K. Chad Burgess
Director & Deputy General Counsel

chad.burgess@scana.com

January 12, 2018

VIA ELECTRONIC FILING

The Honorable Jocelyn Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29211

RE: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc. for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated merger benefits and cost recovery plans
Docket No. 2017-370-E

Dear Ms. Boyd:

Enclosed for filing, on behalf of South Carolina Electric & Gas Company and Dominion Energy, Inc., is a Joint Application and Petition for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated merger benefits and cost recovery plans. Additionally, enclosed for filing is a Motion to Expedite for consideration by the Public Service Commission of South Carolina.

By copy of this letter, we are serving the South Carolina Office of Regulatory Staff with a copy of the enclosed Petition and attach a certificate of service to that effect.

If you have any questions or need additional information, please do not hesitate to contact us.

Very truly yours,

K. Chad Burgess

K. Chad Burgess

KCB/kms
Enclosures

cc: Shannon Bowyer Hudson, Esquire
Jeffrey M. Nelson, Esquire
(both via hand delivery w/enclosures)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2017-370-E

IN RE:

Joint Application of South Carolina Electric & Gas Company and Dominion Energy, Inc. for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated merger benefits and cost recovery plans	)	**CERTIFICATE OF SERVICE**

This is to certify that I have caused to be served this day one (1) copy of the **Joint Application of South Carolina Electric & Gas Company and Dominion Energy, Inc. for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated merger benefits and cost recovery plans and Motion to Expedite Hearing and Proposed Notice of Filing and Hearing and Prefile Testimony Deadlines** via hand delivery to the persons named below at the addresses set forth:

Shannon Bowyer Hudson, Esquire
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201

Jeffrey M. Nelson, Esquire
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201

Karen M. Scruggs

Karen M. Scruggs

Cayce, South Carolina

This 12th day of January 2018

BEFORE

THE PUBLIC SERVICE COMMISSION

OF

SOUTH CAROLINA

DOCKET NO. 2017-370-E

In Re: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc., for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated customer benefits and cost recovery plan.	)))))))))))	**JOINT APPLICATION AND PETITION OF SOUTH CAROLINA ELECTRIC & GAS COMPANY AND DOMINION ENERGY, INC.**

South Carolina Electric & Gas Company ("SCE&G" or the "Company") and Dominion Energy, Inc. ("Dominion Energy") (together, the "Petitioners" or the "Parties") hereby apply to and petition the Public Service Commission of South Carolina (the "Commission") for review and approval, as discussed below, of a proposed transaction whereby SCE&G's parent, SCANA Corporation ("SCANA"), will become a wholly-owned subsidiary of Dominion Energy (the "Merger"). The Parties further request through this petition and application (the "Joint Petition") Commission approval of a customer benefit and cost recovery plan for new nuclear development costs associated with the V.C. Summer Units 2 & 3 Project (the "NND Project" and "Customer Benefits Plan" or "Plan") to accompany the Merger.

The Customer Benefits Plan and the closing of the Merger itself depend on approval of the Merger by this Commission with no material changes to the terms of the Customer Benefits Plan. That approval may take the form of a formal approval of the business combination if the Commission determines that formal approval of the Merger is required under S.C. Code Ann. § 58-27-1300. Alternatively, the Parties respectfully request that the Commission enter a finding that (i) the Merger is in the public interest; or (ii) there is an absence of harm to South Carolina ratepayers as a result of the Merger. Such a ruling or finding by the Commission is a condition of the closing of the Merger.

In this Joint Petition, the Petitioners provide detailed information regarding the Merger and the Customer Benefits Plan, and the immediate and future benefits to the Company's customers and the public in the state of South Carolina that will result from their approval.

I. PETITION SUMMARY

1. This Petition, filed and supported jointly by SCE&G and Dominion Energy, seeks Commission approval of a proposed business combination between Dominion Energy and SCE&G's parent corporation or, alternatively, a finding that the proposed combination is in the public interest or that there is an absence of harm to South Carolina ratepayers as a result of the Merger. Further, and critically, the Petitioners are requesting Commission approval of the Merger-related Customer Benefits Plan, including necessary prudence determinations associated with costs expended for the NND Project. The Customer Benefits Plan's approval, with no material changes to its terms, conditions or

undertakings, and no significant change to its economic value, is an essential and requisite condition of the Merger. Without Plan approval, the Merger will not occur.

2. SCE&G is at a critical crossroads in its greater than one-hundred seventy (170) year history of operations as a South Carolina public utility. And its fate may well be determined through the decisions made on this Joint Petition. SCE&G remains committed to its public service obligations to its customers. But the issues surrounding the Company's recovery of the costs of the now-abandoned NND Project loom large before this Commission and in public debate. These costs were lawfully and prudently incurred and remain properly recoverable through utility rates. However, SCE&G recognizes the importance of attempting to ease the burden on customers of these costs, to the highest reasonable extent, while at the same time ensuring the financial viability of this utility and its continued ability to operate.

3. SCE&G has determined that the proposed Merger with Dominion Energy and the associated Customer Benefits Plan present the best option to achieve these goals. Even setting aside the NND Project issues, this combination would provide benefits for SCE&G's customers and the State of South Carolina. Dominion Energy is one of the largest producers and transporters of electricity and natural gas in the United States. It already maintains an economic and operational presence in South Carolina with its natural gas transportation and renewable electric generation assets in the state. Like SCE&G, Dominion Energy has more than a century of experience operating public utilities, currently serving over six million customers in regulated and retail markets. Dominion Energy's proven leadership team is unfailingly committed to the safe, reliable, cost-

effective and environmentally responsible provision of utility services to its customers. And that commitment will apply equally to its operation of SCE&G once the Merger is consummated.

4. Against this backdrop, Dominion Energy is also dedicated, like SCE&G, to fairly and appropriately addressing the NND Project cost recovery issue in connection with the Merger. Dominion Energy is a large, financially stable and diversified company, and is able to devote substantial resources in this regard. The terms of the Customer Benefits Plan are set out in detail in this Joint Petition. They include an immediate, one-time rate credit to SCE&G's customers totaling $1.3 billion, which translates to an estimated $1,000 per residential electric customer on average, and significantly more for larger consumers in the residential, commercial and industrial customer classes. The following chart presents the total rate credit amounts for certain customer classes:

CHART A

Customer Class	Total Rate Credit
Residential	$628 million
Industrials	$299 million
State agencies[1]	$36.6 million
Municipalities[1]	$22.6 million
Churches[1]	$2.6 million

5. Post-Merger, SCE&G would also write-off $1.4 billion in NND Project costs and approximately $320 million in regulatory assets related to the NND Project, removing

[1] Preliminary estimates.

any future customer obligation for these costs. Dominion Energy will further underwrite a $575 million refund pool for refunding amounts previously collected that, along with the benefit of recent federal income tax reform, will allow SCE&G to provide an immediate reduction in customer bills of at least 5% on a customer class basis, and will keep the portion of the bill reduction that is not attributable to federal tax reform in place for approximately eight years. The deferred tax resulting from the NND Project will be a NND rate base offset. Further, the acquisition cost of the partial replacement generation capacity for the NND Project—a $180 million investment in the gas-fired Columbia Energy Center—will be absorbed by shareholders and not collected in rates. Finally, to further ensure rate stability, other than the adjustments described in this Petition, the Petitioners agree to freeze retail electric base rates until at least January 1, 2021.

6. These voluntary concessions will substantially and immediately reduce the customer obligation for NND Project costs. Dominion Energy cannot make the NND Project costs disappear entirely. But, with the acceptance of these voluntary provisions, the remaining costs can be recovered at much lower rate impacts, and over a much quicker period (twenty years).

7. The Petitioners are unaware of any similar utility industry business combinations with such a direct beneficial impact to customers. The up-front $1.3 billion rate credit element of the Customer Benefits Plan alone is believed to be the largest such utility to customer payment ever. Taken as a whole, the Petitioners submit that this is a clearly superior economic alternative for ratepayers than prior proposals by SCE&G.

8. The Petitioners fully support and endorse the Merger and all elements of the Customer Benefits Plan. However, the Joint Petition also contains two disfavored alternative requests, as detailed in the accompanying exhibits, which SCE&G will pursue independently only if the Merger does not close. In such case, SCE&G requests that the Commission adopt a rate mitigation plan that can be funded by SCE&G and SCANA alone, but as a matter of financial necessity cannot provide customers with all the benefits associated with the Merger (the "No Merger Benefits Plan"). As a second alternative, if the Merger does not close and the Commission does not approve the No Merger Benefits Plan, SCE&G respectfully requests that the Commission issue an order providing for the recovery of all costs and investments associated with the NND Project allowable by law without any present rate increase (the "Base Request"). SCE&G believes that both the No Merger Benefits Plan and the Base Request are disfavored alternatives and economically inferior for customers compared to the Merger-related Customer Benefits Plan (though nonetheless lawful, fair and reasonable). SCE&G supports the alternative plans only in the event of disapproval of the Merger.

9. Dominion Energy's commitments in connection with this Merger extend to SCE&G's employees and its continued presence as a South Carolina institution. The Company's headquarters will remain here, and its workforce will be financially protected until January 1, 2020. SCE&G's generous historical charitable giving levels—all funded by shareholders—also will be increased. Dominion Energy recognizes the significant role that public utilities play in the communities they serve, and does not intend to diminish that role for SCE&G going forward.

10. In short, the Petitioners submit that this proposed business combination, and the proposed multi-billion dollar investment by Dominion Energy in SCE&G and in South Carolina, will provide significant short- and long-term benefits for SCE&G and its customers, employees and shareholders (many of whom are employees, retirees or other South Carolina citizens). It likewise benefits SCE&G's service territory and the State as a whole. Strong, financially viable utilities with an unclouded future are a catalyst for local investment, business generation and economic prosperity. This Merger, including the associated Customer Benefits Plan and other requisite terms, is demonstrably in the public interest, and the Petitioners respectfully request that this Commission issue an order to this effect.

II. INTRODUCTION

a. SCE&G

11. SCE&G is a corporation organized and existing under the laws of the State of South Carolina and headquartered in Cayce, South Carolina. SCE&G is a public utility subject to the regulatory authority of the Commission pursuant to Title 58 of the Code of Laws Annotated of South Carolina. More specifically, SCE&G is an electrical utility engaged in the generation, transmission, distribution, and sale of electricity to the public for compensation. As such, SCE&G operates an integrated electric utility system that serves approximately 717,000 customers in 24 counties covering nearly 16,000 square miles in central, southern and southwestern portions of South Carolina. SCE&G is also a natural gas distribution utility engaged in the distribution and sale of natural gas to the

public for compensation serving approximately 362,000 customers and covering approximately 23,000 square miles.

12. SCE&G is a wholly-owned subsidiary of SCANA. SCANA, a South Carolina corporation, is a publicly-held holding company whose common stock is traded on the New York Stock Exchange under the ticker symbol SCG. The other principal subsidiaries of SCANA are Public Service Company of North Carolina, Inc. ("PSNC Energy") and SCANA Energy Marketing, Inc. ("SEMI").

13. Corporate legal counsel for SCE&G in this proceeding are as follows:

K. Chad Burgess
Matthew W. Gissendanner
South Carolina Electric & Gas Company
Mail Code C222
220 Operation Way
Cayce, SC 29033
(803) 217-8141 (KCB)
(803) 217-5359 (MWG)
chad.burgess@scana.com
matthew.gissendanner@scana.com

Private legal counsel for SCE&G in this proceeding are as follows:

Belton T. Zeigler
Womble Bond Dickinson (US) LLP
1221 Main Street, Suite 1600
Columbia, SC 29201
(803) 454-7720
belton.zeigler@wbd-us.com

Mitchell Willoughby
Willoughby & Hoefer, P.A.
Post Office Box 8416
Columbia, SC 29202
(803) 252-3300
mwilloughby@willoughbyhoefer.com

All correspondence and any other matters relative to this proceeding should be addressed to these representatives.

b. Dominion Energy

14. Dominion Energy is a Virginia corporation with its principal place of business at 120 Tredegar Street, P.O. Box 26532, Richmond, Virginia 23261-6532. Dominion Energy is a publicly-held holding company whose common stock is traded on the New York Stock Exchange under the ticker symbol D. It has the following wholly-owned public utility subsidiaries: Virginia Electric and Power Company (which does business in Virginia under the name "Dominion Energy Virginia" and in North Carolina under the name "Dominion Energy North Carolina"), The East Ohio Gas Company (which does business under the name "Dominion Energy Ohio"), Hope Gas, Inc. (which does business under the name "Dominion Energy West Virginia"), and Questar Gas Company (which does business in Utah under the name "Dominion Energy Utah," in Wyoming under the name "Dominion Energy Wyoming," and in Idaho under the name "Dominion Energy Idaho"). In addition, Dominion Energy owns other subsidiaries in the energy industry, including two solar power generation projects in South Carolina, descriptions of which are provided in more detail below.

15. Corporate legal counsel for Dominion Energy in this proceeding is as follows:

Lisa S. Booth*
Dominion Energy Services, Inc.
120 Tredegar Street
Post Office Box 26532
Richmond, Virginia 23261-6532

(804) 819-2288
lisa.s.booth@dominionenergy.com

Private legal counsel for Dominion Energy in this proceeding are as follows:

Robert A. Muckenfuss
McGuireWoods LLP
201 North Tryon Street
Suite 3000
Charlotte, NC 28202-2146
(704) 343-2052
rmuckenfuss@mcguirewoods.com

Joseph K. Reid, III*
Elaine S. Ryan*
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, VA 23219-3916
(804) 775-1198 (JKR)
(804) 775-1090 (ESR)
jreid@mcguirewoods.com
eryan@mcguirewoods.com

**Application for admission pro hac vice forthcoming*

All correspondence and any other matters relative to this proceeding should be addressed to these representatives.

16. Sedona Corp. ("Sedona") is a South Carolina corporation and a wholly-owned subsidiary of Dominion Energy created solely to accomplish the Merger. Sedona is not a public utility in South Carolina or elsewhere.

