	$ 1,478
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	$ 7,016	$ 6,166	$ 1,512	$ 1,382
Dominion Energy Questar Combination	—	704	—	45
Actual return (loss) on plan assets	1,327	426	236	108
Employer contributions	118	15	13	12
Benefits paid	(323)	(286)	(32)	(35)
Settlements(2)	(76)	(9)	—	—
Fair value of plan assets at end of year	$ 8,062	$ 7,016	$ 1,729	$ 1,512
Funded status at end of year	$ (990)	$ (1,116)	$ 200	$ 34
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	$ 1,117	$ 930	$ 261	$ 148
Other current liabilities	(8)	(43)	—	(5)
Noncurrent pension and other postretirement benefit liabilities	(2,099)	(2,003)	(61)	(109)
Net amount recognized	$ (990)	$ (1,116)	$ 200	$ 34
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	3.80%–3.81%	3.31%–4.50%	3.76%	3.92%–4.47%
Weighted average rate of increase for compensation	4.09%	4.09%	3.95%-4.11%	3.29%
Dominion Energy Gas				
Changes in benefit obligation:				
Benefit obligation at beginning of year	$ 683	$ 608	$ 320	$ 292
Service cost	15	13	4	5
Interest cost	30	30	12	14
Benefits paid	(33)	(32)	(19)	(19)
Actuarial (gains) losses during the year	78	64	34	28
Plan amendments(1)	—	—	(61)	—
Benefit obligation at end of year	$ 773	$ 683	$ 290	$ 320
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	$ 1,542	$ 1,467	$ 299	$ 283
Actual return (loss) on plan assets	294	107	41	23
Employer contributions	—	—	12	12
Benefits paid	(33)	(32)	(19)	(19)
Fair value of plan assets at end of year	$ 1,803	$ 1,542	$ 333	$ 299
Funded status at end of year	$ 1,030	$ 859	$ 43	$ (21)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	$ 1,030	$ 859	$ 57	$ —
Noncurrent pension and other postretirement benefit liabilities(3)	—	—	(14)	(21)
Net amount recognized	$ 1,030	$ 859	$ 43	$ (21)
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	3.81%	4.50%	3.76%	4.47%
Weighted average rate of increase for compensation	4.11%	4.11%	n/a	n/a

(1) 2017 amounts relate primarily to a plan amendment that changed post-65 retiree medical coverage for certain current and future Local 69 retirees effective July 1, 2017. 2016 amount relates primarily to a plan amendment that changed post-65 retiree medical coverage for certain current and future Local 50 retirees effective April 1, 2017.

(2) 2017 amount relates primarily to settlement and curtailment as a result of the voluntary and involuntary separation programs at Dominion Energy Questar. 2016 amount relates primarily to a settlement for certain executives.

(3) Reflected in other deferred credits and other liabilities in Dominion Energy Gas' Consolidated Balance Sheets.

The ABO for all of Dominion Energy's defined benefit pension plans was $8.2 billion and $7.3 billion at December 31, 2017 and 2016, respectively. The ABO for the defined benefit pension plans covering Dominion Energy Gas employees represented by collective bargaining units was $724 million and $640 million at December 31, 2017 and 2016, respectively.

Under its funding policies, Dominion Energy evaluates plan funding requirements annually, usually in the fourth quarter after receiving updated plan information from its actuary. Based on the funded status of each plan and other factors, Dominion Energy determines the amount of contributions for the current year, if any, at that time. During 2017, Dominion Energy and Dominion Energy Gas made no contributions to the qualified defined benefit pension plans other than a $75 million contribution to Dominion Energy's qualified pension plan to satisfy a regulatory condition to closing of the Dominion Energy Questar Combination and no contributions are currently expected in 2018. In July 2012, the MAP 21 Act was signed into law. This Act includes an increase in the interest rates used to determine plan sponsors' pension contributions for required funding purposes. In 2014, the HATFA of 2014 was signed into law. Similar to the MAP 21 Act, the HATFA of 2014 adjusts the rules for calculating interest rates used in determining funding obligations. It is estimated that the new interest rates will reduce required pension contributions through 2019. Dominion Energy believes that required pension contributions will rise subsequent to 2019, resulting in an estimated $200 million reduction in net cumulative required contributions over a 10-year period.

Certain regulatory authorities have held that amounts recovered in utility customers' rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, certain of Dominion Energy's subsidiaries, including Dominion Energy Gas, fund other postretirement benefit costs through VEBAs. Dominion Energy's remaining subsidiaries do not prefund other postretirement benefit costs but instead pay claims as presented. Dominion Energy's contributions to VEBAs, all of which pertained to Dominion Energy Gas employees, totaled $12 million for both 2017 and 2016, and Dominion Energy expects to contribute approximately $12 million to the Dominion Energy VEBAs in 2018, all of which pertains to Dominion Energy Gas employees.

Dominion Energy and Dominion Energy Gas do not expect any pension or other postretirement plan assets to be returned during 2018.

The following table provides information on the benefit obligations and fair value of plan assets for plans with a benefit obligation in excess of plan assets for Dominion Energy and Dominion Energy Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
As of December 31,	2017	2016	2017	2016
(millions)				
Dominion Energy				
Benefit obligation	$8,209	$7,386	$191	$470
Fair value of plan assets	6,103	5,340	156	356
Dominion Energy Gas				
Benefit obligation	$ —	$ —	$157	$320
Fair value of plan assets	—	—	143	299

The following table provides information on the ABO and fair value of plan assets for Dominion Energy's pension plans with an ABO in excess of plan assets:

As of December 31,	2017	2016
(millions)		
Accumulated benefit obligation	$7,392	$5,987
Fair value of plan assets	6,103	4,653

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) plans:

	Estimated Future Benefit Payments	
	Pension Benefits	Other Postretirement Benefits
(millions)		
Dominion Energy		
2018	$373	$ 99
2019	378	101
2020	402	102
2021	418	102
2022	434	102
2023-2027	2,437	486
Dominion Energy Gas		
2018	$ 35	$ 19
2019	37	19
2020	38	20
2021	39	20
2022	41	20
2023-2027	214	94

Plan Assets

Dominion Energy's overall objective for investing its pension and other postretirement plan assets is to achieve appropriate long-term rates of return commensurate with prudent levels of risk. As a participating employer in various pension plans sponsored by Dominion Energy, Dominion Energy Gas is subject to Dominion Energy's investment policies for such plans. To minimize risk, funds are broadly diversified among asset classes, investment strategies and investment advisors. The strategic target asset allocations for Dominion Energy's pension funds are 28% U.S. equity, 18% non-U.S. equity, 35% fixed income, 3% real estate and 16% other alternative investments. U.S. equity includes investments in large-cap, mid-cap and small-cap companies located in the U.S. Non-U.S. equity includes investments in large-cap and small-cap companies located outside of the U.S. including both developed and emerging markets. Fixed income includes corporate debt instruments of companies from diversified industries and U.S. Treasuries. The U.S. equity, non-U.S. equity and fixed income investments are in individual securities as well as mutual funds. Real estate includes equity real estate investment trusts and investments in partnerships. Other alternative investments include partnership investments in private equity, debt and hedge funds that follow several different strategies.

Dominion Energy also utilizes common/collective trust funds as an investment vehicle for its defined benefit plans. A common/collective trust fund is a pooled fund operated by a bank or trust company for investment of the assets of various organizations and individuals in a well-diversified portfolio. Common/collective trust funds are funds of grouped assets that follow various investment strategies.

Strategic investment policies are established for Dominion Energy's prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of Dominion Energy's assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. Future asset/liability studies will focus on strategies to further reduce pension and other postretirement plan risk, while still achieving attractive levels of returns. Financial derivatives may be used to obtain or manage market exposures and to hedge assets and liabilities.

For fair value measurement policies and procedures related to pension and other postretirement benefit plan assets, see Note 6.

The fair values of Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) pension plan assets by asset category are as follows:

At December 31,	2017				2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(millions)								
Dominion Energy								
Cash and cash equivalents	$ 18	$ —	$—	$ 18	$ 12	$ 2	$—	$ 14
Common and preferred stocks:								
U.S.	1,902	—	—	1,902	1,705	—	—	1,705
International	1,151	—	—	1,151	928	—	—	928
Insurance contracts	—	352	—	352	—	334	—	334
Corporate debt instruments	41	729	—	770	35	682	—	717
Government securities	9	676	—	685	13	522	—	535
Total recorded at fair value	$3,121	$1,757	$—	$4,878	$2,693	$1,540	$—	$4,233
Assets recorded at NAV(1):								
Common/collective trust funds				2,272				1,960
Alternative investments:								
Real estate funds				111				121
Private equity funds				606				506
Debt funds				161				153
Hedge funds				19				25
Total recorded at NAV				$3,169				$2,765
Total investments(2)				$8,047				$6,998
Dominion Energy Gas								
Cash and cash equivalents	$ 4	$ —	$—	$ 4	$ 3	$ —	$—	$ 3
Common and preferred stocks:								
U.S.	425	—	—	425	375	—	—	375
International	257	—	—	257	203	—	—	203
Insurance contracts	—	79	—	79	—	73	—	73
Corporate debt instruments	9	163	—	172	8	150	—	158
Government securities	2	151	—	153	3	115	—	118
Total recorded at fair value	$ 697	$ 393	$—	$1,090	$ 592	$ 338	$—	$ 930
Assets recorded at NAV(1):								
Common/collective trust funds				509				430
Alternative investments:								
Real estate funds				25				27
Private equity funds				135				111
Debt funds				36				34
Hedge funds				4				6
Total recorded at NAV				$ 709				$ 608
Total investments(3)				$1,799				$1,538

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

(2) Excludes net assets related to pending sales of securities of $11 million, net accrued income of $19 million, and includes net assets related to pending purchases of securities of $15 million at December 31, 2017. Excludes net assets related to pending sales of securities of $46 million, net accrued income of $19 million, and includes net assets related to pending purchases of securities of $47 million at December 31, 2016.

(3) Excludes net assets related to pending sales of securities of $3 million, net accrued income of $4 million, and includes net assets related to pending purchases of securities of $3 million at December 31, 2017. Excludes net assets related to pending sales of securities of $10 million, net accrued income of $4 million, and includes net assets related to pending purchases of securities of $10 million at December 31, 2016.

The fair values of Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) other postretirement plan assets by asset category are as follows:

At December 31,	2017				2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(millions)								
Dominion Energy								
Cash and cash equivalents	$ 1	$ 2	$—	$ 3	$ 1	$ 1	$—	$ 2
Common and preferred stocks:								
U.S.	636	—	—	636	571	—	—	571
International	196	—	—	196	143	—	—	143
Insurance contracts	—	21	—	21	—	19	—	19
Corporate debt instruments	2	44	—	46	2	40	—	42
Government securities	1	41	—	42	1	30	—	31
Total recorded at fair value	$836	$108	$—	$ 944	$718	$90	$—	$ 808
Assets recorded at NAV(1):								
Common/collective trust funds				689				621
Alternative investments:								
Real estate funds				9				9
Private equity funds				73				59
Debt funds				11				12
Hedge funds				1				1
Total recorded at NAV				$ 783				$ 702
Total investments(2)				$1,727				$1,510
Dominion Energy Gas								
Common and preferred stocks:								
U.S.	$130	$ —	$—	$ 130	$121	$—	$—	$ 121
International	33	—	—	33	24	—	—	24
Total recorded at fair value	$163	$ —	$—	$ 163	$145	$—	$—	$ 145
Assets recorded at NAV(1):								
Common/collective trust funds				154				140
Alternative investments:								
Real estate funds				1				1
Private equity funds				15				12
Debt funds				—				1
Total recorded at NAV				$ 170				$ 154
Total investments				$ 333				$ 299

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

(2) Excludes net assets related to pending sales of securities of $1 million, net accrued income of $2 million, and includes net assets related to pending purchases of securities of $1 million at December 31, 2017. Excludes net assets related to pending sales of securities of $5 million, net accrued income of $2 million, and includes net assets related to pending purchases of securities of $5 million at December 31, 2016.

The Plan's investments are determined based on the fair values of the investments and the underlying investments, which have been determined as follows:

- *Cash and Cash Equivalents*—Investments are held primarily in short-term notes and treasury bills, which are valued at cost plus accrued interest.
- *Common and Preferred Stocks*—Investments are valued at the closing price reported on the active market on which the individual securities are traded.
- *Insurance Contracts*—Investments in Group Annuity Contracts with John Hancock were entered into after 1992 and are stated at fair value based on the fair value of the underlying securities as provided by the managers and include investments in U.S. government securities, corporate debt instruments, state and municipal debt securities.
- *Corporate Debt Instruments*—Investments are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings. When quoted prices are not available for identical or similar instruments, the instrument is valued under a discounted cash flows approach that maximizes observable inputs, such as current yields of similar instruments, but includes adjustments for certain risks that may not be observable, such as credit and liquidity risks or a broker quote, if available.
- *Government Securities*—Investments are valued using pricing models maximizing the use of observable inputs for similar securities.
- *Common/Collective Trust Funds*—Common/collective trust funds invest in debt and equity securities and other instruments with characteristics similar to those of the funds' benchmarks. The primary objectives of the funds are to seek investment returns that approximate the overall performance of their benchmark indexes. These benchmarks are major equity indices, fixed income indices, and money market indices that focus on growth, income, and liquidity strategies, as applicable. Investments in common/collective trust funds are stated at the NAV as determined by the issuer of the common/collective trust funds and are based on the fair value of the underlying investments held by the fund less its liabilities. The NAV is used as a practical expedient to estimate fair value. The common/collective trust funds do not have any unfunded commitments, and do not have any applicable liquidation periods or defined terms/periods to be held. The majority of the common/collective trust funds have limited withdrawal or redemption rights during the term of the investment.
- *Alternative Investments*—Investments in real estate funds, private equity funds, debt funds and hedge funds are stated at fair value based on the NAV of the Plan's proportionate share of the partnership, joint venture or other alternative investment's fair value as determined by reference to audited financial statements or NAV statements provided by the investment manager. The NAV is used as a practical expedient to estimate fair value.

Combined Notes to Consolidated Financial Statements, Continued

NET PERIODIC BENEFIT (CREDIT) COST

Net periodic benefit (credit) cost is reflected in other operations and maintenance expense in the Consolidated Statements of Income. The components of the provision for net periodic benefit (credit) cost and amounts recognized in other comprehensive income and regulatory assets and liabilities for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) plans are as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31, (millions, except percentages)	**2017**	2016	2015	**2017**	2016	2015
Dominion Energy						
Service cost	**$ 138**	$ 118	$ 126	**$ 26**	$ 31	$ 40
Interest cost	**345**	317	287	**60**	65	67
Expected return on plan assets	**(639)**	(573)	(531)	**(128)**	(118)	(117)
Amortization of prior service (credit) cost	**1**	1	2	**(51)**	(35)	(27)
Amortization of net actuarial loss	**162**	111	160	**13**	8	6
Settlements and curtailments	**—**	1	—	**—**	—	—
Net periodic benefit (credit) cost	**$ 7**	$ (25)	$ 44	**$ (80)**	$ (49)	$ (31)
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ 142**	$ 931	$ 159	**$ 12**	$ 178	$ (18)
Prior service (credit) cost	**5**	—	—	**(73)**	(216)	(31)
Settlements and curtailments	**1**	(1)	—	**2**	—	—
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(162)**	(111)	(160)	**(13)**	(8)	(6)
Amortization of prior service credit (cost)	**(1)**	(1)	(2)	**51**	35	27
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ (15)**	$ 818	$ (3)	**$ (21)**	$ (11)	$ (28)
Significant assumptions used to determine periodic cost:						
Discount rate	**3.31%-4.50%**	2.87%-4.99%	4.40%	**3.92%-4.47%**	3.56%-4.94%	4.40%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	8.75%	**8.50%**	8.50%	8.50%
Weighted average rate of increase for compensation	**4.09%**	4.22%	4.22%	**3.29%**	4.22%	4.22%
Healthcare cost trend rate(1)				**7.00%**	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)(1)				**5.00%**	5.00%	5.00%
Year that the rate reaches the ultimate trend rate(1)(2)				**2021**	2020	2019
Dominion Energy Gas						
Service cost	**$ 15**	$ 13	$ 15	**$ 4**	$ 5	$ 7
Interest cost	**30**	30	27	**12**	14	14
Expected return on plan assets	**(141)**	(134)	(126)	**(24)**	(23)	(24)
Amortization of prior service (credit) cost	**—**	—	1	**(3)**	1	(1)
Amortization of net actuarial loss	**16**	13	20	**2**	1	2
Net periodic benefit (credit) cost	**$ (80)**	$ (78)	$ (63)	**$ (9)**	$ (2)	$ (2)
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ (75)**	$ 91	$ 97	**$ 18**	$ 28	$ (9)
Prior service cost	**—**	—	—	**(61)**	—	—
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(16)**	(13)	(20)	**(2)**	(1)	(2)
Amortization of prior service credit (cost)	**—**	—	(1)	**3**	(1)	1
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ (91)**	$ 78	$ 76	**$ (42)**	$ 26	$ (10)
Significant assumptions used to determine periodic cost:						
Discount rate	**4.50%**	4.99%	4.40%	**4.47%**	4.93%	4.40%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	8.75%	**8.50%**	8.50%	8.50%
Weighted average rate of increase for compensation	**4.11%**	3.93%	3.93%	**4.11%**	3.93%	3.93%
Healthcare cost trend rate(1)				**7.00%**	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)(1)				**5.00%**	5.00%	5.00%
Year that the rate reaches the ultimate trend rate(1)				**2021**	2020	2019

(1) Assumptions used to determine net periodic cost for the following year.

(2) The Society of Actuaries model used to determine healthcare cost trend rates was updated in 2014. The new model converges to the ultimate trend rate much more quickly than previous models.

The components of AOCI and regulatory assets and liabilities for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) plans that have not been recognized as components of net periodic benefit (credit) cost are as follows:

	Pension Benefits		Other Postretirement Benefits	
At December 31,	2017	2016	2017	2016
(millions)				
Dominion Energy				
Net actuarial loss	**$3,181**	$3,200	**$ 283**	$ 283
Prior service (credit) cost	**8**	4	**(440)**	(419)
Total(1)	**$3,189**	$3,204	**$(157)**	$(136)
Dominion Energy Gas				
Net actuarial loss	**$ 367**	$ 458	**$ 76**	$ 60
Prior service (credit) cost	**—**	—	**(52)**	7
Total(2)	**$ 367**	$ 458	**$ 24**	$ 67

(1) As of December 31, 2017, of the $3.2 billion and $(157) million related to pension benefits and other postretirement benefits, $1.9 billion and $(87) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities. As of December 31, 2016, of the $3.2 billion and $(136) million related to pension benefits and other postretirement benefits, $1.9 billion and $(103) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities.

(2) As of December 31, 2017, of the $367 million related to pension benefits, $134 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $24 million related to other postretirement benefits is included entirely in regulatory assets and liabilities. As of December 31, 2016, of the $458 million related to pension benefits, $167 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $67 million related to other postretirement benefits is included entirely in regulatory assets and liabilities.

The following table provides the components of AOCI and regulatory assets and liabilities for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) plans as of December 31, 2017 that are expected to be amortized as components of net periodic benefit (credit) cost in 2018:

	Pension Benefits	Other Postretirement Benefits
(millions)		
Dominion Energy		
Net actuarial loss	$193	$ 11
Prior service (credit) cost	1	(52)
Dominion Energy Gas		
Net actuarial loss	$ 19	$ 3
Prior service (credit) cost	—	(4)

The expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates and mortality are critical assumptions in determining net periodic benefit (credit) cost. Dominion Energy develops non-investment related assumptions, which are then compared to the forecasts of an independent investment advisor to ensure reasonableness. An internal committee selects the final assumptions used for Dominion Energy's pension and other postretirement plans, including those in which Dominion Energy Gas participates, including discount rates, expected long-term rates of return, healthcare cost trend rates and mortality rates.

Dominion Energy determines the expected long-term rates of return on plan assets for its pension plans and other postretirement benefit plans, including those in which Dominion Energy Gas participates, by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset volatilities and correlations;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major stock market indices; and
- Investment allocation of plan assets.

Dominion Energy determines discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under its plans, including those in which Dominion Energy Gas participates.

Mortality rates are developed from actual and projected plan experience for postretirement benefit plans. Dominion Energy's actuary conducts an experience study periodically as part of the process to select its best estimate of mortality. Dominion Energy considers both standard mortality tables and improvement factors as well as the plans' actual experience when selecting a best estimate. During 2016, Dominion Energy conducted a new experience study as scheduled and, as a result, updated its mortality assumptions for all its plans, including those in which Dominion Energy Gas participates.

Assumed healthcare cost trend rates have a significant effect on the amounts reported for Dominion Energy's retiree healthcare plans, including those in which Dominion Energy Gas participates. A one percentage point change in assumed healthcare cost trend rates would have had the following effects for Dominion Energy's and Dominion Energy Gas' (for employees represented by collective bargaining units) other postretirement benefit plans:

	Other Postretirement Benefits	
	One percentage point increase	One percentage point decrease
(millions)		
Dominion Energy		
Effect on net periodic cost for 2018	$ 24	$ (15)
Effect on other postretirement benefit obligation at December 31, 2017	158	(132)
Dominion Energy Gas		
Effect on net periodic cost for 2018	$ 4	$ (3)
Effect on other postretirement benefit obligation at December 31, 2017	31	(26)

Dominion Energy Gas (Employees Not Represented by Collective Bargaining Units) and Virginia Power—Participation in Defined Benefit Plans

Virginia Power employees and Dominion Energy Gas employees not represented by collective bargaining units are covered by the Dominion Energy Pension Plan described above. As participating employers, Virginia Power and Dominion Energy Gas are subject to Dominion Energy's funding policy, which is to contribute annually an amount that is in accordance with ERISA. During 2017, Virginia Power and Dominion Energy Gas made no contributions to the Dominion Energy Pension Plan, and no contributions to this plan are currently expected in 2018. Virginia Power's net periodic pension cost related to this plan was $110 million, $79 million and $97 million in 2017, 2016 and 2015, respectively. Dominion Energy Gas' net periodic pension credit related to this plan was $(37) million, $(45) million and $(38) million in 2017, 2016 and 2015, respectively. Net periodic pension (credit) cost is reflected in other operations and maintenance expense in their respective Consolidated Statements of Income. The funded status of various Dominion Energy subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating Dominion Energy subsidiaries. See Note 24 for Virginia Power and Dominion Energy Gas amounts due to/from Dominion Energy related to this plan.

Retiree healthcare and life insurance benefits, for Virginia Power employees and for Dominion Energy Gas employees not represented by collective bargaining units, are covered by the Dominion Energy Retiree Health and Welfare Plan described above. Virginia Power's net periodic benefit (credit) cost related to this plan was $(42) million, $(29) million and $(16) million in 2017, 2016 and 2015, respectively. Dominion Energy Gas' net periodic benefit (credit) cost related to this plan was $(5) million, $(4) million and $(5) million for 2017, 2016 and 2015, respectively. Net periodic benefit (credit) cost is reflected in other operations and maintenance expenses in their respective Consolidated Statements of Income. Employee headcount is the basis for determining the share of total other postretirement benefit costs for participating Dominion Energy subsidiaries. See Note 24 for Virginia Power and Dominion Energy Gas amounts due to/from Dominion Energy related to this plan.

Dominion Energy holds investments in trusts to fund employee benefit payments for the pension and other postretirement benefit plans in which Virginia Power and Dominion Energy Gas' employees participate. Any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that Virginia Power and Dominion Energy Gas will provide to Dominion Energy for their shares of employee benefit plan contributions.

Certain regulatory authorities have held that amounts recovered in rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, Virginia Power and Dominion Energy Gas fund other postretirement benefit costs through VEBAs. During 2017 and 2016, Virginia Power made no contributions to the VEBA and does not expect to contribute to the VEBA in 2018. Dominion Energy Gas made no contributions to the VEBAs for employees not represented by collective bargaining units during 2017 and 2016 and does not expect to contribute in 2018.

Defined Contribution Plans

Dominion Energy also sponsors defined contribution employee savings plans that cover substantially all employees. During 2017, 2016 and 2015, Dominion Energy recognized $45 million, $44 million and $43 million, respectively, as employer matching contributions to these plans. Dominion Energy Gas participates in these employee savings plans, both specific to Dominion Energy Gas and that cover multiple Dominion Energy subsidiaries. During 2017, 2016 and 2015, Dominion Energy Gas recognized $7 million as employer matching contributions to these plans. Virginia Power also participates in these employee savings plans. During 2017, 2016 and 2015, Virginia Power recognized $19 million, $19 million and $18 million, respectively, as employer matching contributions to these plans.

Organizational Design Initiative

In the first quarter of 2016, the Companies announced an organizational design initiative that reduced their total workforces during 2016. The goal of the organizational design initiative was to streamline leadership structure and push decision making lower while also improving efficiency. For the year ended December 31, 2016, Dominion Energy recorded a $65 million ($40 million after-tax) charge, including $33 million ($20 million after-tax) at Virginia Power and $8 million ($5 million after-tax) at Dominion Energy Gas, primarily reflected in other operations and maintenance expense in their Consolidated Statements of Income due to severance pay and other costs related to the organizational design initiative. The terms of the severance under the organizational design initiative were consistent with the Companies' existing severance plans.

NOTE 22. COMMITMENTS AND CONTINGENCIES

As a result of issues generated in the ordinary course of business, the Companies are involved in legal proceedings before various courts and are periodically subject to governmental examinations (including by regulatory authorities), inquiries and investigations. Certain legal proceedings and governmental examinations involve demands for unspecified amounts of damages, are in an initial procedural phase, involve uncertainty as to the outcome of pending appeals or motions, or involve significant factual issues that need to be resolved, such that it is not possible for the Companies to estimate a range of possible loss. For such matters for which the Companies cannot estimate a range of possible loss, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the litigation or investigative processes such that the Companies are able to estimate a range of possible loss. For legal proceedings and governmental examinations for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any accrued liability is recorded on a gross basis with a receivable also recorded for any probable insurance recoveries. Estimated ranges of loss are inclusive of legal fees and net of any anticipated insurance recoveries. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the Companies' maximum possible loss exposure. The circumstances of such legal proceedings and governmental examinations will change from time to time and actual results may vary significantly from the current estimate. For current proceedings not specifically reported below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial position, liquidity or results of operations of the Companies.

Environmental Matters

The Companies are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

AIR

CAA

The CAA, as amended, is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. At a minimum, states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

MATS

The MATS rule requires coal- and oil-fired electric utility steam generating units to meet strict emission limits for mercury, particulate matter as a surrogate for toxic metals and hydrogen chloride as a surrogate for acid gases. Following a one-year compliance extension granted by VDEQ and an additional one-year extension under an EPA Administrative Order, Virginia Power ceased operating the coal units at Yorktown power station in April 2017 to comply with the rule. In June 2017, the DOE issued an order to PJM to direct Virginia Power to operate Yorktown power station's Units 1 and 2 as needed to avoid reliability issues on the Virginia Peninsula. The order was effective for 90 days and can be reissued upon PJM's request, if necessary, until required electricity transmission upgrades are completed approximately 23 months following the receipt in July 2017 of final permits and approvals for construction. Beginning in August 2017, PJM filed requests for 90-day renewals of the DOE order which the DOE has granted. The current renewal is effective until March 2018. The Sierra Club has challenged the DOE order and certain renewal requests, all of which have been denied by the DOE.

Although litigation of the MATS rule is still pending, the regulation remains in effect and Virginia Power is complying with the applicable requirements of the rule and does not expect any adverse impacts to its operations at this time.

Ozone Standards

In October 2015, the EPA issued a final rule tightening the ozone standard from 75-ppb to 70-ppb. To comply with this standard, in April 2016 Virginia Power submitted the NOX Reasonable Available Control Technology analysis for Unit 5 at Possum Point power station. In December 2016, the VDEQ determined that NOX reductions are required on Unit 5. In October 2017, Virginia Power proposed to install NOX controls by mid-2019 with an expected cost in the range of $25 million to $35 million.

The statutory deadline for the EPA to complete attainment designations for a new standard was October 2017. States will have three years after final designations, certain of which were issued by the EPA in November 2017, to develop plans to address the new standard. Until the states have developed implementation plans for the standard, the Companies are unable to predict whether or to what extent the new rules will ultimately require additional controls. The expenditures required to implement additional controls could have a material impact on the Companies' results of operations and cash flows.

NOx and VOC Emissions

In April 2016, the Pennsylvania Department of Environmental Protection issued final regulations, with an effective date of January 2017, to reduce NOX and VOC emissions from combustion sources. To comply with the regulations, Dominion Energy Gas is installing emission control systems on existing engines at several compressor stations in Pennsylvania. The compliance costs associated with engineering and installation of controls and compliance demonstration with the regulation are expected to be approximately $35 million.

Oil and Gas NSPS

In August 2012, the EPA issued an NSPS impacting new and modified facilities in the natural gas production and gathering sectors and made revisions to the NSPS for natural gas processing and transmission facilities. These rules establish equipment performance specifications and emissions standards for control of VOC emissions for natural gas production wells, tanks, pneumatic controllers, and compressors in the upstream sector. In June 2016, the EPA issued a new NSPS regulation, for the oil and natural gas sector, to regulate methane and VOC emissions from new and modified facilities in transmission and storage, gathering and boosting, production and processing facilities. All projects which commenced construction after September 2015 are required to comply with this regulation. In April 2017, the EPA issued a notice that it is reviewing the rule and, if appropriate, will issue a rulemaking to suspend, revise or rescind the June 2016 final NSPS for certain oil and gas facilities. In June 2017, the EPA published notice of reconsideration and partial stay of the rule for 90 days and proposed extending the stay for two years. In July 2017, the U.S. Court of Appeals for the D.C. Circuit vacated the 90-day stay. In November 2017, the EPA solicited comments on the proposed two-year stay of the June 2016 NSPS rules. Dominion Energy and Dominion Energy Gas are implementing the 2016 regulation. Dominion Energy and Dominion Energy Gas are still evaluating whether potential impacts on results of operations, financial condition and/or cash flows related to this matter will be material.

GHG REGULATION

Carbon Regulations

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a PSD or Title V permit for GHGs is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program, and to set a significant emissions rate at 75,000 tons per year of CO_2 equivalent emissions under which a source would not be required to apply BACT for its GHG emissions. Until the EPA ultimately takes final action on this rulemaking, the Companies cannot predict the impact to their financial statements.

In addition, the EPA continues to evaluate its policy regarding the consideration of CO_2 emissions from biomass projects when determining whether a stationary source meets the PSD and Title V applicability thresholds, including those for the application of

BACT. It is unclear how the final policy will affect Virginia Power's Altavista, Hopewell and Southampton power stations which were converted from coal to biomass under the prior biomass deferral policy; however, the expenditures to comply with any new requirements could be material to Dominion Energy's and Virginia Power's financial statements.

Methane Emissions

In July 2015, the EPA announced the next generation of its voluntary Natural Gas STAR Program, the Natural Gas STAR Methane Challenge Program. The program covers the entire natural gas sector from production to distribution, with more emphasis on transparency and increased reporting for both annual emissions and reductions achieved through implementation measures. In March 2016, East Ohio, Hope, DETI and Questar Gas joined the EPA as founding partners in the new Methane Challenge program and submitted implementation plans in September 2016. DECG joined the EPA's voluntary Natural Gas STAR Program in July 2016 and submitted an implementation plan in September 2016. Dominion Energy and Dominion Energy Gas do not expect the costs related to these programs to have a material impact on their results of operations, financial condition and/or cash flows.

WATER

The CWA, as amended, is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. The Companies must comply with applicable aspects of the CWA programs at their operating facilities.

In October 2014, the final regulations under Section 316(b) of the CWA that govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold became effective. The rule establishes a national standard for impingement based on seven compliance options, but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two MGD, with a heightened entrainment analysis for those facilities over 125 MGD. Dominion Energy and Virginia Power have 13 and 11 facilities, respectively, that may be subject to the final regulations. Dominion Energy anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling systems. Dominion Energy and Virginia Power are currently evaluating the need or potential for entrainment controls under the final rule as these decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost and benefit studies. While the impacts of this rule could be material to Dominion Energy's and Virginia Power's results of operations, financial condition and/or cash flows, the existing regulatory framework in Virginia provides rate recovery mechanisms that could substantially mitigate any such impacts for Virginia Power.

In September 2015, the EPA released a final rule to revise the Effluent Limitations Guidelines for the Steam Electric Power Generating Category. The final rule establishes updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to convert from wet to dry or closed cycle coal ash management, improve existing wastewater treatment systems and/or install new wastewater treatment technologies in order to meet the new discharge limits. Virginia Power has eight facilities subject to the final rule. In April 2017, the EPA granted two separate petitions for reconsideration of the Effluent Limitations Guidelines final rule and stayed future compliance dates in the rule. Also in April 2017, the U.S. Court of Appeals for the Fifth Circuit granted the U.S.'s request for a stay of the pending consolidated litigation challenging the rule while the EPA addresses the petitions for reconsideration. In September 2017, the EPA signed a rule to postpone the earliest compliance dates for certain waste streams regulations in the Effluent Limitations Guidelines final rule from November 2018 to November 2020; however, the latest date for compliance for these regulations remains December 2023. The EPA is proposing to complete new rulemaking for these waste streams. While the impacts of this rule could be material to Dominion Energy's and Virginia Power's results of operations, financial condition and/or cash flows, the existing regulatory framework in Virginia provides rate recovery mechanisms that could substantially mitigate any such impacts for Virginia Power.

WASTE MANAGEMENT AND REMEDIATION

The CERCLA, as amended, provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. government either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under the CERCLA, as amended, generators and transporters of hazardous substances, as well as past and present owners and operators of contaminated sites, can be jointly, severally and strictly liable for the cost of cleanup. These potentially responsible parties can be ordered to perform a cleanup, be sued for costs associated with an EPA-directed cleanup, voluntarily settle with the U.S. government concerning their liability for cleanup costs, or voluntarily begin a site investigation and site remediation under state oversight.

From time to time, Dominion Energy, Virginia Power, or Dominion Energy Gas may be identified as a potentially responsible party to a Superfund site. The EPA (or a state) can either allow such a party to conduct and pay for a remedial investigation, feasibility study and remedial action or conduct the remedial investigation and action itself and then seek reimbursement from the potentially responsible parties. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, Dominion Energy, Virginia Power, or Dominion Energy Gas may be responsible for the costs of remedial investigation and actions under the Superfund law or other laws or regulations regarding the remediation of waste. The Companies do not believe these matters will have a material effect on results of operations, financial condition and/or cash flows.

Dominion Energy has determined that it is associated with 19 former manufactured gas plant sites, three of which pertain to Virginia Power and 12 of which pertain to Dominion Energy Gas. Studies conducted by other utilities at their former manufactured gas plant sites have indicated that those sites contain coal tar and other potentially harmful materials. None of the former sites with which the Companies are associated is under investigation by any state or federal environmental agency. At one of the former sites, Dominion Energy is conducting a state-approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. Another site has been accepted into a state-based voluntary remediation program. Virginia Power is currently evaluating the nature and extent of the contamination from this site as well as potential remedial options. Preliminary costs for options under evaluation for the site range from $1 million to $22 million. Due to the uncertainty surrounding the other sites, the Companies are unable to make an estimate of the potential financial statement impacts.

See below for discussion on ash pond and landfill closure costs.

Other Legal Matters

The Companies are defendants in a number of lawsuits and claims involving unrelated incidents of property damage and personal injury. Due to the uncertainty surrounding these matters, the Companies are unable to make an estimate of the potential financial statement impacts; however, they could have a material impact on results of operations, financial condition and/or cash flows.

APPALACHIAN GATEWAY

Pipeline Contractor Litigation

Following the completion of the Appalachian Gateway project in 2012, DETI received multiple change order requests and other claims for additional payments from a pipeline contractor for the project. In July 2015, the contractor filed a complaint against DETI in U.S. District Court for the Western District of Pennsylvania. In March 2016, the Pennsylvania court granted DETI's motion to transfer the case to the U.S. District Court for the Eastern District of Virginia. In July 2016, DETI filed a motion to dismiss. In March 2017, the court dismissed three of eight counts in the complaint. In May 2017, the contractor withdrew one of the counts in the complaint. In November 2017, DETI and the contractor entered into a partial settlement agreement for a release of certain claims. This case is pending. At December 31, 2017, DETI has accrued a liability of $2 million for this matter. Dominion Energy Gas cannot currently estimate additional financial statement impacts, but there could be a material impact to its financial condition and/or cash flows.

Gas Producers Litigation

In connection with the Appalachian Gateway project, Dominion Energy Field Services, Inc. entered into contracts for firm purchase rights with a group of small gas producers. In June 2016, the gas producers filed a complaint in the Circuit Court of Marshall County, West Virginia against Dominion Energy, DETI and Dominion Energy Field Services, Inc., among other defendants, claiming that the contracts are unenforceable and seeking compensatory and punitive damages. During the third quarter of 2016, Dominion Energy, DETI and Dominion Energy Field Services, Inc. were served with the complaint. Also in the third quarter of 2016, Dominion Energy and DETI, with the consent of the other defendants, removed the case to the U.S. District Court for the Northern District of West Virginia. In October 2016, the defendants filed a motion to dismiss and the plaintiffs filed a motion to remand. In February 2017, the U.S. District Court entered an order remanding the matter to the Circuit Court of Marshall County, West Virginia. In March 2017, Dominion Energy was voluntarily dismissed from the case; however, DETI and Dominion Energy Field Services, Inc. remain parties to the matter. In April 2017, the case was transferred to the Business Court Division of West Virginia. In January 2018, the court granted the motion to dismiss filed by the defendants on two counts. All other claims are pending in the Business Court Division of West Virginia. Dominion Energy and Dominion Energy Gas cannot currently estimate financial statement impacts, but there could be a material impact to their financial condition and/or cash flows.

ASH POND AND LANDFILL CLOSURE COSTS

In March 2015, the Sierra Club filed a lawsuit alleging CWA violations at Chesapeake power station. In March 2017, the U.S. District Court for the Eastern District of Virginia ruled that impacted groundwater associated with the on-site coal ash storage units was migrating to adjacent surface water, which constituted an unpermitted point source discharge in violation of the CWA. The court, however, rejected Sierra Club's claims that Virginia Power had violated specific conditions of its water discharge permit. Finding no harm to the environment, the court further declined to impose civil penalties or require excavation of the ash from the site as Sierra Club had sought. In July 2017, the court issued a final order requiring Virginia Power to perform additional specific sediment, water and aquatic life monitoring at and around the Chesapeake power station for a period of at least two years. The court further directed Virginia Power to apply for a solid waste permit from VDEQ that includes corrective measures to address on-site groundwater impacts. In July 2017, Virginia Power appealed the court's July 2017 final order to the U.S. Court of Appeals for the Fourth Circuit. In August 2017, the Sierra Club filed a cross appeal. This case is pending.

In April 2015, the EPA enacted a final rule regulating CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store, CCRs. Virginia Power currently operates inactive ash ponds, existing ash ponds, and CCR landfills subject to the final rule at eight different facilities. This rule created a legal obligation for Virginia Power to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as perform required monitoring, corrective action, and post-closure care activities as necessary.

In 2015, Virginia Power recorded a $386 million ARO related to future ash pond and landfill closure costs, which resulted in a $99 million incremental charge recorded in other operations and maintenance expense in its Consolidated Statement of Income, a $166 million increase in property, plant and equipment associated with asset retirement costs, and a $121 million reduction in other noncurrent liabilities from the reversal of a previously recorded contingent liability since the ARO obligation created by the final CCR rule represents similar activities. In 2016, Virginia Power recorded an increase to this ARO of \$238 million, which resulted in a \$197 million incremental charge recorded in other operations and maintenance expense in its Consolidated Statement of Income, a \$17 million increase in property, plant and equipment and a \$24 million increase in regulatory assets.

In December 2016, legislation was enacted that creates a framework for EPA- approved state CCR permit programs. In August 2017, the EPA issued interim guidance outlining the framework for state CCR program approval. The EPA has enforcement authority until state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. In September 2017, the EPA agreed to reconsider portions of the CCR rule in response to two petitions for reconsideration. Litigation concerning the CCR rule is pending and the EPA has submitted to the court a list of which CCR rule provisions the EPA intends to reevaluate. Virginia Power cannot forecast potential incremental impacts or costs related to existing coal ash sites in connection with future implementation of the 2016 CCR legislation and reconsideration of the CCR rule.

In April 2017, the Virginia Governor signed legislation into law that places a moratorium on the VDEQ issuing solid waste permits for closure of ash ponds at Virginia Power's Bremo, Chesapeake, Chesterfield and Possum Point power stations until May 2018. The law also required Virginia Power to conduct an assessment of closure alternatives for the ash ponds at these four stations, to include an evaluation of excavation for recycling or off-site disposal, surface and groundwater conditions and safety. Virginia Power completed the assessments and provided the report on December 1, 2017. The actual AROs related to the CCR rule may vary substantially from the estimates used to record the obligation.

COVE POINT

Dominion Energy has constructed the Liquefaction Project at the Cove Point facility, which, once commercially operational, would enable the facility to liquefy domestically-produced natural gas and export it as LNG. In September 2014, FERC issued an order granting authorization for Cove Point to construct, modify and operate the Liquefaction Project.

Two parties have separately filed petitions for review of the FERC order in the U.S. Court of Appeals for the D.C. Circuit, which petitions were consolidated. Separately, one party requested a stay of the FERC order until the judicial proceedings are complete, which the court denied in June 2015. In July 2016, the court denied one party's petition for review of the FERC order authorizing the Liquefaction Project. The court also issued a decision remanding the other party's petition for review of the FERC order to FERC for further explanation of FERC's decision that a previous transaction with an existing import shipper was not unduly discriminatory. In September 2017, FERC issued its order on remand from the U.S. Court of Appeals for the D.C. Circuit, and reaffirmed its ruling in its prior orders that Cove Point did not violate the prohibition against undue discrimination by agreeing to a capacity reduction and early contract termination with the existing import shipper. In October 2017, the party filed a request for rehearing of the FERC order on remand. This case is pending.

In September 2013, the DOE granted Non-FTA Authorization approval for the export of up to 0.77 bcfe/day of natural gas to countries that do not have an FTA for trade in natural gas. In June 2016, a party filed a petition for review of this approval in the U.S. Court of Appeals for the D.C. Circuit. In November 2017, the U.S. Court of Appeals for the D.C. Circuit issued an order denying the petition for review.

In July 2017, Cove Point submitted an application for a temporary operating permit to the Maryland Department of the Environment, as required prior to the date of first production of LNG for commercial purposes of exporting LNG. The permit was received in December 2017. In February 2018, the Public Service Commission of Maryland issued an order approving Cove Point's August 2017 application to amend the CPCN issued by the Public Service Commission of Maryland in May 2014 to make necessary updates.

FERC

FERC staff in the Office of Enforcement, Division of Investigations, is conducting a non-public investigation of Virginia Power's offers of combustion turbines generators into the PJM day-ahead markets from April 2010 through September 2014. FERC staff notified Virginia Power of its preliminary findings relating to Virginia Power's alleged violation of FERC's rules in connection with these activities. Virginia Power has provided its response to FERC staff's preliminary findings letter explaining why Virginia Power's conduct was lawful and refuting any allegation of wrongdoing. Virginia Power is cooperating fully with the investigation; however, it cannot currently predict whether or to what extent it may incur a material liability.

GREENSVILLE COUNTY

Virginia Power is constructing Greensville County and related transmission interconnection facilities. In August 2016, the Sierra Club filed an administrative appeal in the Circuit Court for the City of Richmond challenging certain provisions in Greensville County's PSD air permit issued by VDEQ in June 2016. In August 2017, the Circuit Court upheld the air permit, and no appeals were filed.

Nuclear Matters

In March 2011, a magnitude 9.0 earthquake and subsequent tsunami caused significant damage at the Fukushima Daiichi nuclear power station in northeast Japan. These events have resulted in significant nuclear safety reviews required by the NRC and industry groups such as the Institute of Nuclear Power Operations. Like other U.S. nuclear operators, Dominion Energy has been gathering supporting data and participating in industry initiatives focused on the ability to respond to and mitigate the consequences of design-basis and beyond-design-basis events at its stations.

In July 2011, an NRC task force provided initial recommendations based on its review of the Fukushima Daiichi accident and in October 2011 the NRC staff prioritized these recommendations into Tiers 1, 2 and 3, with the Tier 1 recommendations consisting of actions which the staff determined should be started without unnecessary delay. In December 2011, the NRC Commissioners approved the agency staff's prioritization and recommendations, and that same month an appropriations act directed the NRC to require reevaluation of external hazards (not limited to seismic and flooding hazards) as soon as possible.

Based on the prioritized recommendations, in March 2012, the NRC issued orders and information requests requiring specific reviews and actions to all operating reactors, construction permit holders and combined license holders based on the lessons learned from the Fukushima Daiichi event. The orders applicable to Dominion Energy requiring implementation of safety enhancements related to mitigation strategies to respond to extreme natural events resulting in the loss of power at plants, and enhancing spent fuel pool instrumentation have been implemented. The information requests issued by the NRC request each reactor to reevaluate the seismic and external flooding hazards at their site using present-day methods and information, conduct walkdowns of their facilities to ensure protection against the hazards in their current design basis, and to reevaluate their emergency communications systems and staffing levels. The walkdowns of each unit have been completed, audited by the NRC and found to be adequate. Reevaluation of the emergency communications systems and staffing levels was completed as part of the effort to comply with the orders. Reevaluation of the seismic and external flooding hazards is expected to continue through 2018. Dominion Energy and Virginia Power do not currently expect that compliance with the NRC's information requests will materially impact their financial position, results of operations or cash flows during the implementation period. The NRC staff is evaluating the implementation of the longer term Tier 2 and Tier 3 recommendations. Dominion Energy and Virginia Power do not expect material financial impacts related to compliance with Tier 2 and Tier 3 recommendations.

Nuclear Operations

NUCLEAR DECOMMISSIONING—MINIMUM FINANCIAL ASSURANCE

The NRC requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. The 2017 calculation for the NRC minimum financial assurance amount, aggregated for Dominion Energy's and Virginia Power's nuclear units, excluding joint owners' assurance amounts and Millstone Unit 1 and Kewaunee, as those units are in a decommissioning state, was $2.7 billion and $1.8 billion, respectively, and has been satisfied by a combination of the funds being collected and deposited in the nuclear decommissioning trusts and the real annual rate of return growth of the funds allowed by the NRC. The 2017 NRC minimum financial assurance amounts above were calculated using preliminary December 31, 2017 U.S. Bureau of Labor Statistics indices. Dominion Energy believes that the amounts currently available in its decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. Virginia Power also believes that the decommissioning funds and their expected earnings for the Surry and North Anna units will be sufficient to cover decommissioning costs, particularly when combined with future ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. This reflects a positive long-term outlook for trust fund investment returns as the decommissioning of the units will not be complete for decades. Dominion Energy and Virginia Power will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirement, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC. See Note 9 for additional information on nuclear decommissioning trust investments.

NUCLEAR INSURANCE

The Price-Anderson Amendments Act of 1988 provides the public up to $13.44 billion of liability protection per nuclear incident, via obligations required of owners of nuclear power plants, and allows for an inflationary provision adjustment every five years. Dominion Energy and Virginia Power have purchased $450 million of coverage from commercial insurance pools for each reactor site with the remainder provided through a mandatory industry retrospective rating plan. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., the Companies could be assessed up to $127 million for each of their licensed reactors not to exceed $19 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. However, the NRC granted an exemption in March 2015 to remove Kewaunee from the Secondary Financial Protection program. The current levels of nuclear property insurance coverage for Dominion Energy's and Virginia Power's nuclear units are as follows:

(billions)	Coverage
Dominion Energy	
Millstone	**$1.70**
Kewaunee	**1.06**
Virginia Power(1)	
Surry	**$1.70**
North Anna	**1.70**

(1) Surry and North Anna share a blanket property limit of $200 million.

Dominion Energy's and Virginia Power's nuclear property insurance coverage for Millstone, Surry and North Anna exceeds the NRC minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site. Kewaunee meets the NRC minimum requirement of $1.06 billion. This includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first, to return the reactor to and maintain it in a safe and stable condition and second, to decontaminate the reactor and station site in accordance with a plan approved by the NRC. Nuclear property insurance is provided by NEIL, a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. Dominion Energy's and Virginia Power's maximum retrospective premium assessment for the current policy period is $86 million and $50 million, respectively. Based on the severity of the incident, the Board of Directors of the nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. Dominion Energy and Virginia Power have the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

Millstone and Virginia Power also purchase accidental outage insurance from NEIL to mitigate certain expenses, including replacement power costs, associated with the prolonged outage of a nuclear unit due to direct physical damage. Under this program, Dominion Energy and Virginia Power are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. Dominion Energy's and Virginia Power's maximum retrospective premium assessment for the current policy period is $22 million and $10 million, respectively.

ODEC, a part owner of North Anna, and Massachusetts Municipal and Green Mountain, part owners of Millstone's Unit 3, are responsible to Dominion Energy and Virginia Power for their share of the nuclear decommissioning obligation and insurance premiums on applicable units, including any retrospective premium assessments and any losses not covered by insurance.

SPENT NUCLEAR FUEL

Dominion Energy and Virginia Power entered into contracts with the DOE for the disposal of spent nuclear fuel under provisions of the Nuclear Waste Policy Act of 1982. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by Dominion Energy's and Virginia Power's contracts with the DOE. Dominion Energy and Virginia Power have previously received damages award payments and settlement payments related to these contracts.

By mutual agreement of the parties, the settlement agreements are extendable to provide for resolution of damages incurred after 2013. The settlement agreements for the Surry, North Anna and Millstone plants have been extended to provide for periodic payments for damages incurred through December 31, 2016, and have been extended to provide for periodic payment of damages through December 31, 2019. Pursuit of or possible settlement of the Kewaunee claims for damages incurred after December 31, 2013 is being evaluated.

In 2017, Virginia Power and Dominion Energy received payments of $22 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2015 through December 31, 2015, and $14 million for resolution of claims incurred at Millstone for the period of July 1, 2015 through June 30, 2016.

In 2016, Virginia Power and Dominion Energy received payments of $30 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2014 through December 31, 2014, and $22 million for resolution of claims incurred at Millstone for the period of July 1, 2014 through June 30, 2015.

In 2015, Virginia Power and Dominion Energy received payments of $8 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2013 through December 31, 2013, and $17 million for resolution of claims incurred at Millstone for the period of July 1, 2013 through June 30, 2014.

Dominion Energy and Virginia Power continue to recognize receivables for certain spent nuclear fuel-related costs that they believe are probable of recovery from the DOE. Dominion Energy's receivables for spent nuclear fuel-related costs totaled $46 million and $56 million at December 31, 2017 and 2016, respectively. Virginia Power's receivables for spent nuclear fuel-related costs totaled $30 million and $37 million at December 31, 2017 and 2016, respectively.

Dominion Energy and Virginia Power will continue to manage their spent fuel until it is accepted by the DOE.

Long-Term Purchase Agreements

At December 31, 2017, Virginia Power had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that a third party has used to secure financing for the facility that will provide the contracted goods or services:

(millions)	2018	2019	2020	2021	2022	Thereafter	Total
Purchased electric capacity(1)	$93	$61	$52	$46	$—	$—	$252

(1) Commitments represent estimated amounts payable for capacity under a power purchase contract with a qualifying facility and an independent power producer, which ends in 2021. Capacity payments under the contract are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2017, the present value of Virginia Power's total commitment for capacity payments is $221 million. Capacity payments totaled $114 million, $248 million, and $305 million, and energy payments totaled $72 million, $126 million, and $198 million for the years ended 2017, 2016 and 2015, respectively.

Lease Commitments

The Companies lease real estate, vehicles and equipment primarily under operating leases. Payments under certain leases are escalated based on an index such as the consumer price index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2017 are as follows:

(millions)	2018	2019	2020	2021	2022	Thereafter	Total
Dominion Energy(1)	$68	$63	$56	$48	$39	$361	$635
Virginia Power	$34	$31	$27	$22	$15	$ 28	$157
Dominion Energy Gas	$15	$13	$10	$ 9	$ 7	$ 41	$ 95

(1) Amounts include a lease agreement for the Dominion Energy Questar corporate office, which is accounted for as a capital lease. At December 31, 2017 and 2016, the Consolidated Balance Sheets include $27 million and $30 million, respectively, in property, plant and equipment and $33 million and $35 million, respectively, in other deferred credits and other liabilities. The Consolidated Statements of Income include $3 million and less than $1 million recorded in depreciation, depletion and amortization for the years ended December 31, 2017 and 2016.

Rental expense for Dominion Energy totaled $113 million, $104 million, and $99 million for 2017, 2016 and 2015, respectively. Rental expense for Virginia Power totaled $57 million, $52 million, and $51 million for 2017, 2016 and 2015, respectively. Rental expense for Dominion Energy Gas totaled $34 million, $37 million, and $37 million for 2017, 2016 and 2015, respectively. The majority of rental expense is reflected in other operations and maintenance expense in the Consolidated Statements of Income.

In July 2016, Dominion Energy signed an agreement with a lessor to construct and lease a new corporate office property in Richmond, Virginia. The lessor is providing equity and has obtained financing commitments from debt investors, totaling $365 million, to fund the estimated project costs. The project is expected to be completed by mid-2019. Dominion Energy has been appointed to act as the construction agent for the lessor, during which time Dominion Energy will request cash draws from the lessor and debt investors to fund all project costs, which totaled $139 million as of December 31, 2017. If the project is terminated under certain events of default, Dominion Energy could be required to pay up to 89.9% of the then funded amount. For specific full recourse events, Dominion Energy could be required to pay up to 100% of the then funded amount.

The five-year lease term will commence once construction is substantially complete and the facility is able to be occupied. At the end of the initial lease term, Dominion Energy can (i) extend the term of the lease for an additional five years, subject to the approval of the participants, at current market terms, (ii) purchase the property for an amount equal to the project costs or, (iii) subject to certain terms and conditions, sell the property on behalf of the lessor to a third party using commercially reasonable efforts to obtain the highest cash purchase price for the property. If the project is sold and the proceeds from the sale are insufficient to repay the investors for the project costs, Dominion Energy may be required to make a payment to the lessor, up to 87% of project costs, for the difference between the project costs and sale proceeds.