III. DESCRIPTION OF MERGER

17. On January 2, 2018, Dominion Energy, Sedona, and SCANA entered into an Agreement and Plan of Merger ("Merger Agreement") setting forth the terms of the Merger. The board of directors of SCANA and Dominion Energy have approved and

authorized the Merger. A copy of the Merger Agreement is attached to this Joint Petition as ***Exhibit 1***. The Merger, which the Merger Agreement explains in detail, may be fairly summarized as follows:

a. Sedona and SCANA will merge, with SCANA being the surviving entity.

b. Immediately following the time the Merger is effective ("Effective Time"), the officers of SCANA will be those persons that were the officers of SCANA immediately prior to the Effective Time. The names and positions of the officers of SCANA are provided in ***Exhibit 2*** to this Joint Petition. After the Effective Time, changes to the officers of SCANA may be made based upon integration efforts and Dominion Energy's standard entity management conventions.

18. As provided by the Merger Agreement, the Merger can only close if the Commission approves the jointly proposed Customer Benefits Plan, with no material change to the terms, conditions, or undertakings set forth in the plan and no significant change to the economic value of the plan. The proposed Customer Benefits Plan is discussed in more detail below.

19. As provided by the Merger Agreement, upon consummation of the Merger, each issued and outstanding share of common stock of SCANA (other than the cancelled shares as defined in Section 2.01(b) of the Merger Agreement) will be converted into the right to receive 0.6690 validly issued, fully paid and non-assessable shares of common stock of Dominion Energy.

20. Further, upon consummation of the Merger, each issued and outstanding share of common stock of Sedona will be converted into and become one validly issued,

fully paid, and non-assessable share of common stock of SCANA as the surviving corporation. Thus, as a result of the Merger, Dominion Energy (which currently owns all the stock of Sedona) will own all the stock of SCANA.

21. At the Effective Time, SCANA, as the surviving corporation, will become a wholly-owned subsidiary of Dominion Energy.

22. At the Effective Time, SCE&G will remain a direct, wholly-owned subsidiary of SCANA and will continue to exist as a separate legal entity.

IV. LEGAL STANDARDS

23. The Parties file this action under the following legal and statutory authorities:

a. The approval of the Merger is a necessary condition precedent of approval of the Customer Benefits Plan. Therefore, the Parties respectfully seek approval of the Merger under S.C. Code Ann. § 58-27-1300, or alternatively, request that the Commission issue the requested rulings or findings concerning the Merger as a part of its consideration and adoption of the Customer Benefits Plan.

b. The Parties seek approval of the rate credit and bill reductions and related terms included in the Customer Benefits Plan under the provisions of S.C. Code Ann. § 58-27-870(F), which allows the Commission to approve a rate schedule filed by a utility without consideration of the overall rate structure.

c. The Parties also seek approval of the Customer Benefits Plan under the provisions of S.C. Code Ann. § 58-33-280(K), which authorizes recovery of and return on the capital costs of projects approved under the terms of the

Base Load Review Act ("BLRA") after a project is abandoned so long as the abandonment decision is prudent.

d. Furthermore, under the Customer Benefits Plan, all NND Project costs that have not been reviewed and approved for inclusion in rates in previous revised rates orders (approximately $1.2 billion) will be written off if the Merger closes. Accordingly, the NND Project costs recoverable under the Customer Benefits Plan have all been approved for inclusion in rates in final and unappealable revised rates orders previously issued by the Commission under S.C. Code Ann. § 58-33-280. Those orders are not subject to being reopened or being relitigated.

e. If the Merger does not close, then SCE&G seeks approval of the No Merger Benefits Plan under the provisions of S.C. Code Ann. § 58-27-870(F), and S.C. Code Ann. § 58-33-280(K).

f. As a final alternative, if the Merger does not close and if the Commission does not approve the No Merger Benefits Plan, SCE&G seeks approval of the Base Request under that same statutory authority.

g. Under both the No Merger Benefits Plan and the Base Request, SCE&G seeks a determination that the NND Project costs, which were not reviewed and approved for inclusion in rate recovery in prior revised rates proceedings, are reasonable and prudent costs of the NND Project that are in no way incurred due to imprudence by SCE&G and therefore are properly included in the cost schedules for the project in abandonment under S.C. Code Ann. § 58-33-270(E).

24. The Joint Petition does not make any request that might require a full rate case proceeding under S.C. Code Ann. § 58-27-870(G) or any other provision of law.

V. FINANCIAL CONDITION OF PARTIES

a. SCE&G and SCANA

25. SCE&G's assets as of December 31, 2016, totaled $16.1 billion; operating revenues in 2016 were $3.0 billion; and net income in 2016 was $526 million. SCE&G's capital structure as of December 31, 2016, was 48.5 percent long-term debt and 51.5 percent equity (stated under generally accepted accounting principles ("GAAP")). SCE&G's current credit rating for its senior unsecured debt is BBB (evolving) with Fitch. SCE&G's 2016 financial statements are provided on pages 55-59 of the combined SCANA Corporation and SCE&G 2016 Annual Report on Form 10-K ("SCANA 10-K"), ***Exhibit 3*** to this Joint Petition. Additionally, ***Exhibit 4*** is a copy of the Quarterly Report for South Carolina Electric & Gas Company, Retail Electric Operations and Gas Distribution Operations for the twelve months ended September 30, 2017, as previously filed with the Commission.

26. The authorized and outstanding securities issued by SCE&G are described in Notes 3 and 4 to the Financial Statements of SCE&G on pages 71-74 of the SCANA 10-K, ***Exhibit 3*** to this Joint Petition.

27. SCANA's assets as of December 31, 2016, totaled $18.7 billion; operating revenues in 2016 were $4.2 billion; and net income in 2016 was $595 million. SCANA's

capital structure as of December 31, 2016, was 53.1 percent long-term debt and 46.9 percent equity (stated under GAAP). SCANA's issuer credit rating is Baa3 (negative) with Moody's, BB+ (evolving) with Fitch, and BBB (negative) with Standard & Poor's ("S&P"). SCANA's 2016 financial statements are provided on pages 48-53 of the SCANA 10-K, ***Exhibit 3*** to this Joint Petition.

28. After announcement of the Merger, Fitch affirmed its credit ratings for SCANA of BB+ and SCE&G and PSNC of BBB- and revised its rating outlook for SCANA, SCE&G and PSNC from negative to evolving. A summary of these credit ratings and recent actions are provided in ***Exhibit 5*** to this Joint Petition.

29. The authorized and outstanding securities issued by SCANA are described in Notes 3 and 4 to the Financial Statements of SCANA on pages 71-74 of the SCANA 10-K, ***Exhibit 3*** to this Joint Petition.

b. Dominion Energy

30. Dominion Energy's assets as of December 31, 2016, totaled $71.6 billion; revenues in 2016 were $11.7 billion; and net income attributable to Dominion Energy in 2016 was $2.1 billion. Dominion Energy's financial statements are provided on pages 61-85 of the Dominion Energy 2016 Annual Report on Form 10-K ("Dominion Energy 10-K"), ***Exhibit 6*** to this Joint Petition.

31. Dominion Energy's capital structure as of December 31, 2016, was 60.8 percent debt and 39.2 percent equity as calculated per Dominion Energy's revolving credit agreement covenant, which, in Dominion Energy's view, presents the most accurate picture of Dominion Energy's capitalization as it takes into account the equity value of Dominion

Energy's equity-linked securities. For reference, based on the most recent audited financial statements (stated under GAAP) and prior to any adjustments, Dominion Energy's capital structure at December 31, 2016, was 67.6 percent debt and 32.4 percent equity.

32. The authorized and outstanding securities issued by Dominion Energy are described in Notes 16-19 (pages 130-136) to the Financial Statements of Dominion Energy in the Dominion Energy 10-K, ***Exhibit 6*** to this Joint Petition.

33. Dominion Energy's stable regulated operations, strong access to capital markets, ample liquidity, prudent capital structure, and experienced leadership team all contribute to its strong investment grade ratings. After announcement of the Merger, Fitch affirmed both its credit ratings and outlook for Dominion Energy. Moody's affirmed the ratings for Dominion Energy and revised its outlook to negative from stable. S&P affirmed its ratings for Dominion Energy and Dominion Energy's rated subsidiaries and revised the rating outlook for Dominion Energy and its rated subsidiaries to negative from stable. A summary of these credit ratings and recent actions are provided in ***Exhibit 7*** to this Joint Petition.

VI. PLAN FOR FUTURE OPERATIONS OF SCE&G

34. Following the Merger, Dominion Energy and SCANA plan to operate SCE&G in substantially the same manner as it is operated today, enhanced by Dominion Energy's broad and deep experience in the successful management of electric and gas natural gas facilities and systems.

35. Dominion Energy's electric and natural gas utility subsidiaries, like SCE&G, have a track record for making capital investments required to provide safe, reliable and

cost-effective service to customers. Safety in the workplace and in the community is Dominion Energy's highest priority, along with the provision of reliable, cost-effective service to its customers. Dominion Energy and SCE&G also share a history of operating with integrity and a firm commitment to their employees and the communities they serve.

36. Following the Merger, SCE&G will continue to receive certain shared or common services provided to it as part of a larger organization. These services have been provided by SCANA Services, Inc. ("SCANA Services"). The current organizational structure of SCANA and SCE&G is provided in ***Exhibit 8*** to this Joint Petition.

37. SCANA Services currently employs 1,751 individuals. These employees perform shared or common services functions for all SCANA business units, including SCE&G. Some of these services (including investor relations, governance, finance, treasury, tax, accounting, legal, information technology, telecommunications, insurance, purchasing, contracting, environmental management, safety, audit, and human resources) will be provided in the future through Dominion Energy Services, Inc. ("DES"), rather than SCANA Services, by current DES employees or by current employees of SCANA who move under DES after the Merger.

38. Although there is no plan to materially change the operations of SCE&G following the Merger, SCE&G may make appropriate future modifications to its assets, systems, procedures, and services in compliance with applicable laws and regulations. Such changes may be made in the normal course of business in order to adopt new methods, materials, or technology; to meet regulatory requirements; or to address changing customer expectations.

39. Dominion Energy has no plan to change the organizational structure of SCE&G operations as a result of the Merger. In the event Dominion Energy and SCE&G determine that a change in operational organizational structure will be beneficial to customers, ***Exhibit 8*** will be updated.

40. Dominion Energy plans to maintain SCE&G's existing proportions of debt and equity capital.

41. Joint Petition ***Exhibit 9*** contains charts showing the organization of Dominion Energy prior to (pages 1-4) and after (pages 5-9) the Merger.

42. As the foregoing demonstrates, SCE&G customers, communities and regulators will see benefits from the ownership of SCE&G by Dominion Energy, an entity with great financial strength and buying power, broad expertise in utility operations and business planning, and a shared focus on safety, reliability, customer service, and efficiency of business operations over the long term.

VII. DOMINION ENERGY'S IDENTITY, MANAGEMENT, AND EXPERIENCE

43. Dominion Energy, headquartered in Richmond, Virginia, is one of the nation's largest energy infrastructure companies. As of December 31, 2017, Dominion Energy had a public equity market capitalization of over $52 billion. Dominion Energy is a member of leading general and industry-specific equity market indices including the S&P 500, the Dow Jones Composite Average, and the Philadelphia Stock Exchange Utility Index. Dominion Energy's operations are heavily weighted to state and federally regulated energy infrastructure operations. As of December 31, 2016, Dominion Energy's portfolio

of assets includes approximately 26,400 megawatts ("MW") of electric generating capacity; 64,200 miles of electric transmission and distribution lines; and 66,200 miles of natural gas transmission, gathering, distribution, and storage pipelines. As of December 31, 2016, Dominion Energy serves over six 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. Dominion Energy has approximately 16,200 full-time employees and operations in 18 states. As a holding company, Dominion Energy owns direct and indirect subsidiaries that in turn own the properties through which their respective businesses are conducted.

44. Dominion Energy has a wealth of managerial experience on its leadership team. Further, although the assets of its subsidiaries remain wholly within its legal subsidiaries (each of which has its own officers, directors, and management teams), Dominion Energy manages and reports on its consolidated operations through three primary operating segments: Power Delivery Group, Power Generation Group, and Gas Infrastructure Group. The common leadership and management of the similarly situated businesses that comprise Dominion Energy's operating segments provide significant value to each of the individual businesses through the sharing of best practices in such areas as operations, safety, customer service, and environmental stewardship. In this way, each of Dominion Energy's regulated electric and gas subsidiaries benefits from the experience and knowledge of the collective group.

a. The Power Delivery operating segment includes Dominion Energy's electric transmission and distribution operations.

b. The Power Generation operating segment includes Dominion Energy's regulated and merchant electric generating fleet.

c. The Gas Infrastructure operating segment includes the gas transmission and storage and gas gathering operations of Dominion Energy Transmission, Inc., including producer service activities, as well as the gas distribution and storage services of The East Ohio Company, Hope Gas, Inc. and Questar Gas Company.

45. In addition to its operating segments, Dominion Energy has a centralized service company, DES. Support functions housed at DES also provide significant benefits in areas such as environmental compliance and cyber security, as well as providing other centralized departments whose resources are available to all of the subsidiaries of Dominion Energy.

46. Dominion Energy's major regulated public utility subsidiaries are: Virginia Electric and Power Company (which does business in Virginia under the name "Dominion Energy Virginia" and in North Carolina under the name "Dominion Energy North Carolina"), The East Ohio Gas Company (which does business under the name "Dominion Energy Ohio"), Hope Gas, Inc. (which does business under the name "Dominion Energy West Virginia"), and Questar Gas Company (which does business in Utah under the name "Dominion Energy Utah," in Wyoming under the name "Dominion Energy Wyoming," and in Idaho under the name "Dominion Energy Idaho").

47. Dominion Energy's regulated utilities share the same values as SCE&G, including a focus on safe, reliable and cost-effective service, a commitment to employees and the communities served, and integrity in all aspects of their businesses.

48. Dominion Energy's experience in owning and operating its public utility subsidiaries means that it comes to the Merger with a deep understanding of the responsibilities and general opportunities and challenges of current U.S. electric and gas utilities, and with directly applicable experience and knowledge about some of the specific opportunities and challenges now faced by SCE&G.

49. Dominion Energy recognizes that the energy business, whether electric or natural gas, requires capital investment to ensure safe and reliable service to customers. Since 2012, Dominion Energy has invested over $31 billion in capital to maintain and grow its electric and gas infrastructure.

50. Dominion Energy is fully dedicated to meeting customers' energy needs in a manner consistent with protecting the environment and supporting sustainability. In addition to complying with all applicable environmental laws and regulations, Dominion Energy makes environmental concerns an integral part of its planning and decision-making process and devotes substantial resources to implement effective environmental and sustainability programs.

51. Dominion Energy is committed to investing in diverse energy infrastructure to meet customers' energy needs and improve reliability while maintaining reasonable rates and minimizing the impact on the environment. Since 2013, Dominion Energy has invested $2.6 billion to develop, construct and operate small- and large-scale solar

facilities, including $979 million in 2016. Dominion Energy owns two solar power generation projects in South Carolina. The Solvay Solar Energy Facility, a 71.4 MW (AC) solar facility located in Jasper County near Ridgeland, South Carolina, entered commercial operation in December 2017. The Ridgeland Solar Project, a 10 MW (AC) solar facility in Ridgeland, entered commercial operation in May 2017.

52. Safety is another top priority for Dominion Energy. From 2010 to 2016, there has been a 39% decline in OSHA recordable incidents and a 38% decline in lost day/restricted duty cases. For 2016, in about 30 million hours worked, Dominion Energy employees recorded 98 workplace OSHA-recordable injuries (an incidence rate of 0.66) and 45 workplace injuries resulting in lost days or reassignment of duties (a rate of 0.30). Dominion Energy's ultimate goal is zero injuries.

53. Customers of regulated electric and natural gas utilities expect safe, reliable, and quality service. When service disruptions occur, the service teams at Dominion Energy's regulated public utility subsidiaries respond to customers' outage-related service requests as quickly and safely as possible. In 2016, Dominion Energy Virginia reduced average customer call wait time to 42 seconds and the average customer had power, excluding major storms, 99.97% of the year.

54. Dominion Energy recognizes that its electric and natural gas distribution companies are more than just public utilities, they are *public service* companies. Dominion Energy believes that it is important that the local utility also be a contributor to, and be part of, the community it serves. In 2016, Dominion Energy and its philanthropic arm, the Dominion Energy Foundation, awarded nearly $27 million in charitable grants to about

1,500 nonprofit organizations in the states served by Dominion Energy companies, and Dominion Energy employees donated more than 100,000 hours of volunteer service to their communities.

55. Supporting the men and women who have worn a U.S. military uniform in service to their country is also an important priority for Dominion Energy. From 2010 to 2016, Dominion Energy hired more than 900 veterans—almost 20% of new hires during that period. Approximately 1,600 Dominion Energy employees are veterans, about 10% of the workforce. In 2016, Dominion Energy hired 153 military veterans through its "Troops to Energy Jobs" program to support their transition to civilian careers and address Dominion Energy's need for skilled and disciplined workers.

VIII. MERGER TERMS: COMMITMENTS AND BENEFITS

56. The Merger, including the Customer Benefits Plan, is in the public interest and will provide significant short-term and long-term benefits for SCE&G, its customers, and the State of South Carolina. In connection with the Merger, the Petitioners have agreed to the following terms and commitments:

a. Customer Benefits Plan

57. In connection with and subject to approval of the Merger, or the alternative finding that the Merger is in the public interest or that there is an absence of harm to South Carolina ratepayers as a result of the Merger, and subject to the closing of the Merger, SCE&G and Dominion Energy jointly propose the following Customer Benefits Plan:

a. All current SCE&G electric customers as of the date of Merger close will receive an aggregate up-front, one-time rate credit totaling $1.3 billion.[2] The rate credit will be apportioned to all retail electric customer classes based on their 2016 contribution to summer adjusted peak demand as prepared by SCE&G. After the dollar apportionment per customer class and rate schedule is determined on this basis, a rate per kilowatt hour ($/kWh) will be derived by customer class and rate schedule by dividing the total kWh sales of electricity by customer class and rate schedule over a preceding 12-month period (the "Base Period") into the apportioned funding amount. The $/kWh rate will then be applied to each customer's kWh usage over the Base Period to determine the customer's up-front rate credit amount. The rate credit will be issued to eligible customers in the form of a check within ninety (90) days of Merger close. Eligible customers shall be SCE&G retail electric customers as of record on the date of the close of the Merger.

b. Immediately upon Merger closing, SCE&G will write down its investment associated with the NND Project by approximately $1.4 billion, which amount includes approximately $1.2 billion in assets that have not previously been subject to consideration in setting revised rates and approximately $200 million that have been so considered. The amounts written down would be permanently excluded from consideration in establishing retail electric rates going forward.

---

[2] A portion of the one-time rate credit will be funded through issuance of debt and defeasement of the regulatory liability associated with the Toshiba Corporation Guarantee Settlement Payment.

c. SCE&G will not seek recovery of the approximately $320 million in regulatory assets associated with the following items:[3]

i. The regulatory asset associated with interest rate swap losses related to the debt that was not issued for the NND Project;

ii. The regulatory asset associated with the accumulated deferred income taxes arising from NND Project equity AFUDC;

iii. The regulatory asset associated with the carrying costs on deferred tax assets related to nuclear construction; and

iv. The regulatory asset associated with the foregone domestic production activities deductions, net of the research and experimentation related tax credits, as well as accrued interest expense and other costs arising from the uncertain tax position related to the research and experimentation expenditure, will be written off and not be recovered from customers.

d. Dominion Energy will underwrite and recognize a regulatory liability of approximately $575 million in refunds by SCE&G for refunding certain amounts previously collected under the NND Project which is designed to provide the 3.5% retail

---

[3] *See* Order No. 2013-776 issued in Docket No. 2013-382-E (Interest Rate Swap Losses); Order No. 2013-803 issued in Docket No. 2013-336-E (Accumulated Deferred Income Taxes); Order No. 2013-803 issued in Docket No. 2013-336-E (Carrying Costs on Deferred Tax Assets); Order No. 2016-820 issued in Docket No. 2016-373-E (Domestic Production Activities Deductions).

electric bill decrease, on a customer class basis, from the May 2017 rate levels until accumulated amortization of the cost of abandoned plant lowers SCE&G's revenue requirements. The refund amount is calculated to be sufficient to support the 3.5% retail electric bill reduction for approximately eight (8) years following the closing of the Merger. This amount of time is estimated to be sufficient to avoid a future retail electric rate increase resulting from NND Project costs when the refund amount is exhausted.

e. SCE&G will reduce retail electric bills further to reflect the impact of federal tax reform passed in December 2017, which is estimated to lower bills an additional amount resulting in a total estimated bill reduction of approximately 5%. This includes estimated tax reform savings of 1.5%. Actual savings may be higher and, if so, will be provided to reduce bills further.

f. The approximately $180 million initial capital investment in the Columbia Energy Center, a 540-MW combined-cycle, natural gas-fired power plant located in Gaston, South Carolina, will be excluded from rate base and rate recovery, with only the ongoing costs such as fuel costs, operations and maintenance expense, and maintenance or improvement capital investments associated with the plant to be recovered in future base and fuel rates.

g. Transmission projects associated with the NND Project will be closed to rate base and removed from the NND Project costs. The related revenue of approximately $32 million per year currently being recovered in base rates will continue to be recovered through base rates notwithstanding the Merger. The associated depreciation, operating and maintenance costs will be captured in a regulatory asset, including a return, for future rate recovery.

h. Except for rate adjustments for fuel and environmental costs, demand side management costs and other rates routinely adjusted on an annual or biannual basis, SCE&G will commit to freezing retail electric base rates at current levels until January 1, 2021.

i. Any deferred tax liability associated with the tax abandonment of the NND Project shall reduce the NND Project cost to be recovered from SCE&G customers. The deferred tax asset for the net operating loss carryforward will be reflected as a rate base offset, dollar for dollar, to the deferred tax liability. Reductions in the deferred tax asset shall be subject to Dominion Energy's ability to use the SCANA net operating loss carryforward to reduce its consolidated income tax liability in accordance with Internal Revenue Code Sections 172 and 382 and shall be computed on a consolidated and not a separate company basis. Adjustments to the deferred tax liability and the deferred tax asset resulting from a change in tax laws or tax treatment of the abandonment and/or Dominion Energy's ability to use the SCANA net operating loss carryforward will be returned to or recovered from SCE&G customers in the following manner:

i. The regulatory liability resulting from excess deferred tax liabilities on any tax abandonment will be returned to customers over the book recovery period of the property (*i.e.*, 20 years);

ii. The regulatory asset resulting from excess deferred tax assets on any net operating loss will be recovered from customers in a manner that coincides with Dominion Energy's ability to use the net operating loss in filing its consolidated income tax returns and not on a separate company basis; and

iii. The amounts reflected above shall be adjusted for any impacts related to the tax treatment of the NND Project.

58. In furtherance of the proposed Customer Benefits Plan, SCE&G and Dominion Energy request that the Commission make a finding that SCE&G's investment for the NND Project in the amount of approximately $3.3 billion, which reflects the amount of that investment net of write-downs, was prudent; and that the capital costs and amortization of that $3.3 billion may be recovered through retail electric rates.

59. SCE&G and Dominion Energy further request that the Commission enter an order directing the following:

a. That the approximately $3.3 billion of invested capital for the NND Project shall be included in a regulatory asset and recovered over a 20-year amortization and recovery period that is reflected in retail electric revenue requirements without offset or disallowance, except for the deferred taxes discussed above, until the regulatory asset is fully recovered; and

b. That until the balance in the regulatory asset is fully recovered, the capital costs associated with the unrecovered balance in that account shall be subject to SCE&G's cost of capital devoted to retail electric operations at a rate that reflects a return on common equity of 10.25%, a weighted average cost of debt of 5.85%, and a capital structure consisting of 52.81% equity and 47.19% debt, with these percentages fixed over the 20-year amortization period.

b. Other Commitments and Benefits as Terms of the Merger

60. The Merger is in the public interest and will provide benefits to SCE&G customers and to South Carolina. SCE&G's management was fully involved in evaluating the Merger. Management considered the impact of the Merger on SCE&G's customers, employees, and communities, and determined that the Merger was in their best interests. Dominion Energy plans to operate SCE&G in substantially the same way as it is currently being operated and intends the Merger to be about growth, rather than cost reduction. The Commission will continue to exercise its regulatory authority over SCE&G in the same way it does today, thereby ensuring continued protection of the interests of South Carolina customers. SCE&G and Dominion Energy will adopt the following commitments and have the following understandings:

i. Business

a. Dominion Energy intends to maintain SCE&G's corporate headquarters in Cayce, South Carolina.

b. Dominion Energy intends that its board of directors will take all necessary action, as soon as practical after the Effective Time, to appoint a mutually agreeable current member of the SCANA Board or SCANA's executive management team as a director to serve on Dominion Energy's board of directors.

c. SCE&G will be managed from an operations standpoint as a separate regional business under Dominion Energy with responsibility for making decisions that achieve the objectives of customer satisfaction, reliable service, customer, public, and employee safety, environmental stewardship, and collaborative and productive relationships with customers, regulators, other governmental entities, and interested stakeholders.

d. Dominion Energy intends to maintain SCE&G's customer service at no less than current levels and will strive for continued improvements thereto.

e. SCE&G and Dominion Energy share a common focus on installing, upgrading and maintaining facilities necessary for safe and reliable operations. This focus will not be diminished in any way as a result of the Merger.

f. Dominion Energy is committed to the environment and will maintain the environmental monitoring and maintenance programs of SCE&G at or above current levels.

ii. Employee Matters

g. Dominion Energy will maintain compensation levels for employees of SCANA and its subsidiaries following the Effective Time of the Merger until January 1, 2020.

h. Dominion Energy will give employees of SCANA and its subsidiaries due and fair consideration for other employment and promotion opportunities within the larger Dominion Energy organization, both inside and outside of South Carolina, to the extent any such employment positions are re-aligned, reduced or eliminated in the future as a result of the Merger.

iii. Financial

i. Dominion Energy, through SCANA, will provide equity, as needed, to SCE&G with the intent of maintaining SCE&G's current capital structure and improving credit ratings.

j. Dominion Energy intends to maintain credit metrics that are supportive of strong investment-grade credit ratings for SCE&G.

iv. Community

k. Dominion Energy will increase SCANA's historical level of corporate contributions to charities identified by SCANA's leadership by $1,000,000 per year for at least five (5) years after the Effective Time, and will maintain or increase historical levels of community involvement, low income funding, and economic development efforts in SCANA's current operation areas.