Guarantees, Surety Bonds and Letters of Credit

In October 2017, Dominion Energy entered into a guarantee agreement to support a portion of Atlantic Coast Pipeline's obligation under a $3.4 billion revolving credit facility, also entered in October 2017, with a stated maturity date of October 2021. Dominion Energy's maximum potential loss exposure under the terms of the guarantee is limited to 48% of the outstanding borrowings under the revolving credit facility, an equal percentage to Dominion Energy's ownership in Atlantic Coast Pipeline. As of December 31, 2017, Atlantic Coast Pipeline has borrowed $664 million against the revolving credit facility. Dominion Energy's Consolidated Balance Sheet includes a liability of $28 million associated with this guarantee agreement at December 31, 2017.

In addition, at December 31, 2017, Dominion Energy had issued an additional $48 million of guarantees, primarily to support other equity method investees. No amounts related to the other guarantees have been recorded.

Dominion Energy also enters into guarantee arrangements on behalf of its consolidated subsidiaries, primarily to facilitate their commercial transactions with third parties. If any of these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, Dominion Energy would be obligated to satisfy such obligation. To the extent that a liability subject to a guarantee has been incurred by one of Dominion Energy's consolidated subsidiaries, that liability is included in the Consolidated Financial Statements. Dominion Energy is not required to recognize liabilities for guarantees issued on behalf of its subsidiaries unless it becomes probable that it will have to perform under the guarantees. Terms of the guarantees typically end once obligations have been paid. Dominion Energy currently believes it is unlikely that it would be required to perform or otherwise incur any losses associated with guarantees of its subsidiaries' obligations.

At December 31, 2017, Dominion Energy had issued the following subsidiary guarantees:

(millions)	Maximum Exposure
Commodity transactions(1)	$2,027
Nuclear obligations(2)	227
Cove Point(3)	1,900
Solar(4)	1,064
Other(5)	553
Total(6)	$5,771

(1) Guarantees related to commodity commitments of certain subsidiaries. These guarantees were provided to counterparties in order to facilitate physical and financial transaction related commodities and services.

(2) Guarantees related to certain DGI subsidiaries' regarding all aspects of running a nuclear facility.

(3) Guarantees related to Cove Point, in support of terminal services, transportation and construction. Cove Point has two guarantees that have no maximum limit and, therefore, are not included in this amount.

(4) Includes guarantees to facilitate the development of solar projects. Also includes guarantees entered into by DGI on behalf of certain subsidiaries to facilitate the acquisition and development of solar projects.

(5) Guarantees related to other miscellaneous contractual obligations such as leases, environmental obligations, construction projects and insurance programs. Due to the uncertainty of worker's compensation claims, the parental guarantee has no stated limit. Also included are guarantees related to certain DGI subsidiaries' obligations for equity capital contributions and energy generation associated with Fowler Ridge and NedPower. As of December 31, 2017, Dominion Energy's maximum remaining cumulative exposure under these equity funding agreements is $17 million through 2019 and its maximum annual future contributions could range from approximately $4 million to $14 million.

(6) Excludes Dominion Energy's guarantee for the construction of the new corporate office property discussed further within Lease Commitments above.

Additionally, at December 31, 2017, Dominion Energy had purchased $153 million of surety bonds, including $63 million at Virginia Power and $24 million at Dominion Energy Gas, and authorized the issuance of letters of credit by financial institutions of $76 million to facilitate commercial transactions by its subsidiaries with third parties. Under the terms of surety bonds, the Companies are obligated to indemnify the respective surety bond company for any amounts paid.

As of December 31, 2017, Virginia Power had issued $14 million of guarantees primarily to support tax-exempt debt issued through conduits. The related debt matures in 2031 and is included in long-term debt in Virginia Power's Consolidated Balance Sheets. In the event of default by a conduit, Virginia Power would be obligated to repay such amounts, which are limited to the principal and interest then outstanding.

Indemnifications

As part of commercial contract negotiations in the normal course of business, the Companies may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. The Companies are unable to develop an estimate of the maximum potential amount of any other future payments under these contracts because events that would obligate them have not yet occurred or, if any such event has occurred, they have not been notified of its occurrence. However, at December 31, 2017, the Companies believe any other future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on their results of operations, cash flows or financial position.

NOTE 23. CREDIT RISK

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, credit policies are maintained, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, counterparties may make available collateral, including letters of credit or cash held as margin deposits, as a result of exceeding agreed-upon credit limits, or may be required to prepay the transaction.

The Companies maintain a provision for credit losses based on factors surrounding the credit risk of their customers, historical trends and other information. Management believes, based on credit policies and the December 31, 2017 provision for credit losses, that it is unlikely that a material adverse effect on financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

General

DOMINION ENERGY

As a diversified energy company, Dominion Energy transacts primarily with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid-Atlantic, Midwest and Rocky Mountain regions of the U.S. Dominion Energy does not believe that this geographic concentration contributes significantly to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion Energy is not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations.

Dominion Energy's exposure to credit risk is concentrated primarily within its energy marketing and price risk management activities, as Dominion Energy transacts with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of any collateral. At December 31, 2017, Dominion Energy's credit exposure totaled $95 million. Of this amount, investment grade counterparties, including those internally rated, represented 26%, and no single counterparty, whether investment grade or non-investment grade, exceeded $13 million of exposure.

VIRGINIA POWER

Virginia Power sells electricity and provides distribution and transmission services to customers in Virginia and northeastern North Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of Virginia Power's customer base, which includes residential, commercial and industrial customers, as well as rural electric cooperatives and municipalities. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers. Virginia Power's exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Virginia Power's gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2017, Virginia Power's credit exposure totaled $60 million. Of this amount, investment grade counterparties, including those internally rated, represented 9%, and no single counterparty, whether investment grade or non-investment grade, exceeded $13 million of exposure.

DOMINION ENERGY GAS

Dominion Energy Gas transacts mainly with major companies in the energy industry and with residential and commercial energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. Dominion Energy Gas does not believe that this geographic concentration contributes to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion Energy Gas is not exposed to a significant concentration of credit risk for receivables arising from gas utility operations. Dominion Energy Gas' gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2017, Dominion Energy Gas' credit exposure totaled $15 million. Of this amount, investment grade counterparties, including those internally rated, represented 22%, and no single counterparty, whether investment grade or non-investment grade, exceeded $4 million of exposure.

In 2017, DETI provided service to 289 customers with approximately 96% of its storage and transportation revenue being provided through firm services. The ten largest customers provided approximately 38% of the total storage and transportation revenue and the thirty largest provided approximately 68% of the total storage and transportation revenue.

East Ohio distributes natural gas to residential, commercial and industrial customers in Ohio using rates established by the Ohio Commission. Approximately 98% of East Ohio revenues are derived from its regulated gas distribution services. East Ohio's bad debt risk is mitigated by the regulatory framework established by the Ohio Commission. See Note 13 for further information about Ohio's PIPP and UEX Riders that mitigate East Ohio's overall credit risk.

Credit-Related Contingent Provisions

The majority of Dominion Energy's derivative instruments contain credit-related contingent provisions. These provisions require Dominion Energy to provide collateral upon the occurrence of specific events, primarily a credit downgrade. If the credit-related contingent features underlying these instruments that are in a liability position and not fully collateralized with cash were fully triggered as of December 31, 2017 and 2016, Dominion Energy would have been required to post an additional $62 million and $3 million, respectively, of collateral to its counterparties. The collateral that would be required to be posted includes the impacts of any offsetting asset positions and any amounts already posted for derivatives, non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. Dominion Energy had posted no collateral at December 31, 2017 and 2016, related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash. The collateral posted includes any amounts paid related to non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. The aggregate fair value of all derivative instruments with credit-related contingent provisions that are in a liability position and not fully collateralized with cash as of December 31, 2017 and 2016 was $65 million and $9 million, respectively, which does not include the impact of any offsetting asset positions. Credit- related contingent provisions for Virginia Power and Dominion Energy Gas were not material as of December 31, 2017 and 2016. See Note 7 for further information about derivative instruments.

NOTE 24. RELATED-PARTY TRANSACTIONS

Virginia Power and Dominion Energy Gas engage in related party transactions primarily with other Dominion Energy subsidiaries (affiliates). Virginia Power's and Dominion Energy Gas' receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. Virginia Power and Dominion Energy Gas are included in Dominion Energy's consolidated federal income tax return and, where applicable, combined income tax returns for Dominion Energy are filed in various states. See Note 2 for further information. Dominion Energy's transactions with equity method investments are described in Note 9. A discussion of significant related party transactions follows.

VIRGINIA POWER

Transactions with Affiliates

Virginia Power transacts with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. Virginia Power also enters into certain commodity derivative contracts with affiliates. Virginia Power uses these contracts, which are principally comprised of commodity swaps, to manage commodity price risks associated with purchases of natural gas. See Notes 7 and 19 for more information. As of December 31, 2017, Virginia Power's derivative assets and liabilities with affiliates were $11 million and $5 million, respectively. As of December 31, 2016, Virginia Power's derivative assets and liabilities with affiliates were $41 million and $8 million, respectively.

Virginia Power participates in certain Dominion Energy benefit plans as described in Note 21. At December 31, 2017 and 2016, Virginia Power's amounts due to Dominion Energy associated with the Dominion Energy Pension Plan and reflected in noncurrent pension and other postretirement benefit liabilities in the Consolidated Balance Sheets were $505 million and $396 million, respectively. At December 31, 2017 and 2016, Virginia Power's amounts due from Dominion Energy associated with the Dominion Energy Retiree Health and Welfare Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $199 million and $130 million, respectively.

DES and other affiliates provide accounting, legal, finance and certain administrative and technical services to Virginia Power. In addition, Virginia Power provides certain services to affiliates, including charges for facilities and equipment usage.

The financial statements for all years presented include costs for certain general, administrative and corporate expenses assigned by DES to Virginia Power on the basis of direct and allocated methods in accordance with Virginia Power's services agreements with DES. Where costs incurred cannot be determined by specific identification, the costs are allocated based on the proportional level of effort devoted by DES resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DES service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable.

Presented below are significant transactions with DES and other affiliates:

Year Ended December 31,	2017	2016	2015
(millions)			
Commodity purchases from affiliates	**$674**	$571	$555
Services provided by affiliates(1)	**453**	454	422
Services provided to affiliates	**25**	22	22

(1) Includes capitalized expenditures of $144 million, $144 million and $143 million for the year ended December 31, 2017, 2016 and 2015, respectively.

Virginia Power has borrowed funds from Dominion Energy under short-term borrowing arrangements. There were $33 million and $262 million in short-term demand note borrowings from Dominion Energy as of December 31, 2017 and 2016, respectively. The weighted-average interest rate of these borrowings was 1.65% and 0.97% at December 31, 2017 and 2016, respectively. Virginia Power had no outstanding borrowings, net of repayments under the Dominion Energy money pool for its nonregulated subsidiaries as of December 31, 2017 and 2016. Interest charges related to Virginia Power's borrowings from Dominion Energy were immaterial for the years ended December 31, 2017, 2016 and 2015.

There were no issuances of Virginia Power's common stock to Dominion Energy in 2017, 2016 or 2015.

DOMINION ENERGY GAS

Transactions with Related Parties

Dominion Energy Gas transacts with affiliates for certain quantities of natural gas and other commodities at market prices in the ordinary course of business. Additionally, Dominion Energy Gas provides transportation and storage services to affiliates. Dominion Energy Gas also enters into certain other contracts with affiliates, which are presented separately from contracts involving commodities or services. As of December 31, 2017 and 2016, all of Dominion Energy Gas' commodity derivatives were with affiliates. See Notes 7 and 19 for more information. See Note 9 for information regarding transactions with an affiliate.

Dominion Energy Gas participates in certain Dominion Energy benefit plans as described in Note 21. At December 31, 2017 and 2016, Dominion Energy Gas' amounts due from Dominion Energy associated with the Dominion Energy Pension Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $734 million and $697 million, respectively. Dominion Energy Gas' amounts due from Dominion Energy associated with the Dominion Energy Retiree Health and Welfare Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $7 million and $2 million at December 31, 2017 and 2016, respectively.

DES and other affiliates provide accounting, legal, finance and certain administrative and technical services to Dominion Energy Gas. Dominion Energy Gas provides certain services to related parties, including technical services.

The financial statements for all years presented include costs for certain general, administrative and corporate expenses assigned by DES to Dominion Energy Gas on the basis of direct and allocated methods in accordance with Dominion Energy Gas' services agreements with DES. Where costs incurred cannot be determined by specific identification, the costs are allocated based on the proportional level of effort devoted by DES resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DES service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable. The costs of these services follow:

Year Ended December 31, (millions)	2017	2016	2015
Purchases of natural gas and transportation and storage services from affiliates	$ 5	$ 9	$ 10
Sales of natural gas and transportation and storage services to affiliates	70	69	69
Services provided by related parties(1)	143	141	133
Services provided to related parties(2)	156	128	101

(1) Includes capitalized expenditures of $45 million, $49 million and $57 million for the year ended December 31, 2017, 2016 and 2015, respectively.
(2) Amounts primarily attributable to Atlantic Coast Pipeline.

The following table presents affiliated and related party balances reflected in Dominion Energy Gas' Consolidated Balance Sheets:

At December 31, (millions)	2017	2016
Other receivables(1)	$12	$10
Customer receivables from related parties	1	1
Imbalances receivable from affiliates	1	2
Imbalances payable to affiliates(2)	—	4
Affiliated notes receivable(3)	20	18

(1) Represents amounts due from Atlantic Coast Pipeline, a related party VIE.
(2) Amounts are presented in other current liabilities in Dominion Energy Gas' Consolidated Balance Sheets.
(3) Amounts are presented in other deferred charges and other assets in Dominion Energy Gas' Consolidated Balance Sheets.

Dominion Energy Gas' borrowings under the IRCA with Dominion Energy totaled $18 million and $118 million as of December 31, 2017 and 2016, respectively. The weighted-average interest rate of these borrowings was 1.60% and 1.08% at December 31, 2017 and 2016, respectively. Interest charges related to Dominion Energy Gas' total borrowings from Dominion Energy were immaterial for 2017, 2016 and 2015.

NOTE 25. OPERATING SEGMENTS

The Companies are organized primarily on the basis of products and services sold in the U.S. A description of the operations included in the Companies' primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion Energy	Virginia Power	Dominion Energy Gas
Power Delivery	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Power Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Gas Infrastructure	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG terminalling and storage	X		
	Nonregulated retail energy marketing	X		

(1) Includes remaining producer services activities.

In addition to the operating segments above, the Companies also report a Corporate and Other segment.

DOMINION ENERGY

The Corporate and Other Segment of Dominion Energy includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion Energy's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

In 2017, Dominion Energy reported an after-tax net benefit of $389 million in the Corporate and Other segment, with $861 million of the net benefit attributable to specific items related to its operating segments.

The net benefit for specific items in 2017 primarily related to the impact of the following items:

- A $979 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act, primarily attributable to:
  - Gas Infrastructure ($324 million);

  - Power Generation ($655 million); partially offset by
- $158 million ($96 million after-tax) of charges associated with equity method investments in wind-powered generation facilities, attributable to Power Generation.

In 2016, Dominion Energy reported after-tax net expenses of $484 million in the Corporate and Other segment, with $180 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2016 primarily related to the impact of the following items:

- A $197 million ($122 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Power Generation; and
- A $59 million ($36 million after-tax) charge related to an organizational design initiative, attributable to:
  - Power Delivery ($5 million after-tax);
  - Gas Infrastructure ($12 million after-tax); and
  - Power Generation ($19 million after-tax).

In 2015, Dominion Energy reported after-tax net expenses of $391 million in the Corporate and Other segment, with $136 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2015 primarily related to the impact of the following items:

- A $99 million ($60 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Power Generation; and
- An $85 million ($52 million after-tax) write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015, attributable to Power Generation.

Combined Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to Dominion Energy's operations:

Year Ended December 31,	Power Delivery	Power Generation	Gas Infrastructure	Corporate and Other	Adjustments & Eliminations	Consolidated Total
(millions)						
2017						
Total revenue from external customers	$2,206	$6,676	$2,832	$ 16	$ 856	$12,586
Intersegment revenue	22	10	834	610	(1,476)	—
Total operating revenue	2,228	6,686	3,666	626	(620)	12,586
Depreciation, depletion and amortization	593	747	522	43	—	1,905
Equity in earnings of equity method investees	—	(181)	159	4	—	(18)
Interest income	4	92	45	96	(155)	82
Interest and related charges	265	342	109	644	(155)	1,205
Income tax expense (benefit)	334	373	487	(1,224)	—	(30)
Net income attributable to Dominion Energy	531	1,181	898	389	—	2,999
Investment in equity method investees	—	81	1,422	41	—	1,544
Capital expenditures	1,433	2,275	2,149	52	—	5,909
Total assets (billions)	16.7	29.0	28.0	12.0	(9.1)	76.6
2016						
Total revenue from external customers	$2,210	$6,747	$2,069	$ (7)	$ 718	$11,737
Intersegment revenue	23	10	697	609	(1,339)	—
Total operating revenue	2,233	6,757	2,766	602	(621)	11,737
Depreciation, depletion and amortization	537	662	330	30	—	1,559
Equity in earnings of equity method investees	—	(16)	105	22	—	111
Interest income	—	74	34	36	(78)	66
Interest and related charges	244	290	38	516	(78)	1,010
Income tax expense (benefit)	308	279	431	(363)	—	655
Net income (loss) attributable to Dominion Energy	484	1,397	726	(484)	—	2,123
Investment in equity method investees	—	228	1,289	44	—	1,561
Capital expenditures	1,320	2,440	2,322	43	—	6,125
Total assets (billions)	15.6	27.1	26.0	10.2	(7.3)	71.6
2015						
Total revenue from external customers	$2,091	$7,001	$1,877	$ (27)	$ 741	$11,683
Intersegment revenue	20	15	695	554	(1,284)	—
Total operating revenue	2,111	7,016	2,572	527	(543)	11,683
Depreciation, depletion and amortization	498	591	262	44	—	1,395
Equity in earnings of equity method investees	—	(15)	60	11	—	56
Interest income	—	64	25	13	(44)	58
Interest and related charges	230	262	27	429	(44)	904
Income tax expense (benefit)	307	465	423	(290)	—	905
Net income (loss) attributable to Dominion Energy	490	1,120	680	(391)	—	1,899
Investment in equity method investees	—	245	1,042	33	—	1,320
Capital expenditures	1,607	2,190	2,153	43	—	5,993

Intersegment sales and transfers for Dominion Energy are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

VIRGINIA POWER

The majority of Virginia Power's revenue is provided through tariff rates. Generally, such revenue is allocated for management reporting based on an unbundled rate methodology among Virginia Power's Power Delivery and Power Generation segments.

The Corporate and Other Segment of Virginia Power primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

In 2017, Virginia Power reported an after-tax net benefit of $74 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net benefit for specific items in 2017 primarily related to the impact of the following item:

- A $93 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act, attributable to Power Generation.

In 2016, Virginia Power reported after-tax net expenses of $173 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2016 primarily related to the impact of the following item:

- A $197 million ($121 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Power Generation.

In 2015, Virginia Power reported after-tax net expenses of $153 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2015 primarily related to the impact of the following items:

- A $99 million ($60 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Power Generation; and
- An $85 million ($52 million after-tax) write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015, attributable to Power Generation.

The following table presents segment information pertaining to Virginia Power's operations:

Year Ended December 31,	Power Delivery	Power Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
(millions)					
2017					
Operating revenue	**$2,212**	**$5,344**	**$ —**	**$ —**	**$7,556**
Depreciation and amortization	**594**	**547**	**—**	**—**	**1,141**
Interest income	**4**	**15**	**3**	**(3)**	**19**
Interest and related charges	**265**	**232**	**—**	**(3)**	**494**
Income tax expense (benefit)	**334**	**534**	**(94)**	**—**	**774**
Net income	**527**	**939**	**74**	**—**	**1,540**
Capital expenditures	**1,439**	**1,290**	**—**	**—**	**2,729**
Total assets (billions)	**16.6**	**18.6**	**—**	**(0.1)**	**35.1**
2016					
Operating revenue	$2,217	$5,390	$ (19)	$ —	$7,588
Depreciation and amortization	537	488	—	—	1,025
Interest income	—	—	—	—	—
Interest and related charges	244	219	—	(2)	461
Income tax expense (benefit)	307	524	(104)	—	727
Net income (loss)	482	909	(173)	—	1,218
Capital expenditures	1,313	1,336	—	—	2,649
Total assets (billions)	15.6	17.8	—	(0.1)	33.3
2015					
Operating revenue	$2,099	$5,566	$ (43)	$ —	$7,622
Depreciation and amortization	498	453	2	—	953
Interest income	—	7	—	—	7
Interest and related charges	230	210	4	(1)	443
Income tax expense (benefit)	308	437	(86)	—	659
Net income (loss)	490	750	(153)	—	1,087
Capital expenditures	1,569	1,120	—	—	2,689

DOMINION ENERGY GAS

The Corporate and Other Segment of Dominion Energy Gas primarily includes specific items attributable to Dominion Energy Gas' operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Energy Gas as a result of Dominion Energy's basis in the net assets contributed.

In 2017, Dominion Energy Gas reported after-tax net expenses of $179 million in its Corporate and Other segment, with $174 million of these net expenses attributable to its operating segment.

The net benefit for specific items in 2017 primarily related to the impact of the following item:

- A $185 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act.

In 2016, Dominion Energy Gas reported after-tax net expenses of $3 million in its Corporate and Other segment, with $7 million of these net expenses attributable to its operating segment.

The net expense for specific items in 2016 primarily related to the impact of the following item:

- An $8 million ($5 million after-tax) charge related to an organizational design initiative.

In 2015, Dominion Energy Gas reported after-tax net expenses of $21 million in its Corporate and Other segment, with $13 million of these net expenses attributable to specific items related to its operating segment.

The net expenses for specific items in 2015 primarily related to the impact of the following item:

- $16 million ($10 million after-tax) ceiling test impairment charge.

Combined Notes to Consolidated Financial Statements, Continued

The following table presents segment information pertaining to Dominion Energy Gas' operations:

Year Ended December 31,	Gas Infrastructure	Corporate and Other	Consolidated Total
(millions)			
2017			
Operating revenue	**$1,814**	**$ —**	**$1,814**
Depreciation and amortization	**227**	**—**	**227**
Equity in earnings of equity method investees	**21**	**—**	**21**
Interest income	**2**	**—**	**2**
Interest and related charges	**97**	**—**	**97**
Income tax expense (benefit)	**256**	**(205)**	**51**
Net income	**436**	**179**	**615**
Investment in equity method investees	**95**	**—**	**95**
Capital expenditures	**778**	**—**	**778**
Total assets (billions)	**11.3**	**0.6**	**11.9**
2016			
Operating revenue	$1,638	$ —	$1,638
Depreciation and amortization	214	(10)	204
Equity in earnings of equity method investees	21	—	21
Interest income	1	—	1
Interest and related charges	92	2	94
Income tax expense (benefit)	237	(22)	215
Net income (loss)	395	(3)	392
Investment in equity method investees	98	—	98
Capital expenditures	854	—	854
Total assets (billions)	10.5	0.6	11.1
2015			
Operating revenue	$1,716	$ —	$1,716
Depreciation and amortization	213	4	217
Equity in earnings of equity method investees	23	—	23
Interest income	1	—	1
Interest and related charges	72	1	73
Income tax expense (benefit)	296	(13)	283
Net income (loss)	478	(21)	457
Investment in equity method investees	102	—	102
Capital expenditures	795	—	795

NOTE 26. QUARTERLY FINANCIAL AND COMMON STOCK DATA (UNAUDITED)

A summary of the Companies' quarterly results of operations for the years ended December 31, 2017 and 2016 follows. Amounts reflect all adjustments necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

DOMINION ENERGY

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Operating revenue	**$ 3,384**	**$ 2,813**	**$ 3,179**	**$ 3,210**
Income from operations	**1,125**	**801**	**1,200**	**1,004**
Net income including noncontrolling interests	**674**	**417**	**696**	**1,333**
Net income attributable to Dominion Energy	**632**	**390**	**665**	**1,312**
Basic EPS:				
Net income attributable to Dominion Energy	**1.01**	**0.62**	**1.03**	**2.04**
Diluted EPS:				
Net income attributable to Dominion Energy	**1.01**	**0.62**	**1.03**	**2.04**
Dividends declared per share	**0.755**	**0.755**	**0.770**	**0.770**
Common stock prices (intraday high-low)	**$79.36 - 70.87**	**$81.65 - 76.17**	**$80.67 - 75.40**	**$85.30 - 75.75**
2016				
Operating revenue	$ 2,921	$ 2,598	$ 3,132	$ 3,086
Income from operations	882	781	1,145	819
Net income including noncontrolling interests	531	462	728	491
Net income attributable to Dominion Energy	524	452	690	457
Basic EPS:				
Net income attributable to Dominion Energy	0.88	0.73	1.10	0.73
Diluted EPS:				
Net income attributable to Dominion Energy	0.88	0.73	1.10	0.73
Dividends declared per share	0.700	0.700	0.700	0.700
Common stock prices (intraday high-low)	$75.18 - 66.25	$77.93 - 68.71	$78.97 - 72.49	$77.32 - 69.51

Dominion Energy's 2017 results include the impact of the following significant item:

- Fourth quarter results include $851 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act, partially offset by $96 million of after-tax charges associated with our equity method investments in wind-powered generation facilities

Dominion Energy's 2016 results include the impact of the following significant item:

- Fourth quarter results include a $122 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

VIRGINIA POWER

Virginia Power's quarterly results of operations were as follows:

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Operating revenue	**$1,831**	**$1,747**	**$2,154**	**$1,824**
Income from operations	**653**	**613**	**847**	**619**
Net income	**356**	**318**	**459**	**407**
2016				
Operating revenue	$1,890	$1,776	$2,211	$1,711
Income from operations	514	553	914	369
Net income	263	280	503	172

Virginia Power's 2017 results include the impact of the following significant item:

- Fourth quarter results include a $93 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act.

Virginia Power's 2016 results include the impact of the following significant item:

- Fourth quarter results include a $121 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

DOMINION ENERGY GAS

Dominion Energy Gas' quarterly results of operations were as follows:

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Operating revenue	**$490**	**$422**	**$401**	**$501**
Income from operations	**176**	**137**	**206**	**203**
Net income	**108**	**77**	**117**	**313**
2016				
Operating revenue	$431	$368	$382	$457
Income from operations	175	186	133	175
Net income	98	105	83	106

Dominion Energy Gas's 2017 results include the impact of the following significant item:

- Fourth quarter results include a $197 million tax benefit resulting from the remeasurement of deferred income taxes as a result of the 2017 Tax Reform Act.

There were no significant items impacting Dominion Energy Gas' 2016 quarterly results.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

DOMINION ENERGY

Senior management, including Dominion Energy's CEO and CFO, evaluated the effectiveness of Dominion Energy's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Dominion Energy's CEO and CFO have concluded that Dominion Energy's disclosure controls and procedures are effective. There were no changes in Dominion Energy's internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Dominion Energy's internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Dominion Energy understands and accepts responsibility for Dominion Energy's consolidated financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion Energy continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as Dominion Energy does throughout all aspects of its business.

Dominion Energy maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Audit Committee of the Board of Directors of Dominion Energy, composed entirely of independent directors, meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss auditing, internal control, and financial reporting matters of Dominion Energy and to ensure that each is properly discharging its responsibilities. Both the independent registered public accounting firm and the internal auditors periodically meet alone with the Audit Committee and have free access to the Audit Committee at any time.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 require Dominion Energy's 2017 Annual Report to contain a management's report and a report of the independent registered public accounting firm regarding the effectiveness of internal control. As a basis for the report, Dominion Energy tested and evaluated the design and operating effectiveness of internal controls. Based on its assessment as of December 31, 2017, Dominion Energy makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Dominion Energy.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Dominion Energy's internal control over financial reporting as of December 31, 2017. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Dominion Energy maintained effective internal control over financial reporting as of December 31, 2017.

Dominion Energy's independent registered public accounting firm is engaged to express an opinion on Dominion Energy's internal control over financial reporting, as stated in their report which is included herein.

February 27, 2018

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of
Dominion Energy, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Dominion Energy, Inc. and subsidiaries ("Dominion Energy") at December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, Dominion Energy maintained, in all material respects, effective internal control over financial reporting at December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements at and for the year ended December 31, 2017, of Dominion Energy and our report dated February 27, 2018, expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

Dominion Energy's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Dominion Energy's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to Dominion Energy in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP
Richmond, Virginia
February 27, 2018

Virginia Power

Senior management, including Virginia Power's CEO and CFO, evaluated the effectiveness of Virginia Power's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Virginia Power's CEO and CFO have concluded that Virginia Power's disclosure controls and procedures are effective. There were no changes in Virginia Power's internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Virginia Power's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Management of Virginia Power understands and accepts responsibility for Virginia Power's consolidated financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Virginia Power continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as it does throughout all aspects of its business.

Virginia Power maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Board of Directors also serves as Virginia Power's Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss Virginia Power's auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require Virginia Power's 2017 Annual Report to contain a management's report regarding the effectiveness of internal control. As a basis for the report, Virginia Power tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2017, Virginia Power makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Virginia Power.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Virginia Power's internal control over financial reporting as of December 31, 2017. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Virginia Power maintained effective internal control over financial reporting as of December 31, 2017.

This annual report does not include an attestation report of Virginia Power's independent registered public accounting firm regarding internal control over financial reporting. Management's report is not subject to attestation by Virginia Power's independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 27, 2018

Dominion Energy Gas

Senior management, including Dominion Energy Gas' CEO and CFO, evaluated the effectiveness of Dominion Energy Gas' disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Dominion Energy Gas' CEO and CFO have concluded that Dominion Energy Gas' disclosure controls and procedures are effective. There were no changes in Dominion Energy Gas' internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Dominion Energy Gas' internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Management of Dominion Energy Gas understands and accepts responsibility for Dominion Energy Gas' consolidated financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion Energy Gas continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as it does throughout all aspects of its business.

Dominion Energy Gas maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Board of Directors also serves as Dominion Energy Gas' Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss Dominion Energy Gas' auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require Dominion Energy Gas' 2017 Annual Report to contain a management's report regarding the effectiveness of internal control. As a basis for the report, Dominion Energy Gas tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2017, Dominion Energy Gas makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Dominion Energy Gas.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Dominion Energy Gas' internal control over financial reporting as of December 31, 2017. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Dominion Energy Gas maintained effective internal control over financial reporting as of December 31, 2017.

This annual report does not include an attestation report of Dominion Energy Gas' independent registered public accounting firm regarding internal control over financial reporting. Management's report is not subject to attestation by Dominion Energy Gas' independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 27, 2018

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

DOMINION ENERGY

The following information for Dominion Energy is incorporated by reference from the Dominion Energy 2018 Proxy Statement, which will be filed on or around March 23, 2018:

- Information regarding the directors required by this item is found under the heading *Election of Directors.*
- Information regarding compliance with Section 16 of the Securities Exchange Act of 1934, as amended, required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance.*
- Information regarding the Dominion Energy Audit Committee Financial expert(s) required by this item is found under the heading *The Committees of the Board—Audit Committee.*
- Information regarding the Dominion Energy Audit Committee required by this item is found under the headings *The Committees of the Board—Audit Committee* and *Audit Committee Report.*
- Information regarding Dominion Energy's Code of Ethics and Business Conduct required by this item is found under the heading *Other Information—Code of Ethics and Business Conduct.*

The information concerning the executive officers of Dominion Energy required by this item is included in Part I of this Form 10-K under the caption *Executive Officers of Dominion Energy*. Each executive officer of Dominion Energy is elected annually.

Item 11. Executive Compensation

DOMINION ENERGY

The following information about Dominion Energy is contained in the 2018 Proxy Statement and is incorporated by reference: the information regarding executive compensation contained under the headings *Compensation Discussion and Analysis* and *Executive Compensation Tables*; the information regarding Compensation Committee interlocks contained under the heading *Compensation Committee Interlocks and Insider Participation*; the information regarding the Compensation Committee review and discussions of Compensation Discussion and Analysis contained under the heading *Compensation, Governance and Nominating Committee Report*; and the information regarding director compensation contained under the heading *Compensation of Non-Employee Directors.*

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

DOMINION ENERGY

The information concerning stock ownership by directors, executive officers and five percent beneficial owners contained under the heading *Securities Ownership* in the 2018 Proxy Statement is incorporated by reference.

The information regarding equity securities of Dominion Energy that are authorized for issuance under its equity compensation plans contained under the heading *Executive Compensation Tables-Equity Compensation Plans* in the 2018 Proxy Statement is incorporated by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

DOMINION ENERGY

The information regarding related party transactions required by this item found under the heading *Other Information–Certain Relationships and Related Party Transactions*, and information regarding director independence found under the heading *Corporate Governance — Director Independence,* in the 2018 Proxy Statement is incorporated by reference.

Item 14. Principal Accountant Fees and Services

DOMINION ENERGY

The information concerning principal accountant fees and services contained under the heading *Auditor Fees and Pre-Approval Policy* in the 2018 Proxy Statement is incorporated by reference.

VIRGINIA POWER AND DOMINION ENERGY GAS

The following table presents fees paid to Deloitte & Touche LLP for services related to Virginia Power and Dominion Energy Gas for the fiscal years ended December 31, 2017 and 2016.

Type of Fees	2017	2016
(millions)		
Virginia Power		
Audit fees	**$1.93**	$1.82
Audit-related fees	**—**	—
Tax fees	**—**	—
All other fees	**—**	—
Total Fees	**$1.93**	$1.82
Dominion Energy Gas		
Audit fees	**$1.09**	$1.05
Audit-related fees	**0.24**	0.16
Tax fees	**—**	—
All other fees	**—**	—
Total Fees	**$1.33**	$1.21

Audit fees represent fees of Deloitte & Touche LLP for the audit of Virginia Power and Dominion Energy Gas' annual consolidated financial statements, the review of financial statements included in Virginia Power and Dominion Energy Gas' quarterly Form 10-Q reports, and the services that an independent auditor would customarily provide in connection with subsidiary audits, statutory requirements, regulatory filings, and similar engagements for the fiscal year, such as comfort letters, attest services, consents, and assistance with review of documents filed with the SEC.

Audit-related fees consist of assurance and related services that are reasonably related to the performance of the audit or review of Virginia Power and Dominion Energy Gas' consolidated financial statements or internal control over financial reporting. This category may include fees related to the performance of audits and attest services not required by statute or regulations, due diligence related to mergers, acquisitions, and investments, and accounting consultations about the application of GAAP to proposed transactions.

Virginia Power and Dominion Energy Gas' Boards of Directors have adopted the Dominion Energy Audit Committee pre-approval policy for their independent auditor's services and fees and have delegated the execution of this policy to the Dominion Energy Audit Committee. In accordance with this delegation, each year the Dominion Energy Audit Committee pre-approves a schedule that details the services to be provided for the following year and an estimated charge for such services. At its January 2018 meeting, the Dominion Energy Audit Committee approved Virginia Power and Dominion Energy Gas' schedules of services and fees for 2018. In accordance with the pre-approval policy, any changes to the pre-approved schedule may be pre-approved by the Dominion Energy Audit Committee or a delegated member of the Dominion Energy Audit Committee.

Part IV
Item 15. Exhibits and Financial Statement Schedules

(a) Certain documents are filed as part of this Form 10-K and are incorporated by reference and found on the pages noted.

1. Financial Statements
   See Index on page 65.

2. All schedules are omitted because they are not applicable, or the required information is either not material or is shown in the financial statements or the related notes.

3. Exhibits (incorporated by reference unless otherwise noted)

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
3.1.a	Dominion Energy, Inc. Articles of Incorporation as amended and restated, effective May 10, 2017 (Exhibit 3.1, Form 8-K filed May 10, 2017, File No.1-8489).	X		
3.1.b	Virginia Electric and Power Company Amended and Restated Articles of Incorporation, as in effect on October 30, 2014 (Exhibit 3.1.b, Form 10-Q filed November 3, 2014, File No. 1-2255).		X	
3.1.c	Articles of Organization of Dominion Energy Gas Holdings, LLC (Exhibit 3.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
3.1.d	Articles of Amendment to the Articles of Organization of Dominion Energy Gas Holdings, LLC (Exhibit 3.1, Form 8-K filed May 16, 2017, File No. 1-37591).			X
3.2.a	Dominion Energy, Inc. Amended and Restated Bylaws, effective May 10, 2017 (Exhibit 3.2, Form 8-K filed May 10, 2017, File No. 1-8489).	X		
3.2.b	Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255).		X	
3.2.c	Operating Agreement of Dominion Energy Gas Holdings, LLC dated as of September 12, 2013 (Exhibit 3.2, Form 8-K filed May 16, 2017, File No. 001-37591).			X
4	Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of any of their total consolidated assets.	X	X	X
4.1.a	See Exhibit 3.1.a above.	X		
4.1.b	See Exhibit 3.1.b above.		X	
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by Fifty-Eighth Supplemental Indenture (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255); Ninety-Second Supplemental Indenture, dated as of July 1, 2012 (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2012 filed August 1, 2012, File No. 1-2255).	X	X	
4.3	Form of Senior Indenture, dated June 1, 1998, between Virginia Electric and Power Company and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(ii), Form S-3 Registration Statement filed February 27, 1998, File No. 333-47119); Form of Thirteenth Supplemental Indenture, dated as of January 1, 2006 (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Fourteenth Supplemental Indenture, dated May 1, 2007 (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255); Form of Fifteenth Supplemental Indenture, dated September 1, 2007 (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255); Form of Seventeenth Supplemental Indenture, dated November 1, 2007 (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255); Form of Eighteenth Supplemental Indenture, dated April 1, 2008 (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255); Form of Nineteenth Supplemental and Amending Indenture, dated November 1, 2008 (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255); Form of Twentieth Supplemental Indenture, dated June 1, 2009 (Exhibit 4.3, Form 8-K filed June 24, 2009, File No. 1-2255); Form of Twenty-First Supplemental Indenture, dated August 1, 2010 (Exhibit 4.3, Form 8-K filed September 1, 2010, File No. 1-2255);	X	X	

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
	Twenty-Second Supplemental Indenture, dated as of January 1, 2012 (Exhibit 4.3, Form 8-K filed January 12, 2012, File No. 1-2255); Twenty-Third Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.3, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fourth Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.4, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fifth Supplemental Indenture, dated as of March 1, 2013 (Exhibit 4.3, Form 8-K filed March 14, 2013, File No. 1-2255); Twenty-Sixth Supplemental Indenture, dated as of August 1, 2013 (Exhibit 4.3, Form 8-K filed August 15, 2013, File No. 1-2255); Twenty-Seventh Supplemental Indenture, dated February 1, 2014 (Exhibit 4.3, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Eighth Supplemental Indenture, dated February 1, 2014 (Exhibit 4.4, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Ninth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.3, Form 8-K filed May 13, 2015, File No. 1-02255); Thirtieth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.4, Form 8-K filed May 13, 2015, File No. 1-02255); Thirty-First Supplemental Indenture, dated January 1, 2016 (Exhibit 4.3, Form 8-K filed January 14, 2016, File No. 000-55337); Thirty-Second Supplemental Indenture, dated November 1, 2016 (Exhibit 4.3, Form 8-K filed November 16, 2016, File No. 000-55337); Thirty-Third Supplemental Indenture, dated November 1, 2016 (Exhibit 4.4, Form 8-K filed November 16, 2016, File No. 000-55337); Thirty-Fourth Supplemental Indenture, dated March 1, 2017 (Exhibit 4.3, Form 8-K filed March 16, 2017; File No. 000-55337).			
4.4	Senior Indenture, dated as of September 1, 2017, between Virginia Electric and Power Company and U.S. Bank National Association, as Trustee (Exhibit 4.1, Form 8-K filed September 13, 2017, File No.000-55337); First Supplemental Indenture, dated as of September 1, 2017 (Exhibit 4.2, Form 8-K filed September 13, 2017, File No.000-55337).	X	X	
4.5	Indenture, Junior Subordinated Debentures, dated December 1, 1997, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) (Exhibit 4.1, Form S-4 Registration Statement filed April 21, 1998, File No. 333-50653), as supplemented by a Form of Second Supplemental Indenture, dated January 1, 2001 (Exhibit 4.6, Form 8-K filed January 12, 2001, File No. 1-8489).	X		
4.6	Indenture, dated April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York Mellon (as successor trustee to United States Trust Company of New York) (Exhibit (4), Certificate of Notification No. 1 filed April 19, 1995, File No. 70-8107); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2, Form 8-A filed October 18, 1996, File No. 1-3196 and relating to the 6 7/8% Debentures Due October 15, 2026); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2, Form 8-A filed December 12, 1997, File No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027).	X		
4.7	Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed December 21, 1999, File No. 333-93187); Form of Sixteenth Supplemental Indenture, dated December 1, 2002 (Exhibit 4.3, Form 8-K filed December 13, 2002, File No. 1-8489); Form of Twenty-First Supplemental Indenture, dated March 1, 2003 (Exhibits 4.3, Form 8-K filed March 4, 2003, File No. 1-8489); Form of Twenty-Second Supplemental Indenture, dated July 1, 2003 (Exhibit 4.2, Form 8-K filed July 22, 2003, File No. 1-8489); Form of Twenty-Ninth Supplemental Indenture, dated June 1, 2005 (Exhibit 4.3, Form 8-K filed June 17, 2005, File No. 1-8489); Form of Thirty-Fifth Supplemental Indenture, dated June 1, 2008 (Exhibit 4.2, Form 8-K filed June 16, 2008, File No. 1-8489); Form of Thirty-Sixth Supplemental Indentures, dated June 1, 2008 (Exhibit 4.3, Form 8-K filed June 16, 2008, File No. 1-8489); Form of Thirty-Ninth Supplemental Indenture, dated August 1, 2009 (Exhibit 4.3, Form 8-K filed August 12, 2009, File No. 1-8489); Forty-First Supplemental Indenture, dated March 1, 2011 (Exhibit 4.3, Form 8-K, filed March 7, 2011, File No. 1-8489); Forty-Third Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 5, 2011, File No. 1-8489); Forty-Fifth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.3, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Sixth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.4, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Seventh Supplemental Indenture, dated September 1, 2012 (Exhibit 4.5, Form 8-K, filed September 13, 2012, File No. 1-8489);	X		

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
	Forty-Eighth Supplemental Indenture, dated March 1, 2014 (Exhibit 4.3, Form 8-K, filed March 24, 2014, File No. 1-8489); Forty-Ninth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.3, Form 8-K, filed November 25, 2014, File No. 1-8489); Fiftieth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.4, Form 8-K, filed November 25, 2014, File No. 1-8489); Fifty-First Supplemental Indenture, dated November 1, 2014 (Exhibit 4.5, Form 8-K, filed November 25, 2014, File No. 1-8489).			
4.8	Indenture, dated as of June 1, 2015, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form 8-K filed June 15, 2015, File No. 1-8489); First Supplemental Indenture, dated as of June 1, 2015 (Exhibit 4.2, Form 8-K filed June 15, 2015, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2015 (Exhibit 4.2, Form 8-K filed September 24, 2015, File No. 1-8489); Third Supplemental Indenture, dated as of February 1, 2016 (Exhibit 4.7, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489); Fourth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.2, Form 8-K filed August 9, 2016, File No. 1-8489); Fifth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.3, Form 8-K filed August 9, 2016, File No. 1-8489); Sixth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.4, Form 8-K filed August 9, 2016, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2016 (Exhibit 4.1, Form 10-Q filed November 9, 2016, File No. 1-8489); Eighth Supplemental Indenture, dated as of December 1, 2016 (Exhibit 4.7, Form 10-K for the fiscal year ended December 31, 2016 filed February 28, 2017, File No. 1-8489); Ninth Supplemental Indenture, dated as of January 1, 2017 (Exhibit 4.2, Form 8-K filed January 12, 2017, File No. 1-8489); Tenth Supplemental Indenture, dated as of January 1, 2017 (Exhibit 4.3, Form 8-K filed January 12, 2017, File No. 1-8489); Eleventh Supplemental Indenture, dated as of March 1, 2017 (Exhibit 4.3, Form 10-Q filed May 4, 2017, File No. 1-8489); Twelfth Supplemental Indenture, dated as of June 1, 2017 (Exhibit 4.2, Form 10-Q filed August 3, 2017, File No. 1-8489); Thirteenth Supplemental Indenture, dated December 1, 2017 (filed herewith).	X		
4.9	Junior Subordinated Indenture II, dated June 1, 2006, between Dominion Resources, Inc. and The Bank of New York Mellon (successor to JPMorgan Chase Bank, N.A.), as Trustee (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); First Supplemental Indenture dated as of June 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489); Third Supplemental and Amending Indenture, dated as of June 1, 2009 (Exhibit 4.2, Form 8-K filed June 15, 2009, File No. 1-8489); Sixth Supplemental Indenture, dated as of June 1, 2014 (Exhibit 4.3, Form 8-K filed July 1, 2014, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2014 (Exhibit 4.3, Form 8-K filed October 3, 2013, File No. 1-8489); Eighth Supplemental Indenture, dated March 7, 2016 (Exhibit 4.4, Form 8-K filed March 7, 2016, File No. 1-8489); Ninth Supplemental Indenture, dated May 26, 2016 (Exhibit 4.4, Form 8-K filed May 26, 2016, File No. 1-8489); Tenth Supplemental Indenture, dated July 1, 2016 (Exhibit 4.3, Form 8-K filed July 19, 2016, File No. 1-8489); Eleventh Supplemental Indenture, dated August 1, 2016 (Exhibit 4.3, Form 8-K filed August 15, 2016, File No. 1-8489); Twelfth Supplemental Indenture, dated August 1, 2016 (Exhibit 4.4, Form 8-K filed August 15, 2016, File No. 1-8489); Thirteenth Supplemental Indenture, dated May 18, 2017 (Exhibit 4.4, Form 8-K filed May 18, 2017, File No. 1-8489).	X		
4.10	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 23, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.11	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated September 29, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
4.12	2014 Series A Purchase Contract and Pledge Agreement, dated as of July 1, 2014, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.5, Form 8-K filed July 1, 2014, File No. 1-8489).	X		
4.13	2016 Series A Purchase Contract and Pledge Agreement, dated August 15, 2016, between the Company and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed August 15, 2016, File No. 1-8489).	X		
4.14	Indenture, dated as of October 1, 2013, between Dominion Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form S-4 filed April 4, 2014, File No. 333-195066); Second Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.3, Form S-4 filed April 4, 2014, File No. 333-195066); Third Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.4, Form S-4 filed April 4, 2014, File No. 333-195066); Fourth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.2, Form 8-K filed December 8, 2014, File No. 333-195066); Fifth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.3, Form 8-K filed December 8, 2014, File No. 333-195066); Sixth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.4, Form 8-K filed December 8, 2014, File No. 333-195066); Seventh Supplemental Indenture, dated as of November 1, 2015 (Exhibit 4.2, Form 8-K filed November 17, 2015, File No. 001-37591); Eighth Supplemental Indenture, dated as of May 1, 2016 (Exhibit 4.1.a, Form 10-Q filed August 3, 2016, File No. 1-37591); Ninth Supplemental Indenture, dated as of June 1, 2016 (Exhibit 4.1.b, Form 10-Q filed August 3, 2016, File No. 1-37591); Tenth Supplemental Indenture, dated as of June 1, 2016 (Exhibit 4.1.c, Form 10-Q filed August 3, 2016, File No. 1-37591).	X		X
10.1	$5,000,000,000 Second Amended and Restated Revolving Credit Agreement, dated November 10, 2016, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Questar Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Mizuho Bank, Ltd., Bank of America, N.A., Barclays Bank PLC and Wells Fargo Bank, N.A., as Syndication Agents, and other lenders named therein (Exhibit 10.1, Form 8-K filed November 11, 2016, File No. 1-8489).	X	X	X
10.2	$500,000,000 Second Amended and Restated Revolving Credit Agreement, dated November 10, 2016, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Questar Gas Company, KeyBank National Association, as Administrative Agent, U.S. Bank National Association, as Syndication Agent, and other lenders named therein (Exhibit 10.2, Form 8-K filed November 11, 2016, File No. 1-8489).	X	X	X
10.3	$950 million 364-Day Term Loan Agreement, dated February 9, 2018, by and among Dominion Energy, Inc., The Bank of Nova Scotia, as Administrative Agent, The Bank of Nova Scotia, as Lead Arranger and Bookrunner, and other lenders named therein (Exhibit 10.1, Form 8-K filed February 15, 2018, File No. 1-8489).	X		
10.4	DRS Services Agreement, dated January 1, 2003, between Dominion Resources, Inc. and Dominion Resources Services, Inc. (Exhibit 10.1, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489).	X		
10.5	DRS Services Agreement, dated January 1, 2012, between Dominion Resources Services, Inc. and Virginia Electric and Power Company (Exhibit 10.2, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).		X	
10.6	DRS Services Agreement, dated September 12, 2013, between Dominion Gas Holdings, LLC and Dominion Resources Services, Inc. (Exhibit 10.3, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.7	DRS Services Agreement, dated January 1, 2003, between Dominion Transmission Inc. and Dominion Resources Services, Inc. (Exhibit 10.4, Form S-4 filed April 4, 2014, File No. 333-195066).			X

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
10.8	DRS Services Agreement, dated January 1, 2003, between The East Ohio Company and Dominion Resources Services, Inc. (Exhibit 10.5, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.9	DRS Services Agreement, dated January 1, 2003, between Dominion Iroquois, Inc. and Dominion Resources Services, Inc. (Exhibit 10.6, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.10	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255 and File No. 1-8489).	X	X	
10.11	Form of Settlement Agreement in the form of a proposed Consent Decree among the United States of America, on behalf of the United States Environmental Protection Agency, the State of New York, the State of New Jersey, the State of Connecticut, the Commonwealth of Virginia and the State of West Virginia and Virginia Electric and Power Company (Exhibit 10, Form 10-Q for the quarter ended March 31, 2003 filed May 9, 2003, File No. 1-8489 and File No. 1-2255).	X	X	
10.12*	Dominion Energy, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.1, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion Energy, Inc. amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003 filed August 11, 2003, File No. 1-8489 and File No. 1-2255), as amended March 31, 2006 (Exhibit 10.1, Form 8-K filed April 4, 2006, File No. 1-8489).	X	X	X
10.14*	Form of Employment Continuity Agreement for certain officers of Dominion Energy, Inc. dated January 24, 2013 (effective for certain officers elected subsequent to February 1, 2013) (Exhibit 10.9, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.15*	Dominion Energy, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.2, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.16*	Dominion Energy, Inc. Executives' Deferred Compensation Plan, amended and restated effective December 31, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489).	X	X	X
10.17*	Dominion Energy, Inc. New Executive Supplemental Retirement Plan, as amended and restated effective July 1, 2013 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2013 filed August 6, 2013 File No. 1-8489), as amended September 26, 2014 (Exhibit 10.3, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.18*	Dominion Energy, Inc. New Retirement Benefit Restoration Plan, as amended and restated effective January 1, 2009 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-8489 and Exhibit 10.20, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-2255), as amended September 26, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.19*	Dominion Energy, Inc. Stock Accumulation Plan for Outside Directors, amended as of February 27, 2004 (Exhibit 10.15, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.1, Form 8-K filed December 23, 2004, File No. 1-8489).	X		

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
10.20*	Dominion Energy, Inc. Directors Stock Compensation Plan, as amended February 27, 2004 (Exhibit 10.16, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.2, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.21*	Dominion Energy, Inc. Non-Employee Directors' Compensation Plan, effective January 1, 2005, as amended and restated effective December 17, 2009 (Exhibit 10.18, Form 10-K filed for the fiscal year ended December 31, 2009 filed February 26, 2010, File No. 1-8489).	X		
10.22*	Dominion Energy, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001, amended and restated May 7, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended June 30, 2014 filed July 30, 2014, File No. 1-8489 and File No. 1-2250).	X	X	X
10.23*	Letter agreement between Dominion Resources, Inc. and Thomas F. Farrell, II, dated February 27, 2003 (Exhibit 10.24, Form 10-K for the fiscal year ended December 31, 2002 filed March 20, 2003, File No. 1-8489), as amended December 16, 2005 (Exhibit 10.1, Form 8-K filed December 16, 2005, File No. 1-8489).	X	X	X
10.24*	Employment agreement dated February 13, 2007 between Dominion Resources Services, Inc. and Mark F. McGettrick (Exhibit 10.34, Form 10-K for the fiscal year ended December 31, 2006 filed February 28, 2007, File No. 1-8489).	X	X	X
10.25*	Supplemental Retirement Agreement dated October 22, 2003 between Dominion Resources, Inc. and Paul D. Koonce (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-2255).	X	X	X
10.26*	Form of Advancement of Expenses for certain directors and officers of Dominion Energy, Inc., approved October 24, 2008 (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-8489 and Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-2255).	X	X	X
10.27*	Dominion Resources, Inc. 2005 Incentive Compensation Plan, originally effective May 1, 2005, as amended and restated effective December 20, 2011 (Exhibit 10.32, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).	X	X	X
10.28*	Supplemental Retirement Agreement with Mark F. McGettrick effective May 19, 2010 (Exhibit 10.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X	X	X
10.29*	Form of Restricted Stock Award Agreement for Mark F. McGettrick and Paul D. Koonce approved December 17, 2012 (Exhibit 10.1, Form 8-K filed December 21, 2012, File No. 1-8489).	X	X	X
10.30*	Form of Restricted Stock Award Agreement under the 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.2, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.31*	Restricted Stock Award Agreement for Thomas F. Farrell, II, dated December 17, 2010 (Exhibit 10.1, Form 8-K filed December 17, 2010, File No. 1-8489).	X	X	X

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
10.32*	2014 Performance Grant Plan under the 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.40, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.33*	Form of Restricted Stock Award Agreement under the 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.41, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.34*	Dominion Energy, Inc. 2014 Incentive Compensation Plan, effective May 7, 2014 (Exhibit 10.1, Form 8-K filed May 7, 2014, File No. 1-8489).	X	X	X
10.35	Inter-Company Credit Agreement, dated October 17, 2013, between Dominion Resources, Inc. and Dominion Gas Holdings, LLC (Exhibit 10.2, Form S-4 filed April 4, 2014, File No. 333-195066).	X		X
10.36*	2015 Performance Grant Plan under 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2014 filed February 27, 2015, File No. 1-8489).	X	X	X
10.37*	Form of Restricted Stock Award Agreement under the 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.43, Form 10-K for the fiscal year ended December 31, 2014 filed February 27, 2015, File No. 1-8489).	X	X	X
10.38*	2016 Performance Grant Plan under the 2016 Long-Term Incentive Program approved January 21, 2016 (Exhibit 10.47, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489).	X	X	X
10.39*	Form of Restricted Stock Award Agreement under the 2016 Long-Term Incentive Program approved January 21, 2016 (Exhibit 10.48, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489).	X	X	X
10.40*	2017 Performance Grant Plan (Transition Grant) under the 2017 Long-Term Incentive Program approved January 24, 2017 (Exhibit 10.45, Form 10-K for the fiscal year ended December 31, 2016 filed February 28, 2017, File No. 1-8489).	X	X	X
10.41*	Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Program approved January 24, 2017 (Exhibit 10.46, Form 10-K for the fiscal year ended December 31, 2016 filed February 28, 2017, File No. 1-8489).	X	X	X
10.42*	2017 Performance Grant Plan under the 2017 Long-Term Incentive Program approved January 24, 2017 (Exhibit 10.3, Form 10-Q for the quarter ended March 31, 2017 filed May 4, 2017, File No. 1-8489).	X	X	X
10.43*	2018 Performance Grant Plan under the 2018 Long-Term Incentive Program approved January 25, 2018 (filed herewith).	X	X	X
10.44*	Form of Restricted Stock Award Agreement under the 2018 Long-Term Incentive Program approved January 25, 2018 (filed herewith).	X	X	X
10.45*	Base salaries for named executive officers of Dominion Energy, Inc. (filed herewith).	X		
10.46*	Non-employee directors' annual compensation for Dominion Energy, Inc. (filed herewith).	X		
12.1	Ratio of earnings to fixed charges for Dominion Energy, Inc. (filed herewith).	X		
12.2	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X	
12.3	Ratio of earnings to fixed charges for Dominion Energy Gas Holdings, LLC (filed herewith).			X
21	Subsidiaries of Dominion Energy, Inc. (filed herewith).	X		
23	Consent of Deloitte & Touche LLP (filed herewith).	X	X	X

Exhibit Number	Description	Dominion Energy	Virginia Power	Dominion Energy Gas
31.a	Certification by Chief Executive Officer of Dominion Energy, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.b	Certification by Chief Financial Officer of Dominion Energy, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.c	Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.d	Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.e	Certification by Chief Executive Officer of Dominion Energy Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
31.f	Certification by Chief Financial Officer of Dominion Energy Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
32.a	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Energy, Inc. as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).	X		
32.b	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).		X	
32.c	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Energy Gas Holdings, LLC as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).			X
101	The following financial statements from Dominion Energy, Inc., Virginia Electric and Power Company and Dominion Energy Gas Holdings, LLC Annual Report on Form 10-K for the year ended December 31, 2017, filed on February 27, 2018, formatted in XBRL: (i) Consolidated Statements of Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Common Shareholders' Equity (iv) Consolidated Statements of Comprehensive Income (v) Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements.	X	X	X

* *Indicates management contract or compensatory plan or arrangement.*

Item 16. Form 10-K Summary

None.