61. Dominion Energy brings the following additional benefits to SCE&G and its customers through the Merger:

a. The operations of the utility subsidiaries of Dominion Energy provide demonstrable evidence that SCE&G will continue its emphasis on key utility performance areas such as reasonable customer rates, reliable customer service, customer and employee safety, and commitment to employees and communities served.

b. SCE&G will benefit by having an enhanced ability to finance capital investments that ensure safe, reliable, and cost-effective operations across a growing customer base.

c. Dominion Energy's long-term investment focus means that Dominion Energy intends to own SCE&G for the long term, lending stability to, and confidence in, SCE&G's continued commitment to providing safe, reliable and cost-effective electricity and natural gas services to its residential, commercial and industrial customers in South Carolina.

d. SCE&G will benefit from being part of a corporate organization that has enhanced geographic, business, and regulatory diversity and greater financial and operational scale. Dominion Energy brings business diversity to SCANA and SCE&G. In addition to Dominion Energy's extensive experience in the natural gas industry, Dominion Energy is a leader in all aspects of the electric industry. Dominion Energy has invested in a variety of energy resources, including natural gas, coal, nuclear, wind, solar, and biomass and can share best practices learned in operating across this diverse portfolio. Dominion Energy, through its energy subsidiaries, has an established record for formulating its policies and plans in customer or stakeholder processes. Dominion Energy's operations also provide geographical diversity that will strengthen SCANA and SCE&G. A benefit of geographic diversity is that if a natural disaster were to occur in SCE&G's service area after the Merger, SCE&G would have access to resources such as call centers, operations, and management outside the affected area.

e. Dominion Energy has an established record of focusing on customer, employee, and public safety similar to that already in place at SCE&G. SCE&G will be expected to continue that focus as part of the Dominion Energy family.

f. Dominion Energy and its subsidiaries have a demonstrated history of emphasizing the importance of positive relationships with customers, regulators, legislators, and consumer representatives.

g. SCE&G will benefit from participation in the DES model wherein each of Dominion Energy's operations has access to an array and level of services, support and economies of scale that are typically only available to a much larger company.

h. With an enhanced national presence, the combined company and its subsidiaries will benefit from having a relevant and informed perspective and effect on energy policy discussions that stand to positively affect the quality, safety, reliability, and cost of the services offered to customers.

i. As one of the largest and safest operators of energy infrastructure assets, the combined company and its subsidiaries will benefit from the adoption of best practices across an expanded platform of service that stands to improve employee and public safety, customer service, and operational cost effectiveness.

j. As one of the largest and most active regulated energy infrastructure company participants in public equity and debt capital markets, the combined company and its subsidiaries will benefit from an enhanced ability to efficiently finance system growth and reliability to the benefit of customers.

k. The above-mentioned commitments, understandings and benefits will be of substantial value to SCE&G's customers, employees and communities in future years and demonstrate that the Merger is clearly in the public interest.

IX. EVENTS SURROUNDING ABANDONMENT OF THE NND PROJECT AND SCE&G'S DECISION TO PURSUE A MERGER

62. On March 28, 2008, SCE&G and the South Carolina Public Service Authority ("Santee Cooper) signed an Engineering, Procurement and Construction Agreement ("EPC Contract") under which two AP1000 Advanced Passive Safety Nuclear Units (the "Units") were to be constructed by Westinghouse Electric Company, LLC ("Westinghouse") and a consortium partner which at the time was The Shaw Group.

63. SCE&G promptly filed a proceeding under the BLRA to have the Commission conduct a full pre-construction prudency review of the decision to construct the Units. That review encompassed the choice of Westinghouse and the AP1000 technology, the suitability of the site, the qualifications of contractors for the Units, the financial plan for funding construction, and the terms of the EPC Contract.

64. After hearings that spanned three weeks and involved expert testimony from twenty-two witnesses, the Commission, in Order No. 2009-104(A), made prudency determinations affirming the decision to construct the Units and approved a forecasted construction milestone schedule and a forecasted capital cost schedule for that construction.

65. The Commission's decision was upheld on appeal to the South Carolina Supreme Court, which found that "based on the overwhelming amount of evidence in the

record, the Commission's determination that SCE&G considered all forms of viable energy generation, and concluded that nuclear energy was the least costly alternative source, is supported by substantial evidence." *Friends of Earth v. Pub. Serv. Comm'n of S.C.*, 387 S.C. 360, 369, 692 S.E.2d 910, 915 (2010).

66. At the time, the approved capital cost for the project was $6.3 billion in future dollars.[4]

67. In four ensuing orders, the Commission approved the prudency of changes to the schedules of costs or construction schedules for the Units.[5]

68. In the most recent order, Order No. 2016-794, the Commission approved SCE&G's request to update the forecasted capital costs of the Units to approximately $7.7 billion in future dollars, an increase of approximately 21% over the price approved seven years earlier.

69. The schedules approved in Order No. 2016-794 were based on the October 2015 amendment to the EPC Contract in which Westinghouse agreed to complete the principal scopes of work remaining under the EPC Contract for a fixed price (the "Fixed Price Option").

---

[4] Unless otherwise noted, all amounts reflect SCE&G's portion of the cost of the Units in future dollars.
[5] Order No. 2010-12; Order No. 2011-345; Order No. 2012-844; Order No. 2015-661.

a. The Westinghouse Bankruptcy

70. On March 29, 2017, Westinghouse and certain affiliates petitioned for protection under Chapter 11 of the United States Bankruptcy Code and informed SCE&G and Santee Cooper that Westinghouse intended to use the provisions of the Bankruptcy Code to reject its obligations under the Fixed Price Option.

71. On July 27, 2017, SCE&G and Santee Cooper entered into an agreement with Westinghouse's parent company, Toshiba Corporation ("Toshiba"), under which Toshiba agreed to pay SCE&G approximately $1.2 billion in satisfaction of all claims for damages associated with Westinghouse's anticipated rejection of the EPC Contract (the "Toshiba Corporation Guarantee Settlement Payment").

72. On September 27, 2017, SCE&G and Santee Cooper sold to Citibank N.A. all future guarantee payments, except for an October 2017 payment, from Toshiba.

73. After deduction of estimated amounts which may be used to liquidate certain contractors' liens on the Units, the net proceeds of the Toshiba Corporation Guarantee Settlement Payment is estimated at $1.0 billion.

b. The Evaluation of Cost to Complete

74. In anticipation of Westinghouse's rejection of the EPC Contract, SCE&G and Santee Cooper each undertook an evaluation of the options regarding the project.

75. Those options included completing both Units, cancelling both Units, and completing one Unit and delaying or cancelling the other.

76. SCE&G and Santee Cooper each undertook to create cost and completion schedules for the Units based on those provided by Westinghouse.

77. For this purpose, SCE&G assembled a team of construction and financial experts supported by external consulting firms with expertise in scheduling and estimating, as well as direct expert engineering support from Westinghouse and construction expertise from Fluor Corporation.

78. Westinghouse agreed to provide SCE&G with direct access to Westinghouse's construction scheduling and cost data, commodity quantity and installation rates, commercial information, and vendor and supplier contracts for the purpose of conducting this evaluation. Much of this information was previously contractually unavailable to SCE&G.

79. After a careful assessment of this data, SCE&G determined the reasonable, likely and prudent forecasted cost schedule for completion of the Units would be approximately $8.8 billion.

80. SCE&G assessed the cost of completing Unit 2 and abandoning Unit 3. This assessment indicated that the reasonable and likely cost of completing Unit 2 and abandoning Unit 3 would be approximately $7.1 billion.

81. The resulting net estimate to complete both Units was approximately $1.1 billion more than the comparable cost as approved in Order No. 2016-794, and approximately three times the estimate of the additional costs above the Fixed Price Option required to complete the Units that Westinghouse provided SCE&G in the first quarter of 2017.

c. Alternatives for Completing, Modifying or Cancelling the Project

82. In evaluating the options for proceeding with the project or cancelling it, SCE&G reviewed each option using a system planning methodology comparable to that used in the studies presented to the Commission in the 2008 and subsequent BLRA proceedings.

83. In all cases, the analysis assumed that the deadline for Federal Nuclear Production Tax Credits ("PTCs") would be extended such that both Units would qualify for credits valued at $2.2 billion. There were, however, substantial risks associated with the receipt of the PTCs given the then-current construction schedules.

84. These analyses indicated that in a number of reasonably probable planning scenarios there could be significant levelized cost benefits to SCE&G's system and customers over a forty year planning horizon from completing one or both Units.

85. Based on this evaluation, SCE&G anticipated that a prudent and economically practical path in light of capital requirements and rate impacts could be to abandon or delay Unit 3 and complete Unit 2.

86. The anticipated value of completing Unit 2 only was based on the assumption that Santee Cooper would remain a 45% co-owner.

87. Significant risks remained to be evaluated concerning the option of completing Unit 2 only, including construction schedule risk, construction cost risk, risks that the PTCs would not be available and risks that the rate impact of completing Unit 2 would be unacceptable to customers and this Commission.

88. The evaluation of these risks was never brought to a conclusion.

89. On July 31, 2017, Santee Cooper's board announced that it was suspending construction of the project.

90. SCE&G had determined that completing Unit 2 would not be feasible or beneficial to customers if Santee Cooper did not pay its 45% share of the construction and operating costs of that Unit.

91. Therefore, SCE&G determined that the only reasonable and prudent course of action was to abandon construction of the Units and return the site to a stable condition.

92. On July 31, 2017, SCE&G informed Westinghouse and the Fluor Corporation of its decision and instructed them to cease all work on the project other than work necessary to safely and efficiently demobilize construction and to stabilize the site.

d. Financial Impacts of Abandonment

93. Between August and December of 2017, SCANA's market capitalization declined by approximately $3.97 billion, SCANA and SCE&G's credit ratings were downgraded, and rating agencies indicated that downgrades to SCE&G's key ratings to below investment grade status might be forthcoming. SCE&G determined that its continued creditworthiness and ability to finance its on-going utility operations and serve its electric and gas customers effectively was a serious risk.

94. On January 2, 2018, SCANA and Dominion Energy entered into the Merger Agreement which if closed would protect SCE&G's solvency and creditworthiness and would provide Merger benefits to SCE&G's customers in furtherance of a resolution of these regulatory and other uncertainties.

X. ALTERNATIVES ABSENT THE MERGER

95. SCE&G joins with Dominion Energy in affirming that the Merger is in the best interest of SCE&G's customers and the State of South Carolina. Dominion Energy has the resources, personnel, leadership, and culture, and the community, environmental and societal commitments to ensure that after the Merger, SCE&G can continue to provide electric and gas service to its customers in a safe, reliable and efficient manner as a subsidiary of Dominion Energy. Dominion Energy has the financial ability to provide Merger benefits to customers that far exceed what SCE&G or SCANA could provide on a stand-alone basis.

96. As a disfavored alternative to the Merger and the Customer Benefits Plan, SCE&G proposes that the Commission adopt one of the two following plans to take effect if the Merger does not close.

a. The No Merger Benefits Plan

97. As a disfavored alternative to the Customer Benefits Plan, SCE&G requests that the Commission adopt the No Merger Benefits Plan as a just and reasonable resolution of the ratemaking matters surrounding the abandonment of the NND Project in the event that the Merger does not close.

98. The No Merger Benefits Plan does not provide any rate credits to customers ($1.3 billion), any rate moratorium (January 1, 2021) or any fund to reduce customer bills by providing rate refunds ($575 million). It involves write offs of investment of only $810 million compared to $1.7 billion under the Customer Benefits Plan. It requires NND

Project costs to be recovered from customers over 50 years and not 20 years as is the case under the Customer Benefits Plan.

99. Nevertheless, the No Merger Benefits Plan represents the most reasonable plan that SCE&G and SCANA can support financially as stand-alone companies without putting their solvency and access to capital and ultimately their ability to serve customers at unreasonable risk.

100. The key provisions of the No Merger Benefits Plan are as set forth in ***Exhibit 10***.

b. The Base Request

101. If the Merger does not close, and the No Merger Benefits Plan is not approved, then SCE&G requests an order from the Commission affirming the following Base Request.

102. The Base Request reflects the result required by law without any of the customer mitigation components reflected in Customer Benefits Plan or the No Merger Benefits Plan components. Specifically, the Base Request does not include any rate credits, rate moratorium, fund to reduce customer bills by providing rate refunds, write downs of capital, or rate reductions. For these reasons, it is a disfavored plan.

103. The key provisions of the Base Request are as set forth in ***Exhibit 11***.

XI. RATE-RELATED PROVISIONS, PRUDENCY DETERMINATIONS, ACCOUNTING DIRECTIVES FOR THE CUSTOMER BENEFITS PLAN

104. The Customer Benefits Plan described above includes requests for rate-related provisions, accounting directives and prudency determinations as set forth below.

a. Transmission Investment

105. The investments in certain transmission assets which now serve V.C. Summer Unit 1 were included in the scope of work to construct the Units as approved under Order No. 2009-104(A) and subsequent BLRA orders (the "Transmission Projects").

106. These Transmission Projects represent a necessary and valuable addition to the capacity, reliability and efficiency of the transmission system that SCE&G uses to serve its customers daily and will not be abandoned.

107. These assets are or will be used and useful assets providing electric service to customers.

108. To provide for the reasonable and appropriate accounting treatment for the Transmission Projects going forward, SCE&G requests that the Commission direct SCE&G:

a. To remove from the balance of Capital Costs for BLRA purposes SCE&G's capital costs incurred in constructing these assets;

b. To treat the costs associated with these assets as costs that are no longer associated with a base load plant being constructed under the terms of the BLRA; and

c. To defer as a regulatory asset for recovery in a future rate proceeding the operating and maintenance costs associated with the Transmission Projects after they are placed in service, including depreciation, property taxes, insurance, and other operating and maintenance costs. SCE&G also requests authorization to accrue carrying costs, at its weighted average cost of long-term debt, on the balance of the deferred costs in this regulatory asset.

b. Toshiba Corporation Guarantee Settlement Payment

109. To accelerate Toshiba payments, SCANA agreed to sell its shares of its settlement with Toshiba to Citibank N.A., reducing collection risks and accelerating the collection of the proceeds. SCE&G requests that the Commission enter an order recognizing that this decision was just, reasonable and prudent.

110. Under the Customer Benefits Plan, the Toshiba Corporation Guarantee Settlement Payment will be allocated to the payment of the $1.3 billion in rate credits to retail electric customers.

c. Accounting for and Recovery of Capital Costs

i. Capital Cost Rider

111. Under the Customer Benefits Plan, the amount of the capital costs associated with the NND Project for rate making purposes (the "Capital Costs") are approximately $3.3 billion and will be recorded in a regulatory asset. This amount is net of an approximately $1.4 billion write down of those costs and is also net of Transmission Projects costs.

112. The deferred taxes associated with the NND Project include a deferred tax liability estimated to be $1.3 billion, offset by a deferred tax asset (the "Deferred Taxes"). The aforementioned amounts are estimates and are subject to change based on filing and subsequent audits of SCANA's income tax returns.

113. Under the Customer Benefits Plan, the Capital Costs plus the Deferred Taxes will equal the Capital Cost Rate Base (the "Capital Cost Rate Base"). Revenue

requirements associated with the Capital Cost Rate Base will be recovered through a separate rate rider (the "Capital Cost Rider").