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Signatures

DOMINION ENERGY

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DOMINION ENERGY, INC.

By: /s/ Thomas F. Farrell, II
(Thomas F. Farrell, II, Chairman, President and Chief Executive Officer)

Date: February 27, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 27th day of February, 2018.

Signature	Title
/s/ Thomas F. Farrell, II **Thomas F. Farrell, II**	Chairman of the Board of Directors, President and Chief Executive Officer
/s/ William P. Barr **William P. Barr**	Director
/s/ Helen E. Dragas **Helen E. Dragas**	Director
/s/ James O. Ellis, Jr. **James O. Ellis, Jr.**	Director
/s/ John W. Harris **John W. Harris**	Director
/s/ Ronald W. Jibson **Ronald W. Jibson**	Director
/s/ Mark J. Kington **Mark J. Kington**	Director
/s/ Joseph M. Rigby **Joseph M. Rigby**	Director
/s/ Pamela J. Royal **Pamela J. Royal**	Director
/s/ Robert H. Spilman, Jr. **Robert H. Spilman, Jr.**	Director
/s/ Susan N. Story **Susan N. Story**	Director
/s/ Michael E. Szymanczyk **Michael E. Szymanczyk**	Director
/s/ Mark F. McGettrick **Mark F. McGettrick**	Executive Vice President and Chief Financial Officer
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

Virginia Power

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VIRGINIA ELECTRIC AND POWER COMPANY

By: /s/ Thomas F. Farrell, II
(Thomas F. Farrell, II, Chairman of the Board of Directors and Chief Executive Officer)

Date: February 27, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 27th day of February, 2018.

Signature	Title
/s/ Thomas F. Farrell, II **Thomas F. Farrell, II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ Mark F. McGettrick **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ Mark O. Webb **Mark O. Webb**	Director
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

Dominion Energy Gas

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DOMINION ENERGY GAS HOLDINGS, LLC

By: /s/ Thomas F. Farrell, II
(Thomas F. Farrell, II, Chairman of the Board of Directors and Chief Executive Officer)

Date: February 27, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 27th day of February, 2018.

Signature	Title
/s/ Thomas F. Farrell, II **Thomas F. Farrell, II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ Mark F. McGettrick **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ Mark O. Webb **Mark O. Webb**	Director
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

Exhibit 4.8

DOMINION ENERGY, INC.
Issuer

AND

DEUTSCHE BANK TRUST COMPANY AMERICAS
Trustee

Thirteenth Supplemental Indenture

Dated as of December 1, 2017

$300,000,000

2017 Series E Floating Rate Senior Notes

due 2020

TABLE OF CONTENTS[1]

[1] This Table of Contents does not constitute part of the Indenture or have any bearing upon the interpretation of any of its terms and provisions.

THIS THIRTEENTH SUPPLEMENTAL INDENTURE is made as of the 1st day of December, 2017, by and between DOMINION ENERGY, INC. (formerly Dominion Resources, Inc.), a Virginia corporation, having its principal office at 120 Tredegar Street, Richmond, Virginia 23219 (the "Company" or "Issuer"), and DEUTSCHE BANK TRUST COMPANY AMERICAS, a New York banking corporation, as Trustee, having a corporate trust office at 60 Wall Street, 16th Floor, New York, New York 10005 (herein called the "Trustee").

WITNESSETH:

WHEREAS, the Company has heretofore entered into an Indenture dated as of June 1, 2015, between the Company and the Trustee (as amended, restated or otherwise modified, the "Base Indenture") with respect to senior debt securities;

WHEREAS, the Base Indenture is incorporated herein by this reference and the Base Indenture, as heretofore supplemented, as further supplemented by this Thirteenth Supplemental Indenture, and as may be hereafter supplemented or amended from time to time, is herein called the "Indenture";

WHEREAS, under the Base Indenture, a new series of Securities may at any time be established in accordance with the provisions of the Base Indenture and the terms of such series may be described by a supplemental indenture executed by the Company and the Trustee;

WHEREAS, the Company proposes to create under the Indenture a new series of Securities;

WHEREAS, additional Securities of other series hereafter established, except as may be limited in the Base Indenture as at the time supplemented and modified, may be issued from time to time pursuant to the Indenture as at the time supplemented and modified; and

WHEREAS, all conditions necessary to authorize the execution and delivery of this Thirteenth Supplemental Indenture and to make it a valid and binding obligation of the Company have been done or performed.

NOW, THEREFORE, in consideration of the agreements and obligations set forth herein and for other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto hereby agree as follows:

ARTICLE I
2017 SERIES E FLOATING RATE SENIOR NOTES DUE 2020

SECTION 101 Establishment. There is hereby established a new series of Securities to be issued under the Indenture, to be designated as the Company's 2017 Series E Floating Rate Senior Notes due 2020 (the "Series E Senior Notes").

There are to be authenticated and delivered $300,000,000 principal amount of Series E Senior Notes, and such principal amount of the Series E Senior Notes may be increased from time to time pursuant to the penultimate paragraph of Section 301 of the Base Indenture. All Series E Senior Notes need not be issued at the same time and such series may be reopened at any time, without the consent of any Holder, for issuances of additional Series E Senior Notes. Any such additional Series E Senior Notes will have the same interest rate, maturity and other terms as those initially issued, and shall be consolidated with and part of the same series of Series E Senior notes initially issued under this Thirteenth Supplemental Indenture. Further Series E Senior Notes may also be authenticated and delivered as provided by Sections 304, 305, 306, 905 or 1107 of the Base Indenture.

The Series E Senior Notes shall be issued as Registered Securities in global form without coupons, in substantially the form set out in Exhibit A hereto. The entire initially issued principal amount of the Series E Senior Notes shall initially be evidenced by one or more certificates issued to Cede & Co., as nominee for The Depository Trust Company.

The form of the Trustee's Certificate of Authentication for the Series E Senior Notes shall be in substantially the form set forth in Exhibit A hereto.

Each Series E Senior Note shall be dated the date of authentication thereof and shall bear interest from the date of original issuance thereof or from the most recent Interest Payment Date to which interest has been paid or duly provided for.

SECTION 102 Definitions. The following defined terms used herein shall, unless the context otherwise requires, have the meanings specified below. Capitalized terms used herein for which no definition is provided herein shall have the meanings set forth in the Base Indenture. Unless the context otherwise requires, any references to a "Section" refers to a Section of this Thirteenth Supplemental Indenture.

"Business Day" means a day other than (i) a Saturday or a Sunday, (ii) a day on which banks in New York, New York are authorized or obligated by law or executive order to remain closed or (iii) a day on which the Corporate Trust Office is closed for business.

"Calculation Agent" means Deutsche Bank Trust Company Americas, a New York banking corporation, or its successor appointed by the Company, acting as calculation agent.

"Depositary" has the meaning set forth in Section 105.

"Distribution Compliance Period" has the meaning set forth in Section 204.

"Interest Payment Dates" means March 1, June 1, September 1 and December 1 of each year, commencing on March 1, 2018.

"LIBOR Business Day" means any Business Day on which dealings in deposits in U.S. Dollars are transacted in the London Inter-Bank Market.

"LIBOR Interest Determination Date" means the second LIBOR Business Day preceding each LIBOR Rate Reset Date.

"LIBOR Rate Reset Date" means, subject to Section 103, the 1st day of the months of March, June, September and December of each year commencing on March 1, 2018.

"Original Issue Date" means December 8, 2017.

"Outstanding," when used with respect to the Series E Senior Notes, means, as of the date of determination, all Series E Senior Notes theretofore authenticated and delivered under the Indenture, except:

(i) Series E Senior Notes theretofore canceled by the Trustee or delivered to the Trustee for cancellation;

(ii) Series E Senior Notes for whose payment at the Maturity thereof money in the necessary amount has been theretofore deposited (other than pursuant to Section 402 of the Base Indenture) with the Trustee or any Paying Agent (other than the Company) in trust or set aside and segregated in trust by the Company (if the Company shall act as its own Paying Agent) for the Holders of such Series E Senior Notes;

(iii) Series E Senior Notes with respect to which the Company has effected defeasance or covenant defeasance pursuant to Section 402 of the Base Indenture, except to the extent provided in Section 402 of the Base Indenture; and

(iv) Series E Senior Notes that have been paid pursuant to Section 306 of the Base Indenture or in exchange for or in lieu of which other Series E Senior Notes have been authenticated and delivered pursuant to the Indenture, other than any such Series E Senior Notes in respect of which there shall have been presented to the Trustee proof satisfactory to it that such Series E Senior Notes are held by a bona fide purchaser in whose hands such Series E Senior Notes are valid obligations of the Company; provided, however, that in determining whether the Holders of the requisite principal amount of Outstanding Series E Senior Notes have given any request, demand, authorization, direction, notice, consent or waiver under the Indenture or are present at a meeting of Holders of Series E Senior Notes for quorum purposes, Series E Senior Notes owned by the Company or any other obligor upon the Series E Senior Notes or any Affiliate of the Company or such other obligor shall be disregarded and deemed not to be Outstanding, except that, in determining whether the Trustee shall be protected in making any such determination or relying upon any such request, demand, authorization, direction, notice, consent or waiver, only Series E Senior Notes which a Responsible Officer of the Trustee actually knows to be so owned shall be so disregarded. Series E Senior Notes so owned which shall have been pledged in good faith may be regarded as Outstanding if the pledgee establishes to the satisfaction of the Trustee (a) the pledgee's right so to act with respect to such Series E Senior Notes and (b) that the pledgee is not the Company or any other obligor upon the Series E Senior Notes or an Affiliate of the Company or such other obligor.

"QIB" means a "qualified institutional buyer" as defined in Rule 144A.

"Regular Record Date" means, with respect to each Interest Payment Date, the close of business on the Business Day preceding such Interest Payment Date; provided, that with respect to Series E Senior Notes that are not represented by one or more Global Securities, the Regular Record Date shall be the close of business on the fifteenth (15th) calendar day (whether or not a Business Day) preceding such Interest Payment Date.

"Regulation S" means Regulation S promulgated under the Securities Act.

"Regulation S Global Security" has the meaning set forth in Section 105.

"Restricted Legend" has the meaning set forth in Section 202.

"Restricted Security" has the meaning set forth in Section 202.

"Reuters Page LIBOR01" means the display so designated on the Reuters 3000 Xtra (or such other page as may replace that page on that service, or such other service as may be nominated by the Company, for the purpose of displaying rates or prices comparable to the London Inter-Bank Offered Rate for U.S. Dollar deposits).

"Rule 144A" means Rule 144A promulgated under the Securities Act.

"Rule 144A Global Security" has the meaning set forth in Section 105.

"Securities Act" means the Securities Act of 1933, as amended.

"Series E Senior Notes" has the meaning set forth in Section 101.

"Stated Maturity" means December 1, 2020.

"Three Month LIBOR Rate" means the rate determined in accordance with the following provisions:

(i) On the LIBOR Interest Determination Date, the Calculation Agent or its affiliate will determine the Three Month LIBOR Rate which shall be the rate for deposits in U.S. Dollars having a three-month maturity which appears on Reuters Page LIBOR01 as of 11:00 a.m., London time, on the LIBOR Interest Determination Date.

(ii) If no rate appears on Reuters Page LIBOR01 on the LIBOR Interest Determination Date, the Calculation Agent will request the principal London offices of each of four major reference banks (which may include affiliates of the underwriters) in the London Inter-Bank Market selected by the Calculation Agent (after consultation with the Company) to provide the Calculation Agent with their offered quotations for deposits in U.S. Dollars for the period of three months, commencing on the applicable LIBOR Rate Reset Date, to prime banks in the London Inter-Bank Market at approximately 11:00 a.m., London time, on that LIBOR Interest Determination Date and in a principal amount that is representative for a single transaction in U.S. Dollars in that market at that time.

If at least two quotations are provided, then the Three Month LIBOR Rate will be the average (rounded, if necessary, to the nearest one hundredth (0.01) of a percent) of those quotations. If fewer than two quotations are provided, then the Three Month LIBOR Rate will be the average (rounded, if necessary, to the nearest one hundredth (0.01) of a percent) of the rates quoted at approximately 11:00 a.m., New York City time, on the LIBOR Interest Determination Date by three major banks (which may include affiliates of the underwriters) in New York City selected by the Calculation Agent (after consultation with the Company) for loans in U.S. Dollars to leading European banks, having a three-month maturity and in a principal amount that is representative for a single transaction in U.S. Dollars in that market at that time. If the banks selected by the Calculation Agent are not providing quotations in the manner described by this paragraph, the rate for the period following the LIBOR Interest Determination Date will be the rate in effect on that LIBOR Interest Determination Date.

The terms "Company," "Issuer," "Trustee," "Base Indenture," and "Indenture" shall have the respective meanings set forth in the recitals to this Thirteenth Supplemental Indenture and the paragraph preceding such recitals.

SECTION 103 Payment of Principal and Interest. The principal of the Series E Senior Notes shall be due at the Stated Maturity. The unpaid principal amount of the Series E Senior Notes shall bear interest at a floating rate per annum determined by the Calculation Agent as described below, until paid or duly provided for, such interest to accrue from the Original Issue Date or from the most recent Interest Payment Date to which interest has been paid or duly provided for. Interest shall be paid quarterly in arrears on each Interest Payment Date to the Person in whose name the Series E Senior Notes are registered on the Regular Record Date for such Interest Payment Date; provided that interest payable at the Stated Maturity of principal will be paid to the Person to whom principal is payable. Any such interest that is not so punctually paid or duly provided for will forthwith cease to be payable to the Holders on such Regular Record Date and may either be paid to the Person or Persons in whose name the Series E Senior Notes are registered at the close of business on a Special Record Date for the payment of such defaulted interest to be fixed by the Trustee (in accordance with Section 307 of the Base Indenture), notice whereof shall be given to Holders of the Series E Senior Notes not less than ten (10) days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange, if any, on which the Series E Senior Notes may be listed, and upon such notice as may be required by any such exchange, all as more fully provided in the Base Indenture.

The per annum interest rate on the Series E Senior Notes will be equal to the Three Month LIBOR Rate plus 40 basis points (0.40%); provided that the per annum interest rate for the period from the Original Issue Date to the first LIBOR Rate Reset Date will be 1.52263% per annum (the "Initial Interest Rate"). The per annum interest rate shall be reset on each LIBOR Rate Reset Date.

If any LIBOR Rate Reset Date falls on a day that is not a Business Day, the LIBOR Rate Reset Date will be postponed to the next day that is a Business Day, except that if that Business Day is in the next succeeding calendar month, the LIBOR Rate Reset Date will be the next preceding Business Day. The interest rate in effect on any LIBOR Rate Reset Date will be the applicable rate as reset on that date. The interest rate applicable to any other day will either be the Initial Interest Rate or the interest rate as reset on the immediately preceding LIBOR Rate Reset Date.

Payments of interest on the Series E Senior Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series E Senior Notes shall be computed and paid on the basis the actual number of days in the relevant quarterly period (including the first day of the quarterly period and excluding the last day of the quarterly period) divided by 360. If any Interest Payment Date, other than the Stated Maturity, falls on a day that is not a Business Day, the Interest Payment Date will be postponed to the next day that is a Business Day, except that if that Business Day is in the next succeeding calendar month, the Interest Payment Date will be the immediately preceding Business Day. If the Stated Maturity falls on a day that is not a Business Day, the payment of interest and principal will be made on the next succeeding Business Day, and no interest on such payment will accrue for the period from and after the Stated Maturity.

Accrued interest on any Series E Senior Note will be calculated by multiplying the principal amount of the Series E Senior Note by an accrued interest factor. The accrued interest factor will be computed by adding the interest factors calculated for each day in the period for which interest is being paid. The interest factor for each day is computed by dividing the interest rate applicable to that day by 360.

Payment of the principal and interest on the Series E Senior Notes shall be made at the office of the Paying Agent in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts, with any such payment that is due at the Stated Maturity of any Series E Senior Notes, or upon repurchase being made upon surrender of such Series E Senior Notes to the Paying Agent. Payments of interest (including interest on any Interest Payment Date) will be made, subject to such surrender where applicable, at the option of the Company, (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least sixteen (16) days prior to the date for payment by the Person entitled thereto.

SECTION 104 Denominations. The Series E Senior Notes may be issued in denominations of $2,000, or any greater integral multiple of $1,000.

SECTION 105 Global Securities. The Series E Senior Notes offered and sold to QIBs in reliance on Rule 144A will be initially issued in the form of one or more Global Securities (the "Rule 144A Global Security"), and the Series E Senior Notes offered and sold in offshore transactions to non-U.S. persons in reliance on Regulation S will be initially issued in the form of one or more Global Securities (the "Regulation S Global Security"), in each case registered in the name of the Depositary (which shall be The Depository Trust Company) or its nominee. Except under the limited circumstances described below, Series E Senior Notes represented by such Global Securities will not be exchangeable for, and will not otherwise be issuable as, Series E Senior Notes in definitive form registered in names other than the Depositary or its nominee. The Global Securities described above may not be transferred except by the Depositary to a nominee of the Depositary or by a nominee of the Depositary to the Depositary or another nominee of the Depositary or to a successor Depositary or its nominee.

Owners of beneficial interests in such a Global Security will not be considered the Holders thereof for any purpose under the Indenture, and no Global Security representing a Series E Senior Note shall be exchangeable, except for another Global Security of like denomination and tenor to be registered in the name of the Depositary or its nominee or to a successor Depositary or its nominee or except as described below. The rights of Holders of such Global Security shall be exercised only through the Depositary.

A Global Security shall be exchangeable for Series E Senior Notes registered in the names of persons other than the Depositary or its nominee only if (i) the Depositary notifies the Company that it is unwilling or unable to continue as a Depositary for such Global Security and no successor Depositary shall have been appointed by the Company within ninety (90) days of receipt by the Company of such notification, or if at any time the Depositary ceases to be a clearing agency registered under the Exchange Act at a time when the Depositary is required to be so registered to act as such Depositary and no successor Depositary shall have been appointed by the Company within ninety (90) days after it becomes aware of such cessation, (ii) the Company in its sole discretion, and subject to the procedures of the Depositary, determines that such Global Security shall be so exchangeable, in which case Series E Senior Notes in definitive form will be printed and delivered to the Depositary, or (iii) an Event of Default has occurred and is continuing with respect to the Series E Senior Notes. Any Global Security that is exchangeable pursuant to the preceding sentence shall be exchangeable for Series E Senior Notes registered in such names as the Depositary shall direct.

SECTION 106 Redemption. The Series E Senior Notes shall not be redeemable at any time prior to the Stated Maturity.

SECTION 107 Sinking Fund; Conversion. The Series E Senior Notes shall not have a sinking fund. The Series E Senior Notes are not convertible into or exchangeable for Equity Securities or any other securities.

SECTION 108 Additional Interest on Overdue Amounts. Any principal of and installment of interest on the Series E Senior Notes that is overdue shall bear interest at the then applicable interest rate (to the extent that the payment of such interest shall be legally enforceable), from the dates such amounts are due until they are paid or made available for payment, and such interest shall be payable on demand.

SECTION 109 Paying Agent; Security Registrar. The Trustee shall initially serve as Paying Agent and Security Registrar with respect to the Series E Senior Notes, with the Place of Payment initially being the Corporate Trust Office. The Company may change the Paying Agent or Security Registrar without prior notice to Holders of the Series E Senior Notes, and the Company or any of its subsidiaries may act as Paying Agent or Security Registrar.

ARTICLE II
TRANSFER AND EXCHANGE

SECTION 201 Transfer and Exchange of Global Securities. The transfer and exchange of beneficial interests in the Global Securities shall be effected through the Depositary, in accordance with this Thirteenth Supplemental Indenture (including applicable restrictions on transfer set forth herein, if any) and the procedures of the Depositary therefor.

SECTION 202 Restricted Legend. Except as otherwise provided in Section 203 and as indicated on Exhibit A, each Series E Senior Note (each a "Restricted Security") shall bear the following legend (the "Restricted Legend") on the face thereof:

THIS SERIES E SENIOR NOTE (OR ITS PREDECESSOR) WAS ORIGINALLY ISSUED IN A TRANSACTION EXEMPT FROM REGISTRATION UNDER THE UNITED

STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), AND THIS SERIES E SENIOR NOTE MAY NOT BE OFFERED, SOLD OR OTHERWISE TRANSFERRED IN THE ABSENCE OF SUCH REGISTRATION OR AN APPLICABLE EXEMPTION THEREFROM. EACH PURCHASER OF THIS SERIES E SENIOR NOTE IS HEREBY NOTIFIED THAT THE SELLER OF THIS SERIES E SENIOR NOTE MAY BE RELYING ON THE EXEMPTION FROM THE PROVISIONS OF SECTION 5 OF THE SECURITIES ACT PROVIDED BY RULE 144A THEREUNDER.

THE HOLDER OF THIS SERIES E SENIOR NOTE AGREES FOR THE BENEFIT OF THE COMPANY THAT (A) THIS SERIES E SENIOR NOTE MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED, ONLY (I) IN THE UNITED STATES TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A, (II) OUTSIDE THE UNITED STATES IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 904 UNDER THE SECURITIES ACT, (III) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE), (IV) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT, OR (V) TO AN INSTITUTIONAL "ACCREDITED INVESTOR" (AS DEFINED IN RULE 501(A)(1), (2), (3) OR (7) OF REGULATION D UNDER THE SECURITIES ACT) THAT IS ACQUIRING THE NOTE FOR ITS OWN ACCOUNT, OR FOR THE ACCOUNT OF SUCH AN INSTITUTIONAL "ACCREDITED INVESTOR" FOR INVESTMENT PURPOSES AND NOT WITH A VIEW TO, OR FOR OFFER OR SALE IN CONNECTION WITH, ANY DISTRIBUTION IN VIOLATION OF THE SECURITIES ACT, IN EACH OF CASES (I) THROUGH (V) IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES, AND (B) THE HOLDER WILL, AND EACH SUBSEQUENT HOLDER IS REQUIRED TO, NOTIFY ANY PURCHASER OF THIS SERIES E SENIOR NOTE FROM IT OF THE RESALE RESTRICTIONS REFERRED TO IN CLAUSE (A) ABOVE.

THE HOLDER AGREES THAT IT WILL DELIVER TO EACH PERSON TO WHOM THIS SERIES E SENIOR NOTE OR AN INTEREST HEREIN IS TRANSFERRED A NOTICE SUBSTANTIALLY TO THE EFFECT OF THIS LEGEND.

THE HOLDER AGREES THAT, BEFORE THE HOLDER OFFERS, SELLS OR OTHERWISE TRANSFERS THIS SERIES E SENIOR NOTE, THE COMPANY MAY REQUIRE THE HOLDER OF THIS SERIES E SENIOR NOTE TO DELIVER A WRITTEN OPINION, CERTIFICATIONS AND/OR OTHER INFORMATION THAT IT REASONABLY REQUIRES TO CONFIRM THAT SUCH PROPOSED TRANSFER IS BEING MADE PURSUANT TO AN EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE UNITED STATES.

AS USED IN THIS SERIES E SENIOR NOTE, THE TERMS "OFFSHORE TRANSACTION," "U.S. PERSON" AND "UNITED STATES" HAVE THE MEANINGS GIVEN TO THEM BY RULE 902 OF REGULATION S UNDER THE SECURITIES ACT.

SECTION 203 Removal of Restricted Legend. The Company may instruct the Trustee in writing to cancel any Series E Senior Note and, upon receipt of a Company Order, authenticate a replacement Series E Senior Note, registered in the name of the Holder thereof (or its transferee), that does not bear the Restricted Legend, and the Trustee will comply with such instruction, if the Company determines (upon the advice of counsel and such other certifications and evidence as the Company may reasonably require) that a Series E Senior Note is eligible for resale pursuant to Rule 144 under the Securities Act (or a successor provision) and that the Restricted Legend is no longer necessary or appropriate in order to ensure that subsequent transfers of such Series E Senior Note (or a beneficial interest therein) are effected in compliance with the Securities Act; provided, however, that in such circumstances, the Trustee shall require an Opinion of Counsel and an Officers' Certificate prior to authenticating any such replacement Series E Senior Note.

SECTION 204 Registration of Transfer or Exchange. The registration of transfer or exchange of any Series E Senior Note (or a beneficial interest therein) that bears the Restricted Legend may only be made in compliance with the provisions of the Restricted Legend and as set forth below.

(i) Prior to and including the fortieth (40th) day after the later of the commencement of the offering of the Series E Senior Notes and the Original Issue Date (such period through and including such fortieth (40th) day, the "Distribution Compliance Period"), transfers by an owner of a beneficial interest in a Regulation S Global Security to a transferee who takes delivery of such interest through a Rule 144A Global Security of that series will be made only upon receipt by the Trustee of a written certification from the transferor of the beneficial interest to the effect that such transfer is being made to a Person whom the transferor reasonably believes is purchasing for its own account or accounts as to which it exercises sole investment discretion and is a QIB in a transaction meeting the requirements of Rule 144A and the requirements of applicable securities laws of any state of the United States or any other jurisdiction.

(ii) Transfers by an owner of a beneficial interest in the Rule 144A Global Security to a transferee who takes delivery through the Regulation S Global Security of that series, whether before or after the expiration of the Distribution Compliance Period, will be made only upon receipt by the Trustee of a certification from the transferor to the effect that such transfer is being made in accordance with Rule 904 of Regulation S or Rule 144 under the Securities Act and that, if such transfer is being made prior to the expiration of the Distribution Compliance Period, the interest transferred will be held immediately thereafter through Euroclear Bank SA/NV, as operator of the Euroclear System or Clearstream Banking, société anonyme, Luxembourg.

(iii) Any beneficial interest in one of the Global Securities that is transferred to a Person who takes delivery in the form of an interest in another Global Security of that series will, upon transfer, cease to be an interest in the initial Global Security of that series and will become an interest in the other Global Security of that series and, accordingly, will thereafter be subject to all transfer restrictions, if any, and other procedures applicable to beneficial interests in such other Global Security of that series for as long as it remains such an interest.

SECTION 205 Preservation of Information. The Trustee will retain copies of all certificates, opinions and other documents received in connection with the registration of transfer or exchange of a Series E Senior Note (or a beneficial interest therein) in accordance with its customary policy, and the Company will have the right to request copies thereof at any reasonable time upon written notice to the Trustee.

SECTION 206 Acknowledgment of Restrictions; Indemnification; No Obligation of Trustee. By its acceptance of any Series E Senior Note bearing the Restricted Legend, each Holder of such a Series E Senior Note acknowledges the restrictions on registrations of transfer or exchange of such Series E Senior Note set forth in this Thirteenth Supplemental Indenture and in the Restricted Legend and agrees that it will register the transfer or exchange of such Series E Senior Note only as provided in this Thirteenth Supplemental Indenture. The Security Registrar shall not register a transfer or exchange of any Series E Senior Note unless such transfer or exchange complies with the restrictions on transfer or exchange of such Series E Senior Note set forth in this Thirteenth Supplemental Indenture. In connection with any registration of transfer or exchange of Series E Senior Notes, each Holder agrees by its acceptance of the Series E Senior Notes to furnish the Security Registrar or the Company such certifications, legal opinions or other information as either of them may reasonably require to confirm that such registration of transfer or exchange is being made pursuant to an exemption from, or a transaction not subject to, the registration requirements of the Securities Act; provided that the Security Registrar shall not be required to determine (but may rely on a determination made by the Company with respect to) the sufficiency of any such certifications, legal opinions or other information.

The Security Registrar shall retain copies of all letters, notices and other written communications received pursuant to the Indenture in accordance with its customary policy. The Company shall have the right to request copies of all such letters, notices or other written communications at any reasonable time upon the giving of written notice to the Security Registrar.

Each Holder of a Series E Senior Note agrees to indemnify the Company, the Security Registrar and the Trustee against any liability that may result from the transfer, exchange or assignment of such Holder's Series E Senior Note in violation of any provision of this Thirteenth Supplemental Indenture and/or applicable United States Federal or state securities law.

The Trustee shall have no obligation or duty to monitor, determine or inquire as to compliance with any restrictions on transfer or exchange imposed under this Thirteenth Supplemental Indenture or under applicable law with respect to any registrations of transfer or exchange of any interest in any Series E Senior Note (including any transfers between or among members of, or participants in, the Depositary or beneficial owners of interests in any Global Security) other than to require delivery of such certificates and other documentation or evidence as are expressly required by, and to do so if and when expressly required by the terms of, this Thirteenth Supplemental Indenture, and to examine the same to determine substantial compliance as to form with the express requirements hereof.

ARTICLE III
MISCELLANEOUS PROVISIONS

SECTION 301 Ratification and Incorporation of Base Indenture. As supplemented hereby, the Base Indenture is in all respects ratified and confirmed by the Company. The Base Indenture and this Thirteenth Supplemental Indenture shall be read, taken and construed as one and the same instrument.

SECTION 302 Executed in Counterparts. This Thirteenth Supplemental Indenture may be executed in several counterparts, each of which shall be deemed to be an original, and such counterparts shall together constitute but one and the same instrument. The exchange of copies of this Thirteenth Supplemental Indenture and of signature pages by facsimile or PDF transmission shall constitute effective execution and delivery of this Thirteenth Supplemental Indenture as to the parties hereto and may be used in lieu of the original, manually executed Thirteenth Supplemental Indenture for all purposes. Signatures of the parties hereto transmitted by facsimile or PDF shall be deemed to be their original signatures for all purposes.

SECTION 303 Assignment. The Company shall have the right at all times to assign any of its rights or obligations under the Indenture with respect to the Series E Senior Notes to a direct or indirect wholly owned subsidiary of the Company; provided that, in the event of any such assignment, the Company shall remain primarily liable for the performance of all such obligations. The Indenture may also be assigned by the Company in connection with a transaction described in Article VIII of the Base Indenture.

SECTION 304 Trustee's Disclaimer. All of the provisions contained in the Base Indenture in respect of the rights, powers, privileges, protections, duties and immunities of the Trustee, including without limitation its right to be indemnified, shall be applicable in respect of the Series E Senior Notes and of this Thirteenth Supplemental Indenture as fully and with like effect as if set forth herein in full. The Trustee accepts the amendments of the Indenture effected by this Thirteenth Supplemental Indenture, but on the terms and conditions set forth in the Indenture, including the terms and provisions defining and limiting the liabilities and responsibilities of the Trustee. Without limiting the generality of the foregoing, the Trustee shall not be responsible in any manner whatsoever for or with respect to any of the recitals or statements contained herein, all of which recitals or statements are made solely by the Company, or for or with respect to (i) the validity or sufficiency of this Thirteenth Supplemental Indenture or any of the terms or provision hereof, (ii) the proper authorization hereof by the Company by action or otherwise, (iii) the due execution hereof by the Company, or (iv) the consequences of any amendment herein provided for, and the Trustee makes no representation with respect to any such matters.

[Signature Page Follows]

IN WITNESS WHEREOF, each party hereto has caused this instrument to be signed in its name and behalf by its duly authorized officer, all as of the day and year first above written.

DOMINION ENERGY, INC.

By: /s/ James R. Chapman
Name: James R. Chapman
Title: Senior Vice President – Mergers & Acquisitions and Treasurer

DEUTSCHE BANK TRUST COMPANY AMERICAS, as Trustee

By: /s/ Carol Ng
Name: Carol Ng
Title: Vice President

By: /s/ James Briggs
Name: James Briggs
Title: Vice President

EXHIBIT A

FORM OF
2017 SERIES E FLOATING RATE SENIOR NOTE
DUE 2020

[UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (55 WATER STREET, NEW YORK, NEW YORK) TO THE ISSUER OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND ANY CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF [CEDE & CO.] OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY AND ANY PAYMENT IS MADE TO [CEDE & CO.], ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL SINCE THE REGISTERED OWNER HEREOF, [CEDE & CO.], HAS AN INTEREST HEREIN.]**

[THIS SERIES E SENIOR NOTE IS A GLOBAL SECURITY WITHIN THE MEANING OF THE INDENTURE HEREINAFTER REFERRED TO AND IS REGISTERED IN THE NAME OF A DEPOSITARY OR A NOMINEE THEREOF. THIS SERIES E SENIOR NOTE MAY NOT BE EXCHANGED IN WHOLE OR IN PART FOR A SECURITY REGISTERED, AND NO TRANSFER OF THIS SERIES E SENIOR NOTE IN WHOLE OR IN PART MAY BE REGISTERED, IN THE NAME OF ANY PERSON OTHER THAN SUCH DEPOSITARY OR A NOMINEE THEREOF, EXCEPT IN THE LIMITED CIRCUMSTANCES DESCRIBED IN THE INDENTURE. EVERY SERIES E SENIOR NOTE AUTHENTICATED AND DELIVERED UPON REGISTRATION OF, TRANSFER OF, OR IN EXCHANGE FOR OR IN LIEU OF, THIS SERIES E SENIOR NOTE SHALL BE A GLOBAL SECURITY SUBJECT TO THE FOREGOING, EXCEPT IN SUCH LIMITED CIRCUMSTANCES.]***

[THIS SERIES E SENIOR NOTE (OR ITS PREDECESSOR) WAS ORIGINALLY ISSUED IN A TRANSACTION EXEMPT FROM REGISTRATION UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), AND THIS SERIES E SENIOR NOTE MAY NOT BE OFFERED, SOLD OR OTHERWISE TRANSFERRED IN THE ABSENCE OF SUCH REGISTRATION OR AN APPLICABLE EXEMPTION THEREFROM. EACH PURCHASER OF THIS SERIES E SENIOR NOTE IS HEREBY NOTIFIED THAT THE SELLER OF THIS SERIES E SENIOR NOTE MAY BE RELYING ON THE EXEMPTION FROM THE PROVISIONS OF SECTION 5 OF THE SECURITIES ACT PROVIDED BY RULE 144A THEREUNDER.]****

[THE HOLDER OF THIS SERIES E SENIOR NOTE AGREES FOR THE BENEFIT OF THE COMPANY THAT (A) THIS SERIES E SENIOR NOTE MAY BE OFFERED, RESOLD, PLEDGED OR OTHERWISE TRANSFERRED, ONLY (I) IN THE UNITED

*** Insert in Global Securities.
**** Insert in Restricted Securities

STATES TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A, (II) OUTSIDE THE UNITED STATES IN AN OFFSHORE TRANSACTION IN ACCORDANCE WITH RULE 904 UNDER THE SECURITIES ACT, (III) PURSUANT TO AN EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER (IF AVAILABLE), (IV) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT, OR (V) TO AN INSTITUTIONAL "ACCREDITED INVESTOR" (AS DEFINED IN RULE 501(A)(1), (2), (3) OR (7) OF REGULATION D UNDER THE SECURITIES ACT) THAT IS ACQUIRING THE NOTE FOR ITS OWN ACCOUNT, OR FOR THE ACCOUNT OF SUCH AN INSTITUTIONAL "ACCREDITED INVESTOR" FOR INVESTMENT PURPOSES AND NOT WITH A VIEW TO, OR FOR OFFER OR SALE IN CONNECTION WITH, ANY DISTRIBUTION IN VIOLATION OF THE SECURITIES ACT, IN EACH OF CASES (I) THROUGH (V) IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES, AND (B) THE HOLDER WILL, AND EACH SUBSEQUENT HOLDER IS REQUIRED TO, NOTIFY ANY PURCHASER OF THIS SERIES E SENIOR NOTE FROM IT OF THE RESALE RESTRICTIONS REFERRED TO IN CLAUSE (A) ABOVE.]***

[THE HOLDER AGREES THAT IT WILL DELIVER TO EACH PERSON TO WHOM THIS SERIES E SENIOR NOTE OR AN INTEREST HEREIN IS TRANSFERRED A NOTICE SUBSTANTIALLY TO THE EFFECT OF THIS LEGEND.]***

[THE HOLDER AGREES THAT, BEFORE THE HOLDER OFFERS, SELLS OR OTHERWISE TRANSFERS THIS SERIES E SENIOR NOTE, THE COMPANY MAY REQUIRE THE HOLDER OF THIS SERIES E SENIOR NOTE TO DELIVER A WRITTEN OPINION, CERTIFICATIONS AND/OR OTHER INFORMATION THAT IT REASONABLY REQUIRES TO CONFIRM THAT SUCH PROPOSED TRANSFER IS BEING MADE PURSUANT TO AN EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE UNITED STATES.]***

[AS USED IN THIS SERIES E SENIOR NOTE, THE TERMS "OFFSHORE TRANSACTION," "U.S. PERSON" AND "UNITED STATES" HAVE THE MEANINGS GIVEN TO THEM BY RULE 902 OF REGULATION S UNDER THE SECURITIES ACT.]***

DOMINION ENERGY, INC.

[Up to]**
$[_____]
2017 SERIES E FLOATING RATE SENIOR NOTE
DUE 2020

No. R- CUSIP No. __________

Dominion Energy, Inc. (formerly Dominion Resources, Inc.), a corporation duly organized and existing under the laws of Virginia (herein called the "Company" or "Issuer", which terms include any successor Person under the Indenture hereinafter referred to), for value received, hereby promises to pay to [Cede & Co.]**, or registered assigns (the "Holder"), the principal sum [of__________ Dollars ($_____)] [subject to the increases and decreases set forth in Schedule I hereto]** on December 1, 2020 and to pay interest thereon from December 8, 2017 or from the most recent Interest Payment Date to which interest has been paid or duly provided for, quarterly in arrears on March 1, June 1, September 1 and December 1 of each year, commencing on March 1, 2018, at a floating rate per annum determined by Deutsche Bank Trust Company Americas, or its successors as calculation agent (the "Calculation Agent") in accordance with the procedures referred to herein, until the principal hereof is paid or made available for payment, provided that any principal, and any such installment of interest, that is overdue shall bear interest at the then applicable interest rate (to the extent that the payment of such interest shall be legally enforceable), from the dates such amounts are due until they are paid or made available for payment, and such interest shall be payable on demand. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in the Indenture referred to on the reverse hereof, be paid to the Person in whose name this Series E Senior Note (or one or more Predecessor Securities) is registered at the close of business on the Regular Record Date for such interest; provided that the interest payable at Stated Maturity will be paid to the Person to whom principal is payable. The Regular Record Date shall be the close of business on the Business Day preceding such Interest Payment Date; provided, that with respect to Series E Senior Notes that are not represented by one or more Global Securities, the Regular Record Date shall be the close of business on the fifteenth (15th) calendar day (whether or not a Business Day) preceding such Interest Payment Date. Any such interest not so punctually paid or duly provided for will forthwith cease to be payable to the Holder on such Regular Record Date and may either be paid to the Person in whose name this Series E Senior Note (or one or more Predecessor Securities) is registered at the close of business on a Special Record Date for the payment of such Defaulted Interest to be fixed by the Trustee, notice whereof shall be given to Holders of Series E Senior Notes not less than ten (10) days prior to such Special Record Date, or be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange on which the Series E Senior Notes may be listed, and upon such notice as may be required by such exchange, all as more fully provided in the Indenture.

The per annum interest rate on the Series E Senior Notes will be equal to the Three Month LIBOR Rate plus 40 basis points (0.40%); provided that the per annum interest rate for the period from the Original Issue Date to the first LIBOR Rate Reset Date will be 1.52263% per annum (the "Initial Interest Rate"). The per annum interest rate shall be reset on each LIBOR Rate Reset Date.

If any LIBOR Rate Reset Date falls on a day that is not a Business Day, the LIBOR Rate Reset Date will be postponed to the next day that is a Business Day, except that if that Business Day is in the next succeeding calendar month, the LIBOR Rate Reset Date will be the next preceding Business Day. The interest rate in effect on any LIBOR Rate Reset Date will be the applicable rate as reset on that date. The interest rate applicable to any other day will either be the Initial Interest Rate or the interest rate as reset on the immediately preceding LIBOR Rate Reset Date.

Payments of interest on the Series E Senior Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series E Senior Notes shall be computed and paid on the basis of the actual number of days in the relevant quarterly period (including the first day of the quarterly period and excluding the last day of the quarterly period) divided by 360. In the event that any date on which interest is payable on the Series E Senior Notes is not a Business Day, then payment of the interest payable on such date will be made on the next succeeding day that is a Business Day (and without any interest or payment in respect of any such delay), except that if that business day is in the next succeeding calendar month, the Interest Payment Date will be the immediately preceding business day, in each case with the same force and effect as if made on the date the payment was originally payable.

Payment of the principal of and interest on this Series E Senior Note will be made at the office of the Paying Agent, in the Borough of Manhattan, City and State of New York, in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts, with any such payment that is due at the Stated Maturity of any Series E Senior Note, or upon repurchase being made upon surrender of such Series E Senior Note to such office or agency; provided, however, that at the option of the Company payment of interest, subject to such surrender where applicable, may be made (i) by check mailed to the address of the Person entitled thereto as such address shall appear in the Security Register or (ii) by wire transfer at such place and to such account at a banking institution in the United States as may be designated in writing to the Trustee at least sixteen (16) days prior to the date for payment by the Person entitled thereto.

Reference is hereby made to the further provisions of this Series E Senior Note set forth on the reverse hereof, which further provisions shall for all purposes have the same effect as if set forth at this place.

Unless the certificate of authentication hereon has been executed by the Trustee referred to on the reverse hereof by manual signature, this Series E Senior Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed.

DOMINION ENERGY, INC.

By: ______________________
Name: ______________________
Title: ______________________

TRUSTEE'S CERTIFICATE OF AUTHENTICATION

This is one of the Securities of the series designated therein referred to in the within-mentioned Indenture.

DEUTSCHE BANK TRUST COMPANY AMERICAS, as Trustee

By: ______________________
Authorized Signatory

Dated:

[REVERSE OF 2017 SERIES E FLOATING RATE SENIOR NOTE]

This Security is one of a duly authorized issue of securities of the Company (herein called the "Securities"), issued and to be issued in one or more series under an Indenture dated as of June 1, 2015 (the "Base Indenture"), between the Company and Deutsche Bank Trust Company Americas, as Trustee (the "Trustee"), as heretofore supplemented and as further supplemented by a Thirteenth Supplemental Indenture dated as of December 1, 2017 (the "Thirteenth Supplemental Indenture" and, together with the Base Indenture, as it may be hereafter supplemented or amended from time to time, the "Indenture," which term shall have the meaning assigned to it in such instrument), by and between the Company and the Trustee, and reference is hereby made to the Indenture for a statement of the respective rights, limitations of rights, duties and immunities thereunder of the Company, the Trustee and the Holders of the Securities and of the terms upon which the Securities are, and are to be, authenticated and delivered. This Security is one of the series designated on the face hereof (the "Series E Senior Notes") which is unlimited in aggregate principal amount.

The Series E Senior Notes are not redeemable at any time prior to the Stated Maturity.

If an Event of Default with respect to Series E Senior Notes shall occur and be continuing, the principal of the Series E Senior Notes may be declared due and payable in the manner and with the effect provided in the Indenture.

The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Securities of each series to be affected under the Indenture at any time by the Company and the Trustee for the series of Securities affected, with the consent of the Holders of a majority in principal amount of the Securities at the time Outstanding of each series to be affected. The Indenture also contains provisions permitting the Holders of specified percentages in principal amount of the Securities of each series at the time Outstanding, on behalf of the Holders of all Securities of such series, to waive certain past defaults under the Indenture and their consequences. Any such consent or waiver by the Holder of this Series E Senior Note shall be conclusive and binding upon such Holder and upon all future Holders of this Series E Senior Note and of any Series E Senior Note issued upon the registration of transfer hereof or in exchange therefor or in lieu hereof, whether or not notation of such consent or waiver is made upon this Series E Senior Note.

As provided in and subject to the provisions of the Indenture, the Holder of this Series E Senior Note shall not have the right to institute any proceeding with respect to the Indenture or for the appointment of a receiver or trustee or for any other remedy thereunder, unless such Holder shall have previously given the Trustee written notice of a continuing Event of Default with respect to the Series E Senior Notes, the Holders of not less than a majority in principal amount of the Series E Senior Notes at the time Outstanding shall have made written request to the Trustee to institute proceedings in respect of such Event of Default as Trustee and offered the Trustee indemnity or security reasonably satisfactory to it, and the Trustee shall not have received from the Holders of a majority in principal amount of Series E Senior Notes at the time Outstanding a direction inconsistent with such request, and shall have failed to institute any such proceeding for sixty (60) days after receipt of such notice, request and offer of indemnity. The foregoing shall not apply to any suit instituted by the Holder of this Series E Senior Note for the enforcement of any payment of principal hereof or premium, if any, or interest hereon on or after the respective due dates expressed or provided for herein.

No reference herein to the Indenture and no provision of this Series E Senior Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of, premium, if any, and interest on this Series E Senior Note at the times, place and rate, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein set forth, the transfer of this Series E Senior Note is registrable in the Security Register, upon surrender of this Series E Senior Note for registration of transfer at the office or agency of the Company in any place where the principal of, premium, if any, and interest on this Series E Senior Note are payable, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar duly executed by, the Holder hereof or his attorney duly authorized in writing, and thereupon one or more new Series E Senior Notes of like tenor, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

The Series E Senior Notes are issuable only in registered form without coupons in denominations of $2,000 and any greater integral multiple of $1,000. As provided in the Indenture and subject to certain limitations therein set forth, Series E Senior Notes are exchangeable for a like aggregate principal amount of Series E Senior Notes having the same Stated Maturity and of like tenor of any authorized denominations as requested by the Holder upon surrender of the Series E Senior Note or Series E Senior Notes to be exchanged at the office or agency of the Company.

No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Series E Senior Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Security is registered as the owner hereof for all purposes, whether or not this Series E Senior Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

All terms used in this Series E Senior Note that are defined in the Indenture shall have the meanings assigned to them in the Indenture.

ABBREVIATIONS

The following abbreviations, when used in the inscription on the face of this instrument, shall be construed as though they were written out in full according to applicable laws or regulations:

TEN COM -	as tenants in common
TEN ENT -	as tenants by the entireties
JT TEN -	as joint tenants with rights of survivorship and not as tenants in common
UNIF GIFT MIN ACT -	____________________ Custodian for (Cust) ____________________ (Minor) Under Uniform Gifts to Minors Act of ____________________ (State)

Additional abbreviations may also be used though not on the above list.

FOR VALUE RECEIVED, the undersigned hereby sell(s) and transfer(s) unto

____.

(please insert Social Security or other identifying number of assignee)

____.

____.

____.

PLEASE PRINT OR TYPEWRITE NAME AND ADDRESS, INCLUDING POSTAL ZIP CODE OF ASSIGNEE

the within Series E Senior Note and all rights thereunder, hereby irrevocably constituting and appointing

____.

____.

____.

____.

____.

____.

agent to transfer said Series E Senior Note on the books of the Company, with full power of substitution in the premises.

Dated:________________ __, ____

____

NOTICE: The signature to this assignment must correspond with the name as written upon the face of the within instrument in every particular without alteration or enlargement, or any change whatever.

DOMINION ENERGY, INC.

2017 SERIES E SENIOR NOTE

DUE 2020

No. R-____

SCHEDULE I**

The initial principal amount of this Series E Senior Note is: $____

The following increases or decreases in this Global Security have been made:

Date of increase or decrease and reason for the change in principal amount	Amount of decrease in principal amount of this Global Security	Amount of increase in principal amount of this Global Security	Principal amount of this Global Security following such decrease or increase	Signature of authorized signatory of Trustee

EXHIBIT 10.43

DOMINION ENERGY, INC.
2018 PERFORMANCE GRANT PLAN

1. Purpose. The purpose of the 2018 Performance Grant Plan (the "Plan") is to set forth the terms of 2018 Performance Grants ("Performance Grants") awarded by Dominion Energy, Inc., a Virginia corporation (the "Company"). This Plan contains the performance goals for the awards, the performance criteria, the target and maximum amounts payable, and other applicable terms and conditions.

2. Definitions.

a. Beneficiary. Means the individual, individuals, entity, entities or the estate of a Participant entitled to receive the amounts payable under a Performance Grant, if any, upon the Participant's death.

b. Cause. For purposes of this Plan, the term "Cause" will have the meaning assigned to that term under a Participant's Employment Continuity Agreement with the Company, as such Agreement may be amended from time to time.

c. Committee. Means the Compensation, Governance and Nominating Committee of the board of directors of the Company (or any successor board committee designated by the board of directors of the Company to administer this Plan).

d. Date of Grant. February 1, 2018.

e. Disability or Disabled. Means a "disability" as defined under Treasury Regulation Section 1.409A-3(i)(4). The Committee will determine whether or not a Disability exists and its determination will be conclusive and binding on the Participant.

f. Dominion Company. Means any corporation or other entity in which the Company owns stock or other equity possessing at least 50% of the combined voting power of all classes of stock or other equity or which is in a chain of corporations or other entities with the Company in which stock or other equity possessing at least 50% of the combined voting power of all classes of stock or other equity is owned by one or more other corporations or other entities in the chain.

g. Participant. An officer of the Company or a Dominion Company who receives a Performance Grant on the Date of Grant.

h. Performance Period. The 36-month period beginning on January 1, 2018 and ending on December 31, 2020.

i. Price-Earnings Ratio. The closing price of a share of common stock on the last trading day of the Performance Period divided by the annual operating earnings per share reported for the 12-month period ending on the last day of the Performance Period.

j. Retire or Retirement. For purposes of this Plan, the term Retire or Retirement means a voluntary termination of employment on a date when the Participant is eligible for early or normal retirement benefits under the terms of the Dominion Energy

Pension Plan, or would be eligible if any crediting of deemed additional years of age or service applicable to the Participant under the Company's Benefit Restoration Plan or New Benefit Restoration Plan was applied under the Dominion Energy Pension Plan, as in effect at the time of the determination, unless the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the Participant's retirement is detrimental to the Company.

k. Target Amount. The dollar amount designated in the written notice to the Participant communicating the Performance Grant.

3. Performance Grants. A Participant will receive a written notice of the amount designated as the Participant's Target Amount for the Performance Grant payable under the terms of this Plan. The actual payout may be from 0% to 200% of the Target Amount, depending on the achievement of the performance goals.

4. Performance Achievement and Time of Payment. Upon the completion of the Performance Period, the Committee will determine the final performance goal achievement of each of the performance criteria described in Section 6. The Company will then calculate the final amount of each Participant's Performance Grant based on such performance goal achievement. Except as provided in Sections 7(b) or 8, the Committee will determine the time of payout of the Performance Grants, provided that in no event will payment be made later than March 15, 2021. Performance Grants shall be paid in cash.

5. Forfeiture. Except as provided in Sections 7 and 8, a Participant's right to payout of a Performance Grant will be forfeited if the Participant's employment with the Company or a Dominion Company terminates for any reason before the end of the Performance Period.