114. Use of the Capital Cost Rider ensures that as the balance of Capital Costs declines, annual rate reductions are passed through to customers on an expedited and efficient basis. Furthermore, through the use of a single rate adjustment mechanism, all cost of service components associated with the Capital Cost Rate Base recovery will be transparent to the Commission and the Office of Regulatory Staff ("ORS").

115. The revenue requirements to be recovered under the Capital Cost Rider will equal (1) the amortization of the Capital Costs over a 20-year period, plus (2) a Return on Rate Base based on the cost of capital.

116. The deferred tax liability discussed above will be recognized as a credit to income tax expense over the same straight line 20-year amortization period as the amortization of the Capital Costs.

117. Reductions in the deferred tax asset shall be subject to Dominion Energy's ability under Internal Revenue Code Sections 172 and 382 to use the SCANA net operating loss carryforward to reduce the consolidated income tax liability of the Dominion Energy group and shall not be computed on a separate company basis.

ii. Refund Credit to Capital Cost Rider

118. Dominion Energy will underwrite $575 million in refunds by SCE&G for amounts previously collected under the NND Project (the "Refund Pool") thereby establishing a regulatory liability to be recorded on SCE&G books.

119. Each year when the Capital Cost Rider amount is being calculated, a refund credit (the "Refund Credit") will be credited to customers to facilitate each customer class receiving an estimated 3.5% bill reduction compared to the electric rates in force in May 2017.

120. The Refund Credit shall be allocated each year to offset any amount of the Capital Cost Rider revenue requirement that exceeds $328 million (an approximate 3.5% reduction from 2017 levels).

121. The amount of the Refund Credit used each year will be deducted from the Refund Pool. When the $575 million Refund Pool is exhausted by the Refund Credits, the amortization of Capital Costs is expected to have reduced the revenue requirement to be collected under the Capital Cost Rider sufficiently to ensure that customer bills do not increase.

iii.Tax Cut and Jobs Act Rider

122. In addition, under the Customer Benefits Plan, SCE&G will provide a further bill credit of approximately 1.5% in recognition of tax expense reductions under the Tax Cut and Jobs Act of 2017 (the "Tax Rider"), with the exception of excess deferred income taxes.

123. The Refund Pool of $575 million is calculated to be sufficient along with the Tax Rider to reduce customer bills by approximately 5% (compared to 2017 rates), and, with the exception of the portion attributable to tax reform, is estimated to remain in place for approximately eight years.

124. The provisions of the Capital Cost Rider, Refund Credit to the Capital Cost Rider, and Tax Rider are also set forth in the tariff sheet provided in ***Exhibit 12***.

125. To properly provide for the recovery of the Capital Cost Rider, SCE&G requests that the Commission authorize and direct SCE&G:

a. To record the Capital Costs to a regulatory asset for future recovery through the Capital Cost Rider;

b. To reduce SCE&G's retail electric rate base by the amount of the Capital Cost Rate Base;

c. To reduce SCE&G's retail electric revenue by approximately $413 million which is the amount of the current revenue requirement associated with the Capital Costs;

d. To create a rate rider to collect (a) the amortization of the Capital Costs over a 20-year straight line basis (the "Amortization Expense"), and (b) the Cost of Capital (as defined below) computed on the current balance in the Capital Cost Rate Base;

e. To require SCE&G to update its retail electric rates annually to recover the Amortization Amount and the Cost of Capital until the Capital Cost Rate Base balance has been fully amortized; and

f. To require SCE&G to provide customers with the Refund Credits and the Tax Rider bill credits as part of the Capital Cost Rider.

d. Cost of Capital

126. SCE&G requests that the Commission rule that until the balance of the Capital Cost Rate Base is fully recovered, the cost of capital associated with the unrecovered balance of the Capital Cost Rate Base shall be a rate that reflects a return on common equity of 10.25%, a weighted average cost of debt of 5.85%, and a capital structure consisting of 52.81% equity and 47.19% debt, with these percentages fixed over the amortization period.

e. Prudency Determination Concerning Abandonment

127. SCE&G seeks an order from the Commission affirming under S.C. Code Ann. § 58-33-280(K) and the other statutes cited above that SCE&G's decision to abandon the NND Project effective July 31, 2017, was reasonable and prudent.

f. The Costs Recoverable Under S.C. Code Ann. § 58-33-280(K)

128. S.C. Code Ann. § 58-33-280(K) provides that "[w]here a plant is abandoned after a base load review order approving rate recovery has been issued, the capital costs and AFUDC related to the plant shall nonetheless be recoverable under this article. . . ." Absent a showing that the abandonment was imprudent, recovery shall include "recovery of capital costs and the utility's cost of capital associated with them." *Id.* "The commission shall order the amortization and recovery through rates of the investment in the abandoned plant as part of an order adjusting rates under this article [*i.e.,* the BLRA]." *Id.*

129. SCE&G requests the Commission issue an order under S.C. Code Ann. § 58-33-280(K) that adopts the cost schedule set forth in ***Exhibit 13*** to this Petition as a reasonable and prudent schedule of the capital costs associated with the Units incurred as

of September 30, 2017 (the "Capital Costs") thereby constituting the investment in the abandoned plant that SCE&G is legally entitled to amortize and recover through rates under the provisions of S.C. Code Ann. § 58-33-280(K) and may properly amortize into retail electric revenue requirements under the Base Request.

130. As shown on ***Exhibit 13***, the gross amount of the Capital Costs incurred through December 31, 2017, is approximately $4.7 billion net of Transmission Projects costs.

131. Under the Customer Benefits Plan, all NND Project costs which have not been reviewed and accepted for including in ratemaking in prior revised rates proceedings will be eliminated through the $1.4 billion write down of NND Project costs.

132. Because the project has been abandoned, no update to the milestone completion schedule is necessary, nor is an updated schedule necessary under S.C. Code Ann. § 58-33-270(A)(1).

g. Miscellaneous Accounting Matters

133. Under the Customer Benefits Plan, and if the Merger closes, SCE&G would write off regulatory assets in the amount of approximately $320 million as described above.

134. Should the No Merger Benefits Plan or Base Request be considered, the necessary rate-related provisions, accounting directives and prudency determinations for these plans can be found in ***Exhibit 10 and Exhibit 11***.

XII. EXHIBITS

135. ***Exhibit 14*** provide financial and related information consistent with the exhibits routinely filed in electric rate proceedings to demonstrate the financial results that

would be expected to be realized by approving the Customer Benefits Plan. It indicates that under that plan, SCE&G would earn a return on equity of 9.52% which is 73 basis points lower than its allowed return of 10.25% as established in Order No. 2012-951, but only after the payment of $1.3 billion in immediate rate refund payments to customers, the funding of the $575 million Refund Pool, and write offs of assets in the amount of $1.7 billion.

136. ***Exhibit 15*** provide financial and related information consistent with the exhibits routinely filed in electric rate proceedings to demonstrate the financial results that would be expected to be realized by granting the relief requested under the No Merger Benefits Plan. It indicates that with the implementation of the No Merger Benefits Plan, SCE&G would earn a return on equity of 8.73% which is 152 basis points lower than its allowed return of 10.25% as established in Order No. 2012-951 but also requires a write down of $810 million in assets.

137. ***Exhibit 16*** provide financial and related information consistent with the exhibits routinely filed in rate proceedings to demonstrate the financial results that would be expected to be realized by granting the relief requested under the Base Request. It indicates that with the implementation of the Base Request, SCE&G would earn a return on equity of 9.06% which is 119 basis points lower than its allowed return of 10.25% as established in Order No. 2012-951.

138. ***Exhibit 17*** provide financial and related information consistent with the exhibits routinely filed in rate proceedings to demonstrate the financial results that would be expected to be realized by granting the relief previously requested by ORS in Docket

No. 2017-305-E and reflects the deduction of $417 million in retail electric revenue from SCE&G. It indicates that with the implementation of the ORS request, SCE&G would earn a return on equity of 3.39% which is 841 basis points lower than its allowed return of 10.25% as established in Order No. 2012-951. Under GAAP this would require a write down of SCE&G's equity by an amount which would make it impossible for SCE&G to ensure its ongoing solvency and creditworthiness. In such circumstances, it would be unlikely that SCANA could recapitalize SCE&G to restore its creditworthiness and SCE&G's ability to continue to finance its utility operations outside of bankruptcy would be at grave risk.

139. ***Exhibit 12*** provides the tariff sheet setting out the tariffs that would result from implementing a 3.5% bill reduction under either the Customer Benefits Plan or under the No Merger Benefits Plan. The tariffs under these plans would be identical except that the tariffs under the Customer Benefits Plan would include language indicating that rates would be subject to annual recalculation under the Capital Cost Rider and such language would not be retained under the No Merger Benefits Plan.

140. ***Exhibit 12*** also includes tariffs sheets setting forth the provisions of the Capital Cost Rider, the Refund Credits to the Capital Cost Rider and the Tax Rider.

XIII. CONCLUSION

141. Dominion Energy is a strong and well-financed company that is committed to the safe, reliable, cost-effective and environmentally responsible provision of utility services to its customers. The proposed combination, and the proposed multi-billion dollar investment by Dominion Energy in SCE&G and South Carolina, will provide significant

short-term and long-term benefits for SCE&G and its customers, employees and shareholders. It will also provide benefits to SCE&G's service territory and the state as a whole by ensuring the utility remains strong and financially viable.

142. Dominion Energy looks forward to being able to invest in the future of SCE&G, focusing on the objectives of safety, customer satisfaction, reliable economic service, environmental stewardship and collaborative and productive relationships with customers, regulators and other governmental entities and interested stakeholders. This Joint Petition demonstrates that Dominion Energy is committed to these objectives.

XIV. REQUEST FOR RELIEF

WHEREFORE, SCE&G and Dominion Energy respectfully request that the Commission:

a. Formally approve the Merger with no material changes to the terms of the Merger, if the Commission determines that formal approval of the Merger is required under S.C. Code Ann. § 58-27-1300 or other applicable South Carolina law.

b. Alternatively, find that (i) the Merger is in the public interest; or (ii) there is an absence of harm to South Carolina ratepayers as a result of the Merger. Such a ruling or finding by the Commission is a condition of the closing of the Merger, unless formal approval is granted.

c. Issue an order adopting the Customer Benefits Plan and associated rate-related provisions, prudency determinations, and accounting directives as set forth above.

d. As a disfavored alternative, if the Merger does not close or if the Commission does not approve the Merger or the Customer Benefits Plan, issue an order adopting the No Merger Benefits Plan with associated rate-related provisions, prudency determinations, and accounting directives as set forth herein and in ***Exhibit 10***.

e. As a disfavored alternative, if the Merger does not close or if the Commission does not approve the Merger or the Customer Benefits Plan, and if the Commission also decides not to adopt the No Merger Benefits Plan, issue an order adopting the Base Request with associated rate-related provisions, prudency determinations, and accounting directives as set forth herein and in ***Exhibit 11***.

f. Terminate the requirement that SCE&G provide the semi-annual update on construction progress as required by Order No. 2016-794.

g. Acknowledge that with the cession of construction the filing of quarterly reports on construction progress is no longer required under S.C. Code Ann. § 58-33-277 and Order No. 2009-104(A).

h. To grant the other relief requested above and such other, different of further relief as may be warranted in the premises.

Respectfully submitted,

K. Chad Burgess

K. Chad Burgess
Matthew W. Gissendanner
South Carolina Electric & Gas Company
Mail Code C222
220 Operation Way
Cayce, SC 29033
(803) 217-8141 (KCB)
(803) 217-5359 (MWG)
chad.burgess@scana.com
matthew.gissendanner@scana.com

Belton T. Zeigler
Womble Bond Dickinson (US) LLP
1221 Main Street, Suite 1600
Columbia, SC 29201
(803) 454-7720
belton.zeigler@wbd-us.com

Mitchell Willoughby
Willoughby & Hoefer, P.A.
Post Office Box 8416
Columbia, SC 29202
(803) 252-3300
mwilloughby@willoughbyhoefer.com

Attorneys for South Carolina Electric & Gas Company

Cayce, South Carolina

Date: January 12, 2018

Robert A. Muckenfuss
McGuireWoods LLP
201 North Tryon Street
Suite 3000
Charlotte, NC 28202-2146
(704) 343-2052
rmuckenfuss@mcguirewoods.com

Lisa S. Booth*
Dominion Energy Services, Inc.
120 Tredegar Street
P.O. Box 26532
Richmond, VA 23261-6532
(804) 819-2288
lisa.s.booth@dominionenergy.com

Joseph K. Reid, III*
Elaine S. Ryan*
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, VA 23219-3916
(804) 775-1198 (JKR)
(804) 775-1090 (ESR)
jreid@mcguirewoods.com
eryan@mcguirewoods.com

**Application for admission pro hac vice forthcoming*

Attorneys for Dominion Energy, Inc.

Charlotte, North Carolina

Date: January 12, 2018

BEFORE

THE PUBLIC SERVICE COMMISSION

OF

SOUTH CAROLINA

DOCKET NO. 2017-370-E

In Re: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc., for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated customer benefits and cost recovery plans	**JOINT MOTION OF SOUTH CAROLINA ELECTRIC & GAS COMPANY AND DOMINION ENERGY, INC. TO EXPEDITE HEARING**

South Carolina Electric & Gas Company ("SCE&G" or the "Company") and Dominion Energy, Inc. ("Dominion Energy") (together, the "Petitioners" or the "Parties"), through their undersigned counsel, pursuant to 10 S.C. Code Ann. Regs. 103-829, 103-836, and 103-837, hereby respectfully move the Public Service Commission of South Carolina for an order granting an expedited hearing in the above-captioned matter for the reasons set forth below.

On January 12, 2018, the Parties filed a joint application and petition for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated customer benefits and cost recovery plans (the "Petition"). As explained in the Petition, the Parties seek approval of a proposed transaction whereby SCE&G's parent, SCANA Corporation ("SCANA"), will become a wholly-owned subsidiary of Dominion Energy (the "Merger"). The Parties further seek approval of a customer benefits plan and a cost recovery plan for new nuclear development costs related to the decision of SCE&G to abandon construction of two 1,117 net megawatt nuclear units at the V.C. Summer Nuclear Station site near Jenkinsville, South Carolina.