6. Performance Goals. Payout of Performance Grants will be based on the performance goal achievement of the performance criteria described in this Section 6 and further defined in Exhibit A.

a. TSR Performance. Total Shareholder Return Performance ("TSR Performance") will determine fifty percent (50%) of the Target Amount ("TSR Percentage"). TSR Performance is defined in Exhibit A. The percentage of the TSR Percentage that will be paid out, if any, is based on the following table:

Relative TSR Performance Percentile Ranking	Percentage Payout of TSR Percentage
85th or above	200%
50th	100%
25th	50%
Below 25th	0%

To the extent that the Company's Relative TSR Performance ranks in a percentile between the 25th and 85th percentile in the table above, then the TSR Percentage payout will be interpolated between the corresponding TSR Percentage payout set forth above. No payment of the TSR Percentage will be made if the Relative TSR Performance is below the 25th percentile, except that a payment of 25% of the TSR Percentage will be made if the Company's Relative TSR Performance is below the 25th percentile but its Absolute

TSR Performance is at least 9%. In addition to the foregoing payments, and regardless of the Company's Relative TSR Performance, either (but not both) of the following may be earned: (i) an additional payment of 25% of the TSR Percentage will be made if the Company's Absolute TSR Performance is at least 10% but less than 15%, and/or if the Company's Price-Earnings Ratio is at or above the 50th percentile and below the top third of the group of companies (inclusive of the Company) used to measure Relative TSR Performance in accordance with Exhibit A hereto, or (ii) an additional payment of 50% of the TSR Percentage will be made if the Company's Absolute TSR Performance is at least 15%, and/or if the Company's Price-Earnings Ratio is at or above the top third of the group of companies (inclusive of the Company) used to measure Relative TSR Performance in accordance with Exhibit A hereto (in either case, the "Performance Adder"). The Committee may reduce or eliminate payment of the Performance Adder in its sole discretion.

The aggregate payments under this Section 6(a) may not exceed 250% of the TSR Percentage. In addition, the overall percentage payment under the entire Performance Grant may not exceed 200%.

b. ROIC Performance. Return on Invested Capital Performance ("ROIC Performance") will determine fifty percent (50%) of the Target Amount ("ROIC Percentage"). ROIC Performance is defined in Exhibit A. The percentage of the ROIC Percentage that will be paid out, if any, is based on the following table:

ROIC Performance	Percentage Payout of ROIC Percentage
7.16% and above	200%
6.87%	100%
6.55%	50%
Below 6.55%	0%

- To the extent that the Company's ROIC Performance is greater than 6.55% and less than 6.87%, the ROIC Percentage payout will be interpolated between the applicable Percentage Payout of ROIC Percentage range set forth above.
- To the extent that the Company's ROIC Performance is greater than 6.87% and less than 7.16%, the ROIC Percentage payout will be interpolated between the applicable Percentage Payout of ROIC Percentage range set forth above.

7. Retirement, Involuntary Termination without Cause, Death or Disability.

a. Retirement or Involuntary Termination without Cause. Except as provided in Section 8, if a Participant Retires during the Performance Period or if a Participant's employment is involuntarily terminated by the Company or a Dominion Company without Cause during the Performance Period, and in either case the Participant would have been eligible for a payment if the Participant had remained employed until the end of the Performance Period, the Participant will receive a pro-rated payout of the Participant's Performance Grant equal to the payment the Participant would have received had the Participant remained employed until the end of the Performance Period multiplied by a fraction, the numerator of which is the number of whole months from the Date of Grant to the first day of the month coinciding with or immediately following the date of the Participant's retirement or termination of employment, and the denominator of which is thirty-five (35). Payment will be made after the end of the Performance Period at the time provided in Section 4 based on the performance goal achievement approved by the Committee. If the Participant Retires, however, no payment will be made if the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the Participant's Retirement is detrimental to the Company.

b. Death or Disability. If, while employed by the Company or a Dominion Company, a Participant dies or becomes Disabled during the Performance Period, the Participant or, in the event of the Participant's death, the Participant's Beneficiary will receive a lump sum cash payment equal to the product of (i) and (ii) where:

(i) is the amount that would be paid based on the predicted performance used for determining the compensation cost recognized by the Company for the Participant's Performance Grant for the latest financial statement filed with the Company's Annual Report on Form 10-K or Quarterly Report on Form 10-Q immediately prior to the event; and

(ii) is a fraction, the numerator of which is the number of whole months from the Date of Grant to the first day of the calendar month coinciding with or immediately following the date of the Participant's death or Disability, and the denominator of which is thirty-five (35).

Payment under this Section 7(b) will be made as soon as administratively feasible (and in any event within sixty (60) days) after the date of the Participant's death or Disability, and the Participant shall not have the right to any further payment under this Agreement. In the event of the Participant's death, payment will be made to the Participant's designated Beneficiary.

8. Qualifying Change of Control. Upon a Qualifying Change of Control (as defined in the Company's 2014 Incentive Compensation Plan, as amended) prior to the end of the Performance Period, provided the Participant has remained continuously employed with the Company or a Dominion Company from the Date of Grant to the date of the Qualifying Change of Control, the Participant will receive a lump sum cash payment equal to the greater of (i) the Target Amount or (ii) the total payout that would be made at the end of the Performance Period if the predicted performance used for determining the compensation cost recognized by the Company for the Participant's Performance Grant for the latest financial statement filed with the Company's Annual Report on Form 10-K or Quarterly Report on Form 10-Q immediately prior to the Qualifying Change of Control was the actual performance for the Performance Period (in either case, the "COC Payout Amount"). Payment will be made on or as soon as administratively feasible following the Qualifying Change of Control date and in no event later than sixty (60) days following the Qualifying Change of Control date. If a Qualifying Change of Control occurs prior to the end of the Performance Period and after a Participant has Retired or been involuntarily terminated without Cause pursuant to Section 7(a) above, then the Participant will receive a pro-rated payout of the Participant's Performance Grant, equal to the COC Payout Amount multiplied by the fraction set forth in Section 7(a) above, with payment occurring in a cash lump sum on or as soon as administratively feasible (but in any event within sixty (60) days) after the Qualifying Change of Control date. Following any payment under this Section 8, the Participant shall not have the right to any further payment under this Agreement.

9. Termination for Cause. Notwithstanding any provision of this Plan to the contrary, if the Participant's employment with the Company or a Dominion Company is terminated for Cause (as defined by the Employment Continuity Agreement between the Participant and the Company), the Participant will forfeit all rights to his or her Performance Grant.

10. Clawback of Award Payment.

a. Restatement of Financial Statements. If the Company's financial statements are required to be restated at any time within a two (2) year period following the end of the Performance Period as a result of fraud or intentional misconduct, the Committee may, in its discretion, based on the facts and circumstances surrounding the restatement, direct the Company to recover all or a portion of the Performance Grant payout from the Participant if the Participant's conduct directly caused or partially caused the need for the restatement.

b. Fraudulent or Intentional Misconduct. If the Company determines that the Participant has engaged in fraudulent or intentional misconduct related to or materially affecting the Company's business operations or the Participant's duties at the Company, the Committee may, in its discretion, based on the facts and circumstances surrounding the misconduct, direct the Company to withhold payment, or if payment has been made, to recover all or a portion of the Performance Grant payout from the Participant.

c. Recovery of Payout. The Company reserves the right to recover a Performance Grant payout pursuant to this Section 10 by (i) seeking repayment from the Participant; (ii) reducing the amount that would otherwise be payable to the Participant under another Company benefit plan or compensation program to the extent permitted by applicable law; (iii) withholding future annual and long-term incentive awards or salary increases; or (iv) taking any combination of these actions.

d. No Limitation on Remedies. The Company's right to recover a Performance Grant payout pursuant to this Section 10 shall be in addition to, and not in lieu of, actions the Company may take to remedy or discipline a Participant's misconduct including, but not limited to, termination of employment or initiation of a legal action for breach of fiduciary duty.

e. Subject to Future Rulemaking. The Performance Grant payout is subject to any claw back policies the Company may adopt in order to conform to the requirements of Section 954 of the Dodd-Frank Wall Street Reform Act and Consumer Protection Act and resulting rules issued by the Securities and Exchange Commission or national securities exchanges thereunder and that the Company determines should apply to this Performance Grant Plan.

11. Miscellaneous.

a. Nontransferability. Except as provided in Section 7(b), a Performance Grant is not transferable and is subject to a substantial risk of forfeiture until the end of the Performance Period.

b. No Right to Continued Employment. A Performance Grant does not confer upon a Participant any right with respect to continuance of employment by the Company, nor will it interfere in any way with the right of the Company to terminate a Participant's employment at any time.

c. Tax Withholding. The Company will withhold Applicable Withholding Taxes from the payout of Performance Grants.

d. Performance Goal Adjustments. The Committee may at any time, in its sole discretion, remove or revise any performance goals or other performance objectives for this 2018 Performance Grant Plan. The Committee retains the authority to exercise negative discretion to reduce payments under this Plan as it deems appropriate.

e. Governing Law. This Plan shall be governed by the laws of the Commonwealth of Virginia, without regard to its choice of law provisions.

f. Binding Effect. This Plan will be binding upon and inure to the benefit of the legatees, distributes, and personal representatives of Participants and any successors of the Company.

g. Section 409A. This Plan and the Performance Grants hereunder are intended to comply with Section 409A of the Internal Revenue Code of 1986, as amended ("Code Section 409A"), and shall be interpreted to the maximum extent possible in accordance with such intent. To the extent necessary to comply with Code Section 409A, no payment will be made earlier than six months after a Participant's termination of employment other than for death if the Performance Grant is subject to Code Section 409A and the Participant is a "specified employee" (within the meaning of Code Section 409A(a)(2)(B)(i)).

h. Administration. The Plan shall be administered by the Committee, which shall have all of the applicable powers and authority set forth in Section 19 of the Company's 2014 Incentive Compensation Plan with respect to this Plan and the Performance Grants awarded hereunder, the terms of which are incorporated by reference herein.

i. Termination and Amendment. The Committee may amend the Plan and Performance Grants awarded hereunder, provided that, except as otherwise provided herein, no termination or amendment of the Plan or any Performance Grants under the Plan shall materially adversely affect a Participant's rights with respect to any outstanding Performance Grant without that Participant's consent. Notwithstanding the foregoing, the Committee may amend the Plan and Performance Grants awarded hereunder without having to obtain the consent of any affected Participant as it deems necessary or appropriate to ensure compliance with applicable laws or to cause Performance Grants to avoid adverse tax consequences under the Code and regulations thereunder.

j. Notice. All notices and other communications required or permitted to be given under this Plan shall be in writing and shall be deemed to have been duly given if delivered personally or mailed first class, postage prepaid, as follows: (a) if to the Company—at the principal business address of the Company to the attention of the Corporate Secretary of the Company; and (b) if to any Participant—at the last address of the Participant known to the sender at the time the notice or other communication is sent.

k. Interpretation. Unless otherwise specifically provided under the terms of any such plan or program, settlements of awards received by participants under the Plan shall not be deemed a part of a participant's regular, recurring compensation for purposes of calculating payments or benefits from any benefit plan or severance program of the Company or a Dominion Company or any severance pay law of any country. Nothing contained in the Plan will be deemed in any way to limit or restrict the Company or any Dominion Company from making any award or payment to any person under any other plan, arrangement or understanding, whether now existing or hereafter in effect. The terms of this Plan shall be governed by the laws of the Commonwealth of Virginia, without regard to its conflict of law principles.

l. Beneficiary Matters. A Participant may designate a Beneficiary to receive benefits due under a Performance Grant, if any, upon the Participant's death. Designation of a Beneficiary shall be made by execution of a form approved or accepted by the Committee. In the absence of a valid Beneficiary designation, a Participant's surviving spouse, if any, and if none, the Participant's estate, shall be the Beneficiary. A Participant may change a prior Beneficiary designation by a subsequent execution of a new Beneficiary designation form. The change in Beneficiary will be effective upon receipt by the Committee. Any payment made to a Beneficiary under this Plan in good faith shall fully discharge the Company and the Dominion Companies from all further obligations with respect to that payment. If the Committee has any doubt as to the proper Beneficiary to receive a payment under this Plan, the Committee shall have the right to withhold such payment until the matter is fully adjudicated. In making any payment to or for the benefit of any minor or an incompetent Participant or Beneficiary, the administrator, in its sole and absolute discretion, may make a distribution to a legal or natural guardian or other relative of a minor or court-appointed representative of such incompetent. Alternatively, it may make a payment to any adult with whom the minor or incompetent temporarily or permanently resides. The receipt by a guardian, representative, relative or other person shall be a complete discharge of the Company and the Dominion Companies' obligations under the Plan. The Company shall have no responsibility to see to the proper application of any payment so made. The Plan shall be binding on all successors and assigns of a Participant, including, without limitation, the estate of such participant and the executor, administrator or trustee of such estate, or any receiver or trustee in bankruptcy or representative of the Participant's creditors.

m. Unfunded Plan. Unless otherwise determined by the Committee, the Plan shall be unfunded and shall not create (or be construed to create) a trust or a separate fund or funds. The Plan shall not establish any fiduciary relationship between the Company and any Participant or other person. To the extent any person holds any rights by virtue of a Performance Grant granted under the Plan, such rights (unless otherwise determined by the Committee) shall be no greater than the rights of an unsecured general creditor of the Company.

EXHIBIT A

DOMINION ENERGY, INC.
2018 PERFORMANCE GRANT PLAN
PERFORMANCE CRITERIA

Total Shareholder Return

Relative TSR Performance will be measured based on where the Company's total shareholder return during the Performance Period ranks in relation to the total shareholder returns of the companies that are members of the Company's compensation peer group as of the Grant Date as set forth below (the "Comparison Companies"):

Ameren Corporation	Exelon Corporation
American Electric Power Company	FirstEnergy Corporation
CenterPoint Energy	NextEra Energy
Consolidated Edison Company	PG&E Corporation
DTE Energy Company	PPL Corporation
Duke Energy Corporation	Public Service Enterprise Group
Edison International	Southern Company
Entergy Corporation	Xcel Energy
Eversource Energy	

The Comparison Companies shall be adjusted during the Performance Period as follows:

(i) In the event of a merger, acquisition or business combination transaction of a Comparison Company with or by another Comparison Company, effective upon the public announcement of the transaction, the surviving entity shall remain a Comparison Company and the non-surviving entity shall cease to be a Comparison Company (provided that, if the proposed transaction is subsequently terminated before the Relative TSR Performance is calculated, then the non-surviving company shall be retroactively reinstated as a Comparison Company);

(ii) If it is publicly announced that a Comparison Company will be acquired by another company that is not a Comparison Company, or in the event a "going private transaction" is publicly announced where the Comparison Company will not be the surviving entity or will otherwise no longer be publicly traded, the company shall cease to be a Comparison Company as of the date such announcement is made (provided that, if the proposed transaction is subsequently terminated before the Relative TSR Performance is calculated, then the company shall be retroactively reinstated as a Comparison Company);

(iii) In the event of a spinoff, divestiture, or sale of assets of a Comparison Company, the Comparison Company shall no longer be a Comparison Company if the company's reported revenue for the four most recently reported quarters ending on or before the last day of the Performance Period falls below 40% of Dominion Energy's reported revenue for last year of the Performance Period; and

(iv) In the event of a bankruptcy of a Comparison Company, such company shall remain a Comparison Company and its stock price will continue to be tracked for purposes of Relative TSR Performance. If the company liquidates, it will remain a Comparison Company and its stock price will be reduced to zero for the remaining Performance Period.

Absolute TSR Performance will be the Company's total shareholder return on an average annual basis for the Performance Period. In general, total shareholder return consists of the difference between the value of a share of common stock at the beginning and end of the Performance Period, plus the value of dividends paid as if reinvested in stock and other appropriate adjustments for such events as stock splits. For purposes of TSR Performance, the total shareholder return of the Company and the Comparison Companies will be calculated using Bloomberg L.P. As soon as practicable after the completion of the Performance Period, the total shareholder returns of the Comparison Companies will be obtained from Bloomberg L.P. and ranked from highest to lowest by the Committee. The Company's total shareholder return will then be ranked in terms of which percentile it would have placed in among the Comparison Companies.

Price-Earnings Ratio performance will be measured based on where the Company's Price-Earnings Ratio ranks in relation to the Price-Earnings Ratios of the Comparison Companies as determined above. For purposes of Price-Earnings Ratio performance, the Price-Earnings Ratio of the Company and the Comparison Companies will be calculated using such method as the Committee shall determine. As soon as practicable after the completion of the Performance Period, the Price-Earnings Ratios of the Comparison Companies will be determined and ranked from highest to lowest by the Committee. The Company's Price-Earnings Ratio will then be ranked in terms of which percentile it would have placed in among the Comparison Companies.

Return on Invested Capital

Return on Invested Capital (ROIC)

The following terms are used to calculate ROIC for purposes of the 2018 Performance Grant:

ROIC means Total Return divided by Average Invested Capital. Performance will be calculated for the three successive fiscal years within the Performance Period, added together and then divided by three to arrive at an annual average ROIC for the Performance Period.

Total Return means Operating Earnings plus After-tax Interest & Related Charges, all determined for the three successive fiscal years within the Performance Period.

Operating Earnings means operating earnings as disclosed on the Company's earnings report furnished on Form 8-K for the applicable fiscal year.

Average Invested Capital means the Average Balances for Long & Short-term Debt plus Preferred Equity plus Common Shareholders' Equity. The Average Balances for a year are calculated by performing the calculation at the end of each month during the fiscal year plus the last month of the prior fiscal year and then averaging those amounts over 13 months. Long and short-term debt shall exclude debt that is non-recourse to Dominion Energy, Inc. (Dominion Energy) or its subsidiaries where Dominion Energy or its subsidiaries has not made an associated investment. Short-term debt shall be net of cash and cash equivalents.

Average Invested Capital will be calculated by excluding (i) accumulated other comprehensive income/(loss) from Common Shareholders' Equity (as shown on the Company's financial statements during the Performance Period); (ii) impacts from changes in accounting principles that were not prescribed as of the Date of Grant; and (iii) the effects of incremental impacts from non-operating gains or losses during the Performance Period, as disclosed on the Company's earnings report furnished on Form 8-K, that were not included in the projection on which the original ROIC calculation was based at the time of the grant.

DOMINION ENERGY, INC.
RESTRICTED STOCK AWARD AGREEMENT

PARTICIPANT	DATE OF GRANT	NUMBER OF SHARES OF RESTRICTED STOCK GRANTED
«First_Name» «Last_Name»	January 31, 2018	«##,###»
PERSONNEL NUMBER	**VESTING DATE**	**VESTING SCHEDULE** Vesting Date / Percentage
«#####»	February 1, 2021	February 1, 2021 / 100%

THIS AGREEMENT, effective as of the Date of Grant shown above, between Dominion Energy, Inc., a Virginia corporation (the "Company") and the Participant named above is made pursuant and subject to the provisions of the Dominion Energy, Inc. 2014 Incentive Compensation Plan and any amendments thereto (the "Plan"). All terms used in this Agreement that are defined in the Plan have the same meaning given to such terms in the Plan.

1. Award of Stock. Pursuant to the Plan, the Number of Shares of Restricted Stock Granted shown above (the "Restricted Stock") were awarded to the Participant on the Date of Grant shown above, subject to the terms and conditions of the Plan, and subject further to the terms and conditions set forth in this Agreement.

2. Vesting. Except as provided in Sections 3, 4, 5 or 6, one hundred percent (100%) of the shares of Restricted Stock awarded under this Agreement will vest on the Vesting Date shown above.

3. Forfeiture. Except as provided in Sections 4 or 5, the Participant will forfeit any and all rights in the Restricted Stock if the Participant's employment with the Company or a Dominion Company terminates for any reason prior to the Vesting Date.

4. Death, Disability, Retirement or Involuntary Termination without Cause. Except as provided in Section 5, if the Participant terminates employment due to death, Disability, or Retirement (as such term is defined in Section 8(e)) before the Vesting Date or if the Participant's employment is involuntarily terminated by the Company or a Dominion Company without Cause (as defined in the Employment Continuity Agreement between the Participant and the Company) before the Vesting Date, the Participant will become vested in the number of shares of Restricted Stock awarded under this Agreement multiplied by a fraction, the numerator of which is the number of whole months from February 1, 2018 to the first day of the month coinciding with or immediately following the date of the Participant's termination of employment, and the denominator of which is the number of whole months from February 1, 2018 to the Vesting Date, rounded

down to the nearest whole share. If the Participant Retires, however, the Participant's Restricted Stock will not vest if the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the Participant's Retirement is detrimental to the Company. The vesting will occur on the date of the Participant's termination of employment due to death, Disability, Retirement, or termination by the Company without Cause. Any shares of Restricted Stock that do not vest in accordance with this Section 4 will be forfeited.

5. Change of Control. Upon a Change of Control prior to the Vesting Date, provided the Participant has remained continuously employed with the Company or a Dominion Company from the Date of Grant to the date of the Change of Control, the Participant's rights in the Restricted Stock will become vested as follows:

a. A portion of the Restricted Stock will be immediately vested equal to the number of shares of Restricted Stock awarded under this Agreement multiplied by a fraction, the numerator of which is the number of whole months from February 1, 2018 to the Change of Control date, and the denominator of which is the number of whole months from February 1, 2018 to the Vesting Date, rounded down to the nearest whole share.

b. Unless previously forfeited, the remaining shares of Restricted Stock will become vested after a Change of Control at the earliest of the following events and in accordance with the terms described in subsections (i) through (iii) below:

(i) Vesting Date. All remaining shares of Restricted Stock will become vested on the Vesting Date.

(ii) Death, Disability or Retirement. If the Participant terminates employment due to death, Disability or Retirement (as defined in Section 8(e)) before the Vesting Date, the Participant will become vested in the remaining shares of Restricted Stock multiplied by a fraction, the numerator of which is the number of whole months from the first day of the month in which the Change of Control occurs to the first day of the month coinciding with or immediately following the Participant's termination of employment, and the denominator of which is the number of whole months from the first day of the month in which the Change of Control occurs to the Vesting Date, rounded down to the nearest whole share. If the Participant Retires, however, the Participant's Restricted Stock will not vest if the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the

Participant's Retirement is detrimental to the Company. The vesting will occur on the date of the Participant's termination of employment due to death, Disability, or Retirement. Any shares of the Restricted Stock that do not vest in accordance with the terms of this subsection (ii) will be forfeited.

(iii) Involuntary Termination without Cause. All remaining shares of Restricted Stock will become vested upon the Participant's involuntary termination by the Company or a Dominion Company without Cause before the Vesting Date, or upon the Participant's Constructive Termination before the Vesting Date, as such terms are defined by the Employment Continuity Agreement between the Participant and the Company.

6. Termination for Cause. Notwithstanding any provision of this Agreement to the contrary, if the Participant's employment with the Company or a Dominion Company is terminated for Cause (as defined by the Employment Continuity Agreement between the Participant and the Company), the Participant will forfeit all Restricted Stock shares awarded pursuant to this Agreement.

7. Clawback of Award Payment.

a. Restatement of Financial Statements. If the Company's financial statements are required to be restated at any time within a two (2) year period following the Vesting Date as a result of fraud or intentional misconduct, the Committee may, in its discretion, based on the facts and circumstances surrounding the restatement, direct the Company to withhold issuance of all or a portion of the shares granted pursuant to this Agreement, or if shares have been issued, to recover all or a portion of the shares from the Participant if the Participant's conduct directly caused or partially caused the need for the restatement.

b. Fraudulent or Intentional Misconduct. If the Company determines that the Participant has engaged in fraudulent or intentional misconduct related to or materially affecting the Company's business operations or the Participant's duties at the Company, the Committee may, in its discretion, based on the facts and circumstances surrounding the misconduct, direct the Company to withhold issuance of all or a portion of the shares granted pursuant to this Agreement, or if shares have been issued, to recover all or a portion of the shares from the Participant.

c. Recovery of Payout. The Company reserves the right to recover a Restricted Stock Award payout pursuant to this Section 7 by (i) seeking recovery of the vested shares from the Participant; (ii) reducing the amount that would otherwise be payable to the Participant under another Company benefit plan or compensation program to the extent permitted by applicable law; (iii) withholding future annual and long-term incentive awards or salary increases; or (iv) taking any combination of these actions.

d. No Limitation on Remedies. The Company's right to recover Restricted Stock or issued shares pursuant to this Section 7 shall be in addition to, and not in lieu of, actions the Company may take to remedy or discipline a Participant's misconduct including, but not limited to, termination of employment or initiation of a legal action for breach of fiduciary duty.

e. Subject to Future Rulemaking. The Restricted Stock granted under this Agreement is subject to any claw back policies the Company may adopt in order to conform to the requirements of Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act and resulting rules issued by the Securities and Exchange Commission or national securities exchanges thereunder and that the Company determines should apply to said Restricted Stock.

8. Terms and Conditions.

a. Nontransferability. Except as provided in Sections 4 and 5, the shares of Restricted Stock are not transferable and are subject to a substantial risk of forfeiture until the Vesting Date.

b. Uncertificated Shares; Power of Attorney. The Company may issue the Restricted Shares in uncertificated form. Such uncertificated shares shall be credited to a book entry account maintained by the Company (or its transfer agent) on behalf of the Participant. As a condition of accepting this award, the Participant hereby irrevocably appoints Dominion Energy Services, Inc., or its successor, as the Participant's attorney-in-fact, with full power of substitution, to transfer (or provide instructions to the Company's transfer agent to transfer) such shares on the Company's books.

c. Custody of Share Certificates; Stock Power. The Company will retain custody of any share certificates for the Restricted Stock that may be issued until such shares vest or are forfeited. If share certificates are issued, the Participant shall execute and deliver a stock power, endorsed in blank, to Dominion Energy Services, Inc., with respect to such shares.

d. Shareholder Rights. The Participant will have the right to receive dividends and will have the right to vote the shares of Restricted Stock awarded under Section 1, both vested and unvested.

e. Retirement. For purposes of this Agreement, the term Retire or Retirement means a voluntary termination when the Participant is eligible for early or normal retirement benefits under the terms of the Dominion

Energy Pension Plan, or would be eligible if any crediting of deemed additional years of age or service applicable to the Participant under the Company's Benefit Restoration Plan or New Benefit Restoration Plan was applied under the Pension Plan, as in effect at the time of the determination, unless the Company's Chief Executive Officer in his sole discretion (or, if the Participant is the Company's Chief Executive Officer, the Committee in its sole discretion) determines that the Participant's retirement is detrimental to the Company.

f. Delivery of Shares.

(i) Share Delivery. On or as soon as administratively feasible after the Vesting Date or the date on which the shares of Restricted Stock have become vested due to the occurrence of an event described in Section 4 or 5, the Company will remove (or provide instructions to its transfer agents to remove) the transfer restrictions described herein, and (if any share certificate has been issued) shall deliver to the Participant (or in the event of the Participant's death, the Participant's Beneficiary) any such certificates free of the transfer restrictions described herein. The Company will also cancel any stock power covering such shares.

(ii) Withholding of Taxes. No Company Stock will be delivered until the Participant (or the Participant's Beneficiary) has paid to the Company the amount that must be withheld under federal, state and local income and employment tax laws (the "Applicable Withholding Taxes") or the Participant and the Company have made satisfactory arrangements for the payment of such taxes. Unless the Participant makes an alternative election, the Company will retain the number of shares of Restricted Stock (valued at their Fair Market Value) required to satisfy the Applicable Withholding Taxes. As an alternative to the Company retaining shares, the Participant or the Participant's Beneficiary may elect to (i) deliver Mature Shares (valued at their Fair Market Value) or (ii) make a cash payment to satisfy Applicable Withholding Taxes.

g. Fractional Shares. Fractional shares of Company Stock will not be issued.

h. No Right to Continued Employment. This Agreement does not confer upon the Participant any right with respect to continuance of employment by the Company or a Dominion Company, nor shall it interfere in any way with the right of the Company or a Dominion Company to terminate the Participant's employment at any time.

i. Change in Capital Structure. The number and fair market value of shares of Restricted Stock awarded by this Agreement shall be automatically adjusted as provided in Section 18(a) of the Plan if the Company has a change in capital structure.

j. Governing Law. This Agreement shall be governed by the laws of the Commonwealth of Virginia, other than its choice of law provisions.

k. Conflicts. In the event of any conflict between the provisions of the Plan and the provisions of this Agreement, the provisions of the Plan shall govern.

l. Participant Bound by Plan. By accepting this Agreement, Participant hereby acknowledges receipt of a copy of the prospectus and Plan document accessible on the Company Intranet and agrees to be bound by all the terms and provisions thereof.

m. Binding Effect. This Agreement shall be binding upon and inure to the benefit of the legatees, distributees, and personal representatives of the Participant and any successors of the Company.

EXHIBIT 10.45

Dominion Energy, Inc.
2018 Base Salaries for Named Executive Officers*

The 2018 base salaries for Dominion Energy's named executive officers are as follows: Thomas F. Farrell, II, Chairman, President and Chief Executive Officer—$1,554,992; Mark F. McGettrick, Executive Vice President and Chief Financial Officer—$906,223; Paul D. Koonce, Executive Vice President and President and Chief Executive Officer—Power Generation Group—$739,158; Diane Leopold, Executive Vice President and President and Chief Executive Officer—Gas Infrastructure Group—$623,150; and Robert M. Blue, Executive Vice President and President and Chief Executive Officer—Power Delivery Group—$623,150.

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* Effective March 1, 2018

Exhibit 10.46

Dominion Energy, Inc.
Non-Employee Directors' Annual Compensation
As of December 31, 2017

Annual Retainer	**Amount**
Service as Director	$265,000 ($107,500 cash; $157,500 stock)
Service as Audit Committee or Compensation, Governance and Nominating Committee Chair	$25,000
Service as Finance and Risk Oversight Committee Chair	$15,000
Service as Lead Director	$30,000

Meeting Fees

An excess meeting fee of $2,000 will be paid to each director who attends more than 25 meetings per calendar year, including Board and Committee meetings but not special education sessions, for each such meeting in excess of 25.

Exhibit 12.1

Dominion Energy, Inc. and Subsidiaries
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Years Ended December 31,				
	2017(a)	2016(b)	2015(c)	2014(d)	2013(e)
Earnings, as defined:					
Income from continuing operations including noncontrolling interest before income tax expense (benefit)	$3,090	$2,867	$2,828	$1,778	$2,704
Distributed income from unconsolidated investees, less equity in earnings	177	(32)	12	(8)	17
Fixed charges included in income	1,276	1,068	953	1,237	930
Total earnings, as defined	$4,543	$3,903	$3,793	$3,007	$3,651
Fixed charges, as defined:					
Interest charges	$1,238	$1,033	$ 920	$1,208	$ 899
Rental interest factor	38	35	33	29	31
Fixed charges included in income	$1,276	$1,068	$ 953	$1,237	$ 930
Preference security dividend requirement of consolidated subsidiary	23	2	—	17	25
Capitalized interest	164	124	67	39	28
Interest from discontinued operations	—	—	—	—	85
Total fixed charges, as defined	$1,463	$1,194	$1,020	$1,293	$1,068
Ratio of Earnings to Fixed Charges	**3.11**	**3.27**	**3.72**	**2.33**	**3.42**

(a) Earnings for the twelve months ended December 31, 2017 include $158 million of charges associated with our equity method investments in wind-powered generation facilities; $72 million in transition and integration costs primarily associated with Dominion Energy's acquisition of Dominion Energy Questar; and a $51 million charge related to other items, partially offset by $46 million of net gain related to our investments in nuclear decommissioning trust funds. Excluding the net effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2017.

(b) Earnings for the twelve months ended December 31, 2016 include a $197 million charge associated with ash pond and landfill closure costs; a $65 million charge associated with an organizational design initiative; a $74 million in transaction and transition costs associated with Dominion Energy's acquisition of Dominion Energy Questar; a $23 million charge related to storm and restoration costs; and a $45 million charge related to other items, partially offset by $34 million of net gain related to our investments in nuclear decommissioning trust funds. Excluding the net effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2016.

(c) Earnings for the twelve months ended December 31, 2015 include an $85 million write-off of prior-period deferred fuel costs associated with Virginia legislation; a $99 million charge associated with ash pond and landfill closure costs; and a $78 million charge related to other items, partially offset by $60 million of net gain related to our investments in nuclear decommissioning trust funds. Excluding the effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2015.

(d) Earnings for the twelve months ended December 31, 2014 include a $374 million charge related to North Anna nuclear power station and offshore wind facilities; a $284 million charge associated with our liability management effort, which is included in fixed charges; a $121 million accrued charge associated with ash pond and landfill closure costs; and a $93 million charge related to other items, partially offset by a $100 million net gain on the sale of our electric retail energy marketing business and $72 million of net gain related to our investments in nuclear decommissioning trust funds. Excluding the effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2014.

(e) Earnings for the twelve months ended December 31, 2013 include a $55 million impairment charge related to certain natural gas infrastructure assets; a $40 million charge in connection with the Virginia State Corporation Commission's final ruling associated with its biennial review of Virginia Electric and Power Company's base rates for 2011-2012 test years; a $28 million charge associated with our operating expense reduction initiative, primarily reflecting severance pay and other employee related costs; a $26 million charge related to the expected early shutdown of certain coal-fired generating units; and a $29 million charge related to other items, partially offset by $81 million of net gain related to our investments in nuclear decommissioning trust funds; a $47 million benefit due to a downward revision in the nuclear decommissioning asset retirement obligations for certain merchant nuclear units that are no longer in service; and a $29 million net benefit primarily resulting from the sale of the Elwood power station. Excluding the net effect of these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2013.

Exhibit 12.2

Virginia Electric and Power Company
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Years Ended December 31,				
	2017	2016	2015	2014	2013
Earnings, as defined:					
Income from continuing operations before income tax expense	$2,314	$1,945	$1,746	$1,406	$1,797
Fixed charges included in income	532	495	474	438	401
Total earnings, as defined	$2,846	$2,440	$2,220	$1,844	$2,198
Fixed charges, as defined:					
Interest charges	$ 513	$ 478	$ 457	$ 425	$ 388
Rental interest factor	19	17	17	13	13
Fixed charges included in income	$ 532	$ 495	$ 474	$ 438	$ 401
Capitalized interest	1	—	—	—	—
Total fixed charges, as defined	$ 533	$ 495	$ 474	$ 438	$ 401
Ratio of Earnings to Fixed Charges	**5.34**	**4.93**	**4.68**	**4.21**	**5.48**

Exhibit 12.3

Dominion Energy Gas Holdings, LLC
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Years Ended December 31,				
	2017	2016	2015	2014	2013
Earnings, as defined:					
Income from continuing operations before income tax expense	$ 666	$ 607	$ 740	$ 846	$ 762
Distributed income from unconsolidated investees, less equity in earnings	1	—	(3)	(1)	(2)
Fixed charges included in income	116	109	86	39	43
Total earnings, as defined	$ 783	$ 716	$ 823	$ 884	$ 803
Fixed charges, as defined:					
Interest charges	$ 106	$ 97	$ 74	$ 28	$ 30
Rental interest factor	10	12	12	11	13
Total fixed charges, as defined	$ 116	$ 109	$ 86	$ 39	$ 43
Ratio of Earnings to Fixed Charges	**6.75**	**6.57**	**9.57**	**22.67**	**18.67**

Exhibit 21

Dominion Energy, Inc.
Subsidiaries of the Registrant
As of February 15, 2018

Name	Jurisdiction of Incorporation	Name Under Which Business is Conducted
Dominion Energy, Inc.	Virginia	Dominion Energy, Inc.
CNG Coal Company	Delaware	CNG Coal Company
Dominion ACP Holding, Inc.	Virginia	Dominion ACP Holding, Inc.
Dominion Atlantic Coast Pipeline, LLC	Virginia	Dominion Atlantic Coast Pipeline, LLC
Dominion Alternative Energy Holdings, Inc.	Virginia	Dominion Alternative Energy Holdings, Inc.
Dominion Energy Technologies, Inc.	Virginia	Dominion Energy Technologies, Inc.
Dominion Energy Technologies II, Inc.	Virginia	Dominion Energy Technologies II, Inc.
Dominion Voltage, Inc.	Virginia	Dominion Voltage, Inc. DVI
Tredegar Solar Fund I, LLC	Delaware	Tredegar Solar Fund I, LLC
Dominion Capital, Inc.	Virginia	Dominion Capital, Inc.
Dominion Cove Point, Inc.	Virginia	Dominion Cove Point, Inc.
Dominion Energy Midstream GP, LLC	Delaware	Dominion Energy Midstream GP, LLC
Dominion Energy Midstream Partners, LP	Delaware	Dominion Energy Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Energy Cove Point LNG, LP	Delaware	Dominion Energy Cove Point LNG, LP
Dominion Energy Carolina Gas Transmission, LLC	South Carolina	Dominion Energy Carolina Gas Transmission, LLC
Dominion Energy Questar Pipeline, LLC	Utah	Dominion Energy Questar Pipeline, LLC
Dominion Energy Overthrust Pipeline, LLC	Utah	Dominion Energy Overthrust Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Dominion Gas Projects Company, LLC	Delaware	Dominion Gas Projects Company, LLC
Dominion Energy Cove Point LNG, LP	Delaware	Dominion Energy Cove Point LNG, LP
Dominion MLP Holding Company, LLC	Delaware	Dominion MLP Holding Company, LLC
Dominion Energy Midstream Partners, LP	Delaware	Dominion Energy Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Energy Cove Point LNG, LP	Delaware	Dominion Energy Cove Point LNG, LP
Dominion Energy Carolina Gas Transmission, LLC	South Carolina	Dominion Energy Carolina Gas Transmission, LLC
Dominion Energy Questar Pipeline, LLC	Utah	Dominion Energy Questar Pipeline, LLC
Dominion Energy Overthrust Pipeline, LLC	Utah	Dominion Energy Overthrust Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Dominion Energy Carolina Gas Services, Inc.	Virginia	Dominion Energy Carolina Gas Services, Inc.
Dominion Energy Field Services, Inc.	Delaware	Dominion Energy Field Services, Inc.
Dominion Energy Fuel Services, Inc.	Virginia	Dominion Energy Fuel Services, Inc.
Dominion Energy Gas Holdings, LLC	Virginia	Dominion Energy Gas Holdings, LLC
Dominion Energy Transmission, Inc.	Delaware	Dominion Energy Transmission, Inc.
Dominion Brine, LLC	Delaware	Dominion Brine, LLC
Tioga Properties, LLC	Delaware	Tioga Properties, LLC
Farmington Properties, Inc.	Pennsylvania	Farmington Properties, Inc.
NE Hub Partners, L.L.C.	Delaware	NE Hub Partners, L.L.C.

NE Hub Partners, L.P.	Delaware	NE Hub Partners, L.P.
Dominion Gathering & Processing, Inc.	Virginia	Dominion Gathering & Processing, Inc.
Dominion Iroquois, Inc.	Delaware	Dominion Iroquois, Inc.
The East Ohio Gas Company	Ohio	Dominion Energy Ohio
Dominion Energy Payroll Company, Inc.	Virginia	Dominion Energy Payroll Company, Inc.
Dominion Energy Questar Corporation	Utah	Dominion Energy Questar Corporation
Dominion Energy Questar Pipeline Services, Inc.	Utah	Dominion Energy Questar Pipeline Services, Inc.
Dominion Energy Wexpro Services Company	Utah	Dominion Energy Wexpro Services Company
QPC Holding Company	Utah	QPC Holding Company
Dominion Energy Midstream Partners, LP	Delaware	Dominion Energy Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Energy Cove Point LNG, LP	Delaware	Dominion Energy Cove Point LNG, LP
Dominion Energy Carolina Gas Transmission, LLC	South Carolina	Dominion Energy Carolina Gas Transmission, LLC
Dominion Energy Questar Pipeline, LLC	Utah	Dominion Energy Questar Pipeline, LLC
Dominion Energy Overthrust Pipeline, LLC	Utah	Dominion Energy Overthrust Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Questar InfoComm, Inc.	Utah	Questar InfoComm, Inc.
Questar Energy Services, Inc.	Utah	Questar Energy Services, Inc.
Questar Project Employee Company	Utah	Questar Project Employee Company
Questar Southern Trails Pipeline Company	Utah	Questar Southern Trails Pipeline Company
Questar Gas Company	Utah	Dominion Energy Utah (in Utah)
		Dominion Energy Wyoming (in Wyoming)
		Dominion Energy Idaho (in Idaho)
Wexpro Company	Utah	Dominion Energy Wexpro
Wexpro II Company	Utah	Wexpro II Company
Wexpro Development Company	Utah	Wexpro Development Company
Dominion Energy Services, Inc.	Virginia	Dominion Energy Services, Inc.
Dominion Energy Solutions, Inc.	Delaware	Dominion Energy Solutions
		Dominion East Ohio Energy
		Dominion Peoples Plus
Dominion Energy Technical Solutions, Inc.	Virginia	Dominion Energy Technical Solutions, Inc.
Dominion Generation, Inc.	Virginia	Dominion Generation, Inc.
CNG Power Services Corporation	Delaware	CNG Power Services Corporation
Dominion Bridgeport Fuel Cell, LLC	Virginia	Dominion Bridgeport Fuel Cell, LLC
Dominion Cogen WV, Inc.	Virginia	Dominion Cogen WV, Inc.
Dominion Energy Generation Marketing, Inc.	Delaware	Dominion Energy Generation Marketing, Inc.
Dominion Energy Nuclear Connecticut, Inc.	Delaware	Dominion Energy Nuclear Connecticut, Inc.
Dominion Energy Manchester Street, Inc.	Virginia	Dominion Energy Manchester Street, Inc.
Dominion Energy Solar CA, LLC	Delaware	Dominion Energy Solar CA, LLC
Dominion Energy Terminal Company, Inc.	Virginia	Dominion Energy Terminal Company, Inc.
Dominion Equipment, Inc.	Virginia	Dominion Equipment, Inc.
Dominion Equipment III, Inc.	Delaware	Dominion Equipment III, Inc.
Dominion Fairless Hills, Inc.	Delaware	Dominion Fairless Hills, Inc.
Dominion Energy Fairless, LLC	Delaware	Dominion Energy Fairless, LLC
Dominion Mt. Storm Wind, LLC	Virginia	Dominion Mt. Storm Wind, LLC
Dominion North Star Generation, Inc.	Delaware	Dominion North Star Generation, Inc.
North Star Generation, LLC	Delaware	North Star Generation, LLC
Dominion Nuclear Projects, Inc.	Virginia	Dominion Nuclear Projects, Inc.

Dominion Energy Kewaunee, Inc.	Wisconsin	Dominion Energy Kewaunee, Inc.
Dominion Person, Inc.	Delaware	Dominion Person, Inc.
Dominion Solar Projects III, Inc.	Virginia	Dominion Solar Projects III, Inc.
Four Brothers Solar, LLC	Delaware	Four Brothers Solar, LLC
Enterprise Solar, LLC	Delaware	Enterprise Solar, LLC
Escalante Solar I, LLC	Delaware	Escalante Solar I, LLC
Escalante Solar II, LLC	Delaware	Escalante Solar II, LLC
Escalante Solar III, LLC	Delaware	Escalante Solar III, LLC
Granite Mountain Holdings, LLC	Delaware	Granite Mountain Holdings, LLC
Granite Mountain Solar East, LLC	Delaware	Granite Mountain Solar East, LLC
Granite Mountain Solar West, LLC	Delaware	Granite Mountain Solar West, LLC
Iron Springs Holdings, LLC	Delaware	Iron Springs Holdings, LLC
Iron Springs Solar, LLC	Delaware	Iron Springs Solar, LLC
Dominion Solar Projects IV, Inc.	Virginia	Dominion Solar Projects IV, Inc.
Eastern Shore Solar LLC	Delaware	Eastern Shore Solar LLC
Hecate Energy Cherrydale LLC	Delaware	Hecate Energy Cherrydale LLC
Hecate Energy Clarke County LLC	Delaware	Hecate Energy Clarke County LLC
Southampton Solar LLC	Delaware	Southampton Solar LLC
Virginia Solar 2017 Projects LLC	Delaware	Virginia Solar 2017 Projects LLC
Buckingham Solar I LLC	Delaware	Buckingham Solar I LLC
Correctional Solar LLC	Delaware	Correctional Solar LLC
Sappony Solar LLC	Delaware	Sappony Solar LLC
Scott-II Solar LLC	Delaware	Scott-II Solar LLC
Dominion Solar Projects V, Inc.	Virginia	Dominion Solar Projects V, Inc.
Summit Farms Solar, LLC	North Carolina	Summit Farms Solar, LLC
Dominion Solar Projects C, Inc.	Virginia	Dominion Solar Projects C, Inc.
Dominion Solar Holdings IV, LLC	Virginia	Dominion Solar Holdings IV, LLC
96WI 8me LLC	Delaware	96WI 8me LLC
Clipperton Holdings LLC	North Carolina	Clipperton Holdings LLC
Fremont Farm, LLC	North Carolina	Fremont Farm, LLC
Innovative Solar 37, LLC	North Carolina	Innovative Solar 37, LLC
Moffett Solar 1, LLC	Delaware	Moffett Solar 1, LLC
Moorings Farm 2, LLC	North Carolina	Moorings Farm 2, LLC
Mustang Solar, LLC	North Carolina	Mustang Solar, LLC
Pikeville Farm, LLC	North Carolina	Pikeville Farm, LLC
Ridgeland Solar Farm I, LLC	Delaware	Ridgeland Solar Farm I, LLC
Wakefield Solar, LLC	North Carolina	Wakefield Solar, LLC
Dominion Solar Projects D, Inc.	Virginia	Dominion Solar Projects C, Inc.
Dominion Solar Holdings IV, LLC	Virginia	Dominion Solar Holdings IV, LLC
96WI 8me LLC	Delaware	96WI 8me LLC
Clipperton Holdings LLC	North Carolina	Clipperton Holdings LLC
Fremont Farm, LLC	North Carolina	Fremont Farm, LLC
Innovative Solar 37, LLC	North Carolina	Innovative Solar 37, LLC
Moffett Solar 1, LLC	Delaware	Moffett Solar 1, LLC
Moorings Farm 2, LLC	North Carolina	Moorings Farm 2, LLC
Mustang Solar, LLC	North Carolina	Mustang Solar, LLC
Pikeville Farm, LLC	North Carolina	Pikeville Farm, LLC
Ridgeland Solar Farm I, LLC	Delaware	Ridgeland Solar Farm I, LLC
Wakefield Solar, LLC	North Carolina	Wakefield Solar, LLC
Dominion Solar Services, Inc.	Virginia	Dominion Solar Services, Inc.

Dominion State Line, LLC	Delaware	Dominion State Line, LLC
Dominion Wholesale, Inc.	Virginia	Dominion Wholesale, Inc.
Dominion Wind Projects, Inc.	Virginia	Dominion Wind Projects, Inc.
Dominion Fowler Ridge Wind, LLC	Virginia	Dominion Fowler Ridge Wind, LLC
Dominion Wind Development, LLC	Virginia	Dominion Wind Development, LLC
Prairie Fork Wind Farm, LLC	Virginia	Prairie Fork Wind Farm, LLC
SBL Holdco, LLC	Virginia	SBL Holdco, LLC
Dominion Solar Projects I, Inc.	Virginia	Dominion Solar Projects I, Inc.
Dominion Solar Holdings III, LLC	Virginia	Dominion Solar Holdings III, LLC
Alamo Solar, LLC	California	Alamo Solar, LLC
Catalina Solar 2, LLC	Delaware	Catalina Solar 2, LLC
Cottonwood Solar, LLC	Delaware	Cottonwood Solar, LLC
Imperial Valley Solar Company (IVSC) 2, LLC	California	Imperial Valley Solar Company (IVSC) 2, LLC
Maricopa West Solar PV, LLC	Delaware	Maricopa West Solar PV, LLC
Pavant Solar LLC	Delaware	Pavant Solar LLC
Richland Solar Center, LLC	Georgia	Richland Solar Center, LLC
Dominion Solar Projects II, Inc.	Virginia	Dominion Solar Projects II, Inc.
Dominion Solar Holdings III, LLC	Virginia	Dominion Solar Holdings III, LLC
Alamo Solar, LLC	California	Alamo Solar, LLC
Catalina Solar 2, LLC	Delaware	Catalina Solar 2, LLC
Cottonwood Solar, LLC	Delaware	Cottonwood Solar, LLC
Imperial Valley Solar Company (IVSC) 2, LLC	California	Imperial Valley Solar Company (IVSC) 2, LLC
Maricopa West Solar PV, LLC	Delaware	Maricopa West Solar PV, LLC
Pavant Solar LLC	Delaware	Pavant Solar LLC
Richland Solar Center, LLC	Georgia	Richland Solar Center, LLC
Dominion Solar Projects A, Inc.	Virginia	Dominion Solar Projects A, Inc.
Dominion Solar Holdings I, LLC	Virginia	Dominion Solar Holdings I, LLC
Azalea Solar, LLC	Delaware	Azalea Solar, LLC
Dominion Solar Construction and Maintenance, LLC	Virginia	Dominion Solar Construction and Maintenance, LLC
Indy Solar Development, LLC	Delaware	Indy Solar Development, LLC
Indy Solar I, LLC	Delaware	Indy Solar I, LLC
Indy Solar II, LLC	Delaware	Indy Solar II, LLC
Indy Solar III, LLC	Delaware	Indy Solar III, LLC
Somers Solar Center, LLC	Delaware	Somers Solar Center, LLC
Dominion Solar Holdings II, LLC	Virginia	Dominion Solar Holdings II, LLC
CID Solar, LLC	Delaware	CID Solar, LLC
Dominion Solar Gen-Tie, LLC	Delaware	Dominion Solar Gen-Tie, LLC
Mulberry Farm, LLC	North Carolina	Mulberry Farm, LLC
		Mulberry Solar Farm, LLC
RE Adams East LLC	Delaware	RE Adams East LLC
RE Camelot LLC	Delaware	RE Camelot LLC
RE Columbia, LLC	Delaware	RE Columbia LLC
RE Columbia Two LLC	Delaware	RE Columbia Two LLC
RE Columbia, LLC	Delaware	RE Columbia LLC
RE Kansas LLC	Delaware	RE Kansas LLC
RE Kent South LLC	Delaware	RE Kent South LLC
RE Old River One LLC	Delaware	RE Old River One LLC
Selmer Farm, LLC	North Carolina	Selmer Farm, LLC
TA – Acacia, LLC	Delaware	TA – Acacia, LLC

		West Antelope Solar Park
Dominion Solar Projects B, Inc.	Virginia	Dominion Solar Projects B, Inc.
Dominion Solar Holdings I, LLC	Virginia	Dominion Solar Holdings I, LLC
Azalea Solar, LLC	Delaware	Azalea Solar, LLC
Dominion Solar Construction and Maintenance, LLC	Virginia	Dominion Solar Construction and Maintenance, LLC
Indy Solar Development, LLC	Delaware	Indy Solar Development, LLC
Indy Solar I, LLC	Delaware	Indy Solar I, LLC
Indy Solar II, LLC	Delaware	Indy Solar II, LLC
Indy Solar III, LLC	Delaware	Indy Solar III, LLC
Somers Solar Center, LLC	Delaware	Somers Solar Center, LLC
Dominion Solar Holdings II, LLC	Virginia	Dominion Solar Holdings II, LLC
CID Solar, LLC	Delaware	CID Solar, LLC
Dominion Solar Gen-Tie, LLC	Delaware	Dominion Solar Gen-Tie, LLC
Mulberry Farm, LLC	North Carolina	Mulberry Farm, LLC
		Mulberry Solar Farm, LLC
RE Adams East LLC	Delaware	RE Adams East LLC
RE Camelot LLC	Delaware	RE Camelot LLC
RE Columbia LLC	Delaware	RE Columbia LLC
RE Columbia Two LLC	Delaware	RE Columbia Two LLC
RE Columbia LLC	Delaware	RE Columbia LLC
RE Kansas LLC	Delaware	RE Kansas LLC
RE Kent South LLC	Delaware	RE Kent South LLC
RE Old River One LLC	Delaware	RE Old River One LLC
Selmer Farm, LLC	North Carolina	Selmer Farm, LLC
TA – Acacia, LLC	Delaware	TA – Acacia, LLC
		West Antelope Solar Park
Dominion Greenbrier, Inc.	Virginia	Dominion Greenbrier, Inc.
Greenbrier Pipeline Company, LLC	Delaware	Greenbrier Pipeline Company, LLC
Greenbrier Marketing Company, LLC	Delaware	Greenbrier Marketing Company, LLC
Dominion High Voltage Holdings, Inc.	Virginia	Dominion High Voltage Holdings, Inc.
Dominion High Voltage MidAtlantic, Inc.	Virginia	Dominion High Voltage MidAtlantic, Inc.
Dominion Investments, Inc.	Virginia	Dominion Investments, Inc.
Dominion Keystone Pipeline Holdings, Inc.	Delaware	Dominion Keystone Pipeline Holdings, Inc.
Dominion Keystone Pipeline, LLC	Delaware	Dominion Keystone Pipeline, LLC
Dominion MLP Holding Company II, Inc.	Virginia	Dominion MLP Holding Company II, Inc.
Dominion MLP Holding Company III, Inc.	Virginia	Dominion MLP Holding Company III, Inc.
Dominion Modular LNG Holdings, Inc.	Virginia	Dominion Modular LNG Holdings, Inc.
Niche LNG, LLC	Delaware	Niche LNG, LLC
Dominion Natrium Holdings, Inc.	Delaware	Dominion Natrium Holdings, Inc.
Dominion Oklahoma Texas Exploration & Production, Inc.	Delaware	Dominion Oklahoma Texas Exploration & Production, Inc.
Dominion Privatization Holdings, Inc.	Virginia	Dominion Privatization Holdings, Inc.
Dominion Privatization Florida, LLC	Virginia	Dominion Privatization Florida, LLC
Dominion Privatization Georgia, LLC	Virginia	Dominion Privatization Georgia, LLC
Dominion Privatization Kentucky, LLC	Virginia	Dominion Privatization Kentucky, LLC
Dominion Privatization South Carolina, LLC	Virginia	Dominion Privatization South Carolina, LLC
Dominion Privatization Texas, LLC	Virginia	Dominion Privatization Texas, LLC
Dominion Products and Services, Inc.	Delaware	Dominion Products and Services, Inc.
		Dominion Energy Solutions

Dominion Projects Services, Inc.	Virginia	Dominion Projects Services, Inc.
Dominion Resources Capital Trust III	Delaware	Dominion Resources Capital Trust III
Dominion South Holdings I, Inc.	Delaware	Dominion South Holdings I, Inc.
Dominion South Holdings II, LLC	Delaware	Dominion South Holdings II, LLC
Dominion South Pipeline Company, LP	Delaware	Dominion South Pipeline Company, LP
Hope Gas, Inc.	West Virginia	Dominion Energy West Virginia
Sedona Corp.	South Carolina	Sedona Corp.
Virginia Electric and Power Company	Virginia	Dominion Energy Virginia (in Virginia) Dominion Energy North Carolina (in North Carolina)
Virginia Power Fuel Corporation	Virginia	Virginia Power Fuel Corporation
Virginia Power Services, LLC	Virginia	Virginia Power Services, LLC
Virginia Power Nuclear Services Company	Virginia	Virginia Power Nuclear Services Company
Virginia Power Services Energy Corp., Inc.	Virginia	Virginia Power Services Energy Corp., Inc.
VP Property, Inc.	Virginia	VP Property, Inc.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-216476, 333-219088 and 333-221291 on Form S-3, Registration Statement No. 333-223036 on Form S-4, and Registration Statement Nos. 033-62705, 333-02733, 333-09167, 333-18391, 333-25587, 333-49725, 333-78173, 333-85094, 333-87529, 333-95795, 333-110332, 333-124256, 333-124257, 333-130566, 333-130570, 333-143916, 333-149989, 333-149993, 333-156027, 333-163805, 333-189578, 333-189579, 333-189580, 333-189581, 333-195768, 333-202364, 333-202366 and 333-203952 on Form S-8 of our reports dated February 27, 2018, relating to the consolidated financial statements of Dominion Energy, Inc. and subsidiaries and the effectiveness of Dominion Energy, Inc. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Dominion Energy, Inc. for the year ended December 31, 2017.

We consent to the incorporation by reference in Registration Statement No. 333-219085 on Form S-3 of our report dated February 27, 2018, relating to the consolidated financial statements of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Energy, Inc.) and subsidiaries, appearing in this Annual Report on Form 10-K of Virginia Electric and Power Company for the year ended December 31, 2017.

We consent to the incorporation by reference in Registration Statement No. 333-219086 on Form S-3 of our report dated February 27, 2018, relating to the consolidated financial statements of Dominion Energy Gas Holdings, LLC (a wholly-owned subsidiary of Dominion Energy, Inc.) and subsidiaries, appearing in this Annual Report on Form 10-K of Dominion Energy Gas Holdings, LLC for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 27, 2018

Exhibit 31.a

I, Thomas F. Farrell, II, certify that:

1. I have reviewed this report on Form 10-K of Dominion Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Thomas F. Farrell, II

Thomas F. Farrell, II
President and Chief Executive Officer

Exhibit 31.b

I, Mark F. McGettrick, certify that:

1. I have reviewed this report on Form 10-K of Dominion Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer

Exhibit 31.c

I, Thomas F. Farrell, II, certify that:

1. I have reviewed this report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Thomas F. Farrell, II

Thomas F. Farrell, II
Chief Executive Officer

Exhibit 31.d

I, Mark F. McGettrick, certify that:

1. I have reviewed this report on Form 10-K of Virginia Electric and Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer

Exhibit 31.e

I, Thomas F. Farrell, II, certify that:

1. I have reviewed this report on Form 10-K of Dominion Energy Gas Holdings, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Thomas F. Farrell, II

Thomas F. Farrell, II
Chief Executive Officer

Exhibit 31.f

I, Mark F. McGettrick, certify that:

1. I have reviewed this report on Form 10-K of Dominion Energy Gas Holdings, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2018

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer

Exhibit 32.a

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Dominion Energy, Inc. (the "Company"), certify that:

1. the Annual Report on Form 10-K for the year ended December 31, 2017 (the "Report"), of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2017, and for the period then ended.

/s/ Thomas F. Farrell, II

Thomas F. Farrell, II
President and Chief Executive Officer
February 27, 2018

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 27, 2018

Exhibit 32.b

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Virginia Electric and Power Company (the "Company"), certify that:

1. the Annual Report on Form 10-K for the year ended December 31, 2017 (the "Report"), of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2017, and for the period then ended.

/s/ Thomas F. Farrell, II

Thomas F. Farrell, II
Chief Executive Officer
February 27, 2018

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 27, 2018

Exhibit 32.c

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Dominion Energy Gas Holdings, LLC (the "Company"), certify that:

1. the Annual Report on Form 10-K for the year ended December 31, 2017 (the "Report"), of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of December 31, 2017, and for the period then ended.

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chief Executive Officer
February 27, 2018

/s/ Mark F. McGettrick
Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 27, 2018

AG
Exhibit 5

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE CONSTRUCTION OF AN ADVANCED METERING INFRASTRUCTURE; (2) REQUEST FOR ACCOUNTING TREATMENT; AND (3) ALL OTHER NECESSARY WAIVERS, APPROVALS, AND RELIEF	)	CASE NO. 2016-00152

ORDER

On April 25, 2016, Duke Energy Kentucky, Inc. ("Duke Kentucky") filed an application requesting a Certificate of Public Convenience and Necessity ("CPCN") to replace and upgrade its current electric and gas metering infrastructure to a digital Advanced Metering Infrastructure ("AMI") for its electric and combination customers, and an Automated Meter Reading ("AMR") infrastructure for its gas-only customers, collectively ("AMI Project"). Duke Kentucky also sought approval of new depreciation rates for the new metering equipment, and to establish a regulatory asset for the retirement of its existing electric metering equipment, associated inventory, and inventory of existing gas modules. Last, Duke Kentucky also requested deviations from Commission regulations 807 KAR 5:006, Section 7(5)(b), and 807 KAR 5:006, Section 14, as they relate to Duke Kentucky's proposed AMI Project.

The Attorney General ("AG"), by and through his Office of Rate Intervention, sought and was granted leave to intervene on May 17, 2016, and is the only intervenor in this proceeding. Duke Kentucky responded to two rounds of requests for information from both Commission Staff and the AG, and the AG filed testimony and responded to one round of requests for information from Commission Staff and Duke Kentucky. Duke Kentucky filed rebuttal testimony on October 13, 2016, and a hearing was held in this matter on December 8, 2016. Duke Kentucky provided responses to a post-hearing request for information on December 22, 2016. Prior to the hearing, on December 6, 2016, Duke Kentucky and the AG filed a Stipulation and Recommendation ("Stipulation") intended to address all the issues raised in this proceeding.

BACKGROUND

Duke Kentucky proposes to install approximately 143,000 electric AMI meters, approximately 82,500 gas AMI modules for its combination customers, and approximately 20,500 gas AMR modules for its gas-only customers, at an estimated cost of $49 million.[1] Duke Kentucky describes several issues with its current metering system which consists mainly of electromechanical meters. Duke Kentucky also has a small number of early generation smart meters that were deployed as part of a pilot Power Line Carrier ("PLC") system.[2] However, due to the limited bandwidth on the PLC system, Duke Kentucky's existing smart meters are unable to obtain daily electric usage data.[3] Duke Kentucky also discovered that its PLC meter system had limited ability to retrieve meter readings during circuit re-routing events such as substation maintenance,

[1] Application, ¶ 14 and ¶ 18.

[2] *Id.* at ¶ 6.

[3] *Id.* at ¶ 7.

outages, or seasonal switching situations, which often results in lost data, which would then require manual or estimated meter reads.[4] Duke Kentucky's PLC system also lacks the ability to perform remote connections and disconnections.[5]

Duke Kentucky states that it has approximately 65,000 meters located inside the customers' premises, and nearly 50,000 of those meters are electromechanical meters requiring a meter reader to enter the premises to obtain a manual reading.[6] Duke Kentucky states that the proposed AMI Project will alleviate the issues mentioned above and will also make more detailed usage information available to its customers. In addition, Duke Kentucky has been developing a suite of additional customer services that it would like to provide to its customers once the AMI Project is complete. Such services would allow customers to choose their bill due date, enroll in prepay metering, and provide outage notifications.[7] Duke Kentucky asserts that with the new metering system, customers will benefit by having greater and more detailed access to their usage information.[8] In addition, customers needing to start or stop service will no longer be required to schedule an appointment, and customers who are disconnected for non-payment will be able to have their service turned on nearly instantaneously, rather than having to wait for a Duke Kentucky technician.[9] Duke Kentucky states that

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[4] *Id.* at ¶ 7.

[5] *Id.*

[6] Direct Testimony of James P. Henning ("Henning Testimony") at 10–11.

[7] *Id.* at 13–14.

[8] Direct Testimony of Donald L. Schneider Jr. ("Schneider Testimony") at 12.

[9] *Id.*

the new metering system will also serve to reduce its outage restoration time as Duke Kentucky can "ping" individual meters after an outage event to determine if any have not had service reconnected.[10] Duke Kentucky contends that customers will also eventually experience savings through Duke Kentucky's rates due to fewer daily and monthly truck rolls to perform disconnects and reconnects, and reduced meter reading expenses.[11] Duke Kentucky has selected Itron to provide its new metering system.

STIPULATION

The Stipulation filed on December 6, 2016, reflects the agreement of Duke Kentucky and the AG on all issues raised during this proceeding. The major provisions of the Stipulation are as follows:

- Approval of Application. The parties agree that Duke Kentucky's application be approved as filed and described in its application and testimony, except as modified by the stipulation.

- Regulatory Asset. The parties agree that Duke Kentucky should be authorized to establish a regulatory asset for the actual costs of the balance of the undepreciated value of the existing metering infrastructure upon retirement, including related inventory, as a result of the AMI Project. In its next base rate case, Duke Kentucky will propose an amortization period of 15 years for this regulatory asset, without carrying charges, for inclusion in the revenue requirement in Duke Kentucky's

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[10] *Id.* at 12–13.

[11] *Id.* at 12.

electric base rates. Duke Kentucky reserves the right to request carrying costs if the Commission approves an amortization period that is greater than 15 years.

- Cost Over-Runs. Duke Kentucky anticipates filing a base electric rate case no later than December 31, 2019. Although Duke Kentucky does not anticipate any cost over-runs during the deployment of the AMI Project, in the event such cost over-runs occur at the time Duke Kentucky seeks recovery in that future rate case, Duke Kentucky commits that it will specifically identify any such cost over-runs on an itemized basis that is consistent with the itemization contained in the Direct Testimony of Donald S. Schneider, Jr., Confidential Attachment DLS-4 ("DLS-4") in this proceeding.

- Operational Benefits. In its next base electric rate case, Duke Kentucky agrees to make appropriate adjustments to its test period to reflect the actual costs and associated savings related to the AMI Project, including: 1) the projected deployment costs or actual costs if deployment is completed; 2) ongoing costs of operations; 3) an adjustment to reflect the non-fuel-related portion of the Benefit Type: Increased Revenues reflected in DLS-4; 4) an adjustment to reflect the Operational Savings to date if a historical test year, and, if a forecasted test year, the forecasted Operational Savings that would be obtained during that test year;[12] and 5) a pro-forma adjustment to account for the projected ongoing Operational Savings as reflected in DLS-4, adjusted

[12] The specific Operational Savings categories to be included in the adjustment are set forth in footnote 2 of the Stipulation.

to factor in any Operational Savings degradation that my accrue due to the establishment of an electric AMI opt-out tariff.[13]

- Natural Gas. Duke Kentucky does not currently have a natural gas rate case planned during the period when the AMI Project is being deployed. In order to provide an opportunity for its natural gas customers to timely receive the anticipated levels of Operational Savings attributed to the natural gas portion of the AMI Project and for Duke Kentucky to timely recover its deployment costs, the parties agree that Duke Kentucky will file, as a separate application for Commission review and consideration for approval, a proposal to establish a gas AMI/AMR deployment cost/benefit tracking mechanism. The tracking mechanism will be designed to enable, among other things: an opportunity for Duke Kentucky to timely recover its costs of deployment (i.e., incremental operation and maintenance ["O&M"], return, depreciation, amortization of regulatory assets, and property taxes net of the O&M savings) for the natural gas portion of the AMI Project; the deferral of natural gas metering infrastructure of the regulatory asset established in this proceeding; and will factor in the appropriate level of ongoing Operational Savings attributed to reductions in meter reading and other O&M expense that is allocable to natural gas metering operations and attributable to the AMI Project as indicated in DLS-4. The gas tracking mechanism will continue with annual adjustments and true-ups until Duke Kentucky's next natural gas base rate case. The initial application will include deployment costs and any Operational Savings incurred to

[13] The Stipulation states that the pro-forma adjustment for the projected Operational Savings calculation will be in the form of a levelized net present value calculated using the 7.05 percent as presented in DLS-4 for the projected future Operation Savings which will be factored into Duke Kentucky's ongoing revenue requirement.

date and a projection for the remainder of calendar year 2017 and calendar year 2018. Subsequent annual applications will true-up the actual costs from the previous year and adjust for recovery of the remainder of costs incurred during the year. The tracking mechanism will cease on the day that new gas base rates, which will include the gas AMI costs and Operational Savings, becomes effective.

- Customer Opt-Out Program. Duke Kentucky agrees to implement an Electric AMI Opt-Out Program Tariff for residential customers to be effective at the time of initial AMI Project deployment. The Advanced Meter Opt-Out (AMO) – Residential Tariff ("Rider AMO") includes a one-time initial set-up fee of $100 and a $25 per month ongoing charge for manual meter reading. Customers who notify Duke Kentucky before an AMI meter is installed on their premise will not incur the $100 initial set up fee but will be subject to the $25 monthly charge.

- Residential Peak Time Rebate Pilot and Mandatory Residential Demand-Based Charges. No later than six months from completion of the AMI Project, Duke Kentucky agrees to file a pilot Peak-Time Rebate voluntary pilot tariff for up to 1,000 customers to have the opportunity to earn rebates by reducing usage during peak event periods. Duke Kentucky commits not to implement mandatory residential demand-based charges for at least six years unless otherwise ordered by the Commission or law.

- Customer Data. Duke Kentucky commits to allow its customers to have access to their own usage information through its web portal as part of the AMI Project. Duke Kentucky also agrees to provide non-customer specific usage data in aggregate form to governmental and educational agencies, provided the information is solely for educational or research purposes.

- Annual and Semi-Annual Reporting. Duke Kentucky agrees that during deployment of its new metering infrastructure and for three years following completion of deployment, it will provide annual reporting to the AG and the Commission regarding the development of products and services designed to engage its customers around their energy consumption.

- Reconnection Charges. Duke Kentucky agrees that in its next electric base rate proceeding, it will revise its reconnection charges to reflect the then-current actual costs of performing a reconnection.

- Future Smart Grid Investments. Duke Kentucky agrees that in any future applications for major AMR or AMI meter investments, distribution grid investments for distribution automation, or "SCADA or volt/var resources" that require a CPCN, it will include a detailed cost-benefit analysis similar to what was submitted in this case.

DISCUSSION

The Commission's standard of review of a request for a CPCN is well settled. No utility may construct or acquire any facility to be used in providing utility service to the public until it has obtained a CPCN from this Commission except as provided for in KRS 278.020(1) and (2) and 807 KAR 5:001, Section 15(3). Based on the cost and nature of the project proposed by Duke Kentucky, the Commission finds that the exceptions are not applicable and, thus, a CPCN is required.[14] To obtain a CPCN, the utility must demonstrate a need for such facilities and an absence of wasteful duplication.[15]

"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 or operated.
>
> [T]he 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.[16]

"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."[17] 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 reasonable alternatives has been performed.[18] Selection of a proposal that ultimately costs more than an alternative does not necessarily result in

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[14] KRS 278.020(1).

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

[16] *Id.* at 890.

[17] *Id.*

[18] 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).

wasteful duplication.[19] All relevant factors must be balanced.[20] The statutory touchstone for ratemaking in Kentucky is the requirement that rates set by the Commission must be fair, just and reasonable.[21]

Duke Kentucky's Application

Having reviewed the record and being otherwise sufficiently advised, the Commission finds that Duke Kentucky has established a need to upgrade its metering system in order to enhance its ability to serve its customers by providing them with innovative programs and services to have greater access to data and better control over their energy consumption as well as to improve the reliability of Duke Kentucky's distribution system. We note that electro-mechanical meters are no longer being manufactured, and Duke Kentucky's current AMI meters are limited in its capabilities with respect to data collection and communication. In addition, we note that Duke Kentucky currently has 64,883 meters that are located inside its customers' premises.[22] Of these interior meters, nearly 50,000 are standard electro-mechanical meters, which require manual reading.[23] The proposed AMI Project will eliminate the costs and resources associated with Duke Kentucky having to enter these customers' homes on a

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[19] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, *Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky* (Ky. PSC Aug. 19, 2005), final Order.

[20] Case No. 2005-00089, *East Kentucky Power Cooperative, Inc.* (Ky. PSC Aug. 19, 2005), final Order at 6.

[21] KRS 278.190(3).

[22] Henning Testimony at 10–11.

[23] *Id.*

monthly basis to conduct a meter reading.[24] In addition, the AMI Project will improve Duke Kentucky employee safety.[25]

The Commission further finds that the benefits from the proposed AMI Project outweigh the cost. Duke Kentucky performed a cost-benefit analysis, which showed that the proposed AMI Project would result in a net benefit of $7,418,653, on a net present value basis over a 17-year study period.[26] The main benefits identified and quantified by Duke Kentucky are the elimination of monthly and off-cycle manual meter reads, the elimination of truck rolls due to the ability to conduct electric disconnects and reconnects remotely, enhanced theft detection, reduction of meter installation errors, reduction of underperforming meters, and the availability of interval usage data that can empower customers to better understand their energy usage and save energy.[27]

Duke Kentucky's application also requests a nine-year depreciable life for its gas modules. In support of the nine-year life, Duke Kentucky stated that "[t]his shorter depreciable life for the gas modules is driven by the operational efficiency created by aligning the replacement of the gas module with the nine-to-ten year replacement/testing schedule of the residential natural gas meters in accordance with Commission regulations."[28] [29] Information provided in Duke Kentucky's Application from

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[24] Henning Testimony at 11.

[25] *Id.*

[26] Schneider Testimony, Exhibit DLS-4.

[27] Schneider Testimony at 26.

[28] Application, ¶ 23.

[29] 807 KAR 5:022, Section 8 requires that gas meters be tested every ten years.

Itron, the gas module manufacturer, shows that the battery life of the modules can range from 13–20 years.[30] Furthermore, Itron information included in the Application specifically states that the expected battery life is 18 to 20 years for one scheduled transmission per day and 15 to 17 years for two scheduled transmissions per day.[31] The Commission is not convinced that a shorter, nine-year depreciable life is appropriate given that it is well below the shortest life estimate provided by the manufacturer. Therefore, the Commission finds that Duke Kentucky should use a 15-year depreciable life for its gas modules. When questioned about the useful life of the gas modules at the December 8, 2016 hearing, Duke Kentucky stated that it would be agreeable to a 15-year life if it were granted a deviation from 807 KAR 5:022, Section 8(5), to allow meter testing every 15 years rather than every ten years, as required by the regulation. However, Duke Kentucky has not provided sufficient information in compliance with KRS 278.210(4) to demonstrate through sample testing that no statistically significant number of its residential gas meters over-register. Thus, the Commission is unable to grant the requested deviation. As previously stated, Duke Kentucky currently replaces/tests its residential natural gas meters on a nine-to-ten year cycle. Given the information provided in the Application, the Commission believes it is likely that the gas modules will last through two replacement/testing cycles.

Duke Kentucky's application also requests, among other things, a deviation from 807 KAR 5:006, Section 7(5)(b), and 807 KAR 5:006, Section 14. 807 KAR 5:006,

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[30] Application, Exhibit 4, at 7 of 8.

[31] *Id.*, at 3 of 8.

Section 7(5)(b), requires each customer-read meter to be read manually at least once during a calendar year. Duke Kentucky asserts that "[t]o the extent this regulation could be interpreted as requiring Duke Energy Kentucky to manually read a meter at least once a year, the Company respectfully requests a waiver of such a requirement."[32] Duke Kentucky further asserts that requiring the proposed new meters to be manually read every year would reduce one of the primary benefits of the AMI Project of being able to remotely read meters on a monthly basis. The Commission finds that the annual meter reading requirement under 807 KAR 5:006, Section 7(5)(b), applies only to customer-read meters. Because the proposed meters under the AMI Project are capable of being read remotely and do not fall within the class of meters that are customer read, the Commission finds that 807 KAR 5:006, Section 7(5)(b), would not apply to the proposed AMI Project and, thus, a waiver is not necessary.

With respect to 807 KAR 5:006, Section 14(3), which requires an electric utility to inspect the condition of its meter before making service connections to a new customer so that prior or fraudulent use of the meter shall not be attributed to the new customer, Duke Kentucky maintains that advanced theft detection and remote connection and disconnection provided by the new meters would allow Duke Kentucky to know if energy continues to flow through the meter after a customer has requested to be disconnected.[33] This would allow Duke Kentucky to fully investigate the theft and address it prior to a new customer's taking service at that location, ensuring that the

[32] Application ¶ 49.

[33] Schneider Testimony at 17.

new customer will not be adversely affected by the consumption or fraudulent acts of a prior customer.[34] The Commission finds that Duke Kentucky has established good cause to allow it a deviation from the inspection requirements of 807 KAR 5:006, Section 14(3).

Stipulation

The Commission finds that, with the exception of the Gas Cost/Benefit Tracker provision, the Stipulation entered into between Duke Kentucky and the AG is reasonable and should be approved. Duke Kentucky's application as filed did not request a Gas Cost/Benefit Tracker provision. However, as part of the stipulation, Duke Kentucky commits to submitting an application, within six months from the date of the Commission's decision approving the instant application, to establish a tracking mechanism designed to enable Duke Kentucky to timely recover the deployment costs related to the gas portion of the AMI Project, the deferral of natural gas metering infrastructure included in the regulatory asset established in this proceeding, and take into account the appropriate level of ongoing Operational Savings attributed to reductions in meter reading and other O&M expense that is allocable to natural gas metering operations and attributable to the AMI Project as indicated in DLS-4.

In reviewing the cost-benefit analysis performed by Duke Kentucky, the Commission finds that there will be large upfront capital costs in years one through three for the of the natural gas portion of the AMI Project, and the net benefits will not be achieved until year four. For these reasons, the Commission is not convinced that a

[34] *Id.*

gas tracking mechanism is in the best interest of Duke Kentucky's ratepayers. Thus, we find that the commitment by Duke Kentucky to request immediate implementation of a tracking mechanism to be unreasonable and should be rejected. Consistent with the recovery and recognition of the costs and benefits of the electric metering infrastructure related portion of the AMI Project in Duke Kentucky's next electric base rate case, Duke Kentucky should include all of the costs and benefits associated with the gas metering infrastructure portion of the AMI Project in its next gas base rate case.

Pilot Peak Time Rebate Tariff

The Commission recognizes that the Stipulation contains a provision requiring Duke Kentucky to file a separate application for a Pilot Peak Time Rebate tariff as part of a future Demand-Side Management ("DSM") filing. The Commission gives notice that the merits of the Pilot Peak Time Rebate tariff will be reviewed at the time it is filed. As the Commission stated in a recent order in a Duke Kentucky DSM case,[35] we are concerned about the increasing number of utility DSM programs and the associated increase in costs to ratepayers, particularly as the costs of the programs are borne by all customers in a rate class and are not limited to the participants in the DSM programs. Therefore, the Commission will apply greater scrutiny in its review of all future DSM filings, with a particular emphasis on reviewing the costs, benefits, and rate impact of each program and measure.

[35] Case No. 2016-00289, *Electronic Application of Duke Energy Kentucky, Inc. to Amend Its Demand Side Management Programs* (Ky. PSC Jan. 24, 2017).

Depreciation of Existing Meters

At the December 8, 2016 hearing in this matter, Duke Kentucky stated that after receiving a final Order approving its AMI Project, and an additional internal approval, it would stop recording depreciation on the meters being replaced due to accounting rules governing the impairment of assets.[36] The Commission finds that a meter still being used to obtain a customer's usage information could not be considered to be impaired, because it is still used and useful. Furthermore, the Commission has approved a number of meter replacement projects and is unaware of any other jurisdictional utility that has been required to cease depreciating their meters upon the granting of a CPCN for such project and prior to the existing meters' being replaced by a new AMI meter. Therefore, the Commission finds that Duke Kentucky should continue to depreciate its meters until they are removed from service. Furthermore, the Commission finds that Duke Kentucky should make all reasonable efforts to mitigate the amount of the regulatory asset due to the stranded meter costs.

IT IS THEREFORE ORDERED that:

1. The Stipulation attached hereto as the Appendix is conditionally approved and Duke Kentucky is conditionally granted a CPCN to install AMI infrastructure for its electric and combination customers and AMR infrastructure for its gas-only customers subject to Duke Kentucky and the AG jointly or individually filing within seven days of the date of this Order a statement accepting the Commission's modifications to the Stipulation as set forth in Ordering Paragraphs 2, 3, and 4 below.

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[36] December 8, 2016 Hearing Video at 11:06.

2. Duke Kentucky shall use a 15-year depreciable life for its gas modules.

3. Duke Kentucky is not authorized to file a Gas Cost/Benefit Tracker mechanism prior to filing its next gas base gas base rate case.

4. Any request for cost recovery of the gas-related infrastructure approved in this case shall be included by Duke Kentucky in its next gas base rate case.

5. Duke Kentucky's request to deviate from 807 KAR 5:006, Section 7(5)(b), is denied as unnecessary.

6. Duke Kentucky's request to deviate from 807 KAR 5:006, Section 14(3), as it relates to Duke Kentucky's proposed AMI Project is granted.

7. Within 20 days of the date of this Order, Duke Kentucky shall file with this Commission, using the Commission's electronic Tariff Filing System, its Electric AMI Opt-Out Tariff Rider AMO, setting out the rates approved herein and reflecting that they were approved pursuant to this Order.

By the Commission

ENTERED
MAY 25 2017
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Talina R. Mathews
Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00152

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Duke Energy Kentucky, Inc., for (1) a Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief.	)))))))	Case No. 2016-00152

STIPULATION AND RECOMMENDATION

On or about April 25, 2016 Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) filed its application with the Kentucky Public Service Commission (Commission), pursuant to KRS 278.020, and 807 KAR 5:001, Sections 14 and 15, for Certificate of Public Convenience and Necessity (CPCN) for approval to replace and upgrade its existing metering infrastructure by constructing and installing a more advanced system of digital technologies including Advanced Metering Infrastructure (AMI) for its electric and combination electric and natural gas operations and an Automated Meter Reading (AMR) infrastructure for its gas only operations (Metering Upgrade). The Company also requested establishment of equipment depreciation rates for the new metering equipment (15 years for electric AMI meters, and 9 years for gas modules) and approval of the creation of a regulatory asset related to the retirement of existing electric metering equipment, associated inventories and any waivers, approval, and relief necessary to implement the Metering Upgrade and achieve the anticipated functionality. On or about May 10, 2016, the Attorney General of the Commonwealth of Kentucky (Attorney General) filed its motion to intervene, which was subsequently granted by the Commission.

The Attorney General and the Commission Staff have engaged in substantial investigation of the Company's Application by issuing numerous information requests to which the Company has responded.

Duke Energy Kentucky and the Attorney General (the Parties), representing diverse interests and viewpoints, have reached a complete settlement of all the issues raised in this proceeding and have executed this Stipulation and Recommendation (Stipulation) for purposes of submitting their agreement to the Commission for consideration and approval. It is the intent and purpose of the Parties to express their agreement to a mutually satisfactory resolution of all issues in the instant proceeding.

The Parties understand that this Stipulation is not binding upon the Commission, but believe it is entitled to careful consideration by the Commission. The Parties agree that this Stipulation, viewed in its entirety, constitutes a reasonable resolution of all issues in this proceeding.

The Parties request that the Commission issue an Order approving this Stipulation in its entirety pursuant to KRS 278.020, and 807 KAR 5:001, Sections 14 and 15, including granting of the Company's Application as requested and as further modified below. The request is based upon the belief that the Parties' participation in settlement negotiations and the materials on file with the Commission adequately support this Stipulation. Adoption of this Stipulation will eliminate the need for the Commission and the Parties to expend significant resources in litigation of this proceeding and will eliminate the possibility of, and any need for, rehearing or appeals of the Commission's final order herein.

NOW, THEREFORE, for and in consideration of the mutual premises set forth above and the agreements set forth herein, the Parties agree as follows:

1. **Approval of Application.** Duke Energy Kentucky's Application shall be approved as filed and described in Company's Application and Supporting Testimony, except as modified below.

2. **Regulatory Asset**. The Parties agree that Duke Energy Kentucky shall establish a regulatory asset for the actual costs of the balance of the undepreciated value of the existing metering infrastructure upon retirement, including related inventory, as a result of the Metering Upgrade. The Parties agree that in its next base rate case, Duke Energy Kentucky shall propose an amortization period of fifteen years, for this regulatory asset, without carrying charges, for inclusion in the revenue requirement in the Company's electric base rates. Duke Energy Kentucky reserves the right to request carrying costs if the Commission approves an amortization period that is greater than fifteen years for this asset.

3. **Cost Over-runs**.

a. The Parties recognize that Duke Energy Kentucky anticipates filing a base electric rate case no later than December 31, 2019. Although Duke Energy Kentucky does not anticipate any cost-over runs during the Metering Upgrade deployment, in the event such cost-over runs occur, at the time the Company seeks recovery in that future rate case, Duke Energy Kentucky commits that it will specifically identify any such cost-over runs on an itemized basis that is consistent with the itemization contained in Confidential Attachment DLS-4 in this proceeding. Duke Energy Kentucky shall include in its direct testimony an explanation of any such cost over-runs. Duke Energy Kentucky shall bear the burden of proof for prudency of the recovery of any such overruns. The Parties and the Commission maintain all rights to either support or oppose the prudency of any cost over-runs.

b. Duke Energy Kentucky commits that there will be no degradation of the AMI capabilities and operational benefits described in its direct testimony in the event of any cost over-run.

c. Duke Energy Kentucky commits to look for opportunities for additional efficiencies and cost savings through the Metering Upgrade Deployment. The Company shall report on its efforts as part of the six month Metering Upgrade Deployment reporting described in section 8 below.

4. **Operational Benefits**.

a. **Electric**. The Parties agree that in its next base electric rate case, estimated to be filed before December 31, 2019, Duke Energy Kentucky shall make appropriate adjustments to its rate case test period to reflect: 1) the projected deployment costs[1]; 2) ongoing costs of operations; 3) an adjustment to reflect the non-fuel-related portion of the Benefit Type: Increased Revenues reflected in Confidential Exhibit DLS-4; 4) an adjustment to reflect the Operational Savings[2] to date if a historic test year, and, if a forecasted test year, the forecasted Operational Savings that would be obtained during that test year; and 5) a pro-forma adjustment to account for the projected ongoing

[1] Or actual costs if deployment is completed.

[2] The term "Operational Savings" is defined as the Benefit Types listed in Confidential Exhibit DLS-4 of Expense Reduction; and the Avoided Costs–[operations and maintenance] O&M savings descriptions associated with: i) Avoided restoration costs-OK on arrival; ii) Avoided restoration costs-major storms; iii) Associated with maintenance of TWACS; iv) Associated with Operations of TWACS; and v) Miscellaneous O&M.

Operational Savings as reflected in Confidential Exhibit DLS-4, adjusted to factor in any Operational Savings degradation that may accrue due to the establishment of an electric AMI opt-out tariff as described below. The pro-forma adjustment for the projected Operational Savings calculations shall be in the form of a levelized net present value calculated using the 7.05% as presented in Confidential Exhibit DLS-4 for the projected future Operational Savings which will be factored into the Company's ongoing revenue requirement.

b. **Gas**. The Parties acknowledge that Duke Energy Kentucky does not currently have a natural gas rate case planned during the scope of the Metering Upgrade deployment. In order to provide an opportunity for its natural gas customers to timely receive the anticipated levels of Operational Savings attributed to the natural gas portion of the Metering Upgrade proposal and for the Company to timely recover its deployment costs, the Parties agree that Duke Energy Kentucky will file , as a separate application for Commission review and consideration for approval, a proposal to establish a gas AMI/AMR deployment cost/benefit tracking mechanism. This separate application shall be filed within six months of the Commission approving the Company's CPCN application in this proceeding. The tracking mechanism will be designed to enable, among other things, an opportunity for the Company to timely recover its costs of deployment (i.e., incremental O&M, return, depreciation, amortization of regulatory assets, and property taxes, net of the O&M savings) for the natural gas portion of the Metering Upgrade, the deferral of natural gas metering infrastructure of the regulatory asset established in this proceeding and will factor in the appropriate level of ongoing Operational Savings attributed to reductions in meter reading and other O&M expense that is allocable to natural gas metering operations and attributable to the Metering Upgrade as indicated in Confidential Attachment DLS-4. The gas tracking mechanism, which shall be modeled after the Company's Accelerated Service Line Replacement Rider (Rider ASRP), shall continue with annual adjustments and true-ups until the Company's next natural gas base rate case. The initial application shall include deployment costs and any Operational Savings incurred to date and a projection for the remainder of calendar year 2017 and calendar year 2018. Subsequent annual applications will true-up the actual costs from the previous year and adjust for recovery of the remainder of costs incurred during the year. The Gas AMI rider will cease on the day that new base rates, which will include the gas AMI costs and Operational Savings, will be effective. The Company will propose a smooth transition so as to ensure that costs will not be double recovered and Operational Savings credited are not double counted. The Attorney General agrees that it will support the establishment of the rider mechanism as contemplated in this Stipulation, but reserves the right to support or oppose other aspects of the filing that are yet to be established, such as rate design, return, etc.

5. **Customer Opt-Out Program**. The Parties agree that Duke Energy Kentucky shall implement an Electric AMI Opt-Out Program Tariff for residential customers to be effective at the time of initial AMI deployment. The Opt-Out Program Tariff, included as Appendix A to this Stipulation, includes recovery of fixed and ongoing costs of providing residential customers a voluntary Electric AMI Opt-Out Program. The costs that will initially be established under the rider are as follows:

a. A one-time initial set-up fee of $100; and

b. $25.00 per month ongoing charge for manual meter reading.

To assure customers have multiple opportunities to become aware of the Metering Upgrade project and installation of an AMI meter, Duke Energy Kentucky will include a bill insert for all electric customers notifying them of the Metering Upgrade program and the installation of an AMI meter within the next 18 months. Secondly, this will be followed up with a direct mail postcard via United States Postal Service to the billing address notifying the customer of the Metering Upgrade program and the installation of an AMI meter starting in the following two weeks period. Each of these written notifications will include Company contact information regarding the Metering Upgrade and Opt-Out Program. And thirdly, on the day of the meter installation, the meter installation technician will attempt to make personal notification to customer if they are on site.

Subject to Commission approval of this Opt-Out Program, and during the Metering Upgrade project deployment phase, if prior to the installation of an AMI meter at a customer's premise, any existing residential electric customer elects to participate in the Opt-Out Program, Duke Energy Kentucky will not charge the one-time set-up fee, if the residential electric customer notifies the Company of such election before an AMI meter is installed under this Metering Upgrade. However, those residential customers electing to participate in the Residential Opt-Out Program will still be subject to the $25.00 per month ongoing charge. Following deployment completion, any residential customer who elects to participate in the Opt-Out Program will be assessed the one-time $100 set-up fee in addition to the ongoing monthly charge.

Any costs that are not fully recovered by the Opt-Out Program Tariff for providing the ongoing Opt-Out Program shall be eligible for recovery in Duke Energy

Kentucky's base rates. The Company reserves the right to update the Opt-Out Program Tariff in future electric base rate proceedings if levels of participation change or if actual costs differ from the estimated costs caused by customers electing the Opt-Out. Duke Energy Kentucky shall have the burden of proof for recovery of these costs and will support such costs with a detailed and itemized schedule.

The Parties acknowledge that the provision of an Opt-Out Program was not included in the Company's application and thus is not reflected in the Company's cost-benefit analysis or deployment costs. The incremental non-recurring O&M costs for the information technology solution required to enable this Opt-Out Program is estimated to be an additional $140,000. The Parties agree that Duke Energy Kentucky should be permitted to defer these costs for future base rate recovery. The accounting for this deferral would be to create a Regulatory Asset Account 182.3 and to credit the relevant O&M expenses to be deferred.

The Parties further acknowledge that the creation of the Opt-out Program will have an impact on the Company's cost benefit analysis and the benefits projected. The Parties agree that such incremental costs shall not be considered as cost-over runs and that any savings that cannot be achieved as a result of the Opt-Out Program implementation shall be factored into any base rate case pro-forma adjustments discussed above.

Additionally, the Company shall have the right to refuse or to terminate a customer's participation in the Residential Opt-Out Program in either of the following circumstances:

a. If providing such a service creates a safety hazard to consumers, their premises, the public or the electric utility's personnel or facilities; or

b. If a customer does not allow the electric utility's employees or agents access to the meter at the customer's premises for maintenance, connection/disconnection, or regular meter-reading.

6. **Residential Peak Time Rebate Pilot and Mandatory Residential Demand-Based Charges.**

a. No later than six months from completion of the Metering Upgrade Deployment, Duke Energy Kentucky commits to design and propose for Commission review and approval, a Residential Peak-Time Rebate Voluntary Pilot (PTR Pilot). The intent of the PTR Pilot will be to collect the information from voluntary participants needed to properly evaluate the potential addition of a Peak-Time Rebate program that could be made available to all eligible residential customers. The PTR design to be tested will provide an after-the-fact bill credit to participating residential customers who, after advance notice by the Company, are able to actually lower their energy consumption from that of a defined consumption baseline in response to, and during, defined pricing "events" throughout the year. The yet-to-be determined bill credit will be designed on a cents per kWh basis. Participating customers who do not lower their consumption during those periods will not earn the rebate credit.

So to avoid any negative earnings impacts to Duke Energy Kentucky during the PTR Pilot period, the PTR Pilot shall be designed and approved as a complementary program to the Company's existing energy efficiency and demand response portfolio of programs and shall be vetted through Duke Energy Kentucky's Residential Demand Side

Management (DSM) Collaborative process, of which the Attorney General is a member. Upon Collaborative approval, the PTR Pilot will be filed for Commission review and approval as part of one of the Company's annual DSM portfolio filings. Should the expiration of the six months from completion of the Metering Upgrade deployment not coincide in such a way that the Company can include the PTR Pilot as part of its annual DSM portfolio update filing currently made on or about August 15th, annually, the Company shall file for approval of the PTR Pilot as a separate application.

Upon Commission approval, the incremental costs of developing, and operating the PTR Pilot, as well as any lost fixed revenues, shall be recoverable through Duke Energy Kentucky's annual Rider DSM adjustments so as to prevent any possible erosion of the Company's lost fixed revenues. The PTR Pilot shall be excluded from the shared savings incentive mechanism calculation computed in the annual Rider DSM.

The initial PTR Pilot shall be conducted for a two-year period and will be limited to the first one thousand (1,000) eligible residential customers that enroll in the program for the opportunity to earn rebates by reducing usage during event periods. The PTR Pilot design phase shall also include a recommended marketing plan with annual caps on spending that will be presented to the DSM Collaborative. Duke Energy Kentucky shall market the program to all eligible residential customers for the duration of the program pilot until it is fully subscribed. Eligibility terms and conditions for the pilot will be determined during the pilot design phase. As part of the registration/application process for interested residential customers, the Company will include a self-identification that indicates whether a participating customer has a programmable thermostat. At the conclusion of the two-year pilot period, enrollment will be closed at the existing level and no new customers will added so that Duke Energy Kentucky can have an independent evaluation, measurement and verification (EM&V) study performed to determine the cost-effectiveness and participation results of the PTR Pilot.

Prior to the PTR pilot commencing, the independent third party EM&V evaluator selected shall provide a detailed presentation to Duke Energy Kentucky's DSM Collaborative on the topics of the EM&V protocols and methodologies to be used as well as feedback related to the pilot design. After completion of the pilot, the evaluator will review the pilot results with the DSM Collaborative. In addition to these formal recommendations, the EM&V report will discuss, among other things, the following questions:

- Did the chosen bill credit motivate behavior change?
- Were customers properly identified for the bill credit and paid accordingly?
- Was the marketing campaign successful?
- Were customers effectively educated and motivated to use the program?
- Did event notifications reach the customer such that they could effectively respond to the event?
- What reasonable enhancements, if any, could be made cost effectively to continue the PTR Program?

Duke Energy Kentucky shall submit the results of the EM&V study to the Commission along with recommendations regarding the continuation of the PTR program, the cost effectiveness of the PTR, whether the PTR program participation limitation should be expanded to additional eligible residential customers and small commercial tariffs , whether any reasonable enhancements that should be made to the program for such expansion and cost-effectiveness, or whether it should simply be terminated.

b. Duke Energy Kentucky commits that, unless ordered by the Commission or otherwise required by law, it will not implement a mandatory default residential charge based upon monthly kilowatt demand for at least six years following Commission approval of this Stipulation and Recommendation. This commitment does not foreclose the Company from seeking approval of any voluntary demand-based rates.

7. **Customer Data**. Duke Energy Kentucky commits to allow its customers to have access to their own usage information as part of the Metering Upgrade through the Company's web portal. Customers with AMI devices will have access to interval usage data that the customer will be able to download at regular intervals, which the customer is free to provide to third parties at the customer's discretion. Additionally, Duke Energy Kentucky agrees that at its sole discretion, such discretion not to be unreasonably withheld, it will provide non-customer specific usage data in aggregate form and within reasonable parameters in terms of frequency and format, upon request, to governmental and educational agencies provided such information is solely for educational or research purposes. Duke Energy Kentucky commits to continue developing additional products and to engage customers around their energy consumption.

8. **Annual and Semi-Annual Reporting:** During deployment, and for three years following completion of deployment, Duke Energy Kentucky agrees to provide annual reporting to the Attorney General and the Commission regarding the development and implementation of products and services designed to engage Duke Energy Kentucky's customers around energy consumption. This annual reporting shall include, but is not limited to, the development of Company portal enhancements, flexible billing

programs, and other payment programs. The Company commits to making a monthly usage alert program as described on page 10 of Company witness Weintraub's testimony in this Case as soon as practicable following completion of deployment. .

During deployment and continuing for one year from completion of deployment, Duke Energy Kentucky agrees to provide periodic reporting in six month increments regarding the progress of deployment. This semi-annual reporting shall identify the costs incurred during deployment and as contained in and compared to the projected cost benefit analysis submitted in this case. Duke Energy Kentucky shall also report on various non-financial metrics of benefits that have been achieved during deployment, with context given in terms of percentages of totals, including:

- Number of electric meters installed;
- Number of gas modules installed;
- Number of grid routers installed;
- Number of meter reading routes;
- Failure rate of electric meters;
- Remote routine electric and gas meter reads;
- Remote electric meter disconnection (non-pay);
- Remote connection (non-pay); and
- Remote Read-in/Read-out.

The annual and semi-annual reporting described above shall be filed in written form in this case as part of the post case correspondence.

9. **Utility Reconnection Charges**. Duke Energy Kentucky agrees that in its next base rate proceeding(s), the Company will include a revision to its reconnection

charges to reflect the then-current actual costs, reflecting the availability of the remote disconnection and reconnection technology for electric customers who have advanced meters and have not opted-out.

10. **Future Smart Grid Investments.** Consistent with the Commission's April 13, 2006 Order in Case No. 2012-00428, Duke Energy Kentucky commits that for any future "major AMR or AMI meter investments, distribution grid investments for DA" [Distribution Automation] or "SCADA or volt/var resources" that require a CPCN, the Company will include a detailed cost-benefit analysis similar to what was submitted in this case.[3]

11. **Commission Approval.** The Parties to this Stipulation shall act in good faith and use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. Each Party hereto waives all cross-examination of the witnesses of the other Party hereto except in support of the Stipulation or unless the Commission fails to adopt this Stipulation in its entirety. Each Party further stipulates and recommends that the Application, Exhibits, direct testimony, rebuttal testimony, pleadings and responses to data requests filed in this proceeding be admitted into the record. The Parties further agree and intend to support the reasonableness of this Stipulation before the Commission and to cause their counsel to do the same in this proceeding and in any appeal from the Commission's adoption and/or enforcement of this Stipulation. If the Commission issues an order adopting this Stipulation in its entirety, each of the Parties hereto agrees that it shall file neither an application for rehearing with

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[3] *See In the Matter of Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky.PSC April 13, 2016) at 11 and 30.

the Commission, nor an appeal to the Franklin County Circuit Court with respect to such order.

12. **Effect of Non-Approval.** If the Commission does not accept and approve this Stipulation in its entirety or imposes any additional conditions or requirements upon the signatory Parties, then:

a. Either Party may elect, in writing docketed in this proceeding, within ten days of such Commission Order, that this Stipulation shall be void and withdrawn by the Parties hereto from further consideration by the Commission and none of the Parties shall be bound by any of the provisions herein;

b. Each Party shall have the right, within twenty days of the Commission's order, to file an application for rehearing, including a notice of termination of and withdrawal from the Stipulation; and

c. In the event of such termination and withdrawal of the Stipulation, neither the terms of this Stipulation nor any matters raised during the settlement negotiations shall be binding on any of the signatory Parties to this Stipulation or be construed against any of the signatory Parties. Should the Stipulation be voided or vacated for any reason after the Commission has approved the Stipulation and thereafter any implementation of the terms of the Stipulation has been made, then the Parties shall be returned to the *status quo* existing at the time immediately prior to the execution of this Stipulation.

12. **Commission Jurisdiction.** This Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

13. **Successors and Assigns.** This Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

14. **Complete Agreement.** This Stipulation constitutes the complete agreement and understanding among the Parties hereto, 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 this Stipulation.

15. **Implementation of Stipulation.** For the purpose of this Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a just and reasonable resolution of the issues herein and are the product of compromise and negotiation. 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 Duke Energy Kentucky are unknown and this Stipulation shall be implemented as written.

16. **Admissibility and Non-Precedential Effect.** 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.

17. **No Admissions.** Making this Stipulation shall not be deemed in any respect to constitute an admission by any Party hereto that any computation, formula, allegation, assertion or contention made by any other Party in these proceedings is true or valid. Nothing in this Stipulation shall be used or construed for any purpose to imply,

suggest, or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of a Party.

18. **Authorizations.** The signatory Parties hereto warrant that they have informed, advised, and consulted with the respective Parties hereto in regard to the contents of the stipulation, and based upon the foregoing, are authorized to execute this Stipulation on behalf of the Parties hereto.

19. **Commission Approval.** This Stipulation is subject to the acceptance of and approval by the Commission.

20. **Interpretation of Stipulation.** 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.

21. **Counterparts.** This Stipulation may be executed in multiple counterparts.

22. **Future Proceedings.** Nothing in this Stipulation shall preclude, prevent or prejudice any Party hereto from raising any argument/issue or challenging any adjustment in any future natural gas rate case proceeding of Duke Energy Kentucky.

IN WITNESS WHEREOF, this Stipulation has been agreed to effective this _____ day of December 2016. By affixing their signatures below, the undersigned Parties respectfully request the Commission to issue its Order approving and adopting this Stipulation the Parties hereto have hereunto affixed their signatures.

DUKE ENERGY KENTUCKY, INC.

By: ______________________
Rocco D'Ascenzo
Title: Associate General Counsel

ATTORNEY GENERAL OF THE
COMMONWEALTH OF KENTUCKY

By: ______________________
Hon. Lawrence Cook
Title: Assistant Attorney General,
Office of Rate Intervention

RIDER AMO

ADVANCED METER OPT-OUT (AMO) – RESIDENTIAL

APPLICABILITY

Applicable to residential customers served under Rate RS who request an electric meter that does not utilize radio frequency communications to transmit data provided that such a meter is available for use by the Company. At the Company's option, meters to be read manually may be either an advanced meter with the radio frequency communication capability disabled or other non-communicating meter. The meter manufacturer and model chosen to service the customer's premise are at the discretion of the Company and are subject to change at the Company's option, at any time. Rider AMO is optional and is available subject to the Terms and Conditions below.

DEFINITION

"Advanced meter" means any electric meter that meets the pertinent engineering standards using digital technology and is capable of providing two-way communications with the electric utility to provide usage and/or other technical data.

CHARGES

Residential customers who elect, at any time, to opt-out of the Company's advanced metering infrastructure (AMI) system shall pay a one-time fee of $100.00 and a recurring monthly fee of $25.00. During the Metering Upgrade project deployment phase, if prior to an advanced meter being installed at a customer premise, any existing residential electric customer that elects to participate in this opt-out program, Duke Energy Kentucky will not charge the one-time set-up fee, providing the residential electric customer notifies the Company of such election in advance of the advanced meter being installed. Those residential customers electing to participate in this residential opt-out program will be subject to the ongoing $25.00 per month ongoing charge. Following deployment completion, any residential customer who later elects to participate in the Opt-Out Program will be assessed the $100 set-up fee in addition to the ongoing monthly charge.

TERMS AND CONDITIONS

The Company shall have the right to refuse to provide advanced meter opt-out service in either of the following circumstances:

(a) If the customer has a history of meter tampering or unauthorized use of electricity at the current or any prior location.
(b) If such a service creates a safety hazard to consumers or their premises, the public, or the electric utility's personnel or facilities.
(c) If a customer does not allow the electric utility's employees or agents access to the meter at the customer's premises for either maintenance, connection/disconnection, or meter-reading.

SERVICE REGULATIONS

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission, as provided by law.

Issued by authority of an Order by the Kentucky Public Service
Commission dated xxxxxx in Case No. 2016-00152.

Issued: December 6, 2016
Effective: August 1, 2017
Issued by James P. Henning, President /s/ James P. Henning

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AG
Exhibit 6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. COMPLAINANT V. KENTUCKY UTILITIES COMPANY, LOUISVILLE GAS AND ELECTRIC COMPANY, KENTUCKY POWER COMPANY, AND DUKE ENERGY KENTUCKY, INC. DEFENDANTS	) CASE NO. 2017-00477

ORDER

On December 21, 2017, Kentucky Industrial Utility Customers, Inc. ("KIUC") filed a formal complaint, on behalf of 18 named customers, against Kentucky Utilities Company ("KU"); Louisville Gas and Electric Company ("LG&E"), operating as an electric and gas utility; Kentucky Power Company ("Kentucky Power"); and Duke Energy Kentucky, Inc. ("Duke Energy"), operating as an electric and gas utility; (collectively, "Defendants"), alleging that their respective rates are no longer fair, just, and reasonable due to the recent enactment of the Tax Cuts and Jobs Act reducing the federal corporate tax rate from 35 percent to 21 percent. The complaint states that the current rates of each of the Defendants were established by the Commission to include recovery of the 35 percent federal corporate tax rate on the equity portion of capital investments, but that as of January 1, 2018, that tax rate is reduced to 21 percent. In addition to requesting rate reductions to reflect the lower tax rate, the complaint alleges that each of the Defendants has on its books deferred taxes which are now in excess of future liability and these excess deferred taxes need to be refunded to ratepayers over the remaining useful life of the property, estimated to be 20 years. In support of its complaint, KIUC filed an affidavit of a consulting accountant recommending revenue reductions for each of the Defendants based on its respective financial figures for the 12 months ended September 30, 2017.

Based on a review of the complaint and being otherwise sufficiently advised, the Commission finds that KIUC has established a *prima facie* case that as of January 1, 2018, the rates of each of the Defendants will no longer be fair, just, or reasonable. Rates must be set at a level to allow a utility to recover all of its reasonable expenses, including taxes, and to provide its shareholders an opportunity to earn a fair return on invested capital. Since ratepayers are required to pay through their rates the tax expenses of a utility, any reduction in tax rates must be timely passed through to ratepayers. Since the tax rate reduction is effective January 1, 2018, and the Commission's ratemaking authority is prospective in nature, each of the Defendants should record a deferred liability starting January 1, 2018, to reflect both the reduced federal corporate tax rate expense of 21 percent and the excess deferred accumulated income taxes to be returned to ratepayers over the next 20 years.

While the exact amount of the tax savings and resulting rate reductions cannot be determined with precision at this time, each of the Defendants should use its best estimate to determine the amount to be recorded as a deferred liability, subject to review and adjustment as part of this case. This is the same procedures followed by utilities in Kentucky when they seek approval of deferred assets before the final amounts are known with certainty. Rate cases were recently concluded for KU and LG&E, and rate cases are now ongoing for Kentucky Power and Duke Energy. Thus, the issues to be addressed in this complaint case are properly limited to the savings resulting from the January 1, 2018, tax reduction, the appropriate level of deferred liabilities to be recorded on an interim basis to reflect the reduced federal corporate tax rate, and the appropriate level of reductions in utility rates to reflect the reduced federal corporate tax rate.

Finally, KU, LG&E, Kentucky Power, and Duke Energy are hereby notified that they have been individually named as Defendants in a formal complaint filed on December 21, 2017, a copy of which is attached as the Appendix to this Order.

IT IS THEREFORE ORDERED that:

1. Pursuant to 807 KAR 5:001, Section 20, KU, LG&E, Kentucky Power, and Duke Energy shall satisfy the matters complained of or file a written answer to the complaint within ten days from the date of service of this Order.

2. KU, LG&E, Kentucky Power, and Duke Energy shall commence recording deferred liabilities on their respective books for electric and gas service, as applicable, to reflect the reduction in the federal corporate tax rate to 21 percent and the associated savings in excess deferred taxes on an interim basis until utility rates are adjusted to reflect the federal tax savings.

Should documents of any kind be filed with the Commission in the course of this proceeding, the documents shall also be served on all parties of record. A party filing a paper containing personal information shall, in accordance with 807 KAR 5:001, Section 4(10), encrypt or redact the paper so that personal information cannot be read.