In its Petition, the Parties are proposing a cost recovery plan that will provide significant short-term and long-term benefits for SCE&G and its customers. However, between August and December of 2017, SCANA's market capitalization has declined by approximately $3.97 billion, SCANA's and SCE&G's credit ratings have been downgraded, and rating agencies have indicated that downgrades to SCE&G's key ratings to below investment grade status might be forthcoming. SCE&G has determined that its continued creditworthiness and ability to finance its on-going utility operations and serve its electric and gas customers effectively is a serious risk. The Commission's approval, allowing closure of this Merger, would protect SCE&G's solvency and creditworthiness and would provide the Merger benefits to SCE&G's customers in furtherance of a resolution of these regulatory and other uncertainties.

In light of the importance of this matter to SCE&G's customers and the State of South Carolina, and the risks and costs of delay, SCE&G respectfully requests that the

Commission expedite the hearing and resolution of this matter, and set the matter for hearing on or before April 17, 2018, with prefiling deadlines as set forth in Exhibit A.

EXPEDITED RELIEF REQUESTED

Wherefore, the Parties respectfully request that the Commission expedite the hearing in the above-captioned matter. A proposed schedule for the filing is attached.

Respectfully submitted,

K. Chad Burgess
Matthew W. Gissendanner
South Carolina Electric & Gas Company
Mail Code C222
220 Operation Way
Cayce, SC 29033
(803) 217-8141 (KCB)
(803) 217-5359 (MWG)
chad.burgess@scana.com
matthew.gissendanner@scana.com

Mitchell Willoughby
Willoughby & Hoefer, P.A.
Post Office Box 8416
Columbia, SC 29202
(803) 252-3300
mwilloughby@willoughbyhoefer.com

Belton T. Zeigler
Womble Bond Dickinson (US) LLP
1221 Main Street, Suite 1600
Columbia, SC 29201
(803) 454-7720
belton.zeigler@wbd-us.com

Attorneys for South Carolina Electric & Gas Company

Robert A. Muckenfuss
McGuireWoods LLP
201 North Tryon Street
Suite 3000
Charlotte, NC 28202-2146
(704) 343-2052
rmuckenfuss@mcguirewoods.com

Lisa S. Booth*
Dominion Energy Services, Inc.
120 Tredegar Street
P.O. Box 26532
Richmond, Virginia 23261-6532
(804) 819-2288 (LSB)
lisa.s.booth@dominionenergy.com

Joseph K. Reid, III*
Elaine S. Ryan*
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, VA 23219-3916
(804) 775-1198 (JKR)
(804) 775-1090 (ESR)
jreid@mcguirewoods.com
eryan@mcguirewoods.com

Application for admission pro hac vice forthcoming

Attorneys for Dominion Energy, Inc.

Cayce, South Carolina

Date: January 12, 2018

BEFORE

THE PUBLIC SERVICE COMMISSION

OF

SOUTH CAROLINA

DOCKET NO. 2017-370-E

In Re: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc., for review and approval of a proposed business combination between SCANA Corporation and Dominion Energy, Inc., as may be required, and for a prudency determination regarding the abandonment of the V.C. Summer Units 2 & 3 Project and associated customer benefits and cost recovery plans	)	**EXHIBIT A: PROPOSED SCHEDULE FOR FILING**

1. The **Applicants** must prefile with the Commission 1 copy of the direct testimony and exhibits of the witnesses it intends to present and serve the testimony and exhibits of the witnesses on all Parties of Record on or before **February 20, 2018** (must be post-marked on or before this date).

2. **All Other Parties of Record and the Office of Regulatory Staff (ORS)** must prefile with the Commission 1 copy of the direct testimony and exhibits of the witnesses they intend to present and serve the testimony and exhibits of the witnesses on all Parties of Record on or before **March 20, 2018** (must be post-marked on or before this date).

3. The **Applicants** filing **Rebuttal Testimony** must prefile with the Commission 1 copy of the testimony and exhibits of the witnesses it intends to present and serve the testimony and exhibits of the witnesses on all Parties of Record on or before **April 3, 2018** (Rebuttal testimony and exhibits must be in the offices of the Commission and in the hands of the parties on this date).

4. **All Other Parties of Record and the ORS** filing **Surrebuttal Testimony** must prefile with the Commission 1 copy of the testimony and exhibits of the witnesses they intend to present and serve the testimony and exhibits of the witnesses on all Parties of Record on or before **April 10, 2018** (Surrebuttal testimony and exhibits must be in the offices of the Commission and in the hands of the parties on this date).

5. **Hearing Date: April 17, 2018**

Exhibit 1

Execution Version

AGREEMENT AND PLAN OF MERGER

by and among

DOMINION ENERGY, INC.,

SEDONA CORP.

and

SCANA CORPORATION

Dated as of January 2, 2018

TABLE OF CONTENTS

Page

ARTICLE VI

CONDITIONS

ARTICLE VII

TERMINATION

ARTICLE VIII

MISCELLANEOUS

AGREEMENT AND PLAN OF MERGER

This AGREEMENT AND PLAN OF MERGER, dated as of January 2, 2018 (this "Agreement"), is entered into by and among DOMINION ENERGY, INC., a Virginia corporation ("Parent"), SEDONA CORP., a South Carolina corporation and a wholly-owned Subsidiary of Parent ("Merger Sub") and SCANA CORPORATION, a South Carolina corporation (the "Company").

RECITALS

WHEREAS, the board of directors of Parent has approved this Agreement and the transactions contemplated by this Agreement, including the merger of Merger Sub with and into the Company (the "Merger"), on the terms and subject to the conditions set forth in this Agreement;

WHEREAS, the board of directors of the Company (the "Company Board") has (a) determined that it is in the best interests of the Company and the shareholders of the Company that the Company enter into this Agreement and consummate the Merger and the other transactions contemplated by this Agreement on the terms and subject to the conditions set forth in this Agreement, (b) adopted this Agreement and approved the transactions contemplated by this Agreement, including the Merger, (c) directed that the approval of this Agreement be submitted to a vote at a meeting of the shareholders of the Company and (d) resolved to recommend that the shareholders of the Company approve this Agreement;

WHEREAS, the board of directors of Merger Sub has (a) determined that it is in the best interests of Merger Sub and the sole shareholder of Merger Sub that Merger Sub enter into this Agreement and consummate the Merger and the other transactions contemplated by this Agreement on the terms and subject to the conditions set forth in this Agreement, (b) adopted this Agreement and approved the transactions contemplated by this Agreement, including the Merger and (c) resolved to recommend that the sole shareholder of Merger Sub approve this Agreement;

WHEREAS, for U.S. federal income tax purposes, the Merger is intended to qualify as a "reorganization" within the meaning of Section 368(a) of the Code (the "Intended Tax Treatment"), and this Agreement is intended to be a "plan of reorganization" for purposes of Sections 354 and 361 of the Code; and

WHEREAS, the Company, Parent and Merger Sub desire to make certain representations, warranties, covenants and agreements in connection with the Merger and also to prescribe various conditions to the Merger.

NOW, THEREFORE, in consideration of the premises, and of the representations, warranties, covenants and agreements contained in this Agreement, and intending to be legally bound hereby, the Company, Parent and Merger Sub hereby agree as follows:

ARTICLE I

THE MERGER

SECTION 1.01. The Merger. Upon the terms and subject to the conditions set forth in this Agreement and in accordance with the SCBCA, at the Effective Time, Merger Sub shall be merged with and into the Company and the separate corporate existence of Merger Sub shall thereupon cease and the Company shall continue as the surviving corporation in the Merger (the "Surviving Corporation") and a wholly-owned Subsidiary of Parent. The Merger shall have the effects set forth in this Agreement and in the applicable provisions of the SCBCA.

SECTION 1.02. Closing. The closing of the Merger (the "Closing") shall take place at the offices of Mayer Brown LLP, 71 South Wacker Drive, Chicago, Illinois 60606, at 9:00 a.m., local time, on the third (3rd) Business Day following the day on which all of the conditions set forth in Article VI (other than those conditions that by their nature are to be satisfied at the Closing, but subject to the satisfaction or waiver of those conditions at the Closing) have been satisfied or waived in accordance with this Agreement, or at such other time and place as the Company and Parent may agree in writing. The date on which the Closing occurs is referred to in this Agreement as the "Closing Date".

SECTION 1.03. Effective Time. As soon as practicable on the Closing Date, the Company and Parent will cause the Merger to become effective by filing the articles of merger (the "Articles of Merger") with the Secretary of State of the State of South Carolina, which Articles of Merger will be executed and filed in accordance with the applicable provisions of the SCBCA. The Merger shall become effective at the time when the Articles of Merger have been duly filed with the Secretary of State of the State of South Carolina or at such later time as may be agreed by Parent and the Company in writing and specified in the Articles of Merger (the "Effective Time").

SECTION 1.04. Articles of Incorporation; Bylaws.

(a) At the Effective Time, the articles of incorporation of the Company, as in effect immediately prior to the Effective Time, shall be the articles of incorporation of the Surviving Corporation until thereafter amended in accordance with the provisions thereof and applicable Law; provided, however, that no such amendment shall be inconsistent with the obligations of Parent under Section 5.08(b).

(b) At the Effective Time, the bylaws of the Company, as in effect immediately prior to the Effective Time, shall be amended as of the Effective Time to be in the form of the bylaws of Merger Sub as of the date hereof (except with respect to the name of the Company, which shall be "SCANA Corporation"), with any changes necessary so that such bylaws shall be in compliance with Section 5.08 and, to the extent not inconsistent with any of the foregoing, such other changes as Parent deems necessary or appropriate) and as so amended shall be the bylaws of the Surviving Corporation until thereafter amended as provided therein or by applicable Law; provided, however, that no such amendment shall be inconsistent with the obligations of Parent under Section 5.08(b).

SECTION 1.05. Directors and Officers.

(a) The directors of Merger Sub will be appointed by Parent pursuant to applicable Law to be the directors of the Surviving Corporation after the Effective Time following the resignation or removal of the individuals serving as directors of the Company prior to the Effective Time in accordance with Section 5.15, with such directors appointed by Parent to serve until their respective successors have been duly elected or appointed and qualified or until their earlier death, resignation or removal in accordance with the articles of incorporation and the bylaws of the Surviving Corporation.

(b) The officers of the Company as of immediately prior to the Effective Time shall, from and after the Effective Time, be the officers of the Surviving Corporation until their respective successors have been duly elected or appointed and qualified or until their earlier death, resignation or removal in accordance with the articles of incorporation and the bylaws of the Surviving Corporation.

SECTION 1.06. Plan of Merger. This Agreement will constitute a "plan of merger" for purposes of the SCBCA.

ARTICLE II

EFFECT OF THE MERGER ON THE CAPITAL STOCK OF THE CONSTITUENT CORPORATIONS

SECTION 2.01. Effect on Capital Stock. At the Effective Time, by virtue of the Merger and without any action on the part of the Company, Parent, Merger Sub or the holders of any shares of capital stock of the Company, Parent or Merger Sub:

(a) Merger Consideration. Each Company Share issued and outstanding immediately prior to the Effective Time (other than the Cancelled Shares, which shall be treated in accordance with Section 2.01(b)) shall cease to be outstanding, shall be cancelled and shall cease to exist, and each such Company Share, whether represented by a certificate ("Certificate") or in non-certificated form and represented by book-entry ("Book-Entry Share"), shall automatically be converted into the right to receive 0.6690 validly issued, fully paid and non-assessable Parent Shares (the "Merger Consideration"). Following the Effective Time, the holders of Company Shares as of immediately prior to the Effective Time shall cease to have any rights with respect thereto, except for the rights set forth in Section 2.03(b)(v).

(b) Cancellation of Cancelled Shares. Each Company Share owned by Parent, Merger Sub or any other wholly-owned Subsidiary of Parent and each Company Share owned by the Company or any wholly-owned Subsidiary of the Company (collectively, the "Cancelled Shares") shall cease to be outstanding, shall be cancelled without payment of any consideration therefor and shall cease to exist.

(c) Capital Stock of Merger Sub. Each share of common stock, without par value, of Merger Sub issued and outstanding immediately prior to the Effective Time shall be converted into and become one (1) validly issued, fully paid and non-assessable share of common stock, without par value, of the Surviving Corporation, and all such shares together shall constitute the only outstanding shares of capital stock of the Surviving Corporation.

SECTION 2.02. Treatment of Company Equity Awards.

(a) Treatment of Performance Shares. At the Effective Time, each performance share award granted under a Company Equity Award Plan that is outstanding immediately prior to the Effective Time (a "Company Performance Share Award") shall fully vest at the target level of performance and shall be cancelled and converted automatically into the right to receive the Equity Award Consideration in respect of each Company Share underlying such Company Performance Share Award.

(b) Treatment of Restricted Stock Units. At the Effective Time, each restricted stock unit award in respect of Company Shares granted under a Company Equity Award Plan that is outstanding immediately prior to the Effective Time (a "Company RSU") shall fully vest and shall be cancelled and converted automatically into the right to receive the Equity Award Consideration in respect of each Company Share underlying such Company RSU.

(c) Treatment of Deferred Units. At the Effective Time, each deferred unit in respect of Company Shares credited or deemed credited to the Company stock ledger under the Director

Compensation and Deferral Plan or the Executive Deferred Compensation Plan that is outstanding immediately prior to the Effective Time (a "Company Deferred Unit") shall be converted automatically into a number of deferred unit(s) in respect of Parent Shares equal to the product of (x) the Company Deferred Unit multiplied by (y) the Merger Consideration, to be payable pursuant to the terms of the applicable plan.

(d) Payment. The Surviving Corporation shall pay the Equity Award Consideration as required under Section 2.02(a) and Section 2.02(b) as soon as reasonably practicable after the Effective Time (but in any event within three (3) Business Days thereafter); provided, however, that to the extent any such payment relates to any Company Performance Share Awards or Company RSUs that are nonqualified deferred compensation subject to Section 409A of the Code, the Surviving Corporation shall make such payment at the earliest time permitted under, and in accordance with, the terms of the applicable award agreement or other relevant documents and in accordance with Section 409A of the Code.