By the Commission

ENTERED

DEC 27 2017

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

for Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00477 DATED DEC 2 7 2017

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VIA OVERNIGHT MAIL

RECEIVED
DEC 21 2017
PUBLIC SERVICE COMMISSION

December 20, 2017

Gwen R. Pinson, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: *Kentucky Industrial Utility Customers, Inc., Complainant vs. Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company and Duke Energy Kentucky, Inc., Defendants,* Case No. 2017-00477

Dear Ms. Pinson:

Please find enclosed the original (unbound) and ten (10) copies of KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC's COMPLAINT AND PETITION FOR THE ESTABLISHMENT OF A REGULATORY LIABILITY TO PROVIDE CONSUMERS A RATE REDUCTION BECAUSE OF TAX EXPENSE SAVINGS for filing in the above-referenced matter.

By copy of this letter, all parties listed on the Certificate of Service have been served. Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service
Richard Raff, Esq. (via email)
Quang Nyugen, Esq. (via email)

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by electronic mail (when available) or by regular, U.S. mail, unless otherwise noted, this 20th day of December, 2017 to the following:

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.

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Stoll Keenon Ogden, PLLC
2000 PNC Plaza
500 W Jefferson Street
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139 East Fourth Street
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Lexington, KY 40507

Kentucky Power Company
1 Riverside Plaza
Columbus, OH 43215-2372

Louisville Gas and Electric
220 West Main Street
Louisville, KY 40202

Duke Energy Kentucky, Inc.
139 East 4th Street
ATTN: Teri O'Neill EA025
Cincinnati, OH 45202

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
DEC 21 2017
PUBLIC SERVICE COMMISSION

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.	:	
Complainant	:	
v.	:	**Case No. 2017-** 00477
KENTUCKY UTILITIES COMPANY	:	
LOUISVILLE GAS AND ELECTRIC COMPANY	:	
KENTUCKY POWER COMPANY	:	
DUKE ENERGY KENTUCKY, INC.	:	
Defendants	:	

COMPLAINT AND PETITION FOR THE ESTABLISHMENT OF A REGULATORY LIABILITY TO PROVIDE CONSUMERS A RATE REDUCTION BECAUSE OF TAX EXPENSE SAVINGS

INTRODUCTION

Pursuant to KRS 278.260, KRS 278.270, KRS 278.040, KRS 278.030 and 807 KAR 5:001 Section 20, Kentucky Industrial Utility Customers, Inc. ("KIUC" or "Complainant") submits this Complaint against Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company, and Duke Energy Kentucky, Inc. (collectively, "Defendants") to the Kentucky Public Service Commission ("Commission"). Complainant submits that because of the tax expense savings that

Defendants will almost certainly receive from the Tax Cuts and Jobs Act,[1] Defendants' rates will no longer be fair, just, and reasonable beginning January 1, 2018.[2]

Effective January 1, 2018, the Tax Cuts and Jobs Act will lower the maximum federal corporate income tax rate from 35% to 21%. This reduction in federal corporate income tax expense is not currently reflected in Defendants' tariff rates, including, but not limited to, their base rates, environmental surcharges, and demand-side management surcharges. Based upon per books financial information for the twelve months ending September 30, 2017, Complainant estimates that the rates of the Defendants should be reduced by $209 million or more annually. Attachment A.[3] The calculations in Attachment A are supported by the Affidavit of Mr. Lane Kollen.

Complainant petitions the Commission for an order: 1) requiring each Defendant to begin deferring as of January 1, 2018 the revenue requirement effect of all income tax expense savings resulting from the federal corporate income tax reduction, including the amortization of excess accumulated deferred income taxes, by recording those savings in a regulatory liability account; and 2) establishing a process by which Defendants' federal corporate income tax savings will be passed back to all retail customers. Although it will vary by utility, we estimate that the rate reductions sought by this Complaint will average 4% – 7%. In support of its request, Complainant states as follows:

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[1] The bill's long title is *"An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018."*

[2] The Tax Cuts and Jobs Act was passed by the both the United States Senate and House of Representatives on December 20, 2017. In a formal White House ceremony, President Trump confirmed his intent to sign the bill into law as soon as possible. But President Trump cannot presently sign the bill before the end of this year without triggering automatic spending cuts to Medicare and other spending categories under the so-called PAYGO law unless he receives a Congressional waiver. Therefore, the White House has stated that the formal signing by the President may not occur until early 2018.

Because this issue and its expeditious resolution are of utmost importance to customers in Kentucky, KIUC has chosen to submit this Complaint now. Should the Commission determine that KIUC's Complaint does not establish a prima facie case because of this formality, then KIUC will amend this Complaint in accordance with 807 KAR 5:001, Section 20(4)(a).

[3] Kentucky Utilities Company and Louisville Gas & Electric Company received rate increases earlier this year. Kentucky Power Company and Duke Energy Kentucky, Inc. both have pending rate increases. The rate increases granted will substantially increase annualized income and income tax expense compared to the per books expense for the twelve months ending September 30, 2017. This will increase the rate reductions shown in Attachment A.

BASES FOR THE COMMISSION'S JURISDICTION

1. The Kentucky Public Service Commission has jurisdiction and venue to hear this complaint under KRS 278.260, KRS 278.270, KRS 278.040, KRS 278.030 and 807 KAR 5:001, Section 20.

PARTIES

2. The Complainant is a non-profit Kentucky corporation. The members of Complainant who purchase utility services from the Defendants are: AAK, USA K2, LLC, Air Liquide Industrial U.S. LP, Air Products and Chemicals, Inc., Airgas, USA, LLC, AK Steel Corporation, Alliance Coal, LLC, Carbide Industries LLC, Catlettsburg Refining LLC, a subsidiary of Marathon Petroleum LP, Cemex, Clopay Plastic Products Co., Inc., Corning Incorporated, Dow Corning Corporation, Ford Motor Company, Ingevity, North American Stainless, Schneider Electric USA, The Chemours Company and Toyota Motor Manufacturing, Kentucky, Inc. The corporate office address of the Complainant is as follows:

   36 East Seventh Street, Suite 1510
   Cincinnati, OH 45202

3. Counsel for Complainant is:

   Michael L. Kurtz, Esq.
   Kurt J. Boehm, Esq.
   Jody Kyler Cohn, Esq.
   Boehm, Kurtz & Lowry
   36 East Seventh Street, Suite 1510
   Cincinnati, Ohio 45202
   Ph: 513.421.2255; Fax: 513.421.2764
   mkurtz@BKLlawfirm.com
   kboehn@BKLlawfirm.com
   jkylercohn@BKLlawfirm.com

4. Defendant Kentucky Utilities Company is a utility as defined in KRS 278.010(3), and a subsidiary of PPL Corporation, subject to the jurisdiction of the Public Service Commission. PPL Corporation's office address is as follows:

   2 N. Ninth Street
   Allentown, PA 18101-1179

Kentucky Utilities Company's office address is:

1 Quality Street
Lexington, KY 40507

5. Counsel for Defendant Kentucky Utilities Company is:

Kendrick R. Riggs
Stoll Keenon Ogden, PLLC
2000 PNC Plaza, 500 W Jefferson Street
Louisville, KY 40202-2828

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

6. Defendant Louisville Gas and Electric Company is a utility as defined in KRS 278.010(3), and a subsidiary of PPL Corporation, subject to the jurisdiction of the Public Service Commission. PPL Corporation's office address is as follows:

2 N. Ninth Street
Allentown, PA 18101-1179
Louisville Gas and Electric's office address is:

220 West Main Street
Louisville, KY 40202

7. Counsel for Defendant Louisville Gas and Electric Company is:

Kendrick R. Riggs
Stoll Keenon Ogden, PLLC
2000 PNC Plaza, 500 W Jefferson Street
Louisville, KY 40202-2828

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

8. Defendant Kentucky Power Company is a utility as defined in KRS 278.010(3), and a subsidiary of American Electric Power, subject to the jurisdiction of the Public Service Commission. American Electric Power's office address is as follows:

1 Riverside Plaza
Columbus, OH 43215-2372

Kentucky Power Company's office address is:

1 Riverside Plaza
Columbus, OH 43215-2372

9. Counsel for Defendant Kentucky Power Company is:

Mark R. Overstreet
Stites & Harbison
421 West Main Street, P. O. Box 634
Frankfort, KY 40602

Kenneth J. Gish, Jr.
Stites & Harbison
250 West Main Street, Suite 2300
Lexington, KY 40507

Hector Garcia
American Electric Power Service Corp.
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215-237

10. Defendant Duke Energy Kentucky, Inc. is a utility as defined in KRS 278.010(3) subject to the jurisdiction of the Public Service Commission whose office address is as follows:

139 East 4th Street
ATTN: Teri O'Neill EA025
Cincinnati, OH 45202

11. Counsel for Defendant Duke Energy Kentucky, Inc. is:

Amy B. Spiller, Associate General Counsel
Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45201

Rocco O D'Ascenzo
Duke Energy Kentucky, Inc.
139 East Fourth Street
Cincinnati, OH 45201

BACKGROUND

12. On December 20, 2017, the Tax Cuts and Jobs Act was passed by both the United States Senate and House of Representatives.

13. President Trump has confirmed his intent to sign the bill into law either in late 2017 or early 2018.

14. The procedural formalities for a potential delay in signing were explained in footnote 2 of this Complaint.

15. The Tax Cuts and Jobs Act will lower the maximum federal corporate income tax rate from 35% to 21% effective January 1, 2018.

16. Defendants currently recover federal corporate income tax expenses at the 35% rate through tariff rates charged to the utility customers in their service territories, including, but not limited to, base rates, environmental surcharges, and demand-side management surcharges.

17. The federal corporate income tax expenses currently recovered from utility customers through Defendants' tariff rates do not reflect the lower federal corporate income tax rate established under the Tax Cuts and Jobs Act that will be effective on January 1, 2018. Complainant estimates that implementation of the new federal tax rate will lower the revenue requirements of the Defendants by $209 million or more annually. The estimated annual revenue requirement reduction for each of the Defendants is listed in Paragraph 33. Although it will vary by utility, we estimate that the rate reductions sought in this Complaint will average 4% – 7%.

BASES FOR COMPLAINANT'S CLAIMS

18. KRS 278.030(1) provides that Kentucky utilities *"may demand, collect and receive fair, just and reasonable rates for the services rendered or to be rendered by it to any person."*

19. Requiring Complainant's members in Defendants' service territories to pay the currently applicable tariff rates, which do not reflect income tax expense savings resulting from the lowered federal corporate income tax rate, would result in unfair, unjust, and unreasonable rates in violation of KRS 278.030(1).

20. The cost savings resulting from the Tax Cuts and Jobs Act that are not currently reflected in Defendants' rates include both: 1) lower income tax expense; and 2) an amortization of "*excess*" accumulated deferred income taxes ("ADIT").

21. Income tax expense is calculated in the ratemaking process by "*grossing up*" the equity component of the utility's rate of return for income taxes. This ensures that the utility has the opportunity to earn its after-tax authorized return on equity. For example, for a utility to earn an authorized 10% after-tax return on equity at the 35% federal tax rate, the utility will charge customers the pre-tax cost of 15.40% (10%/(1-.35). For a utility to earn an authorized 10% after-tax return on equity at the 21% federal tax rate, the utility needs to charge customers the pre-tax cost of 12.66% (10%/(1-.21). This example does not include the gross-up for state corporate income taxes. Because the federal income tax expense will be reduced from 35% to 21%, Defendants' income tax expense will be reduced through a reduction in the equity gross-up.

22. ADIT is the difference between the amount of tax recovered in rates and the amount of tax actually paid by the utility to the federal government. Because of accelerated and bonus depreciation, the amount of tax actually paid by the utility is generally less than the taxes recovered from ratepayers in the early years of a new asset's life. If the income tax rate remains the same in future years, then over time, the process is reversed and the cumulative tax recovered

from ratepayers (reflected in ADIT) and paid by the utility to the federal government is generally equal over the course of an asset's life. Meanwhile, ratepayers receive a return on this ADIT through a reduction to rate base until the utility pays these amounts to the federal government. If the income tax rate remains the same in future years, then the ADIT is never refunded to ratepayers because the tax is paid to the federal government. However, when the tax rate is lowered from 35% to 21%, a portion of the ADIT will never be paid to the federal government and "*excess*" ADIT is created. Because the excess ADIT will never be paid to the federal government, it must be refunded to customers.

23. In a February, 2013 report entitled "*Comprehensive Tax Reform Priorities: Excess Deferred Tax Transition Issues,*" the Edison Electric institute agreed with Complainant's characterization of the excess ADIT issue, stating: "*One of these transition issues is the treatment of so-called excess deferred taxes. Many companies may have excess deferred tax reserves after a federal income tax rate reduction because the change in law requires a recalculation of deferred tax liabilities. However, unlike other companies that would recognize excess deferred taxes as income, regulated shareholder-owned electric utilities are required to refund excess deferred taxes, related to asset depreciation, to their customers...When a tax rate reduction creates excess deferred taxes, all companies must account for the excess. A non-regulated company generally would recognize the excess deferred taxes as income for financial statement purposes. However, an electric utility must refund the excess deferred taxes to ratepayers, requiring the recording of a regulatory liability.*" Attachment B.

24. The Commission has previously acted expeditiously to lower utility rates in light of a federal corporate income tax rate reduction, as it did in response to the Tax Reform Act of 1986.[4] The Tax Reform Act of 1986 lowered the federal corporate income tax rate from 46% to 34%.

25. In the Tax Reform Act of 1986 cases, the Commission held that it *"does not view retaining the savings that result from tax reform as a proper way for a utility to improve its earnings. Likewise, if the Tax Reform Act should result in major cost increases, these costs should be recognized in rates expeditiously."*[5]

26. The Commission also explained that *"[b]ecause the Tax Reform Act represents such a historic change in federal tax policy....it was in the best interests of all concerned--utilities and ratepayers alike--to reflect these tax changes in each company's rates as expeditiously as possible."*[6]

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[4] *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Kentucky Utilities Company*, Case No. 9780 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Louisville Gas and Electric Company*, Case No. 9781 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Kentucky Power Company*, Case No. 9779 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Kentucky-American Water Company*, Case No. 9815 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Union Light, Heat and Power Company - Electric*, Case No. 9782 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Union Light, Heat and Power Company - Gas*, Case No. 9788 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Western Kentucky Gas Company*, Case No. 9789 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Delta Natural Gas Company*, Case No. 9785 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of South Central Bell Telephone Company*, Case No. 9803 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Continental Telephone Company of Kentucky*, Case No. 9799 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of ALLTEL Kentucky*, Case No. 9796 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Thacker-Grigsby Telephone Company, Inc.*, Case No. 9804 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Brandensorg Telephone Company, Inc.*, Case No. 9797 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Harold Telephone Company, Inc.*, Case No. 9801 (June 11, 1987); *In the Matter of the Effects of the Federal Tax Reform Act of 1986 on the Rates of Leslie County Telephone Company, Inc.*, Case No. 9802 (June 11, 1987).

[5] *Id.*

[6] *Id.*

27. The Commission's chosen resolution in the Tax Reform Act of 1986 cases was to make one-time adjustments lowering the revenue requirements of major utilities (those with revenues in excess of $1 million) by an amount in excess of $75 million.[7]

28. In 1986, Kentucky was not alone in taking action to reduce utility rates to reflect the lower tax expense. According to Regulatory Research Associates, "*About 40 of the 50 jurisdictions then covered by RRA initiated generic proceedings to address the impacts of the lower tax rates…*" Attachment C.

29. The Commission has also previously ordered utilities to defer certain rate components to be considered for future recovery.[8]

30. Such Commission-ordered deferrals have included anticipated cost savings that could ultimately be passed on to customers.[9]

31. The Commission has explained that deferral authority may be granted "*when a utility has incurred: (a) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (b) an expense resulting from a statutory or administrative directive; (c) an expense in relation to an industry-sponsored initiative: or (d) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.*"[10]

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[7] *Id.*

[8] *In the Matter of the Application of Big Rivers Electric Corporation for an Adjustment of Rates,* Case No. 2012-00535 (October 29, 2013); *In the Matter of the Application of Big Rivers Electric Corporation for a General Adjustment in Rates Supported by Fully Forecasted Test Period,* Case No. 2013-00199 (April 25, 2014); *In the Matter of the Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with Two 2015 Major Storm Events,* Case No. 2016-00180 (November 3, 2016).

[9] *In the Matter of the 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 an Acquisition of Ownership and Control of Utilities,* Case No. 2010-00204 (September 30, 2010).

[10] *In the Matter of the Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with Two 2015 Major Storm Events,* Case No. 2016-00180 (November 3, 2016).

32. At least two of those criteria apply here. First, the reduction in federal corporate income tax rates resulting from the Tax Cuts and Jobs Act is *"extraordinary," "nonrecurring,"* and *"could not have reasonably been anticipated or included in the utility's planning."* Second, the tax savings stemming from the Tax Cuts and Jobs Act result from a federal statutory directive.

33. There is no legal constraint on the Commission's authority to act upon this Complaint. On the contrary, the Kentucky Supreme Court has expressly recognized the Commission's authority to reflect single issues in rates so long as the end result is fair, just, and reasonable rates. *"In fact, we find nothing in the statutes that would prohibit 'single-issue ratemaking'"* Kentucky Pub. Serv. Comm'n v. Com. ex rel. Conway, 324 S.W.3d 373, 382 (Ky. 2010). *"...the plain language of KRS 278.190 does not actually require that the PSC proceed with a general rate case or other particular process every time some new rate or change in rates is requested."* Id. at 378. *"While the power to approve the AMRP rider at issue may not have been expressly granted by statute before the enactment of KRS 278.509, we, nonetheless, conclude that the PSC has the power to allow such a rider based upon (1) its plenary ratemaking authority derived from KRS 278.030 and KRS 278.040, which essentially require that the PSC act to ensure that rates are "fair, just and reasonable" and (2) the absence of any statutes specifically requiring a particular procedure when determining if rates are fair, just, and reasonable."* Id. at 380-81.

34. If the Commission were to deny Complainant's request for an immediate deferral of Defendants' federal corporate income tax expense savings, then customers would pay unfair, unjust, and unreasonable rates for an extended period of time before Defendants' rates are altered to reflect the effects of the Tax Cuts and Jobs Act. And because the Commission bars retroactive ratemaking under most circumstances, customers may never be refunded for unfair, unjust, and

unreasonable rates paid during that extended consideration period.[11] This is the primary reason for bringing this matter to the attention of the Commission as soon as possible.

35. Attachment A is a quantification of the probable tax savings to Defendants' customers. Attachment A is based upon per books accounting information for the twelve months ending September 30, 2017. Attachment A includes an assumption that excess ADIT will be amortized over twenty years, which we believe is a reasonable proxy for the remaining useful lives of the utility's assets. Attachment A shows representative annual rate reductions as follows:

Kentucky Utilities Company:	$ 76,088,393 per year
Louisville Gas & Electric Company (gas and electric):	$ 90,690,505 per year
Kentucky Power Company:	$ 25,310,650 per year
Duke Energy Kentucky, Inc. (gas and electric):	$ 17,053,495 per year
TOTAL	$209,143,043 per year

[11] *In the Matter of the Notice of Adjustment of the Rates of Kentucky-American Water Company,* Case No. 92-452 (November 19, 1993).

REQUESTED RELIEF

WHEREFORE, Complainant petitions the Commission for an order: 1) requiring each Defendant to begin deferring as of January 1, 2018 the revenue requirement effect of all cost savings resulting from the federal corporate income tax reduction, including the amortization of excess accumulated deferred income taxes, by recording those savings in a regulatory liability account; and 2) establishing a process by which Defendants' regulatory liability for the deferred federal corporate income tax expense savings will be passed back to retail customers. Complainant requests that the Commission issue an expedited ruling in this matter on or before the January 1, 2018 effective date of new tax rates.

Respectfully submitted,

Michael L. Kurtz, Esq.
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Jody Kyler Cohn, Esq.
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December 20, 2017

COUNSEL FOR KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Attachment A

AFFIDAVIT OF LANE KOLLEN

STATE OF GEORGIA
COUNTY OF FULTON

Before me, the undersigned Notary Public in and for the County of Cobb, State of Georgia, personally came and appeared Lane Kollen, who was sworn by me and attested to the following facts:

1. I am a Vice President and Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia. Kennedy and Associates is an economic consulting firm that provides expert analysis and testimony on issues involving rate regulated electric, gas, water and sewer utilities. I am a Certified Public Accountant, Certified Management Accountant, and Chartered Global Management Accountant. I am a member of numerous professional organizations.

2. I have testified before state and federal regulatory commissions and courts on hundreds of occasions on accounting, tax, ratemaking, planning, and other issues related to regulated electric and gas utilities. I have testified before the Kentucky Public Service Commission ("Commission") on these issues in investor owned and cooperative utility base rate, environmental rate, fuel adjustment clause rate, and other proceedings, including proceedings involving the landmark 1986 federal tax legislation and tax rate reductions from 46% to 34%.

3. I was retained by Kentucky Industrial Utility Customers, Inc. to advise it on the effects of tax legislation pending in the U.S. Congress for much of this year.

4. The President recently signed into law the Tax Cuts and Jobs Act, which provides for a reduction in the federal corporate income tax rate from 35% to 21% effective January 1, 2018. The reduction in the income tax rate will result in significant tax expense savings for the investor owned utilities regulated by the Commission. These tax savings will increase the utilities' earned returns if they are allowed to retain the savings rather than deferring the savings starting January 1, 2018 and/or reducing rates on or after January 1, 2018.

5. Federal income tax expense and the return on accumulated deferred income taxes ("ADIT") are significant components of the revenue requirement for all investor owned utilities regulated by the Commission. Federal income tax expense will decline by 40%, all else equal. In addition, 40% of the ADIT will become "excess," meaning that it no longer will be paid to the federal government at some time in the future. As such, the excess ADIT must be amortized as an additional reduction to income tax expense and returned to customers as an additional reduction to the revenue requirement.

6. I have prepared an estimate of the tax savings resulting from the federal corporate income tax rate reduction and the appropriate reduction in base and rider revenues for Kentucky Utilities Company, Louisville Gas & Electric Company, Kentucky Power Company, and Duke Energy Kentucky, the defendants named in the KIUC Complaint. I used per books public information filed by these utilities with the Federal Energy Regulatory Commission for the twelve months ending September 30, 2017. Counsel for KIUC has attached a summary of these estimates as Attachment A to the KIUC Complaint.

7. The estimates of the tax savings are understated for Kentucky Utilities Company and Louisville Gas &Electric Company because the annualized effect of the rate increases that were authorized earlier this year are not yet reflected in the per books revenues and income tax expense during the twelve months ending September 30, 2017. The estimate of tax savings is understated for Kentucky Power Company because the pending rate increase in Case No. 2017-00179 was not yet implemented during the twelve months ending September 30, 2017. The estimate of tax savings is understated for DEK, if, in fact, the Commission authorizes a base rate increase and environmental surcharge in the pending Case No. 2017-00321 because no increases were implemented during the twelve months ending September 30, 2017.

8. The appropriate rate reductions to reflect the tax savings, even though understated, are more than $200 million annually.

9. Although the tax savings commence on January 1, 2018, they will not automatically be deferred by the utilities as a regulatory liability and rates will not automatically be reduced. The Commission must direct the utilities to defer the revenue requirement effect of the savings until it can determine the necessary base and rider rate reductions and the disposition of the regulatory liabilities.

<u>**AFFIDAVIT OF LANE KOLLEN**</u>

The foregoing testimony is true to the best of my knowledge and belief.

Lane Kollen

State of Georgia)
) SS
County of Fulton)

Sworn to and subscribed before me on this
19th day of December, 2017

Notary Public

RANDY A. FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2020
COBB COUNTY, GEORGIA

State	(A) Data Req./ Study Started	(B) Case-By-Case Action	(C) Rate Cut Made	(D) Mechan-ism in Place	(E) Temp Rates/ Def. Acct.
ALABAMA	X	-	-	X	-
ARIZONA	X	-	-	-	-
ARKANSAS	X	-	X	X	-
CALIFORNIA	X	-	-	-	X
COLORADO	X	-	-	-	-
CONNECTICUT	X	X	-	-	-
DELAWARE	-	X	-	-	-
DIST. OF COL.	X	X	-	-	-
FLORIDA	-	-	X	X	-
GEORGIA	-	-	-	-	-
HAWAII	-	X	-	-	-
IDAHO	X	-	-	-	-
ILLINOIS	X	-	-	-	-
INDIANA	X	-	-	-	-
IOWA	X	-	-	-	-
KANSAS	X	-	-	-	-
KENTUCKY	X	-	-	-	-
LOUISIANA	-	X	X	-	-
MAINE	X	X	-	-	-
MARYLAND	X	X	X	-	-
MASSACHUSETTS	X	-	-	-	-
MICHIGAN	X	X	-	-	-
MINNESOTA	X	-	-	-	-
MISSISSIPPI	-	X	-	X	-
MISSOURI	X	X	X	-	-

State	(A) Data Req./ Study Started	(B) Case-By-Case Action	(C) Rate Cut Made	(D) Mechan-ism in Place	(E) Temp Rates/ Def. Acct.
MONTANA	X	X	-	-	-
NEBRASKA	-	-	-	-	-
NEVADA	X	-	-	-	-
NEW HAMPSHIRE	X	-	-	-	-
NEW JERSEY	X	X	X	-	X
NEW MEXICO/PSC	X	-	-	-	-
NEW MEXICO/SCC	-	-	-	-	-
NEW YORK	X	X	-	-	X
NORTH CAROLINA	X	X	X	-	X
NORTH DAKOTA	X	-	-	-	-
OHIO	X	X	X	-	-
OKLAHOMA	X	-	-	-	-
OREGON	X	X	-	-	-
PENNSYLVANIA	X	X	X	-	X
RHODE ISLAND	X	X	-	-	-
SOUTH CAROLINA	X	X	X	-	-
SOUTH DAKOTA	X	-	-	-	-
TENNESSEE	X	X	X	-	-
TEXAS	X	-	-	-	-
UTAH	X	-	-	-	-
VERMONT	X	X	-	-	-
VIRGINIA	X	X	-	-	-
WASHINGTON	X	-	-	-	-
WEST VIRGINIA	X	-	-	-	-
WISCONSIN	-	X	-	-	-
WYOMING	X	-	-	-	-

A - A TRA study has been initiated or data requested. In some instances studies are informal, while in others task forces have been established.
B - Case-by-case action has been initiated for a major company or has been called for as a result of the TRA.
C - One or more companies have reduced rates or is slated to do so as a result of recognition of TRA savings.
D - A tax adjustment mechanism is in place for one or more companies.
E - Rates have been declared temporary, interim or subject to refund, or accrual accounting required for part or all of TRA amounts.

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REGULATORY FOCUS

RRA

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REGULATORY STUDY
July 6, 1987

TAX REFORM ACT OF 1986--STATE-BY-STATE RESPONSE

The RRA Staff has reviewed actions taken by the utility regulatory commissions in 49 states and the District of Columbia as a result of the Tax Reform Act of 1986 (TRA). In making this review we attempted to determine whether studies had been conducted by the commissions and to what extent rate changes have been implemented or accounting for TRA impacts have been required. This study, completed July 2, 1987, is a follow-up to our initial study published February 14, 1987. In the course of this review, which is comprehensive but is not represented as all-encompassing, we determined that four states have tax adjustment mechanisms in place that impact one or more companies. We also ascertained that several utilities have implemented or have been authorized specific rate changes or depreciation adjustments to counter-balance the impact of the TRA. In most general rate cases completed in recent months recognition was given to the impact of the TRA, thereby eliminating the need for separate single-issue treatment. Verbal descriptions of the Commission, Staff, or company actions taken in each state with regard to the TRA are contained in the paragraphs that follow. For additional information concerning developments in a particular state, please refer to the FOCUS NOTES references given within this report or to those contained in the July 6, 1987 Regulatory Focus Index.

ALABAMA--The largest utilities in the state, Alabama Power, Alabama Gas, and South Central Bell Telephone, each has a Rate Stabilization and Equalization (RSE) provision in effect which provides for periodic adjustments to revenues based on the achievement of certain earned return on equity levels. Additionally, the tariffs of the major energy utilities include adjustment provisions to allow for reflection in customer rates of changes in income tax rates. Any tax impacts not covered through the tax riders for the energy companies are expected to be reflected through the RSE provisions. (For additional information concerning the RSE provisions of the companies see pages 3 through 5 of the November 1986 Alabama Annual Review.) The PSC has directed that a task force be established to review the potential impacts of the TRA, with the probable impacts on the telephone companies expected to receive the closest attention since telephone rates do not now contain a tax rider.

ARIZONA--The Staff of the Arizona Corporation Commission (ACC) is holding informal workshops with companies to discuss the effects of the TRA. Arizona Public Service, Southwest Gas, and AT&T Communications have rate petitions pending before the ACC in which the companies have reflected the revenue requirment impact of the TRA.

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ARKANSAS--On August 28, 1986, the Arkansas Public Service Commission (PSC) approved Rate Rider M38 for Arkansas Power & Light (AP&L), a subsidiary of Middle South Utilities. The M38 Rider, as proposed by AP&L, and adopted by the PSC, was designed to reflect the estimated annual reduction in AP&L's revenue requirement as a result of then pending tax reform legislation. The M38 adjustment was based upon a 33% corporate tax rate, effective January 1, 1987, with any deviations from that tax rate or effective date to be reflected in a true-up to be conducted in August 1987. The M38 Rider provides for AP&L to refund, over a four-year period, that portion of its accumulated deferred income tax balance which exceeds the balance required under revised tax rates, where not prohibited by law. Additionally, the PSC initiated a docket requiring all jurisdictional utilities (except cooperatives) to file information and tariffs reflecting the impact of the TRA. Companies were asked to use a recent rate case test year or the data contained in the annual reports as filed with the PSC. The calculations were to reflect the corporate tax rate reduction from 46% to 34% and the refunding, over a two-year period, of the non-depreciation-related excess deferred income taxes. On May 20, 1987, the PSC ordered all utilities to file data reflecting the impact of the TRA on their earned return, "utilizing unadjusted data" for calendar 1986, and giving recognition to a 34% tax rate. The PSC has not yet established a schedule for considering the impact on individual companies and any rate action will be on a prospective basis.

CALIFORNIA--On November 14, 1986, the California Public Utilities Commission (PUC) initiated an investigation into the methods to be utilized by the state's major utilities to establish the proper level of tax expense for ratemaking purposes. The PUC ordered the Public Staff Division (PSD) and the state's major utilities to review and analyze the regulatory implications of the TRA. In establishing the Order Instituting Investigation (OII), the PUC ordered that all rates in effect for these utilities as of January 1, 1987 be collected subject to refund pending a final Commission decision in the OII, with the investigation to be conducted through the workshop process. Hearings concluded June 10, 1987, and a final order is to be issued later in 1987. In its final order the PUC will determine "if and how rates for each utility shall be adjusted." As part of rate filings based on a calendar-1988 test year, Southern California Edison and General Telephone of California have recognized the effects of the TRA. In the Pacific Gas & Electric rate case decided in December 1986, the rate award was determined after giving recognition to roughly $85 million of TRA savings.

COLORADO--The Colorado Public Utilities Commission (PUC) hired an outside consultant to prepare a questionnaire for utilities to use to provide information specifically identifying the effects of the TRA on their operations. The Staff will make recommendations to the PUC based on data gathered, after which the PUC will determine what specific action should be taken with regard to the TRA.

CONNECTICUT--In September 1986, the Connecticut Department of Public Utility Control (DPUC) initiated a proceeding to review the financial and operating results of the state's major investor-owned utilities. Testimony filed in conjunction with this proceeding reflected each utility's best estimate of how the TRA would affect its revenue requirement. Based upon the Department's conclusion in this docket, the DPUC determined that additional action was necessary regarding, Connecticut Natural Gas (CNG), Southern New England Telephone (SNET), United Illuminating (UI), and Connecticut Light & Power (CL&P). Southern Connecticut Gas indicated that it planned to file a rate application during 1987. Settlement agreements have been approved for SNET, UI and CL&P which give recognition to the impact of the TRA. The impact of the TRA was not isolated, but considered in the context of each company's anticipated overall financial performance. Following a DPUC review of the

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earnings of CNG, on June 30, 1987 the Department concluded that no rate change was necessary. (See the July 2, 1987 issue of FOCUS NOTES.) The DPUC ordered utilities to elect one of three options regarding the treatment of contributions in aid of construction. A company can elect to: 1) charge additional tax-related expense to developers; 2) spread additional tax expense across-the-board to all customers; or 3) use a formula proffered by the Department.

DELAWARE--The Commission incorporated its analyses of the impact of the TRA into its recently completed earnings investigation of Delmarva Power & Light and is doing so in its ongoing earnings investigation of Diamond State Telephone. In its April 14, 1987 order for DP&L the PSC utilized a 38% blended corporate tax rate for 1987 and ordered use of a 34% tax rate as of January 1, 1988 which equates to a $4.4 million rate reduction as of that date. The Diamond State proceeding is pending and the company has reported that revenue deferrals have been recorded to reflect the estimated effect on revenue requirements for ratemaking purposes of lower tax rates effective in 1987 due to the TRA. A final PSC decision is expected in this case during October 1987.

DISTRICT OF COLUMBIA--On February 27, 1987, the PSC approved a joint petition calling for Potomac Electric Power (PEPCO) to reduce base electric rates by $18.2 million (3.2%). On December 23, 1986, PEPCO and the District of Columbia Office of People's Counsel (OPC) had filed a joint petition with the PSC seeking expedited PSC approval of an $18.2 million decrease in PEPCO's rates to reflect the impact of the TRA. The rate decrease was effective retroactive to January 1, 1987. The PSC approved the settlement's provision that neither PEPCO nor the OPC may apply for a further change in the company's rates prior to January 1, 1988.

On April 1, 1987, the PSC approved a joint settlement petition calling for District of Columbia Natural Gas (DCNG), a division of and formerly known as Washington Gas Light, to reduce rates by approximately $0.4 million. On December 31, 1986, DCNG and the OPC filed a joint stipulation and agreement with the PSC providing for DCNG to institute this rate reduction to reflect the impact of the TRA on the company's rates. The rate decrease was implemented retroactive to January 1, 1987.

In January 1987 the PSC instituted a TRA-related investigation for Chesapeake and Potomac Telephone (C&P), a subsidiary of Bell Atlantic. On February 11, 1987 C&P, the OPC, and the Commission's Staff filed a joint stipulation and agreement with the PSC to institute a rate reduction of $3.3 million to reflect the impact of the TRA. The stipulation specifies that the rates be reduced retroactive to January 1, 1987 and that there be no further rate changes for C&P during 1987. Hearings have been held and a PSC decision is expected during July 1987.

FLORIDA--One of the Florida Public Service Commission's (PSC) regulations, its Tax Savings Rule, provides that any earnings in excess of the mid-point of the last authorized return on equity range are required to be refunded to the extent these earnings are generated by changes in tax rates. In each rate case the PSC establishes the mid-point of a 200 basis point return on equity range as the target equity return for the utility. For most major utilities the target return last established was between 14.5% and 16%. In recent months, various actions and settlements have provided that lower return levels be utilized for the measurement of any refund obligation under the Tax Savings Rule for calendar 1987.

On November 4, 1986, the PSC approved a settlement agreement entered into between Florida Power Corporation (FPC) and the Florida Office of Public

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Counsel (OPC) which provided for FPC to institute a temporary rate reduction of approximately $54 million for calendar-year 1987. FPC agreed to "credit the monthly rates charged its retail customers in the total annual amount of $54,000,000," with the provision that this reduction "contemplates savings from pending federal income tax revisions" based on a blended statutory tax rate of approximately 40% for 1987 versus the 1986 statutory rate of 46%. It was anticipated that the company's federal income tax requirement would be reduced by approximately $30 million in calendar-1987. The rates provided for in the settlement affect only 1987, and FPC's rates to become effective January 1, 1988, will be determined in a PSC-ordered rate proceeding which commenced July 1, 1987. (See the May 8, 1987 and July 2, 1987 issues of FOCUS NOTES.).

On December 16, 1986, the PSC approved a settlement agreement in the Southern Bell Telephone (SBT) earnings investigation proceeding. In the settlement, SBT, a subsidiary of BellSouth, identified the tax benefits related to the TRA to be $54 million in calendar-1987 and applied this amount toward increased capital recovery expense.

On January 20, 1987, the PSC accepted the offers of Florida Power & Light, Gulf Power, and Tampa Electric that any rate refunds that might be required as a result of the application of the Tax Savings Rule should be calculated based upon a 13.6% return on equity rather than utilizing the previously authorized equity return levels established for each company. (For additional information see pages 1 and 2 of the January 23, 1987 issue of FOCUS NOTES.)

On March 31, 1987, the PSC voted to require United Telephone of Florida, a subsidiary of United Telecom, to reduce its revenues by $7.2 million to reflect the 1987 impact of the TRA. Approximately $6.7 million of the total revenue requirement reduction will be accomplished through a reduction in the access charges which long distance companies pay to use the local telephone network. United was also ordered to make a one-time depreciation reserve adjustment of roughly $0.5 million. On April 7, 1987, the PSC approved terms of a General Telephone of Florida (GTF) proposal to pass along $12.8 million of TRA-related savings to customers. GTF, a subsidiary of GTE, had initially offered this TRA-related proposal earlier in the year. The proposal approved by the PSC includes a $10.4 million reduction in access charges, effective May 1, 1987, a $1.5 million reduction in zone or mileage charges and a $0.9 million one-time increase in depreciation expenses. On June 8, 1987, Central Telephone Company of Florida and the Office of Public Counsel filed a stipulation with the PSC providing for the settlement of questions regarding Centel's 1986, 1987 and 1988 earnings. The stipulation provides for a $19.1 million refund and a $15 million prospective rate reduction on the part of Centel. If adopted by the PSC, the agreement would settle all open TRA questions.

GEORGIA--On June 16, 1987, the Georgia Public Service Commission (PSC) issued an accounting order with regard to the PSC's consideration of the TRA. The PSC determined that the change in the tax rate would result in an immediate reduction in utility revenue requirements and stated that the change in revenue requirements resulting from this reduction "should be identified and deferred on the books of each utility until the overall impact of the various changes resulting from the Act can be determined." Consequently, each utility was placed on notice that the federal income tax expense component of existing rates and charges in effect on July 1, 1987 "will be billed and collected on a provisional basis pending further investigation and disposition of this matter." The utilities are to place in a deferred account the "estimated annual effect on revenue requirement resulting solely from the reduction in tax expense because of the change in the federal corporate tax rate from 46 percent to 34 percent," with such amounts to accumulate pending

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final disposition of the matter by the PSC. Each utility must also file with the PSC by September 1, 1987, indicating the dollar impact of the TRA on the annual level of income tax expense included in its jurisdictional cost of service, based on a calendar-1986 test period. The companies were also instructed to "file proposals as to the manner in which these impacts of the [TRA] should be reflected in their operations for the years 1987 and 1988." The order states that "Consideration could be given to tariff changes, offsetting jurisdictional cost increases, and other pertinent facts and data." On June 25, 1987, the PSC voted to approve a stipulation entered into on June 17, 1987 by Atlanta Gas Light (AGL) and the parties to its rate case. The stipulation specifically provides that the effects of the TRA were taken into account in calculating the revenue requirement, and, therefore, AGL will not be subject to the provisions of the TRA accounting order issued by the PSC on June 16, 1987.

HAWAII--On May 4, 1987, the PUC held hearings in its investigation regarding the net effect of the TRA on Hawaiian Electric Company's (HECO) 1987 rates. On January 21, 1987, HECO, together with Hawaiian Electric Industries' other utility subsidiaries, filed to voluntarily reduce base rates to reflect the impact of TRA changes on each company's 1987 revenue requirement. The PUC subsequently accepted the company-proposed rate reductions of approximately $3.3 million for HECO, $1.2 million for Maui Electric (MECO), and $0.4 million for Hawaii Electric Light (HELCO). The rate reductions were made effective February 1, 1987. The company-proposed reductions for MECO and HELCO reflected the full impact of the TRA-related savings; however, the rate reduction proposed and implemented, to date, for HECO reflected only about 50% of the TRA-related annual revenue requirement reduction for the company. Due to the limited nature of the TRA-related savings to HECO's ratepayers, on February 6, 1987 the Commission instituted a proceeding (Docket 5740) in which the company was ordered to "show cause" why its rates should not be reduced to reflect the full impact of the TRA-related savings, or, stated quantitatively, reduce rates by an additional $3.3 million. On June 30, 1987 the PUC ordered HECO to reduce rates by an additional $1.7 million or roughly half of the 50% additional TRA-related savings considered in the show cause proceeding. The new rates were effective July 1, 1987. On June 12, 1987, the PUC issued a "show cause" order to Hawaiian Telephone. The PUC ordered Hawaiian Telephone, a subsidiary of GTE, "to show cause why its rates and charges should not be reduced to reflect the full effect of the Tax Reform Act of 1986 [TRA] for calendar year 1987." The PUC stated that the investigation shall "be confined to the net effect" of the TRA on the company's 1987 calendar year service rates. A prehearing conference was held on June 30, 1987 with final PUC action not likely for several months. In January 1987, the PUC had approved Hawaiian Telephone's request to amortize $5 million of central office depreciation in the calendar years, 1987 and 1988, effective January 1, 1987. The PUC noted "the proposed amortization is an initial step towards necessary resolution of the depreciation reserve imbalance in this account." The increased depreciation charge was approved without a commensurate increase in customer service rates.

IDAHO--On January 7, 1987, the Idaho Public Utilities Commission (PUC) ordered all utilities under its jurisdiction to file data comparing the utility's tax expense for 1986 under the old tax law with the utility's hypothetical tax expense for 1986 utilizing new tax rates. Companies showing a decrease in tax expense were required to file tariffs designed to reflect the reduction to become effective July 1, 1987. The PUC approved a $0.6 million decrease for Intermountain Gas. Commission actions regarding Idaho Power, Utah Power & Light and Washington Water Power are pending. In December 1986, the PUC approved a plan for Mountain Bell Telephone to upgrade central offices with digital facilities. The Commission agreed that expected savings from tax reform could be appropriated to help fund the upgrade.

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ILLINOIS--On December 31, 1986, the Chief Accountant of the Rate Review Department of the Public Utilities Division of the Illinois Commerce Commission (ICC) wrote to all the state's major utilities requesting them to file data and a rate rider with the ICC within 30 days in order for the Commission "to implement the ratemaking effects of the new tax law on a timely basis." It was requested that "the rider state the percentage by which all utility rates must be reduced to reflect the use of a 40% tax rate for 1987" based on each company's most recent rate order. This percentage reduction has been applied to all utility billings. However, customer bills have not been reduced. Instead, the amounts have been accrued in a deferred credit account, with an offsetting debit to revenue. This deferred credit account will continue to accrue until a final ICC determination later in 1987 with regard to each company's financial position. It was the Chief Accountant's view that "if the Commission determines that current earnings when adjusted to reflect all aspects of the new tax law are excessive, refunds will then be made to customers from the deferred credit account." Although not specifically described, excess earnings were indicated to be earnings above the previously authorized return on equity level. Formal ICC action has not as yet been forthcoming with regard to implementation of rate changes in contested cases, however, a number of settlements have been considered. On May 19, 1987, the ICC approved a motion by Union Electric (UEP) to revise its Callaway rate-phase-in plan in order to reflect the savings to be derived from the TRA. The company voluntarily proposed the tariff reduction so as to reduce the rate impact on customers. Effective May 19, 1987, rates rose by \$3.7 million (2.2%) rather than \$11.5 million (6.8%). The final step increase scheduled for May 19, 1988 will also be revised downward, in this instance from \$12.5 million (6.7%) to \$3.8 million (2.1%). On June 24, 1987, the ICC approved astipulation filed by Iowa-Illinois Gas & Electric (I-I) and other parties, which will produce a \$13.8 million electric rate reduction related to the TRA and provide for certain other rate modifications. No change was required in gas rates. The electric reduction becames effective July 1, 1987, but was accompanied by a restructuring of the Louisa Phase-In Clause so that the final three phase-in amounts will be levelized over a six year period. Giving consideration to the base rate decrease of \$13.8 million and the Louisa Phase-In increase of \$6.6 million that became effective July 1, 1987, a net \$7.2 million reduction occurred in customer rates on that date. (See the May 29, 1987 and June 26, 1987 issues of FOCUS NOTES.) In a related matter, on January 27, 1987, the ICC ordered Northern Illinois Gas (NIGAS), a subsidiary of NICOR, to temporarily reduce base rates by approximately \$7.4 million (1.9%). The ICC concluded that the company was earning a 16.29% return on equity compared to its previously authorized 15.55% and, therefore, a \$7.4 million rate reduction was necessary "to ensure that the Company's rates are not excessive." The ICC also ordered a general rate case for NIGAS, which has not had a rate case since 1982. The rate case will examine, along with the usual issues, the effect of the TRA on the company's revenue requirement. A rate settlement proposal by Commonwealth Edison that is under consideration by the ICC gives effect to the impacts of the TRA in 1987 and years following.

INDIANA--On June 1, 1987, the Indiana Utility Regulatory Commission (URC) voted to approve, with only minor modifications, the Executive Committee Report on the TRA as filed with the Commission on April 15, 1987. This proceeding was initiated on November 26, 1986, when the URC appointed an Executive Committee and provided for the establishment of four task forces to examine the effect of the TRA on utilities in Indiana. On April 15, 1987, the Committee issued a report recommending that the utilities voluntarily file for rate reductions to reflect lower tax costs occasioned by the passage of the TRA. The Executive Committee was comprised of representatives of the URC Staff, the Utility Consumer Counselor, and members of the various utility industry associations. The Committee unanimously recommended that the

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investor-owned utilities be asked to voluntarily file rate reductions through the Commission's 30-day filing procedure. These filings would be examined by the Staff and then approved or disapproved by the URC. Any utility not voluntarily filing would be subject to an investigation and hearings as to why its rates should not be reduced. Proposed rate changes are to be based on the utilities most recent cost-of-service studies. In order to avoid problems caused by a decrease in cash flow, the Committee recommended that the lower tax rates be phased in, with service rates proposed to be effective July 1, 1987 to be premised upon a 38.5% tax rate. Rate changes to be made January 1, 1988 would be based upon a 37% tax rate, with the final adjustment, July 1, 1988, to reflect a 34% rate. The Commission noted that the initial step in the TRA phase-in plan provides for a rate reduction "some 4 1/2% less than the implementation of the 34% tax rate may alone produce. This generic proposal is clearly a compromise situation designed to be applicable to that vast number of utilities whose rates presently in effect have not been reviewed and adjusted for some time." The URC stated that to achieve a high level of accuracy would have required case-by-case reviews of each utility. Such a procedure was found to be not in the public interest, with the Commission finding that "a more expedient procedure dealing with all such similarly situated utilities in a generic fashion is appropriate. It is such treatment that has been recommended by the Executive Committee report."

IOWA--On February 6, 1987, the Iowa Utilities Board (IUB) adopted emergency rules, effective April 1, 1987. "The purpose of these rules is to recognize the substantial impact on the tax liability of rate-regulated investor-owned utilities as a result of the TRA and prevent unnecessary utility revenue shortfalls or windfalls." Additionally, the IUB ordered the utilities to determine a revised revenue requirement and to design rates which reflect the adjusted revenue requirement. The IUB devised a formula, which was applied to 1986 financial data and was designed to isolate the revenue requirement impact of the TRA. Legislation was subsequently adopted ratifying the IUB's authority to require tax-related rate adjustments effective July 1, 1987. However, the legislation provides that a company may delay implementation until September 30, 1987, "if sufficient bond or corporate undertaking is approved." A company may then file a general rate proceeding. Filed tariff revisions indicate the following TRA-related decreases: Iowa Electric Light & Power, $5.7 million; Iowa Public Service, $11.5 million; Iowa Power, $13.6 million; Interstate Power, $5.1 million; and Northwestern Bell Telephone, $12 million. Iowa Power has indicated its intention to delay implementation until September 30, 1987.

KANSAS--On March 18, 1987, the Kansas State Corporation Commission (KCC) ordered most of the state's major utilities, effective April 1, 1987, to begin placing the savings arising from the TRA into a separate account. The monies in that account will be subject to refund, pending a full review by the SCC of the effect of the TRA on each utility's revenue requirements. The utilities were instructed to use a blended 38% tax rate for purposes of calculating the tax savings. A formal docket was also opened by the SCC to initiate such an investigation, which is expected to be completed by the end of the year. The SCC specifically authorized the Staff to investigate other cost-of-service items while conducting the TRA review. The order covers all of the state's major utilities except the following companies: Kansas Gas and Electric, which was allowed to retain tax savings in the rate stabilization plan previously approved by the SCC (refer to the March 13, 1987 issue of FOCUS NOTES); KN Energy, which has a rate case pending; and KPL/Gas Service, which voluntarily filed for a rate reduction that reflects the effect of the TRA. On March 31, 1987 SCC approved electric and gas rate decreases totalling $18.7 million for KPL/Gas Service. The rate decreases went into effect April 7, 1987, and reflect electric and gas department TRA-related revenue requirement reductions of $11.6 million and $0.9 million respectively. KPL estimates that additional

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TRA savings for 1988 will approximate $10.8 million for electric operations and $1.8 million for the gas department. On June 12, 1987, the SCC voted to adopt a rate stabilization plan for Kansas City Power & Light (KCP&L) which incorporates, among other items, the impact of the TRA. KCP&L will be required to reduce rates by $4.3 million in 1987 and by $10.4 million in 1988.

KENTUCKY--On June 11, 1987, the Kentucky Public Service Commission (PSC) issued orders with regard to the rate reductions to be required as a result of the TRA. This proceeding was initiated on December 11, 1986, at which time the PSC determined to isolate the effects of the TRA on the state's major utilities and concluded that it would not consider additional rate increase issues. Company filings were required by January 26, 1987. Louisville Gas and Electric (LG&E) filed exhibits indicating a revenue requirement reduction of $12.1 million based on a 40% tax rate for 1987 and an annual revenue requirement reduction of $21.9 million based on an effective tax rate of 34% in calendar-1988. Additionally, LG&E petitioned the Commission to suspend implementation of any rate change until such time as the company filed its next general rate case. Kentucky Power (KP) filed data indicating a total tax reduction impact of $6.7 million. For Kentucky Utilities (KU) the 1987 and 1988 rate reduction amounts indicated were $9.8 million and $13 million, respectively. South Central Bell Telephone (SCBT) filed data reflecting a revenue requirement reduction of $7.9 million based on a 40% tax rate and a reduction of $19.3 million using a 34% rate. The PSC decided to require a one-time rate reduction on July 2, 1987, for each company, with the change calculated on the basis of a 34% tax rate, and determined that LG&E should reduce rates by $24.1 million effective July 2, 1987. KP, KU, and SCBT, were ordered to reduce rates by $6.9 million, $19.3 million, and $19.4 million, respectively. The PSC approved a TRA-related revenue adjustment for General Telephone of the South in conjunction with its recently concluded general rate case, and Columbia Gas of Kentucky adjusted its rates July 1, 1987, pursuant to a stipulation entered into in its last rate case. (See the June 19, 1987 issue of FOCUS NOTES.)

LOUISIANA--On December 2, 1986, the Louisiana Public Service Commission (PSC) approved a petition by Central Louisiana Electric Company (CLECO), filed the same day, proposing that its electric rates be reduced by $11.5 million over the next two years. This filing was tendered by CLECO on December 2, 1986 in order to pass along to customers the benefits of the TRA. The rate decrease for calendar-1987 is $5.3 million, with an additional decrease of $6.2 million to become effective in 1988. The average decrease in residential customers bills will be roughly 4% over the two years. The PSC authorized a rate increase for Louisiana Power & Light in February 1987, and in so doing gave recognition to the impacts of the TRA. The TRA impacts will be considered in the presently pending Gulf States Utilities (GSU) rate case. For other utilities in the state the TRA impacts will be considered on a case-by-case basis. No other specific actions have yet been initiated.

MAINE--On March 17, 1987, the Maine Public Utilities Commission (PUC) approved a stipulation in which New England Telephone (NET) agreed to implement a $9.2 million permanent rate decrease. The stipulation, which was entered into between NET, the PUC Staff, and the Public Advocate, also calls for a one-time $2 credit for each residential and business line. NET submitted the rate case filing in which the company supported the continuation of present rate levels. A PUC order had directed NET to file a rate case in order to provide an opportunity for the PUC to examine the company's jurisdictional earnings and the effects of the TRA. On March 3, 1987, Bangor Hydro-Electric (BHE) filed with the PUC for a two-step rate decrease totalling roughly $6.9 million. The rate filing was ordered by the PUC in order to examine the effects of the TRA. The first step, which took effect April 1, 1987, was a $6.2 million (9.7%) decrease, and the second-step, to be

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implemented on December 1, 1987, is roughly a $0.7 million decrease. The filing was based upon a 12% return on common stock equity (44.8% of capital) and a 12.17% return on an average rate base for a test year ended December 31, 1986. The 12% equity return used by BHE in the filing was agreed to in a stipulation between the company and the PUC Staff. On May 6, 1987, the PUC approved a stipulation between Central Maine Power (CMP), the PUC Staff, the Maine Public Advocate, and the Industrial Energy Consumers' Group that provided for a reduction in base rates of $9.1 million, effective May 1, 1987. Almost all of the reduction was attributable to a lower, although unspecified, cost of capital for the company. The increase is in addition to, and makes permanent, the $6.7 million rate reduction implemented on February 1, 1987, mostly to account for the effect on revenue requirements of the TRA. Another rate reduction is expected in January 1988 to adjust rates for the further reduction of the corporate tax rate under the TRA. Although no return on equity was specifically authorized, the approved stipulation provides that any CMP earnings above a 12% return on average common equity during the next two years will be set aside to cover deferred costs and increased operating and maintenance expense in later years.

MARYLAND--On January 2, 1987, the PSC adopted a stipulation calling for Delmarva Power & Light (DP&L) to reduce base rates by $3.3 million to reflect the impact of the TRA. The stipulation had been filed on December 31, 1986 by DP&L, the PSC Staff and the Office of People's Counsel (OPC). The stipulation occurred in the Phase II proceeding initiated by the PSC in its October 2, 1986 order. That order accepted a settlement in DP&L's earnings level investigation which resulted in the implementation of a $5.6 million base electric rate reduction. The January 2, 1987 PSC action, as set forth in the stipulation, directs DP&L to propose, by December 1, 1987, an additional base rate reduction to reflect the TRA's impact on the company's financial position on and after January 1, 1988. On March 3, 1987, Conowingo Power, a subsidiary of Philadelphia Electric was authorized a $3.7 million rate increase in its rate case which was initiated on September 5, 1986. The final order included the impact of the TRA on the company's service rates and was based upon a 37% blended tax rate rather than the blended 40% rate used by the company.

On May 5, 1987 the PSC issued its decision in the earnings investigation of Baltimore Gas & Electric (BG&E), which it had initiated in July 1986. The impact of the TRA was incorporated into the proceeding. At the end of the case BG&E supported use of a 40% blended corporate tax rate, whereas the PSC utilized a 36% blended rate. The new service rates were ordered to be made effective by June 1, 1987. On May 12, 1987, the PSC issued its decision in the earnings investigation for Potomac Electric Power (PEPCO), which it had initiated in July 1986. The impact of the TRA was incorporated into the proceeding. At the end of the case PEPCO supported a two-step approach to the tax rate changes resulting from passage of TRA. The company proposed that customer rates for 1987 be set based upon a 40% tax rate and that a second set of service rates reflecting a 34% tax rate take effect January 1, 1988 (amounting to a $4.1 million rate decrease). The OPC and the Staff each recommended use of a blended tax rate of 36%, which the Commission adopted, effective May 27, 1987.

MASSACHUSETTS--On January 28, 1987, the Massachusetts Department of Public Utilities (DPU) ordered the state's utilities to file information computing the effect that the decrease in the federal corporate tax rate would have on their revenue requirements as of July 1, 1987. The Department stated that "while we recognize that resolving all of the ratemaking consequences of the new tax code is a complicated matter that may eventually have to be considered in more detail in the context of each company's next general rate proceeding, it is administratively impossible for the Department to conduct a complete rate proceeding for every Massachusetts company before July 1, 1987. It is

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for this reason that we are voting to open this limited proceeding." On June 1, 1987, the DPU ordered all electric, gas and telephone companies to reduce rates, effective July 1, 1987,to reflect the cut in the corporate tax rate from 46% to 34%. Rate schedules filed by various companies reflect the following rate reductions: Boston Edison, $34 million; Commonwealth Electric, $3.7 million; Eastern Edison, $1.4 million; Massachusetts Electric, $16.8 million; Bay State Gas, $4.2 million; Boston Gas, $7.1 million; Commonwealth Gas, $3 million; and New England Telephone, $29.4 million. Rates approved by the DPU in Western Massachusetts Electric's general rate case decided June 30, 1987 reflect the impact of the TRA.

MICHIGAN--On October 28, 1986, the Michigan Public Service Commission (PSC) opened an official docket to receive information with regard to the impact of the TRA on the state's utilities. In this docket the PSC required that all investor-owned, state-regulated companies submit information on how each would be affected by the TRA. The action came on the PSC's own motion, and was a follow-up of a September 3, 1986 memorandum from the PSC's Director of Technical Services to each jurisdictional utility. That memo requested each company to submit to the PSC, 30 days after the signing of the new tax law, data to show the effect of the new law on utility rates. On December 17, 1986, the PSC ordered the state's electric, gas and telephone utilities to file data by February 17, 1987, indicating the impact of the TRA on their 1986 test year operations. The PSC noted that the lower federal tax rates will mean increased profits for most utilities and may make possible a downward adjustment of present rates. The utilities were ordered to file the documentation showing the net effects of the new tax law on their rates and to show cause why their rates should not be reduced to reflect the lower taxes. Settlements were encouraged for TRA items only and as indicated below many were reached. A separate docket was established for each utility, and in instances where settlements were not achieved contested rate proceedings were conducted in which interested parties were permitted to address the effects of the tax bill on the prospective utility rates.

On May 27, 1987, the PSC approved a settlement agreement that provided for Michigan Consolidated Gas (MichCon) to make refunds and reduce rates so as to reduce customer charges by $61.1 million during the 12-month period beginning June 1, 1987. The settlement had been entered into on April 28, 1987 by MichCon, a subsidiary of Primark, and the parties to several pending matters before the PSC. The settlement provided for $21.9 million of refunds and a $39.2 million rate reduction to be implemented June 1, 1987. The reduction is comprised of a $16.2 million annualized rate reduction resulting from the benefits of the TRA and a $23 million rate cut flowing from a temporary reduction resolving issues in a show cause proceeding with regard to alleged excess earnings. The $21.9 million of refunds will consist of the flow through of $9.9 million of excess deferred taxes arising from the TRA and $12 million associated with the settlement of a gas cost issue related to years 1986 through 1988. The reductions and refunds are expected to total $61.1 million over the 12 months ending May 31, 1988, however, the total ratepayer benefit will approximate $64.1 million over 15 months because the TRA-related rate reduction will continue through August 1988. If new rates are not in effect by August 1988, the TRA rate reduction will be revised from $16.2 million to $21.5 million annually, and this level of rate reduction will be made permanent.

Also on May 27, 1987, the PSC approved a settlement agreement that provided for Michigan Bell (MB), a subsidiary of Ameritech, to reduce its rates by $79.6 million effective July 1, 1987, to reflect the impact of the TRA. The parties to the TRA proceeding for MB reached agreement and a stipulation was filed with the PSC on April 13, 1987. The settlement is silent on all regulatory issues except the dollar value of the impact of the

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TRA. The company agrees that the annual revenue value of $79.6 million will be applied as a direct flow-through to customers commencing July 1, 1987. A $40 million reduction will be reflected through a negative surcharge to basic exchange rates for residence and business customers, a $20 million annual reduction will be made in interLATA access charges through the Michigan Transition Mechanism (MTM), a $17.2 million reduction to intraLATA message toll service rates will be accomplished, and a $2.4 million intraLATA WATS reduction will be implemented. AT&T Communications of Michigan (ATTCOM) agreed to flow through to its customers the TRA benefits resulting from the reduction of the MTM. For ATTCOM the TRA reduction approximated $17.6 million. On June 9, 1987 the PSC approved a settlement that provided for GTE-MTO to reduce rates by $10.4 million annually to reflect the impact of the TRA. (See the June 19, 1987 issue of FOCUS NOTES.) Contested proceedings are in progress with regard to both the electric and gas rate levels for Consumers Power (see the June 19, 1987 issue of FOCUS NOTES) and for the electric rates of Detroit Edison.

MINNESOTA--The Minnesota Public Utilities Commission (PUC) initiated a rulemaking proceeding requiring the state's utilities to file recomputed 1986 data utilizing the 34% tax rate scheduled to become effective July 1, 1987. The PUC has issued rulings regarding the TRA for, Northern States Power (Gas), People's Gas, and Otter Tail Power in recently decided rate cases. For Northern State's Power, the PUC adopted a gas rate increase with step reductions effective July 1, 1987 and January 1, 1988 to reflect the effects of the TRA. (For further details please refer to the Minnesota Final Report dated February 20, 1987.) The effect of the TRA will be considered in the currently pending rate case for Minnesota Power. For the electric division of Northern States Power, the TRA effect was considered in conjunction with a proceeding in which NSP sought rate base inclusion of Sherco 3, which is coming on line later in 1987. (For further details please refer to page 3 of the May 22, 1987 issue of FOCUS NOTES.) For the remaining companies, the PUC has developed a procedure designed to reflect the effects of the TRA in rates. The companies can either file tariffs by July 29, 1987, reflecting the TRA, utilizing a PUC developed formula, or attempt to reach a stipulated agreement with the Department of Public Service and the State Attorney General by late October 1987. Rates under the latter option would be made subject to refund subsequent to July 1, 1987.

MISSISSIPPI--The impact of the TRA is, for the most part, being dealt with on a case-by-case basis. Mississippi Power & Light (MP&L), Mississippi Power and the gas distribution companies have income tax riders in place which are adjusted routinely to reflect tax law changes; however, the anticipated effects of tax law changes were incorporated into MP&L's rates when the second step of the Grand Gulf phase-in was approved by the Mississippi Public Service Commission (PSC). The PSC opened a docket for South Central Bell (SCB) for the specific purpose of investigating the impact of the TRA. On April 23, 1987 the PSC ordered SCB to reduce rates by approximately $10.3 million to reflect the tax rate change and changes in SCB's net operating income.

MISSOURI--On November 3, 1986, the Missouri Public Service Commission (PSC) established an investigatory docket to receive information from utility companies as to how they will be affected by the TRA. The utilities were required to file information regarding their revenue requirement based on calendar-1985 data under the old tax law and the new tax law. Similar data based upon calendar-1986 results was also required. On January 30, 1987, the PSC ordered the Staff to set up informal meetings with the parties for the purpose of negotiating settlements regarding rate reductions to reflect the effect of the TRA. Negotiated settlements have been reached between specific companies and other interested parties. Rate reductios have been approved for St. Joseph Light & Power, Laclede Gas and General Telephone. In these

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instances the rate changes are also reflective of other modifications to the individual company's cost of service. Modifications to Union Electric's (UE) and Kansas City Power & Light's (KCP&L) phase-in plans were approved by the PSC. UE's revenue requirement for the third step increase was reduced by approximately \$33 million, with equivalent revenue requirement reductions to be reflected in the subsequent phase-in steps. KCP&L's second step increase was reduced from \$19.2 million to \$7.7 million. Third through seventh year phase-in increases will be reduced from 3.5% to 2.2%.

MONTANA--In November 1986 the Montana Public Service Commission (PSC) issued an Order to Show Cause requiring each Montana public utility to submit data, by February 1, 1987, reflecting the impact of the TRA. The PSC is currently considering a generic docket (Docket No. 86-1162) based on the data submitted by the 14 largest companies in the state. The purpose of this case is to determine whether the effects of the TRA warrant rate adjustments for these companies.

NEBRASKA--No action has been taken by either the Nebraska Public Service Commission or by the utilities with respect to the impact of the TRA.

NEVADA--In October 1986 the Nevada Public Service Commission (PSC) opened a generic docket to establish new rules and policies concerning the TRA. A prehearing conference was held February 3, 1987, and a workshop involving all interested parties took place in April 1987. Hearings will be held concerning all items not resolved by the April workshop. The PSC is expected to issue its new rules and policies in the fall of 1987. No rate changes related to the TRA are expected to be implemented prior to 1988, and it is uncertain at this time whether the changes will take place in the context of a general rate case or a limited-issue case.

NEW HAMPSHIRE--On December 1, 1986, the New Hampshire Public Utilities Commission issued an order directing the state's public utilities to file, by February 1, 1987, data concerning the effect on each company of the TRA. For Public Service Company of New Hampshire the revenue requirement reduction flowing from the TRA was considered in the context of the company's rate case that was decided on June 29, 1987. Since New England Telephone has no rate case pending, the impact of the TRA will be considered in the company's depreciation represcription proceeding, which is expected to be decided in the near future.

NEW JERSEY--On October 10, 1986, the New Jersey Board of Public Utilities (BPU) directed the Staff to conduct a review of utility company obligations under the TRA and to determine whether customer rates could be reduced without detriment to company services. On January 6, 1987, the BPU issued an order directing that the effects of the TRA "should be deferred upon the utilities' books and records effective January 1, 1987, so as to preserve its effects and ultimately pass along fully the likely reduction in revenue requirement to ratepayers." The companies' were required to submit data showing detailed calculations of the TRA upon their revenue requirement.

On December 22, 1986, the BPU issued an order allowing New Jersey Bell Telephone (NJBT) to accelerate the amortization of its depreciation reserve deficiency, effective January 1, 1987, with the deficiency to be amortized over a 3.5-year period versus a 15-year period. NJBT proposed that the BPU require a rate reduction July 1, 1987, only of the net difference between recognized revenue requirement increases associated with increased depreciation and the reductions associated with the TRA. The BPU largely adopted the company's proposal, but voted to give further consideration to the precise amount of revenue reduction to become effective July 1, 1987, initially estimated at \$33.7 million annually. On May 21, 1987, the BPU

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adopted a stipulation that had been signed by the BPU Staff, the New Jersey Department of Public Advocate, and NJBT, concerning the disposition of the savings flowing from the TRA. Of the $88.4 million of TRA savings, $40.2 million will be used by NJBT to accelerate its recovery of the depreciation reserve deficiency, while the remaining $48.2 million will flow through to customers in the form of a rate reduction. On December 18, 1986, the BPU approved a $23.3 million rate reduction proposal submitted by Jersey Central Power & Light to reflect the 1987 impact of the TRA. Elizabethtown Gas currently has a proceeding before the BPU in which it seeks a $21.5 million rate increase. As part of the proceeding the company gives recognition to the provisions of the TRA. On April 16, 1987, South Jersey Gas (SJG), a subsidiary of South Jersey Industries, filed for a $16 million (8%) gas rate increase which reflects the 1988 effects of the TRA. In the recent Public Service Electric & Gas (PSE&G) electric rate case, the BPU gave consideration to the $77 million 1987 rate reduction impact of the TRA. The 1988 impacts of the TRA will be considered for PSE&G's electric operations along with other rate changes to become effective January 1, 1988. Effective June 12, 1987, Rockland Electric (RE), a subsidiary of Orange & Rockland Utilities, implemented a $0.7 million rate decrease to reflect the 1987 effects fo the TRA. Effective January 1, 1988, RE will reduce rates by $1.5 million for 1988 TRA savings. This action occurred in the company's levelized energy adjustment clause filing before the BPU. On June 30, 1987, New Jersey Natural Gas a subsidiary of New jersey Resources, filed for a $27.4 million (11%) permanent rate increase which reflects the effects of the TRA.

NEW MEXICO--The Staff of the New Mexico Public Service Commission (PSC) filed a petition, asking the Commission to require each jurisdictional utility to file an updated cost-of-service based upon a recent test year, including the impacts of the TRA. On December 31, 1986, the PSC ruled that it would not docket the case, but issued a formal letter requesting that each company file the information sought by the Staff by March 30, 1987. The New Mexico State Corporation Commission (SCC) requested information from the state's telephone companies regarding the impact of the TRA, but no SCC action has been forthcoming.

NEW YORK--On January 28, 1987 the New York Public Service Commission (PSC) voted to have each of the state's utilities defer the savings attributable to the TRA as of January 1, 1987. The PSC ruled that the changes resulting from the TRA would be considered in the next rate case for each company. National Fuel Gas Distribution (NFGD) became the first New York company to receive rate treatment related to the TRA. On January 14, 1987, the PSC adopted a settlement agreement for NFGD that was based on a calculation of the current revenue requirement effect of the TRA through March 31, 1988. In a March 13, 1987 rate decision for Niagara Mohawk Power, the PSC reflected the impact of the TRA in the revenue requirement adopted. Recent rate decisions for Central Hudson Gas & Electric and Rochester Gas & Electric also reflected the effects of the TRA. Pending rate cases for Long Island Lighting and New York State Electric & Gas will reflect tax reform impacts. For most of the remaining companies, the PSC initiated comprehensive rate plans to consider such issues as tax reform and rate of return. On March 18, 1987, the PSC approved a settlement agreement regarding the revenue requirement of Consolidated Edison. As a result, Con Ed reduced its electric rates by $132.5 million and will provide for rate stability for three years. Savings attributable to the TRA are reflected in this rate reduction. On April 8, 1987, the PSC adopted a comprehensive rate plan for New York Telephone Company, a subsidiary of NYNEX. The rate plan provides for a $100 million permanent rate reduction to become effective in August 1987. On July 2, 1987, the PSC adopted a comprehensive rate plan for Orange & Rockland Utilities which calls for a rate reduction of approximately $8 million, partly to reflect tax reform. Tax

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reform is among the issues that are reflected in this rate reduction. Similar cases have been initiated for AT&T Communications of New York, ALLTEL of New York, Continental Telephone of New York, and the gas departments of Central Hudson Gas & Electric and Consolidated Edison.

NORTH CAROLINA--On October 23, 1986, the North Carolina Utilities Commission (NCUC) ordered the initiation of an investigation to determine the effects of the TRA on the obligations of each utility company under its jurisdiction. The NCUC ordered each utility to determine the dollar impact of the tax law change and to file such with the Commission no later than November 30, 1986. In addition, the NCUC order placed the affected utilities on notice that the federal income tax expense component of all existing rates and charges, effective January 1, 1987, will be billed and collected on a provisional rate basis pending further investigation and disposition of this matter. In December 1986, Duke Power filed with the NCUC recommending an approximate $48 million TRA-related rate reduction. The NCUC subsequently accepted Duke's proposal and made the rate reduction effective as of January 1, 1987. On May 12, 1987, the NCUC ordered all utilities subject to its October 1986 order to file a statement of the amount by which accumulated deferred income taxes exceed accrued taxes due to the lower tax rates included in the TRA. The companies were directed to show calculations and workpapers reflecting the excess deferred tax amount subject to flowback restrictios and those not subject to flowback restrictions. The requisite data and comments were filed by the companies during June 1987 and NCUC action is pending. On June 29, 1987, the Commission approved ATTCOM's proposal to reduce interLATA toll rates by approximately $8.8 million effective July 1, 1987. Approximately $1.4 million of the approved rate reduction reflects a flow through of TRA-related tax savings. Several other utilities have filed proposed TRA-related tax reductions, however the Commission has not yet issued orders in these cases. Carolina Power & Light has included the TRA's impacts in its pending rate case and a Commission decision is expected in that case during August 1987. All the TRA-related filings, including Duke's, are to be examined by the NCUC, with decisions likely later in the year. In all likelihood, the treatment of deferred tax balances will be an issue in the Commission's study, and further investigation may be undertaken in the future with regard to the tax rate reductions scheduled to take effect January 1, 1988.

NORTH DAKOTA--On December 30, 1986 the North Dakota Public Service Commission (PSC) issued an order directing the utilities to file information on the TRA and its effect on revenue requirements. The companies were also asked to submit proposals regarding rate changes occasioned by the TRA. Based on the submitted information, the PSC determined, in orders issued on June 16, 1987, that the TRA will not cause Great Plains Natural Gas, Inter-Community Telephone and Montana-Dakota Utilities to realize excessive earnings from North Dakota operations and that the investigation of TRA impacts for these companies should be closed. Also, on June 16, 1987 the PSC ordered refunds totalling $1.5 million in 1987 and $3.1 million in 1988 for Otter Tail Power Company, in the form of "Tax Reform Act Credits" on customers' monthly bills. Refunds were also ordered for Northern States Power Company in the amounts of $0.2 million for 1987 and $0.4 million for 1988.

OHIO--On November 12, 1986, the Chairman of the Ohio Public Utilities Commission (PUC) requested that each company submit an estimate of the effects of the TRA by December 31, 1986, and that each utility submit a proposal recommending an appropriate methodology to dispose of the tax issue. All of the major Ohio utilities have responded to the Chairman's request, and the responses have included proposals to reduce rates to reflect the tax savings as well as proposals to retain the tax savings in order to postpone the filing of future rate cases. Two companies, Monongahela Power and East Ohio Gas,

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received rate recognition of the TRA in rate cases decided in December 1986. On January 13, 1987, the PUC adopted Columbia Gas' proposal to reduce rates by $6.7 million, and on February 10, 1987, the PUC approved Ohio Power's proposal to reduce rates by $7.1 million. On April 28, 1987, Ohio Edison, the Ohio Consumers' Counsel, and the Staff of the PUC signed an agreement which, if adopted by the PUC, would permit OEC to increase its rates by approximately $152 million (10%). TRA benefits are reflected in this stipulation. On June 9, 1987, the PUC approved a two-year rate plan that had been filed by Cincinnati Bell Telephone. The company will institute a temporary, two-year credit on customer access lines amounting to a revenue decrease of roughly $2.4 million. This rate reduction reflects savings attributable to the TRA as well as the company's proposal to accelerate amortization of its depreciation reserve deficiency and to accelerate the retirement of the Station Connection Account. Also, on June 9, 1987, the PUC agreed with a proposal by Ohio Bell Telephone, a subsidiary of Ameritech, to utilize TRA savings to offset the effects of reduced toll and carrier access charges, reduced intraLATA toll rates, and increased depreciation rates. On June 16, 1987, the PUC approved a request by Dayton Power & Light to reduce its electric and gas rates by a net of $10.4 million (2%). The company's proposal included a $14.6 million rate reduction required by the TRA, with this decrease offset by $4.2 million for increased expenses related to conservation programs. TRA benefits are issues in the pending rate cases for Cleveland Electric Illuminating and Toledo Edison, both subsidiaries of Centerior Energy Corporation.

OKLAHOMA--On October 23, 1986 the Staff of the Oklahoma Corporation Commission (OCC) filed an application seeking OCC approval to commence an investigation of the state's largest investor-owned utilities to determine if rate decreases should be required as a result of changes in federal tax laws. The Staff held a technical conference with the state's utilities to establish a time schedule for audits of company records and public hearings. The companies named in the Staff's application included Empire District Electric, Oklahoma Gas & Electric (OG&E), Public Service of Oklahoma (PSO), Southwestern Public Service, Arkansas-Louisiana Gas, Arkansas-Oklahoma Gas, Lone Star Gas, KPL/Gas Service, Oklahoma Natural Gas (ONG), General Telephone of the Southwest, and Southwestern Bell Telephone (SWBT). On December 31, 1986, a rate reduction of $0.1 million was ordered for Empire District Electric in conjunction with the company's biennial review and to reflect the impact of the TRA. On June 26, 1987 the OCC approved a $32.8 million rate reduction for OG&E and a $1.9 million rate decrease for ONG to reflect the impact of the TRA. Commission action regarding SWBT, General Telephone, Arkansas Louisiana Gas, and KPL/Gas Service has been postponed, but whatever rate determinations are subsequently made will be effective from July 1, 1987. PSO's rates will also be reviewed at a later date. Lone Star has a rate case pending before the Commission.

OREGON--In early 1987 the Oregon Public Utility Commissioner (PUC) informed the state's utilities that the disposition of the savings from the TRA would be considered in the context of an open docket, if one was available. For those utilities without an open docket, the PUC requested that information be filed indicating the effect of the TRA in 1987. On May 7, 1987, the PUC approved a stipulation for PacifiCorp which included a $14 million revenue reduction due to the flow through of savings related to the TRA. Portland General Electric's currently pending general rate case was expanded to include the effects of the TRA. General Telephone of the Northwest, Idaho Power, and Northwest Natural Gas each have cases pending which specifically deal with tax reform.

PENNSYLVANIA--On December 18, 1986, the Pennsylvania Public Utility Commission (PUC) issued a ruling requiring the state's large utilities to establish temporary rates effective January 1, 1987, pending final PUC action

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with regard to any rate changes ultimately occasioned by passage of the TRA. Those utilities that had previously settled rate cases that accounted for the TRA impacts, or that had rate cases in progress in which the impacts of the Act would be considered, were to be accorded different treatment. The PUC declined to adopt a proposal that had been offered by the Office of Consumer Advocate that the Commission establish a negative federal tax adjustment surcharge. On December 18, 1986, the PUC largely approved the request by Pennsylvania Power & Light (PP&L) to place the impact of three proposed rate changes into effect simultaneously on January 1, 1987, one of the changes being the $47 million impact of the TRA. Major utilities in the state with rate cases in progress were to have the effects of the TRA considered in their rate proceedings. On January 30, 1987 the PUC approved settlement petitions providing for TRA rate reductions for Metropolitan Edison and Pennsylvania Electric, both subsidiaries of GPU. These rate reductions were negotiated as provided for in settlement rate orders for both companies issued on November 25, 1986. The rate reductions negotiated for 1987 are based on estimated blended tax rate of 40% for this year, with next year's reductions assuming a further corporate tax rate reduction to 34%. (See page 3 of the February 6, 1987 issue of FOCUS NOTES for additional detail.)

On April 9, 1987, the PUC acted on a petition for rehearing by Duquesne Light and voted to rehear one tax issue and to reverse one tax ruling. This reversal had the effect of revising a previously ordered rate reduction from $18.5 million to $15.8 million. The item reversed was related to the tax treatment of capitalized overheads. Duquesne had previously treated certain of these expenditures as deductible expenses for income tax purposes, but it is now required by the TRA to capitalize such amounts. An issue with approximately $5 million of revenue impact has been set for rehearing. The PUC initially required that no recognition be given to taxes attributable to the unbilled revenue provisions of the TRA. The Commission has subsequently granted rate recognition of this tax impact to other utilities. The PUC rejected a plea for a stay and denied reconsideration of other issues, including the imposition of a 34% effective tax rate from March 10, 1987 forward. On April 9, 1987, Duquesne appealed the PUC action to the Commonwealth Court of Pennsylvania, including in its appeal the use of a 34% tax rate, the PUC's reliance on a 13.5% return on equity, the in-service criteria established, and certain other matters. On June 2, 1987, the Commonwealth Court of Pennsylvania granted DQU a stay of the March 10, 1987, PUC order, requiring a revised rate reduction of $15.8 million. The Court ruling came in response to DQU's May 1, 1987 petition for a stay pending review of the PUC order. The Court found that the company had met the standards for a stay and therefore it was granted. (See the June 5, 1987 issue of FOCUS NOTES.)

On April 16, 1987, the PUC authorized Philadelphia Electric (PE) and Bell Telephone of Pennsylvania (BTP), a subsidiary of Bell Atlantic, to implement 1987 TRA rate reductions in the amounts requested. PE had proposed no change in gas rates, and this proposal was adopted. The company had proposed a $32.2 million reduction in revenue requirement to reflect the impact of the TRA in 1987, and requested that this be applied to the uncollected revenue portion of the phase-in plan established for the Limerick 1 nuclear plant. While this specific request was denied, the PUC adopted the company-proposed amount of $32.2 million as the 1987 rate refund, and required this amount to be returned to customers over the remainder of the year.

On June 4, 1987, the PUC adopted a Staff recommendation that 76 of the state's larger utilities be ordered to reduce rates by nearly $54 million to reflect reductions in their taxes as a result of the TRA. Fifteen state utilities had already implemented TRA rate reductions, and certain others will

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have the TRA benefits considered in rate cases that are currently awaiting PUC action. The two utilities most substantially affected by the June 4, 1987 action are West Penn Power (WPP) and Equitable Gas. WPP was ordered to implement an interim 2.27% rate reduction, estimated to reduce rates by over $20 million, effective July 1, 1987. Equitable Gas was ordered to reduce rates by 2.12%, or about $7 million, on the same date. The companies required to reduce rates were permitted to elect to make the new lower rates permanent, or to file complaints against such rates.

RHODE ISLAND--During the first week of February 1987, the Division of Public Utilities (DPU) of the Rhode Island Public Utilities Commission (PUC) sent letters to utilities requesting cost-of-service, rate base, and return data for calendar-1986, and also asked for information on the impact of the TRA on revenue requirements. A January 12, 1987 rate decision for Blackstone Valley Electric Company (BVE) included the effect of the TRA. BVE was also ordered to file a second set of tariffs that will reflect the further lowering of the tax rate in 1988 under the TRA. The secondary tariffs will be implemented when the additional tax rate reduction takes effect. On May 29, 1987, the PUC approved a stipulation agreement between New England Telephone (NET), the DPU, the Rhode Island Attorney General, and the Rhode Island Consumers Council that will reduce rates approximately $5.3 million. The reduction was attributable to the tax rate reductions in the TRA and the Rhode Island Gross Receipts Tax, FCC separations changes, depreciation represcription, inside wire deregulation, changes in the Uniform System of Accounts, and a reduction in NET's overall rate of return to 11.36%.

SOUTH CAROLINA--In July 1986 the South Carolina Public Service Commission (PSC) directed utilities to file data on "the impact of federal tax changes as applied to the company's 1985 operations" within 60 days after Congress and the President acted on tax reform legislation. As well, the PSC had separately directed the Staff to investigate the cost of common equity for the major utilities in the state and determined that if the Staff's cost of equity determinations are available by the time the tax-impact reports are filed, the PSC would be in a position to formulate its position and make any decisions on the basis of the knowledge provided from both reports. On December 16, 1986, the PSC voted to order Duke Power to lower its base electric rates by approximately $20.2 million (2.3%) effective January 1, 1987 to reflect the impact of the TRA. On December 12, 1986, Duke had filed data with the PSC indicating that it would experience approximately $20.2 million of savings due to the TRA. The PSC indicated its intention to continue to investigate the impact of the tax bill on Duke and to ensure that the company's customers receive the full benefits of any tax savings. On January 14, 1987, the PSC directed South Carolina Electric & Gas (SCE&G) to reduce retail electric rates by approximately $25.5 million (3%) to reflect anticipated savings from the TRA. In December 1986 SCE&G had filed its report setting forth its estimated tax savings under the TRA. The Commission voted unanimously to pass the full savings through to customers. The PSC instructed its Staff to continue its analysis of SCE&G's tax savings report and to notify the Commission if any further rate adjustments should be made, especially in 1988 or thereafter. Carolina Power & Light filed a full rate case in February 1987 which includes the impact of the TRA. A PSC decision is expected in this case during August 1987. The Commission's investigations into the TRA impacts on other utilities are ongoing, with decisions not expected until the latter half of 1987.

SOUTH DAKOTA--The South Dakota Public Utilities Commission (PUC) has formally opened a generic docket to examine the effects of the TRA and the current earnings of South Dakota utilities. The PUC is still in the process of gathering data. While it was thought that changes in rates could be expected before the middle of 1987, none have occurred to date.

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TENNESSEE--On December 30, 1986, the Tennessee Public Service Commission (PSC) voted for an $11.8 million revenue requirement reduction for South Central Bell Telephone (SCBT) to reflect the financial impact of the TRA. Roughly half of the reduction was authorized to be accounted for through the recording of higher depreciation charges, with the other half coming from reductions in rates. The Commission accounted for the TRA in a recently finalized rate case for General Telephone Company of the South, and also incorporated the impact of the TRA in a United Cities Gas rate case completed in February 1987. In all three of these completed cases the PSC allowed the use of a blended corporate tax rate for 1987 service rates, with the understanding that as of January 1, 1988, service rates for these three companies will reflect a 34% corporate tax rate. On December 30, 1986, in a separate order, the PSC voted to initiate a generic hearing to investigate the impact of the TRA on all other utilities within the state. Initially, the utilities were required to file their responses by the end of January; however, the PSC changed the response deadline time to June 1987. On June 30, 1987 the PSC voted approval of most of the companies proposals while requiring additional data from several small utilities. The Commission approved the flow through of TRA-related savings for both AT&T Communications and for United Intermountain Telephone. Final Commission orders are expected to be issued in the near future.

TEXAS--The Texas Public Utility Commission (PUC) Staff sent letters to all utilities requesting comments as to the general and specific effects of the TRA on the companies, their tax liabilities and their cash flow. A task force consisting of Staff members is responsible for gathering the information and making recommendations to the PUC, with any PUC action to be taken to occur during the second half of 1987.

UTAH--The Utah Public Service Commission (PSC) informally requested information from the major utilities in the state regarding the TRA. No further action has been taken

VERMONT--On January 9, 1987, the Vermont Public Service Board (PSB) sent letters to the state's utilities requesting that the companies file with the PSB estimates of the effects of the TRA for 1987 and 1988. The letter required responses to be filed by January 30, 1987, and all of the major Vermont utilities have submitted their estimates. For Central Vermont Public Service, the PSB disposed of the issue in the company's general rate case, which was decided January 2, 1987. On March 11, 1987, the PSB issued an order providing for a $3.5 million (4.5%) rate reduction as requested by Green Mountain Power (GMP). GMP initiated the case February 24, 1987, when it filed for a $3.5 million rate reduction, with roughly $2.4 million of this amount to flow from the savings attributable to the TRA utilizing a 40% blended rate. As for New England Telephone (NET), on January 6, 1987 the Department of Public Service and the company agreed on a new regulatory framework that will provide for the stabilization of basic telephone rates, with most other services partially or totally deregulated. The plan provides for an immediate revenue requirement reduction of $5.4 million, which reflects, among other items, the TRA. The State Legislature has passed a bill that allows the PSB to deregulate certain services.

VIRGINIA--On February 4, 1987, the Virginia State Corporation Commission (SCC) informed the utilities in its jurisdiction that due primarily to the impetus of the TRA, investigations of the financial conditions of large electric and telephone companies could soon be undertaken. During 1987 the Commission Staff, as directed by the SCC in late 1986, has been receiving data from the utilities with regard to estimates of the TRA's impact. Continental Telephone Company responded with a proposal to reduce rates by approximately $3.3 million which the SCC subsequently accepted. On February 12, 1987

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Chesapeake & Potomac Telephone (C&P) filed with the SCC to institute a $15 million rate reduction to reflect the impact of the TRA. C&P's filing was accepted by the Commission in March 1987 and the proposed rate reduction was effective July 1, 1987 as an across the board reduction. On March 3, 1987, the SCC sent letters to the utilities within its jurisdiction directing each to defer all savings related to the TRA, effective January 1, 1987. On March 6, 1987, the SCC sent orders to the investor-owned electric utilities under its jurisdiction directing each to file an "expanded" annual informational filing (AIF) based upon a calendar-1986 test period and a hypothetical rate year beginning September 1, 1987. The AIF is normally used as a "make-whole" procedure for the utilities in the state. The SCC's stated reason for such filings was as follows, "Because of this Commission's awareness of vast improvements in the national and local economies and changes in the federal tax laws, the Commission has determined that a more detailed Commission awareness of the financial condition of the investor-owned electric utilities is necessary at the present time than will be provided by our review of the standard Annual Informational Filings required of these utilities." The expanded AIF's essentially allow the Commission to determine whether or not it should initiate a general rate case for the utility. In light of these expanded AIF filings, the SCC subsequently modified its TRA-related instructions and directed that the utilities not be required to defer savings related to the tax bill. All companies are to continue to monitor the impact of the tax changes and supply such information in their expanded AIF filings. The status of each expanded AIF is as follows: Appalachian Power, a subsidiary of American Electric Power, was required to file data by July 6, 1987. Delmarva Power & Light filed its AIF on April 10, 1987 supporting an approximate $0.8 million rate reduction which the SCC subsequently approved on an interim basis. Final Commission action is pending. Potomac Edison filed the necessary data and SCC action is pending. In an order issued on April 16, 1987, the SCC established a schedule for Virginia Electric & Power's "expanded" AIF case which required company testimony to be filed by June 1, 1987 and hearings to commence September 14, 1987. On April 9, 1987, the SCC had severed several issues proposed in the company's fuel review filing and directed that these be considered in an "expanded" AIF proceeding. (See page 6 of the April 24, 1987 issue of FOCUS NOTES.)

WASHINGTON--The Washington Utilities & Transportation Commission (WUTC) required each of the state's utilities to file data by December 31, 1986 estimating the effects on cost of service resulting from the TRA. On March 19, 1987, the WUTC approved a $2.8 million rate decrease for PacifiCorp to recognize the 1987 effects of the TRA. The rate decrease took into account the accrued tax savings, with interest, from January 1, 1987, to March 19, 1987. On April 17, 1987, Pacific Northwest Bell (PNB) and other parties signed an agreement regarding the company's revenue requirement. PNB agreed to reduce its rates by $51.4 million, to reflect, in part, savings related to the TRA. (Refer to page 3 of the May 1, 1987 issue of FOCUS NOTES.) On April 23, 1987, the WUTC ordered rate reductions, effective July 1, 1987, for three companies: Puget Sound Power & Light--$19.2 million; Washington Natural Gas--$2.9 million; and, General Telephone of the Northwest--$4.4 million. The rate reductions for these companies reflect a 34% tax rate.

WEST VIRGINIA--On January 20, 1987, the West Virginia Public Service Commission (PSC) issued an order directing utilities within the state to file written statements estimating the potential impact of the TRA on their operations. These responses were due by March 16, 1987 and hearings were held during April 1987. Commission action is now pending. On June 24, 1987, the PSC issued an order approving Appalachian Power Company's (APCO) proposal to reduce rates by approximately $27.8 million. APCO, a subsidiary of American Electric Power, initiated this filing on May 28, 1987 in order to reflect in customer rates the impact of the TRA, changes in West Virginia state tax

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laws, and approximately $15.6 million of lower fuel costs which would not otherwise be reflected in rates until October 1987 (after PSC determination of the company's appropriate "expanded net energy cost factor" (ENEC). (See page 6 of the June 5, 1987 issue of FOCUS NOTES.) During hearings the Commission Staff had proposed that the PSC conditionally approve APCO's proposal, "subject to a notice requirement and certain specific recommendations." The Commission decided it should waive the notice requirements and approve the filing and concluded that "an expedited disposition will enable APCO's West Virginia customers to immediately receive the benefits of the rate reduction." The PSC clarified in its order that "APCO also recognizes that the exact amount of its ENEC level effective October 1, 1987, will be reviewed and determined by the Commission" in a separate docket. The lower rates were effective July 1, 1987.

WISCONSIN--The Wisconsin Public Service Commission (PSC) requires the state's 12 largest utilities to file forecasted financial data each year, and the effects of the TRA have been or will be dealt with in each of these annual reviews on an individual company basis. Companies not undergoing annual reviews were required to submit data by April 1, 1987 to show the impact of the TRA on their operations and then to file new rates effective July 1, 1987 reflecting that impact.

WYOMING--The PSC has informally requested information from utilities regarding the effect of the TRA. The implications of the TRA for ratemaking purposes will be handled on a case-by-case basis as part of each company's next rate case.

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July 7, 1987

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ESTIMATED REVENUE REQUIREMENT EFFECTS OF FEDERAL INCOME TAX RATE REDUCTION FROM 35% TO 21% ON KENTUCKY ELECTRIC UTILITIES*

Data Source: 2016 FERC Form 1s and 3rd Qtr 2017 FERC Form 3Qs	Kentucky Power Company (1)	Kentucky Utilities Company (2)	Louisville Gas and Electric (3) **	Duke Energy Kentucky (4) ***	Total Kentucky
FEDERAL INCOME TAX RATE ASSUMPTIONS					
New Federal IncomeTax Rate	21%	21%	21%	21%	
Old Federal Income Tax Rate	35%	35%	35%	35%	
Percentage Reduction in Federal Income Tax Rate	40%	40%	40%	40%	
REDUCTION IN FEDERAL INCOME TAX EXPENSE					
Current Income Tax Expense	3,665,047	(35,720,271)	(2,350,008)	(13,605,989)	
Deferred Income Tax Expense -Debit	91,174,070	361,341,480	315,294,906	120,202,825	
Deferred Income Tax Expense -Credit	(79,048,558)	(239,775,392)	(187,485,676)	(89,849,065)	
Total Federal Income Tax Expense @35%	15,790,559	85,845,817	125,459,222	16,747,771	243,843,369
Federal Income Tax Expense @21%	9,474,335	51,507,490	75,275,533	10,048,663	146,306,021
Reduction in Federal Income Tax Expense to 21%	(6,316,224)	(34,338,327)	(50,183,689)	(6,699,108)	(97,537,348)
Gross-Up Factor Using 21% Federal Rate	1.27	1.27	1.27	1.27	
Reduction in Annual Revenue Requirement	**(7,995,220)**	**(43,466,236)**	**(63,523,657)**	**(8,479,884)**	**(123,464,997)**
REDUCTION IN DEF INCOME TAX EXP DUE TO AMORT OF EXCESS ADIT					
Acct 190 (Asset)	52,424,245	258,240,706	210,421,679	31,647,540	
Acct 281 (Liability)	(56,212,721)	-	-	(330,074)	
Acct 282 (Liability)	(409,970,123)	(1,380,616,565)	(1,131,472,272)	(335,656,481)	
Acct 283 (Liability)	(270,200,898)	(166,199,333)	(152,039,898)	(34,318,626)	
Total ADIT @35%	(683,959,497)	(1,288,575,192)	(1,073,090,491)	(338,657,641)	(3,384,282,821)
Total ADIT @21%	(410,375,698)	(773,145,115)	(643,854,295)	(203,194,585)	(2,030,569,693)
Excess ADIT Due to Federal Rate Change	(273,583,799)	(515,430,077)	(429,236,196)	(135,463,056)	(1,353,713,128)
Estimated Amortization Period (Years)	20	20	20	20	
Negative Deferred Income Tax Expense (Amortization)	(13,679,190)	(25,771,504)	(21,461,810)	(6,773,153)	(67,685,656)
Gross-Up Factor Using 21% Federal Rate	1.27	1.27	1.27	1.27	
Reduction in Annual Revenue Requirement	**(17,315,430)**	**(32,622,157)**	**(27,166,848)**	**(8,573,611)**	**(85,678,046)**
TOTAL REDUCTION IN ANNUAL REVENUE REQUIREMENT	**(25,310,650)**	**(76,088,393)**	**(90,690,505)**	**(17,053,495)**	**(209,143,043)**

(1) Kentucky Power Company rates are expected to increase in early 2018 resulting from the Commission's pending decision in Case No. 2017-00179. Rate increase not proformed.
(2) Kentucky Utilities Company rates increased during 2017 due to the Commission's June 22, 2017 final order in Case No. 2016-00370. Rate increase not proformed.
(3) Louisville Gas and Electric rates increased during 2017 due to the Commission's June 22, 2017 final order in Case No. 2016-00371. Rate increase not proformed.
(4) Duke Energy Kentucky's request for a basic rate increase is pending in Case No. 2017-00321. No rate increase is assumed or proformed.

* Quantifications based on the twelve months ended September 30, 2017 data. Quantifications will change somewhat if calendar year 2017 data is used. Quantifications include effects on riders, but do not include effects on the costs of transmission services purchased pursuant to cost-based tariffs.

** Louisville Gas and Electric includes both electric and gas effects. Electric Utility share of net utility operating income (FERC Form 1 and 3Q, pg 115, line 26) (2015, 82.56%) (2016,83.01%) (3 Quarters Ended September 30, 2017, 85.72%)

*** Duke Kentucky includes both electric and gas effects. Electric Utility share of net utility operating income (2016 FERC Form 1 and 3Q, pg 115, line 26) (2016, 76.89%) (3 Quarters Ended September 30, 2017, 81.99%)

ESTIMATED EFFECTS ON EARNINGS (NOT REVENUE REQUIREMENTS) OF FEDERAL INCOME TAX RATE REDUCTION FROM 35% TO 21% ON KENTUCKY ELECTRIC UTILITIES*

Data Source: 2016 FERC Form 1s and 3rd Qtr 2017 FERC Form 3Qs	Kentucky Power Company [1]	Kentucky Utilities Company [2]	Louisville Gas and Electric [3] **	Duke Energy Kentucky [4] ***	Total Kentucky
FEDERAL INCOME TAX RATE ASSUMPTIONS					
New Federal IncomeTax Rate	21%	21%	21%	21%	
Old Federal Income Tax Rate	35%	35%	35%	35%	
Percentage Reduction in Federal Income Tax Rate	40%	40%	40%	40%	
REDUCTION IN FEDERAL INCOME TAX EXPENSE					
Current Income Tax Expense	3,665,047	(35,720,271)	(2,350,008)	(13,605,989)	
Deferred Income Tax Expense -Debit	91,174,070	361,341,480	315,294,906	120,202,825	
Deferred Income Tax Expense -Credit	(79,048,558)	(239,775,392)	(187,485,676)	(89,849,065)	
Total Federal Income Tax Expense @35%	15,790,559	85,845,817	125,459,222	16,747,771	243,843,369
Increase in Earnings Due to Reduction in Income Tax Expense	**6,316,224**	**34,338,327**	**50,183,689**	**6,699,108.40**	**97,537,348**
REDUCTION IN DEF INCOME TAX EXP DUE TO AMORT OF EXCESS ADIT					
Acct 190 (Asset)	52,424,245	258,240,706	210,421,679	31,647,540	
Acct 281 (Liability)	(56,212,721)	-	-	(330,074)	
Acct 282 (Liability)	(409,970,123)	(1,380,616,565)	(1,131,472,272)	(335,656,481)	
Acct 283 (Liability)	(270,200,898)	(166,199,333)	(152,039,898)	(34,318,626)	
Total ADIT @35%	(683,959,497)	(1,288,575,192)	(1,073,090,491)	(338,657,641)	(3,384,282,821)
Excess ADIT Due to Federal Rate Change	(273,583,799)	(515,430,077)	(429,236,196)	(135,463,056)	(1,353,713,128)
Amortization Period (Years)	20	20	20	20	
Increase in Earnings Due to Amort of Excess ADIT	**13,679,190**	**25,771,504**	**21,461,810**	**6,773,153**	**67,685,656**
INCREASE IN ANNUAL EARNINGS	**19,995,414**	**60,109,831**	**71,645,499**	**13,472,261**	**165,223,004**

(1) Kentucky Power Company rates are expected to increase in early 2018 resulting from the Commission's pending decision in Case No. 2017-00179. Rate increase not proformed.
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(3) Louisville Gas and Electric rates increased during 2017 due to the Commission's June 22, 2017 final order in Case No. 2016-00371. Rate increase not proformed.
(4) Duke Energy Kentucky's request for a basic rate increase is pending in Case No. 2017-00321. No rate increase is assumed or proformed.

* Quantifications based on the twelve months ended September 30, 2017 data. Quantifications will change somewhat if calendar year 2017 data is used. Quantifications include effects on riders, but do not include effects on the costs of transmission services purchased pursuant to cost-based tariffs.

** Louisville Gas and Electric includes both electric and gas effects. Electric Utility share of net utility operating income (FERC Form 1 and 3Q, pg 115, line 26) (2015, 82.56%) (2016,83.01%) (3 Quarters Ended September 30, 2017, 85.72%)

ESTIMATED EARNINGS EFFECTS OF FEDERAL INCOME TAX RATE REDUCTION FROM 35% TO 21%*

Data Source: 2016 FERC Form 1s and 3rd Qtr 2017 FERC Form 3Qs	Kentucky Power Company [1]	Kentucky Utilities Company [2]	Louisville Gas and Electric [3] **	Duke Energy Kentucky [4] ***	Total Kentucky
EARNINGS					
Net Income (Three Quarters Ended September 30, 2017 Form 3Q page 117)	19,949,397	194,721,259	162,267,661	27,096,051	404,034,368
Net Income (2016 Form 1 page 117)	50,210,335	265,627,602	203,173,880	42,583,938	561,595,755
Net Income (Three Quarters Ended September 30, 2016 Form 3Q page 117)	40,174,861	207,892,946	159,364,604	34,870,116	442,302,527
Net Income 4th Quarter 2016	10,035,474	57,734,656	43,809,276	7,713,822	
Net Income (12 Months Ended September 30, 2017)	29,984,871	252,455,915	206,076,937	34,809,873	523,327,596
COMMON EQUITY					
Common Stock Issues (201)	50,450,000	308,139,978	425,170,424	8,779,995	792,540,397
Premium on Capital Stock (207)				18,838,946	18,838,946
Other Paid-In Capital (208-211)	526,135,279	2,616,446,834	1,682,167,368	148,655,189	4,973,404,670
Capital Stock Expense (214)		(321,289)	(835,889)		(1,157,178)
Retained Earnings (215, 215.1, 216)	86,870,006	423,902,076	382,339,314	287,837,418	1,180,948,814
Accumulated other Comprehensive Income (219)	(1,290,989)				(1,290,989)
Total Common Equity	662,164,296	3,348,167,599	2,488,841,217	464,111,548	6,963,284,660
EARNED RETURN ON EQUITY					
Earned Return on September 30, 2017 Common Equity Per Books	4.53%	7.54%	8.28%	7.50%	7.52%
Increase in Earnings Due to Reduction in Federal Income Tax Rate	19,995,414	60,109,831	71,645,499	13,472,261	165,223,004
Earned Return Adjusted for Reduction in Federal Income Tax Rate	7.55%	9.34%	11.16%	10.40%	9.89%

(1) Kentucky Power Company rates are expected to increase in early 2018 resulting from the Commission's pending decision in Case No. 2017-00179. Rate increase is not proformed.
(2) Kentucky Utilities Company rates increased during 2017 due to the Commission's June 22, 2017 final order in Case No. 2016-00370. Rate increase is not proformed.
(3) Louisville Gas and Electric rates increased during 2017 due to the Commission's June 22, 2017 final order in Case No. 2016-00371. Rate increase is not proformed.
(4) Duke Energy Kentucky's requests for a base rate increase and environmental surcharge are pending in Case No. 2017-00321. No rate increase is assumed or proformed.

* Quantifications based on the twelve months ended September 30, 2017 data. Quantifications will change somewhat if calendar year 2017 data is used. Quantifications include effects on riders, but do not include effects on the costs of transmission services purchased pursuant to cost-based tariffs.
** Louisville Gas and Electric includes both electric and gas effects. Electric Utility share of net utility operating income (FERC Form 1 and 3Q, pg 115, line 26) (2015, 82.56%) (2016,83.01%) (3 Quarters Ended September 30, 2017, 85.72%)
*** Duke Kentucky includes both electric and gas effects. Electric Utility share of net utility operating income (2016 FERC Form 1 and 3Q, pg 115, line 26) (2016, 76.89%)

Attachment B

Edison Electric Institute
Power By Association

Comprehensive Tax Reform Priorities: Excess Deferred Tax Transition Issues

Shareholder-owned electric utilities support the goals of tax reform to simplify the U.S. tax code, broaden the tax base, and reduce rates. Reducing federal income tax rates for heavily regulated shareholder-owned electric utilities, however, will create a number of transition issues that Congress should address in any tax reform legislation.

One of these transition issues is the treatment of so-called excess deferred taxes. Many companies may have excess deferred tax reserves after a federal income tax rate reduction because the change in the law requires a recalculation of deferred tax liabilities. However, unlike other companies that would recognize excess deferred taxes as income, regulated shareholder-owned electric utilities are required to refund excess deferred taxes, related to asset depreciation, to their customers.

Electric utilities support a fair and equitable distribution of excess deferred taxes across their customer base. To meet this goal, any tax reform legislation should include a provision to require state public utility commissions (PUCs) to refund excess deferred taxes, related to asset depreciation, over the remaining lives of the assets being depreciated.

Understanding Deferred Taxes And Excess Deferred Taxes

A deferred tax liability—or a deferred tax—is the amount of taxes currently saved by a company that will be repaid in the future due to a temporary timing difference between the "book" treatment of an asset on a company's financial records and the tax treatment based on Internal Revenue Code rules.

The most common example of a deferred tax occurs when a company claims accelerated tax depreciation for an asset. (For an electric utility, an asset could be a power plant or large power transformer, for example.) Accelerated depreciation means that a company will record more depreciation in the first few years of an asset's life and less depreciation in the later years, relative to book or regulatory depreciation. While this approach results in a timing difference, cumulative tax and book depreciation generally are equal over the course of an asset's life.

Following is a basic example of how deferred taxes work:

- Assume the tax depreciation of an asset is $20.00 in the year the asset is placed in service.
- If the book depreciation of the asset is $10.00 that year, there is a $10.00 temporary difference between the tax depreciation and the book depreciation.
- The $10.00 temporary difference creates a current tax savings of $3.50 ($10.00 taxed at the current 35 percent federal income tax rate) and a future (deferred) tax liability in the same amount. This future liability is recorded in a reserve on the balance sheet and generally is titled "Accumulated Deferred Income Taxes."

Excess deferred taxes arise as the result of an income tax rate reduction. If the federal income tax rate is reduced from 35 percent to 25 percent, for example, the amount of deferred taxes that would be needed to pay the future obligation to the federal government would decrease by approximately 28 percent (10 percent divided by 35 percent).

Using the accelerated depreciation example, the $3.50 of deferred taxes would be reduced to $2.50 ($10.00 of future income taxed at the 25 percent tax rate). For a company with an accumulated deferred income tax liability, the tax rate reduction is equivalent to the federal government reducing a portion of future tax liabilities. This reduction is known as the excess deferred taxes which, in this the example, would be $1.00 ($3.50 minus $2.50).

How Electric Utilities Manage Excess Deferred Taxes

Because shareholder-owned electric utilities are heavily regulated by state PUCs, these utilities must handle excess deferred taxes differently than other businesses. A state PUC sets the rates that a regulated electric utility may charge its customers for electricity service. The PUC allows the utility to recover its "cost of service" and also gives the utility an opportunity to earn a reasonable rate of return on its invested capital (i.e., its "rate base"). Among the items included in cost of service are fuel costs, operations and maintenance costs, depreciation expense, and income tax expense.

If an electric utility accelerates the depreciation of an asset, the IRS requires utilities to follow specific accounting rules, called normalization, that follow this process:

- Collect the deferred taxes from current customers;
- Use the deferred taxes to reduce the rate base; and
- Return the deferred taxes to future customers.

When a tax rate reduction creates excess deferred taxes, all companies must account for the excess. A non-regulated company generally would recognize the excess deferred taxes as income for financial statement purposes. However, an electric utility must refund the excess deferred taxes to ratepayers, requiring the recording of a regulatory liability.

The challenging issue facing electric utilities is the timing of the payments to customers. Generally, if the excess deferred taxes are returned to the customers immediately, the utility's cash flow is sharply reduced. In addition, an immediate payment disproportionately benefits current customers—who receive the entire refund—and unfairly penalizes future customers, who pay for the cost of long-lived utility assets over their remaining useful lives and who may not receive any of the refund.

When Congress last reduced corporate tax rates in the Tax Reform Act of 1986, lawmakers resolved this issue by enacting a provision that would require state PUCs to refund the excess deferred taxes related to depreciation over the remaining lives of the assets. Congress should include a similar provision in any tax reform legislation that reduces the federal income tax rate. This would allow all customers who pay for the cost of utility assets over their useful lives to share in the return of the excess deferred taxes.

February 2013

EEI Edison Electric Institute
www.eei.org

Edison Electric Institute (EEI) is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have as Affiliate members more than 80 International electric companies, and more than 200 industry suppliers and related organizations as Associate Members.

Attachment C

SNL

RRA REGULATORY FOCUS

Wednesday, January 25, 2017 1:43 PM ET RRA

The past sheds light on how utility regulators may address tax changes

By Lillian Federico

Over the last several weeks, speculation has run rampant with respect to which of newly-inaugurated President Donald Trump's campaign positions will actually be implemented as national policy. Based on post-election pronouncements by Trump and House Republicans, there appears to be a consensus that an initiative to lower the corporate tax rate will come to fruition. Trump proposes to lower the corporate tax rate to 15%, and others have expressed support for a decrease in the tax rate to 20%, from the current 35%.