(e) Corporate Actions. At or prior to the Effective Time, the Company, the Company Board or any authorized committee thereof, as applicable, shall adopt any resolutions and take any actions that are necessary to effectuate the provisions of Section 2.02(a), Section 2.02(b) and Section 2.02(c). The Company shall take all actions necessary to ensure that, from and after the Effective Time, neither Parent nor the Surviving Corporation will be required to deliver Company Shares or other capital stock of the Company to any Person pursuant to or in settlement of Company Performance Share Awards, Company RSUs, Company Deferred Units or any other awards under any Company Equity Award Plan.

SECTION 2.03. Exchange of Company Shares.

(a) Exchange Agent. Prior to the Effective Time, Parent shall select a paying and exchange agent reasonably acceptable to the Company (the "Exchange Agent") and enter into an agreement with such Exchange Agent in form and substance reasonably acceptable to the Company pursuant to which the Exchange Agent will (i) act as agent for the shareholders of the Company in connection with the Merger and receive payment and delivery of the Merger Consideration to which the shareholders of the Company shall become entitled pursuant to Section 2.01(a) and (ii) act as agent for Parent in transmitting the Merger Consideration to such shareholders following the occurrence of the Effective Time in accordance with this Agreement. At or prior to the Effective Time, Parent shall deposit, or cause to be deposited, with the Exchange Agent, in trust for the benefit of the holders of Company Shares, an amount of Parent Shares in book-entry form sufficient for the Exchange Agent to pay and deliver the Merger Consideration required to be paid and delivered by Parent in accordance with Section 2.01(a). In addition, Parent shall deposit, or cause to be deposited, with the Exchange Agent, from time to time after the Effective Time, (A) any dividends or other distributions payable pursuant to Section 2.03(g) and (B) cash in lieu of any fractional Parent Shares payable pursuant to Section 2.03(h). All cash and Parent Shares, together with any dividends or other distributions, deposited with the Exchange Agent pursuant to this Section 2.03(a) shall be referred to as the "Exchange Fund."

(b) Exchange Procedures.

(i) Transmittal Materials and Instructions. Promptly after the Effective Time (and in any event within three (3) Business Days thereafter), Parent shall cause the Exchange Agent to mail or otherwise provide to each holder of record of Company Shares (other than holders of Cancelled Shares) (A) transmittal materials, including a letter of transmittal in form as agreed by Parent and the Company, specifying that delivery shall be effected, and risk of loss and title shall pass, with respect to Book-Entry Shares, only upon delivery of an "agent's message" regarding the book-entry transfer of Book-Entry Shares (or such other evidence, if any, of the transfer as the Exchange Agent may reasonably request), and with respect to Certificates, only upon delivery of the Certificates (or affidavits of loss in lieu of the Certificates as provided in Section 2.03(f) to the Exchange Agent), such transmittal materials to be in such form and have such other provisions as Parent and the Company may reasonably agree, and (B) instructions for use in effecting the surrender of the Book-Entry Shares or Certificates (or affidavits of loss in lieu of the Certificates as provided in Section 2.03(f)) to the Exchange Agent.

(ii) Certificates. Upon surrender of a Certificate (or affidavit of loss in lieu of the Certificate as provided in Section 2.03(f)) to the Exchange Agent in accordance with the terms of transmittal materials and instructions referred to in Section 2.03(b)(i), the holder of such Certificate shall be entitled to receive in exchange therefor (A) a cash amount in immediately available funds equal to (1) any dividends and other distributions such holder has the right to receive pursuant to Section 2.03(g) plus (2) any cash in lieu of any fractional Parent Shares such holder has the right to receive pursuant to Section 2.03(h) and (B) the number of Parent Shares, in uncertificated book-entry form, equal to the number of Company Shares represented by such Certificate (or affidavit of loss in lieu of the Certificate as provided in Section 2.03(f)) multiplied by the Merger Consideration. No interest will be paid or accrued on any cash amount payable upon due surrender of the Certificates.

(iii) Book-Entry Shares. Notwithstanding anything to the contrary contained in this Agreement, any holder of Book-Entry Shares shall not be required to deliver a Certificate or an executed letter of transmittal to the Exchange Agent to receive the aggregate Merger Consideration that such holder is entitled to receive as a result of the Merger pursuant to Section 2.01(a). In lieu thereof, each holder of record of one or more Book-Entry Shares (other than Cancelled Shares) shall upon receipt by the Exchange Agent of an "agent's message" in customary form (it being understood that the holders of Book-Entry Shares shall be deemed to have surrendered such Company Shares upon receipt by the Exchange Agent of such "agent's message" or such other evidence, if any, as the Exchange Agent may reasonably request) be entitled to receive, and Parent shall cause the Exchange Agent to pay and deliver as promptly as practicable after the Effective Time, (A) a cash amount in immediately available funds equal to (1) any dividends and other distributions such holder has the right to receive pursuant to Section 2.03(g) plus (2) any cash in lieu of any fractional Parent Shares such holder has the right to receive pursuant to Section 2.03(h) and (B) the number of Parent Shares, in uncertificated book-entry form, equal to the number of Company Shares represented by such Book-Entry Shares multiplied by the Merger Consideration. No interest will be paid or accrued on any cash amount payable upon due surrender of the Book-Entry Shares.

(iv) Unrecorded Transfers; Other Payments. In the event of a transfer of ownership of Company Shares that is not registered in the transfer records of the Company or if payment and delivery of the Merger Consideration and the other payments contemplated by Section 2.01(a) and this Section 2.03 is to be made to a Person other than the Person in whose name the surrendered Certificate or Book-Entry Share is registered, such Certificate or Book-Entry Share may be exchanged in accordance with this Article II if the Certificate or Book-Entry Share formerly representing such Company Shares is presented to the Exchange Agent accompanied by all documents required to evidence and effect such transfer and to evidence that any applicable transfer or other similar Taxes have been paid or are not applicable.

(v) Rights of Holders of Company Shares; Expenses. Until surrendered or exchanged pursuant to this Section 2.03(b), each Certificate or Book-Entry Share shall be deemed at any time after the Effective Time to represent only the right to receive upon such surrender or exchange the Merger Consideration pursuant to Section 2.01(a), any dividends and other distributions pursuant to Section 2.03(g) and any cash in lieu of any fractional Parent Shares pursuant to Section 2.03(h). Parent shall pay all charges and expenses, including those of the Exchange Agent, in connection with the exchange of Company Shares pursuant to this Article II.

(c) Termination of the Exchange Fund; No Liability. Any portion of the Exchange Fund (including the proceeds of any investment thereof) that remains undistributed one (1) year after the Effective Time shall be delivered to Parent or the Surviving Corporation, upon demand by Parent. Any holders of Company Shares (other than Cancelled Shares) who have not theretofore complied with this Article II shall thereafter be entitled to look only to Parent and the Surviving Corporation for payment and delivery of the Merger Consideration pursuant to Section 2.01(a), any dividends and other distributions pursuant to Section 2.03(g) and any cash in lieu of any fractional Parent Shares pursuant to Section 2.03(h) upon surrender of their Certificates or exchange of their Book-Entry Shares in accordance with the provisions set forth in Section 2.03(b), and Parent and the Surviving Corporation shall remain liable for (subject to applicable abandoned property, escheat or other similar Law) payment of their claims for the Merger Consideration payable upon surrender of their Certificates or exchange of their Book-Entry Shares. Notwithstanding the foregoing, none of the Surviving Corporation, Parent, the Company, the Exchange Agent or any other Person shall be liable to any former holder of Company Shares for any amount properly delivered to a public official pursuant to applicable abandoned property, escheat or other similar Law.

(d) Investment of the Exchange Fund. The Exchange Agent shall invest the cash portion of the Exchange Fund as directed by Parent; provided, however, that such investments shall be in obligations of or guaranteed by the United States of America, in commercial paper obligations rated A-1 or P-1 or better by Moody's Investors Service, Inc. or Standard & Poor's Corporation, respectively, in certificates of deposit, bank repurchase agreements or banker's acceptances of commercial banks with capital exceeding $1 billion, or in money market funds which are invested in instruments that consist of U.S. Treasury obligations and repurchase agreements collateralized by U.S. Treasury obligations or having a rating in the highest investment category granted by a recognized credit rating agency at the time of acquisition or a combination of the foregoing and, in any such case, no such instrument shall have a maturity that could prevent or delay payments to be made pursuant to this Agreement. Subject to Section 2.03(c), to the extent that there are losses with respect to such investment of the cash portion of the Exchange Fund, or the cash portion of the Exchange Fund diminishes for other reasons, such that the amount of cash in the Exchange Fund is below the level required to make prompt cash payment of any dividends and other distributions pursuant to Section 2.03(g) and any cash in lieu of any fractional Parent Shares pursuant to Section 2.03(h), Parent shall promptly replace or restore the cash in the Exchange Fund lost through such investments or other events so as to ensure that the Exchange Fund is at all applicable times maintained at a level sufficient to make such cash payments. Any interest and other income resulting from such investment shall become a part of the Exchange Fund, and any amounts in excess of the aggregate amount of the payments described in the immediately preceding sentence will be promptly returned to Parent or the Surviving Corporation, as requested by Parent. The Exchange Fund shall not be used for any purpose other than as contemplated by Section 2.03(a) and this Section 2.03(d).

(e) Transfers. From and after the Effective Time, the stock transfer books of the Company shall be closed and there shall be no transfers on the stock transfer books of the Company of the Company Shares that were outstanding immediately prior to the Effective Time. If, after the Effective Time, acceptable evidence of a Certificate or Book-Entry Share is presented to the Surviving Corporation, Parent or the Exchange Agent for transfer, (i) in the case of Certificates, the holder of such Certificate shall be given a copy of the transmittal materials and instructions referred to in Section

2.03(b)(i) and instructed to comply with the instructions thereto in order to receive the Merger Consideration pursuant to Section 2.01(a) and (ii) in the case of Book-Entry Shares, such Book-Entry Share shall be cancelled and exchanged as contemplated by this Article II.

(f) Lost Certificates. In the case of any Certificate that has been lost, stolen or destroyed, upon the making of an affidavit of that fact by the Person claiming such Certificate to be lost, stolen or destroyed and, if required by the Exchange Agent or Parent, the posting by such Person of a bond in a reasonable amount as indemnity against any claim that may be made against it with respect to such Certificate, the Exchange Agent shall pay and deliver in exchange for such Certificate the Merger Consideration pursuant to Section 2.01(a), any dividends or other distributions payable pursuant to Section 2.03(g) and any cash in lieu of any fractional Parent Shares pursuant to Section 2.03(h).

(g) Dividends.

(i) Certificates. No dividends or other distributions declared or made with respect to Parent Shares with a record date after the Effective Time shall be paid to the holder of any Certificate with respect to the Parent Shares that such holder would be entitled to receive upon surrender of such Certificate, until such holder shall surrender such Certificate in accordance with Section 2.03(b)(ii). Subject to applicable Law, following surrender of any such Certificate, there shall be paid to the holder of Parent Shares issued in exchange therefor, without interest, (A) promptly after the time of such surrender, the amount of dividends and other distributions with a record date after the Effective Time but prior to such surrender and a payment date prior to such surrender payable with respect to such Parent Shares and (B) at the appropriate payment date, the amount of dividends and other distributions with a record date after the Effective Time but prior to such surrender and a payment date subsequent to such surrender payable with respect to such Parent Shares.

(ii) Book-Entry Shares. Subject to applicable Law, there shall be paid to the holder of Parent Shares issued in exchange for Book-Entry Shares in accordance with Section 2.03(b)(iii), without interest, (A) promptly upon receipt by the Exchange Agent of an “agent’s message” (or such other evidence, if any, of surrender as the Exchange Agent may reasonably request), the amount of dividends and other distributions with a record date after the Effective Time but prior to such receipt and a payment date prior to such receipt payable with respect to such Parent Shares and (B) at the appropriate payment date, the amount of dividends and other distributions with a record date after the Effective Time but prior to such receipt and a payment date subsequent to such receipt payable with respect to such Parent Shares.

(h) Fractional Shares. No certificates or scrip representing fractional Parent Shares shall be issued upon the conversion of the Company Shares into the Merger Consideration pursuant to Section 2.01(a), and such fractional share interests shall not entitle the owner thereof to vote or to any rights of a holder of Parent Shares. For purposes of this Section 2.03(h), all fractional shares to which a single record holder would be entitled shall be aggregated and calculations shall be rounded to four (4) decimal places. In lieu of any such fractional Parent Shares, each holder of Company Shares who would otherwise be entitled to such fractional Parent Shares shall be entitled to receive an amount in cash, without interest, rounded to the nearest cent, equal to the product of (i) the amount of such fractional Parent Share and (ii) the Average Price.

SECTION 2.04. Withholding Rights. Each of Parent and the Surviving Corporation shall be entitled to deduct and withhold from the consideration otherwise payable pursuant to this Agreement to any holder of Company Shares, Company Performance Share Awards and Company RSUs such amounts as it is required to deduct and withhold with respect to the making of such payment under the Code or any other applicable state, local or foreign Tax Law, taking into account any applicable exemption under such Law. To the extent that amounts are so withheld by Parent or the Surviving Corporation, as the case may be, such withheld amounts (a) shall be promptly remitted by Parent or the Surviving Corporation, as applicable, to the applicable Governmental Entity and (b) shall be treated for all purposes of this Agreement as having been paid to the holder of Company Shares, Company Performance Share Awards and Company RSUs (as applicable) in respect of which such deduction and withholding were made by the Surviving Corporation or Parent, as the case may be.

SECTION 2.05. No Dissenters' Rights. In accordance with Section 33-13-102(B) of the SCBCA, no holder of Company Shares shall be entitled to exercise dissenters' rights, appraisal rights or other similar rights in connection with the Merger and the other transactions contemplated by this Agreement.