While the details of that change are far from certain, and there may or may not be other tax law changes that serve to offset or increase the associated reduction in utilities' ultimate tax liabilities, one thing is certain: regulators will want to see any resultant net tax expense reduction flow to ratepayers. However, when and how this will occur is likely to vary from state to state.

Some thoughts on the likely impact of a lower tax rate

Below are some initial thoughts on how a lower corporate tax rate might impact utility ratemaking.

Current/test year expense — Simplistically, a lower tax rate would mean lower tax expense that would need to be reflected in utility rate cases prospectively. In addition, the revenue conversion factor used to gross up targeted net operating income to determine the revenue requirement in a rate case would be reduced, thus lowering the overall revenue requirement. Depending on how soon after the new tax law becomes effective a utility has a rate case, there could be some refund exposure relative to existing rates reflecting the higher rate, depending on what approach the state regulatory commissions take, e.g., if commissions require all or the tax portion of utility revenue requirements to be collected subject to refund until a permanent solution is developed.

Depreciation — The lower corporate tax rate would, all else being equal, reduce the cash flow benefit of accelerated/bonus depreciation for tax purposes, which may or may not reduce the tendency of utility holding companies to take advantage of this favorable tax treatment. Assuming that there is a pull-back in reliance on accelerated depreciation, the build-up of accumulated deferred tax balances would slow. Since accumulated deferred tax balances are either used as an offset to rate base, or included in utility capital structures as zero-cost capital—both of which tend to reduce the overall revenue requirement—the prospective reduction in deferred tax balances, would at least partially offset the impact of the lower tax rates on revenue requirements.

Existing accumulated deferred tax balances — It is uncertain whether a reduction in the corporate tax rate would require a re-valuation of the existing deferred tax balances, but this could be the case since the philosophy behind the current treatment is designed to reflect the fluctuations in tax expense as a timing difference. In other works, all else being equal, if you looked at taxes on an asset-specific basis, the utility is paying lower taxes in the years where it is recognizing accelerated depreciation, i.e., recognizing a higher depreciation expense level than would be the case under a straight-line depreciation method, due to accelerated depreciation, but would pay higher taxes in later years once the asset is fully depreciated and there is theoretically no depreciation expense left to recognize.

Consolidated tax adjustments — A handful of states utilize consolidated tax adjustments in the context of setting rates for the utilities that are part of holding companies that file consolidated tax returns. The idea behind a consolidated tax adjustment, also referred to as an "actual-taxes -paid" methodology for determining the amount of tax expense to be reflected in a utility's revenue requirement, is essentially to capture for ratepayers the benefits associated with losses on non-utility operations. (For a more detailed discussion of this issue, refer to the Topical Special Report CONSOLIDATED TAX ADJUSTMENTS (a.k.a. Regulatory Confiscation?). The philosophical pros and cons of consolidated tax adjustments notwithstanding, their impact would be reduced if the corporate tax rate were reduced.

Will history repeat itself?

It has been 30 years since the Tax Reform Act of 1986 lowered corporate income tax rates to the current 34% from the previous 40% — the corporate tax rate increased to 35% during former President Bill Clintons' administration — and much about the framework of the industry and the state of the economy has changed since then.

• At that time, many utilities were stand-alone, vertically integrated, entities and were not part of holding companies, not to mention that foreign ownership was virtually non-existent. In addition, mergers and consolidations have markedly reduced the number of players, at least in the traditional power and gas utility space.

• The prior corporate tax reduction predated the introduction of electric wholesale and retail competition, and utilities were a more homogeneous group overall.

• The U.S. was coming to the end of the generation construction boom and capital spending was trending downward, while today capital spending is trending upward, and is focused largely on "non-revenue- producing" investments in infrastructure, i.e., investments that are not meant to meet demand growth or expand their service territories/acquire new customers.

• Demand growth while slowing, was robust by today's standards, and the related growth in revenue allowed utilities to stay out of the rate case arena to fund new investment and/or offset increases in expenses.

• The use of riders and other mechanisms to expedite the recognition of changes in costs and capital investment were much less prevalent than they are today.

These changes in the economy and the industry may alter the impact that a change in corporate tax rates will have on a given company and, as a result, regulators' responses may not be uniform. Even so, a look at how regulators addressed the issue in the past might be instructive.

Looking at two reports published in 1987 by Regulatory Research Associates, which is now an offering of S&P Global Market Intelligence, entitled The Tax Reform Act of 1986—A State by State Response , one published in February and a follow up published in June, four of the 50 jurisdictions then covered by RRA had tax adjustment mechanisms in place for one or more companies in each jurisdiction that would allow for a more-or-less current recognition of the change in corporate tax rates. As reported by RRA in an August 2016 report entitled Adjustment Clauses—A State-by-State Overview, about 20 of the 53 jurisdictions now covered by RRA has some mechanism in place to flow through to ratepayers changes in "certain taxes and fees." While these mechanisms are primarily related to municipal taxes and franchise fees, they do provide some precedent for the use of limited-issue mechanisms to address tax changes. Hence, these or mechanisms like them could potentially serve as vehicles for addressing at least the ongoing expense portion of the revenue requirement impact of a reduction in tax rates.

In addition, the 1987 report noted that in certain states where formula rate plans, and/or earnings sharing mechanisms are in place, the impact of the change in corporate tax rates would flow through those mechanisms in due course. Examples of such states include Alabama, Louisiana, and Mississippi, where most, if not all, all of the investor-owned electric and gas utilities are subject to formula rate plans, Texas, where many of the local gas distribution companies have implemented annual rate review mechanisms for at least a portion of their service territories, and also New York where many of the companies are subject to multi-year rate plans that include earnings sharing provisions, to name just a few. (Refer to the Alternative Regulation sections of RRA's state Commission Profiles for additional information on each state.)

About 40 of the 50 jurisdictions then covered by RRA initiated generic proceedings to address the impacts of the lower tax rates, 22 took action on a case-by-case basis, regardless of whether a generic proceeding had been conducted, 11 instituted rate cuts to reflect the lower tax rate or were ordered to do so on an issue-specific basis, and five jurisdictions declared rates to be temporary/subject to refund or required the utilities to set up a deferral account to capture tax expense difference, pending some type of proceeding addressing rates on an issue-specific or general basis.

At least one utility commission has already taken action in anticipation of a tax reduction. In a rate case decision for United Illuminating Co. issued on Dec. 14, 2016, the Connecticut CT Public Utilities Regulatory Authority stated: "If income tax rates change in the future, which materially impacts the revenue requirement allowed herein, the Authority may reopen this proceeding."

For a complete, searchable listing of RRA's in-depth research and analysis please go to the Research Library. Arizona Corporation Commission

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REGULATORY STUDY
February 14, 1987

TAX REFORM ACT OF 1986--STATE-BY-STATE RESPONSE

During the week of February 9, 1987 the RRA Staff surveyed utility regulatory agencies in 49 states and the District of Columbia with regard to any Commission, Staff, or utility company actions taken as a result of the Tax Reform Act of 1986 (TRA). In conducting the survey one of our primary goals was to determine whether studies had been initiated and/or data requests filed. In the course of the survey, which is comprehensive, but is not represented as all-encompassing, we determined that four states have tax adjustment mechanisms in place that impact one or more companies. We also ascertained that several utilities have implemented specific rate changes, or depreciation adjustments, to counter-balance the impact of the TRA, or have been authorized to do so. In some general rate cases completed in recent months, recognition was given to the impact of the TRA. Verbal descriptions of the Commission, Staff, or company actions taken in each state with regard to the TRA are contained in the paragraphs that follow. For additional information concerning developments in a particular state, please contact the RRA analyst responsible for regulatory coverage of that jurisdiction. While the data gathered does not lend itself to clear tabular summarization, we have compiled a summary table, which is presented on page 16. In this table we present a rough compendium of some aspects of the treatment, to date, of TRA savings on a state-by-state basis.

ALABAMA--The largest utilities in the state, Alabama Power, Alabama Gas, and South Central Bell Telephone, each has a Rate Stabilization and Equalization (RSE) provision in effect which provides for periodic adjustments to revenues based on the achievement of certain earned return on equity levels. Additionally, the tariffs of the major energy utilities include adjustment provisions to allow for reflection in customer rates of changes in income tax rates. Any tax impacts not covered through the tax riders for the energy companies are expected to be reflected through the RSE provisions. (For additional information concerning the RSE provisions of the companies see pages 3 through 5 of the November 1986 Alabama Annual Review.) The PSC has directed that a task force be established to review the potential impacts of the TRA, with the probable impacts on the telephone companies expected to receive the closest attention since telephone rates do not now contain a tax rider.

ARIZONA--The Staff of the Arizona Corporation Commission (ACC) is holding a series of informal workshops with companies to discuss the effects of the TRA. No pronouncements have been made or action taken by the ACC. The major concern seems to be over the TRA's effect on water companies, especially with

(Summary table appears on page 16.)

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regard to the treatment of contributions in aid of construction. On December 19, 1986, Arizona Public Service, a subsidiary of AZP Group, filed revisions to its Palo Verde 2 rate case. The company's revised filing fully reflects an anticipated $80 million revenue reduction impact of the TRA.

ARKANSAS--On August 28, 1986, the Arkansas Public Service Commission (PSC) approved Rate Rider M38 for Arkansas Power & Light (AP&L), a subsidiary of Middle South Utilities. The M38 Rider, as proposed by AP&L, and adopted by the PSC, was designed to reflect the estimated annual reduction in AP&L's revenue requirement as a result of then pending tax reform legislation. The M38 adjustment was based upon a 33% corporate tax rate, effective January 1, 1987, with any deviations from that tax rate or effective date to be reflected in a true-up to be conducted in August 1987. The M38 Rider provides for AP&L to refund, over a four-year period, that portion of its accumulated deferred income tax balance which exceeds the balance required under revised tax rates, where not prohibited by law. Additionally, the PSC initiated an informational docket requiring all jurisdictional utilities (except cooperatives) to file information that would indicate what, if any, tax savings are anticipated as a result of the TRA and to file informational tariffs to reflect the anticipated impact. Companies were asked to use a recent rate case test year or the data contained in the annual reports as filed with the PSC. The calculations are to reflect the corporate tax rate reduction from 46% to 34% and the refunding, over a two-year period, of the non-depreciation-related excess deferred income taxes. Companies may include comments regarding extenuating circumstances that they believe mitigate the need for rate reductions. While the initial filing deadline was February 10, 1987, extensions have been granted in some instances. No schedule has been established for Commission action.

CALIFORNIA--On November 14, 1986, the California Public Utilities Commission (PUC) initiated an investigation into the methods to be utilized by the state's major utilities to establish the proper level of tax expense for ratemaking purposes. The PUC ordered the Public Staff Division (PSD) and the state's major utilities to review and analyze the regulatory implications of the TRA. In establishing the Order Instituting Investigation (OII), the PUC ordered that all rates in effect for these utilities as of January 1, 1987 be collected subject to refund pending a final Commission decision in the OII. The investigation will be conducted through the workshop process. Hearings are expected to commence in March 1987, with the final order to be issued by mid-1987. In its final order the PUC will determine "if and how rates for each utility shall be adjusted." As part of a December 26, 1986 rate filing based on a calendar-1988 test year, Southern California Edison (SCE) has given recognition to the effects of the TRA. SCE has indicated that the TRA will have a cumulative effect of reducing the 1988 revenue requirement by approximately $250 million. In the Pacific Gas & Electric rate case decided in December 1986, the rate award was determined after giving recognition to roughly $85 million of TRA savings.

COLORADO--The Colorado Public Utilities Commission (PUC) has sent letters to all utilities requesting information as to the effects of the TRA and of FASB 87 (pension accounting) on operations. The PUC Staff is also meeting formally with some utilities to discuss the general effects of the TRA. The PUC plans to hire an outside consultant to prepare a questionnaire for utilities to use to provide information to the PUC by July 1, 1987, that will specifically identify the effects of the TRA on their operations. The Staff and the consultant will both submit reports and recommendations to the PUC based on data gathered, after which the PUC may take specific action with regard to the TRA.

CONNECTICUT--In September 1986, the Connecticut Department of Public Utility Control (DPUC) initiated a proceeding to review the financial and operating results of the state's major investor-owned utilities. Testimony filed in conjunction with this proceeding reflected each utility's best estimate of how

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the TRA would affect its revenue requirement. Based upon the Department's conclusion in this docket, the DPUC determined that additional action was necessary in several specific instances. Further action will be required with regard to Connecticut Natural Gas, Southern New England Telephone, United Illuminating, and Connecticut Light & Power. Southern Connecticut Gas is planning to file a rate application during the first quarter of 1987. The impact of the TRA will not be isolated, but will be considered in the context of each company's anticipated overall financial performance. (Additional detail concerning the DPUC's conclusions in the financial and operational review is presented on page 1 of the January 16, 1987 issue of FOCUS NOTES) The DPUC ordered utilities to elect one of three options regarding the treatment of contributions in aid of construction. A company can elect to: 1) charge additional tax-related expense to developers; 2) spread additional tax expense across-the-board to all customers; or 3) use a formula proffered by the Department.

DELAWARE--The PSC is examining the impacts of the TRA as part of separate earnings investigations initiated by the Commission in 1986 for Delmarva Power & Light and Diamond State Telephone. A decision in the Delmarva case is expected in April 1987 and hearings in the Diamond State case are scheduled for June 1987.

DISTRICT OF COLUMBIA--In December 1986, Potomac Electric Power (PEPCO) and District of Columbia Natural Gas (DCNG), together with the Office of People's Counsel (OPC), filed a joint stipulation and agreement with the PSC providing for the companies to institute rate decreases to reflect the impact of the TRA. PEPCO's filing proposed an $18.2 million rate decrease to be effective as of January 1, 1987, and specified that the PSC not entertain any petition to change rates that would affect PEPCO's authorized revenue level. DCNG filed to institute a rate reduction of slightly less than $0.5 million. The PSC held hearings for DCNG's petition on February 5, 1987 and has scheduled hearings for PEPCO on February 18, 1987. A final PSC decision is expected in each of these cases during March 1987. In January 1987 the PSC instituted a TRA-related investigation for Chesapeake and Potomac Telephone (C&P). On February 10, 1987 C&P, the OPC, and the Commission's Staff filed a joint stipulation and agreement with the PSC to institute a rate reduction of $3.3 million to reflect the impact of the TRA. C&P's filing specifies that the Commission not institute any further rate change during 1987.

FLORIDA--One of the Florida Public Service Commission's (PSC) regulations is its Tax Savings Rule, which provides that any earnings in excess of the mid-point of the last authorized return on equity range are required to be refunded to the extent these earnings are generated by changes in tax rates. In each rate case the PSC establishes the mid-point of a 200 basis point return on equity range as the target equity return for the utility. For most major utilities the target return last established was between 14.5% and 16%. However, various actions and settlements have provided that lower return levels be utilized for the measurement of any refund obligation under the Tax Savings Rule for calendar 1987.

On November 4, 1986, the PSC approved a settlement agreement entered into between Florida Power Corporation (FPC) and the Florida Office of Public Counsel (OPC) which provided for FPC to institute a temporary rate reduction of approximately $54 million for calendar-year 1987. FPC agreed to "credit the monthly rates charged its retail customers in the total annual amount of $54,000,000," with the provision that this reduction "contemplates savings from pending federal income tax revisions" based on a blended statutory tax rate of approximately 40% for 1987 versus the 1986 statutory rate of 46%. It was anticipated that the company's federal income tax requirement would be reduced by approximately $30 million in calendar-1987. Since the rates provided for in the settlement affect only 1987, FPC's rates will revert to 1986 levels effective January 1, 1988, barring some further regulatory action.

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On December 16, 1986, the PSC approved a settlement agreement in the Southern Bell Telephone (SBT) earnings investigation proceeding. In the settlement, SBT, a subsidiary of BellSouth, identified the tax benefits related to the TRA to be $54 million in calendar-1987 and applied this amount toward increased capital recovery expense.

On December 16, 1986, the PSC first considered the request by the Staff that the Commission initiate an investigation into the effects the TRA on the revenue requirements of the regulated utilities, but the PSC did not require revenues to be collected subject to refund. However, the Commission indicated that the docket would be changed from investigatory to a show cause proceeding, and all parties (except those that had previously settled), were encouraged to work towards settling contested issues in an expeditious manner. On January 20, 1987, the PSC accepted the offers of Florida Power & Light, Gulf Power, and Tampa Electric that any rate refunds that might be required as a result of the application of the Tax Savings Rule should be calculated based upon a 13.6% return on equity rather than utilizing the previously authorized equity return levels established for each company. (For additional information see pages 1 and 2 of the January 23, 1987 issue of FOCUS NOTES.) Settlement talks are continuing between the parties with regard to the appropriate action, if any, to be taken with regard to General Telephone Company of Florida, Central Telephone of Florida, and United Telephone of Florida.

GEORGIA--The Georgia Public Service Commission (PSC) has not held or ordered a generic proceeding with respect to the TRA, however, the hiring of a consultant to review and make recommendations on handling of the TRA is probable. With Georgia Power and Atlanta Gas Light expected to file rate cases in 1987, TRA issues are expected to be considered as part of these proceedings.

HAWAII--On January 21, 1987, Hawaiian Electric Industries announced that its subsidiaries had filed with the Hawaii Public Utilities Commission (PUC) to reduce rates by a total of approximately $4.9 million on a system-wide basis. The rate reduction proposed is composed of the following base rate reductions: $3.3 million for Hawaiian Electric, $1.2 million for Maui Electric and $0.4 million for Hawaii Electric Light. All the companies are subsidiaries of Hawaiian Electric Industries. The proposed rate reductions reflect the impact of the TRA as well as higher sales and lower debt costs. The filings are based on the rates of return last authorized by the PUC for each company and are proposed to become effective February 1, 1987. A PUC response is now pending. No such action regarding the TRA has been undertaken by Hawaiian Telephone.

IDAHO--On January 7, 1987, the Idaho Public Utilities Commission (PUC) ordered all utilities under its jurisdiction to file data comparing the utility's tax expense for 1986 under the old tax law with the utility's hypothetical tax expense for 1986 utilizing new tax rates. These filings are to be submitted by March 31, 1987. Companies showing a decrease in tax expense are required to file tariffs designed to reflect the reduction, and revised tariffs will become effective July 1, 1987.

ILLINOIS--On December 31, 1986, the Chief Accountant of the Rate Review Department of the Public Utilities Division of the Illinois Commerce Commission (ICC) wrote to all the state's major utilities requesting them to file data and a rate rider with the ICC within 30 days in order for the Commission "to implement the ratemaking effects of the new tax law on a timely basis." It was requested that "the rider state the percentage by which all utility rates must be reduced to reflect the use of a 40% tax rate for 1987" based on each company's most recent rate order. This percentage reduction would be applied to all utility billings, however, customer bills would not be reduced. Instead, the amount would be accrued in a deferred credit account, with an offsetting debit to revenue. This deferred credit account would continue to accrue until a final ICC determination with regard to each company's financial position. It was the Chief

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Accountant's view that "if the Commission determines that current earnings when adjusted to reflect all aspects of the new tax law are excessive, refunds will then be made to customers from the deferred credit account." Although not specifically described, excess earnings were indicated to be earnings above the previously authorized return on equity level. No formal ICC action has as yet been forthcoming with regard to implementation of any rate changes. On January 27, 1987, the ICC ordered Northern Illinois Gas (NIGAS), a subsidiary of NICOR, to temporarily reduce base rates by approximately $7.4 million (1.9%). The ICC concluded that the company was earning a 16.29% return on equity compared to its previously authorized 15.55% and, therefore, a $7.4 million rate reduction was necessary "to ensure that the Company's rates are not excessive." The ICC also ordered a general rate case for NIGAS, which has not had a rate case since 1982. The rate case will examine, along with the usual issues, the effect of the TRA on the company's revenue requirement. The recent rate settlement proposal by Commonwealth Edison gives effect to the impacts of the TRA in 1987 and years following.

INDIANA--On November 26, 1986, the Indiana Public Service Commission (PSC) appointed an Executive Committee and provided for the establishment of four task forces to examine the effect that the TRA will have on utilities in Indiana. This investigation will help the PSC develop uniform procedures in making any necessary changes in accounting treatment or adjustments to rates as a result of the new law. The Committee, chaired by the PSC Utilities Director Robert Glazier, appointed four separate task forces representing the telephone, electric, gas, and water and sewer industries. The task forces are to report by March 16, 1987. A comprehensive report recommending a specific course of action should be filed by the Executive Committee by April 1, 1987. On December 2, 1986, Northern Indiana Public Service announced it was reducing the requested rate increase amount in its pending rate case by $59.4 million to adjust for the impact of the TRA. Indiana and Michigan Electric Company also has a rate case in progress, and on October 15, 1986, the company lowered its requested rate increase amount to give recognition to the effects of the TRA.

IOWA--On October 24, 1986, the Iowa Utilities Board (IUB) ordered the state's large utility companies to report on the expected impact of the TRA. The investor-owned utilities were ordered to submit the following information: 1) Estimated change in current income tax payments, deferred federal tax accruals, and revenue requirements; 2) Anticipated effect of eliminating the investment tax credit; 3) The overall effect on the company of tax reform, including estimates of when the effects will occur; and 4) A plan for distribution of the benefit or detriment between stockholders and ratepayers. On February 6, 1987, the IUB adopted emergency rules, effective April 1, 1987. "The purpose of these rules is to recognize the substantial impact on the tax liability of rate-regulated investor-owned utilities as a result of the Tax Reform Act of 1986 and prevent unnecessary utility revenue shortfalls or windfalls." The IUB has ordered the utilities to determine a revised revenue requirement and to design rates which reflect the adjusted revenue requirement. The revised tariffs must be filed by May 1, 1987, and are expected to become effective July 1, 1987. The IUB devised a formula, which is to be applied to 1986 financial data and will isolate the revenue requirement impact of the new tax law. Comments on the rulemaking are to be filed by March 17, 1987.

KANSAS--The Staff of the Kansas State Corporation Commission is conducting an investigation into the TRA's impact on each of the state's utilities. Each utility has been asked to submit an analysis of the TRA on its operations for the 1987 to 1991 time period. When the Staff's investigation has been completed, a report will be prepared for the Commissioners. It has not yet been determined whether rate adjustments, if any, will be considered in a generic docket or whether each utility will be treated on a case-by-case basis.

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KENTUCKY--On December 11, 1986, the Kentucky Public Service Commission (PSC) initiated a proceeding to review the effects of the TRA on the state's investor-owned utilities with revenues in excess of $1 million. The Commission intends to isolate the effects of the TRA and not consider additional rate case issues. The PSC indicated that it intends to reflect the revenue effects of the TRA in consumer rates as expeditiously as possible--whether savings or additional costs are identified. The Commission stated that it "does not view retaining the savings that result from tax reform as a proper way for a utility to improve its earnings. Likewise, if the Tax Reform Act should result in major cost increases, these costs should be recognized in rates expeditiously." While testimony from the affected utilities was originally due by January 26, 1987, some companies have been granted filing extensions. The PSC will review the impact of the TRA on General Telephone of the South's revenue requirement in conjunction with its pending general rate case.

LOUISIANA--On December 2, 1986, the Louisiana Public Service Commission (PSC) approved a petition by Central Louisiana Electric Company (CLECO), filed the same day, proposing that its electric rates be reduced by $11.5 million over the next two years. This filing was tendered by CLECO on December 2, 1986 in order to pass along to customers the benefits of the TRA. The rate decrease for calendar-1987 is $5.3 million, with an additional decrease of $6.2 million to become effective in 1988. The average decrease in residential customers bills will be roughly 4% over the two years. The PSC recently authorized a rate increase for Louisiana Power & Light (LP&L). In establishing LP&L's rates the PSC gave recognition to the impacts of the TRA. For other utilities in the state the TRA impacts will be considered on a case-by-case basis. No other specific actions have yet been initiated.

MAINE--The Maine Public Utilities Commission (PUC) has issued a Procedural Rule for the purpose of obtaining from utilities information regarding the TRA, cost of capital, and other revenue requirement data. Other than the two instances noted below, the PUC intends to informally discuss with each company whether any rate changes will be implemented as a result of the new data. On February 2, 1987, New England Telephone (NET) submitted a rate case filing in which the company supported the continuation of present rate levels. A PUC order issued on November 26, 1986 directed NET to file a rate case in order to provide an opportunity for the PUC to examine the company's jurisdictional earnings and the effects of the new tax law. NET's filing includes rate of return data, but the company did not request a change in the 11.21% rate of return last authorized in a case concluded in 1983. (The company calculates that the overall return last authorized equates to about a 13% return on equity currently.) According to NET, the filed data support current rate levels because the effects of the new tax law changes and other known and measurable changes are offset by increased capital recovery expenses incurred because of depreciation represcription. Bangor Hydro-Electric has been directed to file a rate case by February 23, 1986, and the TRA impacts are expected to be reviewed in that case.

MARYLAND--On January 2, 1987, the PSC adopted a stipulation calling for Delmarva Power & Light (DP&L) to reduce base rates by $3.3 million (2.3%) to reflect the impact of the TRA. The stipulation had been filed on December 31, 1986 by DP&L, the PSC Staff and the Office of People's Counsel. The stipulation occurred in the Phase II proceeding initiated by the PSC in its October 2, 1986 order. That order accepted a settlement in DP&L's earnings level investigation which resulted in the implementation of a $5.6 million (5.2%) base electric rate reduction. The January 2, 1987 PSC action, as set forth in the stipulation, directs DP&L to propose, by December 1, 1987, an additional base rate reduction to reflect the TRA's impact on the company's financial position on and after January 1, 1988.

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On November 10, 1986, Potomac Electric Power (PEPCO) filed testimony in a PSC-initiated earnings investigation, with the testimony supporting a \$23.2 million (3.5%) rate increase. As the PSC had directed, PEPCO's filing provides for the impact of the TRA. Hearings are scheduled to conclude in this case in the spring of 1987, with a PSC decision likely by June 1987. Also on November 10, 1986, Baltimore Gas and Electric (BG&E) filed testimony in a PSC-initiated earnings investigation, without proposing any dollar amounts of rate change. Though no tariffs were specified, BG&E's position incorporates the impact of the TRA, as directed by the PSC. Hearings are scheduled to conclude in this case in the spring of 1987, with a PSC decision likely by June 1987. In January 1987, the Commission sent letters directing the remaining utilities in the state to file data reflecting the estimated financial impact of the TRA. The utilities are to file their responses during February 1987. The Commission's Staff shall review the responses and determine if any further steps need to be taken for the utilities involved.

MASSACHUSETTS--On January 28, 1987, the Massachusetts Department of Public Utilities (DPU) ordered the state's utilities to file information computing the effect that the decrease in the federal corporate tax rate will have on their revenue requirements as of July 1, 1987. Each company is being required to submit a method to implement adjustments in its rates to reflect any reduction in revenue requirements resulting from the change in the corporate tax rate. The utilities are to submit their financial plans, with supporting documentation, to the DPU by February 27, 1987. Depending upon the DPU's findings following a Department review of the companies' filings, rate cases to more fully investigate the revenue requirements of individual companies may be initiated. The Department noted that while the total impact resulting from all of the changes in the federal tax law affecting utilities will have to be considered in detail, present utility rates are based on a higher tax rate, and therefore it is appropriate to consider an immediate adjustment to utility rates to pass through to ratepayers any benefits derived from the decrease in the federal corporate tax rate. The Department stated that "while we recognize that resolving all of the ratemaking consequences of the new tax code is a complicated matter that may eventually have to be considered in more detail in the context of each company's next general rate proceeding, it is administratively impossible for the Department to conduct a complete rate proceeding for every Massachusetts company before July 1, 1987. It is for this reason that we are voting to open this limited proceeding."

Western Massachusetts Electric's (WMECO) currently pending rate request reflects the impact of the TRA on WMECO's revenue requirement based upon a blended tax rate of 39.5%. WMECO is a subsidiary of Northeast Utilities. New England Telephone (NET), a subsidiary of NYNEX, incorporated the effect of the TRA in the revenue requirement data filed with the DPU on January 5, 1987 in conjunction with the cost-of-service docket in which the Department is reviewing NET's earnings.

MICHIGAN--On October 28, 1986, the Michigan Public Service Commission (PSC) opened an official docket to receive information with regard to the impact of the TRA on the state's utilities. In this docket the PSC required that all investor-owned, state-regulated companies submit information on how each would be affected by the TRA. The action came on the PSC's own motion, and was a follow-up of a September 3, 1986 memorandum from the PSC's Director of Technical Services to each jurisdictional utility. That memo requested each company to submit to the PSC, 30 days after the signing of the new tax law, data to show the effect of the new law on utility rates. On December 17, 1986, the PSC ordered the state's electric, gas and telephone utilities to file data by February 17, 1987, indicating the impact of the TRA on their 1986 test year operations. The PSC noted that the lower federal tax rates will mean increased profits for most utilities and may make possible a downward adjustment of present rates. The

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utilities were ordered to file the documentation showing the net effects of the new tax law on their rates and to show cause why their rates should not be reduced to reflect the lower taxes. While it appears that settlements will be encouraged for TRA items only, a separate docket will be established for each utility, and in instances where settlements are not achieved a contested rate proceeding will be commenced in which interested parties will be permitted to address the effects of the tax bill on the prospective utility rates. Rate revisions for most utilities are likely to become effective July 1, 1987; however, the effective dates of any rate changes will be decided on a case-by-case basis.

MINNESOTA--The Minnesota Public Utilities Commission (PUC) initiated a rulemaking proceeding requiring the state's utilities to file recomputed 1986 data utilizing the 34% tax rate that will become effective July 1, 1987. In addition, the PUC is intending to introduce a bill to the state legislature which would effectively make all utility rates in the state interim rates, subject to refund, July 1, 1987. The PUC has already issued rulings regarding the TRA for two companies, Northern States Power (Gas) and People's Gas, in recently decided rate cases. The effect of the TRA will be considered in Otter Tail Power's currently pending rate case and in Minnesota Power's forthcoming rate proceeding, which is likely to be filed in May 1987. The effects of the TRA for the remaining companies will be considered generically, although the PUC has yet to determine an appropriate methodology. For the electric division of Northern States Power, the TRA effects will likely be considered in conjunction with a yet-to-be-filed proceeding to reflect the rate base inclusion of Sherco 3, which is coming on line later in 1987.

MISSISSIPPI--The impact of the TRA is, for the most part, being dealt with on a case-by-case basis. Mississippi Power & Light (MP&L) and the gas distribution companies have income tax riders in place which are adjusted routinely to reflect tax law changes; however, the anticipated effects of tax law changes were incorporated into MP&L's rates when the second step of the Grand Gulf phase-in was approved by the Mississippi Public Service Commission (PSC). Discussions are underway to determine how the revenue impact of the TRA can be factored into Mississippi Power's (MP) Performance Evaluation Plan (PEP). The PEP is used by the PSC to evaluate MP's financial and operational performance and to review the reasonableness of the company's rates quarterly. The PSC opened a docket for South Central Bell (SCB) for the specific purpose of investigating the impact of the TRA. Based upon the analysis of the data filed by SCB, rate adjustments are expected to be made. The PSC has not determined whether the rate adjustments will be across-the-board, to particular services, or to access charges.

MISSOURI--On November 3, 1986, the Missouri Public Service Commission (PSC) established an investigatory docket to receive information from utility companies as to how they will be affected by the TRA. The utilities were required to file information regarding their revenue requirement based on calendar-1985 data under the current tax law and the new tax law by December 15, 1986. Similar data based upon calendar-1986 results must be filed with the PSC by March 2, 1987. Furthermore, each company was asked to file comments addressing procedural alternatives for recognizing the effects of the TRA. The companies generally indicated that they did not contemplate filing tariffs to implement rate reductions in the near future. On January 30, 1987, the PSC ordered the Staff to set up informal meetings with the parties for the purpose of negotiating settlements regarding rate reductions to reflect the effect of the TRA. If a negotiated settlement is not reached between a specific company and the other parties, the Staff is expected to file a formal complaint seeking a rate reduction, thereby paving the way for a full rate review. On February 12, 1987, the PSC approved a $5 million rate reduction following a stipulation between St. Joseph Light & Power, the Public Counsel and the Staff. Approximately $2.4 million of the reduction is related to the TRA.

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MONTANA--In November 1986 the Montana Public Service Commission (PSC) issued an Order to Show Cause requiring each Montana public utility to submit data, on February 1, 1987, reflecting the impact of the TRA. Most of the state's utilities filed the required data by February 1, 1987, but some of the smaller utilities were granted extensions. The PSC has not taken any action on the data submitted thus far. In those instances where a company has a rate case pending before the PSC, the effect of the TRA will be treated within the context of that rate case. Where no rate case is pending, the issue will be handled on a case-by-case basis. Each utility not currently before the PSC, is expected to file a limited issue proceeding, incorporating the effects of the TRA as well as updated test period items. Intervenors will be free to propose the expansion of the scope of any proceeding to include the examination of the allowed rate of return.

NEBRASKA--No action has been taken by either the PSC or by the utilities with respect to the impacts of the TRA.

NEVADA--In October 1986 the Nevada Public Service Commission (PSC) opened a generic docket to establish new rules and policies concerning the TRA, but has not yet required the state's utilities to file data reflecting the impact of the TRA. A prehearing conference was held February 3, 1987, and a workshop involving all interested parties will take place during the first two weeks of April 1987. Hearings will be held in June 1987 concerning all items not resolved by the April workshop. The PSC is expected to issue its new rules and policies in the fall of 1987. No rate changes related to the TRA are expected to be implemented prior to 1988, and it is uncertain at this time whether the changes will take place in the context of a general rate case or a limited-issue case.

NEW HAMPSHIRE--On December 1, 1986, the New Hampshire Public Utilities Commission (PUC) issued an order directing the state's public utilities to file, by February 1, 1987, data concerning the effect on each company of the TRA. While some of the smaller utilities in the state were granted extensions, the two largest utilities, Public Service Company of New Hampshire (PSNH) and New England Telephone (NET), submitted their data by the appointed deadline. For PSNH the revenue requirement reduction expected to flow from the TRA will be considered in the context of the company's currently pending rate case. While NET currently has no rate case pending, the impact of the TRA is expected to be considered in the company's depreciation represcription proceeding, which is to be decided in April 1987.

NEW JERSEY--The New Jersey Board of Public Utilities (BPU) has taken a series of actions with regard to the TRA. On October 10, 1986, BPU President Barbara Curran directed the Board Staff to conduct a review of utility company obligations under the new TRA and to determine whether customer rates could be reduced without detriment to company services. She stated that the tax reform legislation allows a significant reduction in corporate tax rates and might "possibly warrant Board action to insure that utility companies reduce their rates to reflect this reduction in operating costs," and noted that the legislation reduces certain tax benefits for companies undertaking building programs. She specifically requested that the review be undertaken to determine if rates could be reduced "without affecting the ability of these companies to raise funds for necessary capital improvement programs" and noted that it would be "important as well to take care that this is not done at the expense of their services." On December 10, 1986, the BPU voted to allow New Jersey Bell Telephone (NJBT), a subsidiary of Bell Atlantic, to accelerate the amortization of its depreciation reserve deficiency, effective January 1, 1987, with the deficiency to be amortized over a 3.5-year period versus a 15-year period. NJBT calculated that the effect of the TRA would be to reduce its revenue requirement by $37 million in 1987 and $82.6 million thereafter, and the company proposed that the BPU require a rate reduction July 1, 1987 only of the net difference

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between recognized revenue requirement increases associated with increased depreciation and the reductions associated with the TRA. The BPU largely adopted NJBT's proposal, but voted to give further consideration to the precise amount of revenue reduction to become effective July 1, 1987, initially estimated at $33.7 million annually.

On December 18, 1986, the BPU approved the $23.3 million rate reduction proposal that had been submitted by Jersey Central Power & Light (JCP&L) on November 24, 1986. JCP&L, a subsidiary of GPU, had requested effectuation of the $23.3 million (1.6%) rate cut on January 1, 1987, to reflect the 1987 impact of the TRA. A similar decrease will be proposed to recognize further tax rate changes scheduled to become effective January 1, 1988. The rate proposal, and BPU action, make no revision in the company's presently established rate of return. The rate change approved by the BPU provides that 1988 rates will be adjusted for further tax rate changes and to reflect any corrections or revisions that Congress makes to the tax law during 1987. Elizabethtown Gas currently has a proceeding before the BPU in which it seeks a $21.5 million rate increase. As part of the proceeding the company gives recognition to the provisions of the TRA. In the recent Public Service Electric & Gas (PSE&G) electric rate case the BPU gave consideration to the $77 million 1987 rate reduction impacts of the TRA when calculating the Electric Department revenue increase requirement. The 1988 impacts of the TRA will be considered for PSE&G's electric operations along with other rate changes to become effective January 1, 1988.

On January 6, 1987 the BPU issued an order directing that the effects of the TRA "should be deferred upon the utilities' books and records effective January 1, 1987, so as to preserve its effect and ultimately pass along fully the likely reduction in revenue requirement to ratepayers." This directive, which applies to all companies not covered by earlier settlements, was issued to "permit the Board full latitude for review and disposition of full recognition of the tax savings to ratepayers." The companies' have been required to submit data showing detailed calculations of the TRA upon their revenue requirement by comparing the last BPU approved test year data under the old and the new tax laws. The utilities were also directed to submit tariff design proposals. The TRA tax deferral impacts are to continue until the effective date of the first base rate, fuel clause or Phase II proceeding for each company during 1987. If no rate change is anticipated or planned during calendar-1987 the utilities affected are to have the 1987 effects of the TRA reflected in rates no later than March 31, 1987. All investor-owned utilities with 1986 annual revenues equal to or greater than $2 million are covered by the order.

NEW MEXICO--The Staff of the New Mexico Public Service Commission (PSC) filed a petition, asking the Commission to require each jurisdictional utility to file an updated cost-of-service based upon a recent test year, including the impacts of the TRA. On December 31, 1986, the PSC ruled that it would not docket the case, but issued a formal letter requesting that each company file the information sought by the Staff by March 30, 1987. The New Mexico State Corporation Commission has not initiated any action regarding the TRA.

NEW YORK--On November 13, 1986, the New York Public Service Commission (PSC) adopted the Staff's recommendation that the Commission seek comments from interested parties regarding the Staff's proposed accounting and ratemaking procedures related to the TRA. The Staff proposed that "the lower tax expense be preserved for ratepayers and that it not enhance the earnings of the State's utilities....We recommend that the utilities defer the impact of TRA-86 until the benefits can be passed on to customers in a rate proceeding....The most effective mechanism for capturing the benefits of the new tax laws for ratepayers is to initially prescribe deferred accounting for the impact of tax changes. The changes can be implemented in the first rate increase (including second or third stage filings) subsequent to the changes. This will provide some measure of rate

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stability for the near term." On December 10, 1986, in response to the Commission's above-noted solicitation for comments, the Consumer Protection Board (CPB) filed a petition for "temporary rate reductions to reflect Tax Reform Act savings and cost of capital decreases." The CPB stated that it was "firmly opposed to Staff's general proposal for deferral accounting. Instead, we recommend prompt temporary rate reductions to reflect the TRA savings as well as the recent sharp decline in the utilities' cost of capital, a factor that Staff's proposal does not address."

On January 28, 1987 the PSC voted to have each of the state's utilities defer the savings attributable to the TRA as of January 1, 1987. The PSC ruled that the changes resulting from the TRA would be considered in the next rate case for each company. National Fuel Gas Distribution (NFGD) became the first New York company to receive rate treatment related to the TRA. On January 14, 1987, the PSC adopted a settlement agreement for NFG&D that was based on a calculation of the current revenue requirement effect of the TRA through March 31, 1988, with the exception of the effects resulting from uncollectable accounts, contributions in aid of construction, and unbilled revenue. On January 8, 1987, the PSC initiated a proceeding to consider a comprehensive rate plan for New York Telephone (NYT). The plan, which calls for a $50 million rate reduction in August 1987 and extends a rate increase moratorium until January 1990, is to be financed by, among other items, a return reduction and cost savings from the TRA. On February 10, 1987, the PSC directed Consolidated Edison to show cause why its electric rates should not be reduced immediately by $165 million, with approximately $53 million of the reduction flowing from anticipated lower tax expense under the TRA. The PSC actions for NYT and Con Ed stem from the fact that these companies do not have a pending rate case and apparently have no plans to file a rate petition in the near future.

NORTH CAROLINA--On October 23, 1986, the North Carolina Utilities Commission ordered initiation of an investigation to determine the effects of the TRA on the obligations of each of the utility companies under its jurisdiction. The NCUC ordered each utility to determine the dollar impact of the tax law change and to file such with the Commission no later than November 30, 1986. The NCUC stated that certain provisions contained in this wide-ranging tax reform will, upon implementation, significantly reduce the effective tax rate of most, if not all, investor-owned public utilities engaged in providing electric, telecommunications, and natural gas distribution services in North Carolina. In addition, the NCUC order placed the affected utilities on notice that the federal income tax expense component of all existing rates and charges, effective January 1, 1987, will be billed and collected on a provisional rate basis pending further investigation and disposition of this matter. In December 1986, Duke Power filed with the NCUC recommending an approximate $48 million TRA-related rate reduction. The NCUC subsequently accepted Duke's proposal and made the rate reduction effective as of January 1, 1987. Several other utilities have filed proposed TRA-related tax reductions, however the Commission has not yet issued orders in these cases. Carolina Power & Light has included the TRA's impacts in its pending rate case. All the TRA-related filings, including Dukes, are to be examined by the NCUC with decisions likely later in the year. In all likelihood, the treatment of deferred taxes balances will be an issue in the Commission's study, and further investigation may be undertaken in the future with regard to the tax rate reductions scheduled to take effect January 1, 1988.

NORTH DAKOTA--The North Dakota Public Service Commission (PSC) has issued an order directing the utilities to file information on the TRA and its effect on revenue requirements. The companies were also asked to submit proposals regarding rate changes occasioned by the TRA. The PSC will then informally deal with each company when deciding what, if anything, will be done to rates. A January 27, 1987 rate decision for Montana-Dakota Utilities reflected the effect of the TRA.

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OHIO--On November 12, 1986, the Chairman of the Ohio Public Utilities Commission (PUC) sent a letter to all of the major utilities in the state requesting that each company submit an estimate of the effects of the TRA by December 31, 1986. In addition, the Chairman requested that each utility submit a proposal recommending an appropriate methodology to dispose of the tax issue. Each of the major Ohio utilities have responded to the Chairman's request, and the responses have included proposals to reduce rates to reflect the tax savings as well as proposals to retain the tax savings in order to postpone the filing of future rate cases. Two companies, Monongahela Power and East Ohio Gas, have already received rate recognition of the TRA in rate cases decided in December 1986. The PUC will be issuing independent responses to the remaining utilities on this issue. In fact, two utilities have already received PUC action on their respective TRA proposals. On January 13, 1987, the PUC adopted Columbia Gas' proposal to reduce rates by $6.7 million and on February 10, 1987, the PUC approved Ohio Power's proposal to reduce rates by $7.1 million. Each of these companies will file a report to the PUC at the end of 1987 estimating the effects of the TRA for 1988.

OKLAHOMA--On October 23, 1986 the Staff of the Oklahoma Corporation Commission (OCC) filed an application seeking OCC approval to commence an investigation of the state's 12 largest investor-owned utilities to determine if rate decreases should be required as a result of changes in federal tax laws. The Staff proposed that the Commission order a technical conference to establish a time schedule for audits of company records and public hearings. The companies named in the Staff's application included: Empire District Electric, Oklahoma Gas & Electric (OG&E) Public Service of Oklahoma (PSO), Southwestern Public Service, Arkansas-Louisiana Gas, Arkansas-Oklahoma Gas, Lone Star Gas, KPL/Gas Service, Oklahoma Natural Gas (ONG), General Telephone of the Southwest, and Southwestern Bell Telephone (SWBT). The OCC has not acted on the Staff's application; however, the information sought by the Staff has been provided by the utilities. Based upon data which incorporated a 40% blended tax rate, the Staff determined no immediate rate action was necessary. The Staff is now asking for information regarding the impact of a 34% corporate tax rate. The Staff is about to begin expedited audits of ONG and PSO. Mini-rate case proceedings are expected to be conducted following the audits. The impact of the TRA, as well as the appropriate allowed rate of return will be reviewed. The Staff intends to conduct audits of OG&E and SWBT as well. On October 22, 1986, OG&E petitioned the OCC for a $50.2 million rate reduction with approximately $32.8 million to become effective July 1, 1987 to reflect the impact of the TRA. On December 31, 1986, a rate reduction of $0.1 million was ordered for Empire District Electric in conjunction with the company's biennial review and to reflect the impact of the TRA.

OREGON--In early 1987 the Oregon Public Utility Commissioner (PUC) informed the state's utilities that the disposition of the savings from the TRA would be considered in the context of an open docket, if one was available. For those utilities without an open docket, the PUC requested that information be filed indicating the effect of the TRA in 1987. The PUC will apparently order that the savings from the TRA be flowed through to customers in those situations where utilities are determined to be "over-earning" the allowed return on equity. Conversely, the PUC will consider allowing those utilities which are "under-earning" allowed returns on equity to retain the benefits from the TRA. The TRA was not an issue in the rate case for PacifiCorp that was concluded January 8, 1987, when the PUC authorized a $22.6 million rate increase following the signing of a stipulation by the parties. The TRA issue for PacifiCorp is now being considered in a one-issue proceeding, with hearings in this case to occur in late March 1987.

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PENNSYLVANIA--On December 18, 1986, the Pennsylvania Public Utility Commission (PUC) issued a ruling requiring the state's large utilities to establish temporary rates effective January 1, 1987, pending final PUC action with regard to any rate changes ultimately occasioned by passage of the TRA. Those utilities that had previously settled rate cases that accounted for the TRA impacts, or that have rate cases in progress in which the impacts of the Act will be considered, are to be accorded different treatment. Although not specifically stated, the implication of the PUC action establishing temporary rates appears to be that the Commission will ultimately require a dollar-for-dollar adjustment of the rates of each utility to reflect the full impact of the TRA. Further company filings are expected to be called for, with final PUC action anticipated by mid-1987. The PUC declined to adopt a proposal that had been offered by the Office of Consumer Advocate that the Commission establish a negative federal tax adjustment surcharge. No action was taken on the petition by Philadelphia Electric (PECO) that would provide a credit for ratepayers rather than passing back dollars at this time. PECO requested that there be a credit of the savings from the TRA against deferred revenues for the Limerick Nuclear Unit No. 1 which is being phased into rates, with this credit tending to reduce the amount of uncollected deferred revenues. Also on December 18, 1986, the PUC largely approved the request by Pennsylvania Power & Light (PP&L) to place the impact of three proposed rate changes into effect simultaneously on January 1, 1987 one of the changes being the $47 million impact of the TRA. Duquesne Light, Pennsylvania Power, and Columbia Gas of Pennsylvania, are major utilities in the state with rate cases currently in progress. The effects of the TRA are being considered in these rate proceedings. On January 30, 1987 the PUC approved settlement petitions providing for TRA rate reductions for Metropolitan Edison and Pennsylvania Electric, both subsidiaries of GPU. These rate reductions were negotiated as provided for in settlement rate orders for both companies issued on November 25, 1986. The rate reductions negotiated for 1987 are based on estimated blended tax rate of 40% for this year, with next year's reductions assuming a further corporate tax rate reduction to 34%. (See page 3 of the February 6, 1987 issue of FOCUS NOTES for additional detail.)

RHODE ISLAND--During the first week of February 1987, the Division of Public Utilities (DPU) sent letters to utilities requesting cost-of-service, rate base, and return data for calendar-1986, and also asked for information on the impact of the TRA on revenue requirements. The DPU is expected to review the information with the companies in March 1987, with any PUC action to follow. A January 12, 1987 rate decision for Blackstone Valley Electric Company (BVE) included the effect of the TRA. BVE was also ordered to file a second set of tariffs that will reflect the further lowering of the tax rate in 1988 under the TRA. The secondary tariffs will be implemented when the additional tax rate reduction takes effect.

SOUTH CAROLINA--In July 1986 the South Carolina Public Service Commission (PSC) directed utilities to file data on "the impact of federal tax changes as applied to the company's 1985 operations" within 60 days after Congress and the President act on tax reform legislation. As well, the PSC had separately directed the Staff to investigate the cost of common equity for the major utilities in the state and determined that if the Staff's cost of equity determinations are available by the time the tax-impact reports are filed, the PSC would be in a position to formulate its position and make any decisions on the basis of the knowledge provided from both reports. On December 16, 1986, the PSC voted to order Duke Power to lower its base electric rates by approximately $20.2 million (2.3%) effective January 1, 1987 to reflect the impact of the TRA. On December 12, 1986, Duke had filed data with the PSC indicating that it would experience approximately $20.2 million of savings due to the TRA. The PSC indicated its intention to continue to investigate the impact of the tax bill on Duke and to ensure that the company's customers receive the full benefits of any tax savings. On January 14, 1987, the PSC directed South Carolina Electric &

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Gas (SCE&G) to reduce retail electric rates by approximately $25.5 million (3%) to reflect anticipated savings from the TRA. In December 1986 SCE&G had filed its report setting forth its estimated tax savings under the TRA. The Commission voted unanimously to pass the full savings through to customers. The PSC instructed its Staff to continue its analysis of SCE&G's tax savings report and to notify the Commission if any further rate adjustments should be made, especially in 1988 or thereafter. Carolina Power & Light indicated in its recently filed letter of intent for a full rate case that it will incorporate the impacts of the TRA in that filing. The Commission's investigations into the TRA impacts on other utilities are ongoing, with decisions not expected until the latter half of 1987.

SOUTH DAKOTA--The South Dakota Public Utilities Commission (PUC) has formally opened a generic docket to examine the effects of the TRA and the current earnings of South Dakota utilities. The PUC is in the process of gathering data, and any change in rates is not likely before the middle of 1987.

TENNESSEE--On December 30, 1986, the PSC voted for an $11.8 million revenue requirement reduction for South Central Bell Telephone (SCBT) to reflect the financial impact of the TRA. Roughly half of the reduction was authorized to be accounted for through the recording of higher depreciation charges, with the other half coming from reductions in rates. The Commission accounted for the TRA in a recently finalized rate case for General Telephone Company of the South, and also is incorporating the impact of the TRA in a soon to be completed rate case for United Cities Gas. On December 30, 1986, in a separate order, the PSC voted to initiate a generic hearing to investigate the impact of the TRA on all other utilities within the state. Initially, the utilities were required to file their responses by the end of January; however, the PSC changed the response deadline time to June 1987.

TEXAS--The Texas Public Utility Commission (PUC) Staff sent letters to all utilities requesting comments as to the general and specific effects of the TRA on the companies, their tax liabilities and their cash flow. A task force made up of Staff members is responsible for gathering the information and making recommendations to the PUC. The Staff will likely hold a conference for interested parties, including companies and intervenors, to discuss the TRA and what, if any, action the PUC should take in response to it.

UTAH--The Utah Public Service Commission (PSC) has informally requested information from the major utilities in the state regarding the TRA. The information will be analyzed by the Department of Public Utilities at which time a determination will be made by the PSC concerning any further action.

VERMONT--On January 9, 1987, the Vermont Public Service Board (PSB) sent letters to the state's utilities requesting that the companies file with the PSB estimates of the effects of the TRA for 1987 and 1988. The letter required responses to be filed by January 30, 1987, and all of the major Vermont utilities have submitted their estimates. For Central Vermont Public Service, the PSB disposed of the issue in the company's general rate case, which was decided January 2, 1987. Green Mountain Power has indicated to the PSB that it will soon file for a rate decrease reflecting not only the savings attributable to the TRA, but also those flowing from a reduction in return on equity from 15.5% to 14%. As for New England Telephone (NET), on January 6, 1987 the Vermont Department of Public Service (DPS) and the company agreed on a new regulatory framework that will provide for the stabilization of basic telephone rates with most other services partially or totally deregulated. The plan provides for an immediate revenue requirement reduction of $5.4 million, which reflects, among other items, the TRA. The State Legislature must pass a bill allowing the Vermont Public Service Board (PSB) to deregulate certain services prior to the PSB's approval of the plan.

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VIRGINIA--On February 4, 1987, the Virginia State Corporation Commission (SCC) informed the utilities in its jurisdiction that due primarily to the impetus of the TRA, investigations of the financial conditions of large electric and telephone companies may soon be undertaken. Continental Telephone Company has responded with a proposal to reduce rates by approximately $3.3 million, but no SCC action has yet been taken on this proposal. On February 12, 1987 Chesapeake & Potomac Telephone (C&P) filed with the SCC to institute a $15 million rate reduction to reflect the impact of the TRA. C&P's filing proposes that the rate reduction be effective July 1, 1987 and it be implemented as an across the board reduction. SCC action is pending in this case. The Commission's staff, as directed by the SCC in late 1986, has been receiving data from the utilities with regard to estimates of the TRA's impact.

WASHINGTON--The Washington Utilities & Transportation Commission (WUTC) required each of the state's utilities to file data by December 31, 1986 estimating the effects on cost of service resulting from the TRA. The WUTC Staff is currently analyzing the data provided by the companies, and, over the next few months, will be recommending to the WUTC an appropriate methodology to have the tax changes reflected in the companies' rates.

WEST VIRGINIA--On January 20, 1987, the PSC issued an order directing utilities within the state to file written statements estimating the potential impact of the TRA on their operations. These responses are due by March 16, 1987 and hearings are scheduled to commence on April 29, 1987.

WISCONSIN--The Wisconsin Public Service Commission (PSC) requires the state's 12 largest utilities to file forecasted financial data each year, and the effects of the TRA will be dealt with in each of these annual reviews on an individual company basis. Companies not undergoing annual reviews, will be required to submit data by April 1, 1987 to show the impact of the TRA on their operations and then to file new rates effective July 1, 1987 reflecting that impact.

WYOMING--The PSC has informally requested information from utilities regarding the effect of the TRA. No proceedings have been commenced to date.

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