SECTION 2.06. Adjustments. In the event of any change to the Company Shares or Parent Shares (or securities convertible thereto or exchangeable or exercisable therefor) issued and outstanding in the period between the date of this Agreement and the Effective Time as a result of a reclassification, stock split (including a reverse stock split), stock dividend or distribution, recapitalization, exchange or readjustment of shares, merger, issuer tender or exchange offer, or other similar transaction, the Merger Consideration and any other payments to be made pursuant to this Article II shall be equitably adjusted, without duplication, to provide the holders of Company Shares, Company Performance Share Awards, Company RSUs and Company Deferred Units the same economic effect contemplated by this Agreement prior to such change; provided, however, that nothing in this Section 2.06 shall be construed to permit the Company, Parent, any of their respective Subsidiaries or any other Person to take any action that is otherwise prohibited by the terms of this Agreement; and provided, further, that any adjustment pursuant to this Section 2.06 to any Company Performance Share Awards, Company RSUs and Company Deferred Units shall be done in all respects in accordance with Section 409A of the Code, if applicable, and the terms of the applicable Company Equity Award Plan.

ARTICLE III

REPRESENTATIONS AND WARRANTIES

SECTION 3.01. Representations and Warranties of the Company. Except (x) as disclosed in the SEC Reports of the Company or South Carolina Electric & Gas Company (each, a "Reporting Company") filed with or furnished to the SEC since January 1, 2016 and publicly available at least twenty-four (24) hours prior to the date of this Agreement (excluding any disclosures set forth in any risk factor section or in any other section to the extent such disclosures are forward-looking statements or are cautionary, predictive or forward-looking in nature) or (y) as set forth in the Company Disclosure Letter (it being agreed that disclosure of any item in any section or subsection of the Company Disclosure Letter shall also be deemed disclosed with respect to any other section or subsection of this Agreement to which the relevance of such item is reasonably apparent), the Company represents and warrants to Parent and Merger Sub as follows:

(a) Organization, Standing and Corporate Power. The Company is a corporation duly incorporated and validly existing under the Laws of the State of South Carolina and has all requisite corporate power and authority to carry on its business as currently conducted and is duly qualified or licensed to do business and is in good standing (where such concept is recognized under applicable Law) in each jurisdiction where the nature of its business or the ownership, leasing or operation of its properties or assets makes such qualification or licensing necessary, other than where the failure to be so qualified, licensed or in good standing has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Each of the Company's Subsidiaries is a legal entity duly organized, validly existing and in good standing (where such concept is recognized under applicable Law) under the Law of its jurisdiction of organization and has all requisite corporate or similar power and authority to carry on its business as currently conducted, and each of the Company's Subsidiaries is duly qualified or licensed to do business and is in good standing (where such concept is recognized under applicable Law) in each jurisdiction where the nature of its business or the ownership, leasing or operation of its properties or assets makes such qualification or licensing necessary, other than where the failure to be so qualified, licensed or in good standing has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. The Company has made available to Parent a true and complete copy of the Restated Articles of Incorporation of the Company and any amendments thereto (collectively, the "Company Articles of Incorporation") and the Amended and Restated Bylaws of the Company (the "Company Bylaws" and together with the Company Articles of Incorporation, the "Company Organizational Documents").

(b) Subsidiaries. Section 3.01(b) of the Company Disclosure Letter sets forth a list of all Subsidiaries of the Company. All of the outstanding shares of capital stock of, or other equity interests in, each Subsidiary of the Company have, in all cases, been duly authorized and validly issued and are fully paid, non-assessable and not subject to preemptive rights, and are wholly-owned, directly or indirectly, by the Company free and clear of all pledges, liens, charges, mortgages, encumbrances, adverse claims and interests, licenses, purchase options, call options, rights of first offer and rights of first refusal, easements, rights-of-way, security interests and other use agreements, covenants and encroachments of any kind or nature whatsoever (including any restriction on the right to vote or transfer the same, except for such transfer restrictions of general applicability as may be provided under the Securities Act, the "blue sky" Laws of the various States of the United States or similar Law of other applicable jurisdictions) (collectively, "Liens"), other than transfer restrictions contained in the articles of incorporation, bylaws and limited liability company agreements (or any equivalent constituent documents) of such Subsidiary. Except for its interests in its Subsidiaries, the Company does not own, directly or indirectly, any capital stock of, or other equity interests in, any Person. The Company has made available to Parent true and complete copies of the articles of incorporation, bylaws and limited liability company agreements (or equivalent constituent documents) of each Subsidiary of the Company as in effect on the date of this Agreement.

(c) Capital Structure.

(i) The authorized capital stock of the Company consists of 200,000,000 Company Shares. The Company is not authorized to issue any preferred stock. At the close of business on December 29, 2017, there were (A)(1)142,916,916.594 Company Shares issued and outstanding and (2) 269,647.326 Company Shares held by the Company in its treasury, (B) 454,325 Company Shares underlying the outstanding Company Performance Share Awards (assuming target level performance), (C) 215,200 Company Shares underlying the outstanding Company RSUs (assuming achievement of required performance measure(s)) and (D) 269,647.326 Company Shares underlying ledgers pursuant to the Director Compensation and Deferral Plan. Except as set forth in the immediately preceding sentence, at the close of business on December 29, 2017, no shares of capital stock or other voting securities of the Company were issued or outstanding or subject to outstanding awards under the Company Equity Award Plans. Since December 29, 2017 to the date of this Agreement, (x) there have been no issuances by the Company of shares of capital stock or other voting securities of the Company other than pursuant to the exercise or vesting of equity awards under the Company Equity Award Plans, in each case, outstanding as of December 29, 2017 and (y) there have been no issuances by the Company of options, warrants, other rights to acquire shares of capital stock of the Company or other rights that give the holder thereof any economic interest of a nature accruing to the holders of Company Shares. All outstanding Company Shares are, and all such Company Shares that may be issued prior to the Effective Time will be when issued, duly authorized, validly issued, fully paid and non-assessable and not subject to preemptive rights.

(ii) No Subsidiary of the Company owns any Company Shares or other shares of capital stock of the Company. There are no bonds, debentures, notes or other Indebtedness of the Company or of any of its Subsidiaries that give the holders thereof the right to vote (or that are convertible into, or exchangeable for, securities having the right to vote) on any matters on which holders of Company Shares may vote ("Voting Company Debt"). Except for any obligations pursuant to this Agreement or as otherwise set forth in Section 3.01(c)(i), as of December 29, 2017, there are no options, warrants, rights (including preemptive, conversion, stock appreciation, redemption or repurchase rights), convertible or exchangeable securities, stock-based performance units, Contracts or undertakings of any kind to which the Company or any of its Subsidiaries is a party or by which any of them is bound (A) obligating the Company or any of its Subsidiaries to issue, deliver or sell, or cause to be issued, delivered or sold, additional shares of capital stock or other securities of, or equity interests in, or any security convertible or exchangeable for any capital stock or other security of, or equity interest in, the Company or any of its Subsidiaries or any Voting Company Debt, (B) obligating the Company or any of its Subsidiaries to issue, grant or enter into any such option, warrant, right, security, unit, Contract or undertaking to declare or pay any dividend or distribution or (C) that give any Person the right to subscribe for or acquire any securities of the Company or any of its Subsidiaries, or to receive any economic interest of a nature accruing to the holders of Company Shares or otherwise based on the performance or value of shares of capital stock of the Company or any of its Subsidiaries. As of the date of this Agreement, there are no outstanding obligations of the Company or any of its Subsidiaries to repurchase, redeem or otherwise acquire any shares of capital stock or other equity interest of the Company or any of its Subsidiaries, other than pursuant to the Company Equity Award Plans. There are no voting agreements, voting trusts, shareholders agreements, proxies or other agreements to which the Company or any of its Subsidiaries is bound with respect to the voting of the capital stock or other equity interests of the Company, or restricting the transfer of, or providing registration rights with respect to, such capital stock or equity interests.

(d) Authority; Noncontravention.

(i) The Company has all requisite corporate power and authority to execute and deliver, and perform its obligations under, this Agreement and to consummate the transactions contemplated by this Agreement, subject, in the case of the Merger only, to receipt of the Company Requisite Vote. The execution, delivery and performance of this Agreement by the Company and the consummation by the Company of the transactions contemplated by this Agreement have been duly authorized by all necessary corporate action on the part of the Company, subject, in the case of the Merger only, to receipt of the Company Requisite Vote. This Agreement has been duly executed and delivered by the Company and, assuming the due authorization, execution and delivery by each of the other parties hereto, constitutes a legal, valid and binding obligation of the Company, enforceable against the Company in accordance with its terms, subject, as to enforceability, bankruptcy, insolvency and other Law of general applicability relating to or affecting creditors' rights and to general equity principles. The Company Board has duly and validly adopted resolutions (A) determining that it is in the best interests of the Company and the shareholders of the Company that the Company enter into this Agreement and consummate the Merger and the other transactions contemplated by this Agreement on the terms and subject to the conditions set forth in this Agreement, (B) adopting this Agreement and approving the transactions contemplated by this Agreement, including the Merger, (C) directing that the approval of this Agreement be submitted to a vote at a meeting of the shareholders of the Company and (D) recommending that the shareholders of the Company approve this Agreement (the "Company Board Recommendation"), which resolutions, as of the date of this Agreement, have not been rescinded, modified or withdrawn in any way.

(ii) The execution, delivery and performance by the Company of this Agreement do not, and the consummation of the Merger and the other transactions contemplated by this Agreement and compliance with the provisions of this Agreement will not, conflict with, or result in any violation of, or default (with or without notice or lapse of time, or both) under, or give rise to any right (including a right of termination, cancellation or acceleration of any obligation or any right of first refusal, participation or similar right) under, or cause the loss of any benefit under, or result in the creation of any Lien (other than Permitted Liens) upon any of the properties or assets of the Company or any of its Subsidiaries under, any provision of (A) the Company Organizational Documents or the comparable organizational documents of any of the Company's Subsidiaries or (B) subject to the filings and other matters referred to in Section 3.01(d)(iii), (1) any Contract, or (2) any Law, in each case, applicable to the Company or any of its Subsidiaries or any of their respective properties or assets, other than, in the case of the foregoing clause (B), any such conflicts, violations, defaults, rights, losses or Liens that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(iii) No Consent of, or registration, declaration or filing with, or notice to, any Governmental Entity is required to be obtained or made by or with respect to the Company or any of its Subsidiaries in connection with the execution, delivery and performance of this Agreement by the Company or the consummation by the Company of the Merger and the other transactions contemplated by this Agreement, except for (A) the Regulatory Conditions and any other Consents of or under, and compliance with any other applicable requirements of, (1) the HSR Act, (2) the Federal Energy Regulatory Commission (the "FERC"), (3) the U.S. Nuclear Regulatory Commission (the "NRC"), (4) the Federal Communications Commission (the "FCC"), (5) the North Carolina Utilities Commission (the "NCUC"), and (6) the Georgia Public Service Commission (the "GPSC") (the items set forth in this clause (A), collectively, the "Company Regulatory Clearances"), (B) the filing with the SEC of such reports and other documents (including the filing of the Proxy Statement/Prospectus) under, and compliance with all other applicable requirements of, the Securities Act or the Exchange Act and the rules and regulations promulgated thereunder and any applicable state securities, takeover and "blue sky" Laws, (C) the filing of the Articles of Merger with the Secretary of State of the State of South Carolina, (D) any filings under, and compliance with all other applicable requirements of, the rules and regulations of the NYSE and (E) such other Consents, registrations, declarations, filings and notices, the failure of which to be obtained or made has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect and would not reasonably be expected to prevent, or materially impair or delay, the consummation of the Merger or any of the other material transactions contemplated by this Agreement.

(e) Applicable Company SEC Reports; Financial Statements; Undisclosed Liabilities.

(i) The Reporting Companies have filed or furnished, as applicable, all SEC Reports such companies were required or otherwise obligated to file with or furnish to the SEC since June 30, 2016 (such SEC Reports, the "Applicable Company SEC Reports"). As of their respective dates of filing, or, if amended or superseded by a subsequent filing made prior to the date of this Agreement, as of the date of the last such amendment or superseding filing prior to the date of this Agreement, the Applicable Company SEC Reports complied in all material respects with the applicable requirements of the Securities Act, the Exchange Act and the Sarbanes-Oxley Act, as the case may be, and the applicable rules and regulations promulgated thereunder, each as in effect on the date of any such filing. As of the time of filing with the SEC (or, if amended prior to the date of this Agreement, as of the date of such amendment), none of the Applicable Company SEC Reports so filed contained any untrue statement of a material fact or omitted to state a material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading, except to the extent that the information in such Applicable Company SEC Reports has been amended or superseded by a later Applicable Company SEC Report.

(ii) As of their respective dates, the audited and unaudited financial statements (consolidated, as applicable, and including any related notes thereto) of each of the Reporting Companies and their Subsidiaries, as applicable, included in the Applicable Company SEC Reports have been prepared in all material respects (except, as applicable, as permitted by Form 10-Q of the SEC or other applicable rules and regulations of the SEC) in accordance with United States generally accepted accounting principles ("GAAP") applied on a consistent basis during the periods involved (except as may be indicated in the notes thereto) and fairly present in all material respects the consolidated financial position of each Reporting Company and its Subsidiaries, as applicable, as of the respective dates thereof (taking into account the notes thereto) and the consolidated results of their operations and cash flows for the periods indicated (taking into account the notes thereto) and subject, in the case of unaudited financial statements, to normal year-end adjustments.

(iii) Each Reporting Company maintains disclosure controls and procedures required by Rule 13a-15(e) or Rule 15d-15(e) under the Exchange Act and such disclosure controls and procedures are effective in all material respects to ensure that information required to be disclosed by such Reporting Company in the SEC Reports it files or submits under the Exchange Act is recorded, processed, summarized and reported on a timely basis to the individuals responsible for the preparation of such Reporting Company's SEC Reports and other public disclosure documents. Each Reporting Company maintains internal control over financial reporting required by Rule 13a-15(f) or Rule 15d-15(f) under the Exchange Act and such internal control is effective in all material respects in providing reasonable assurance regarding the reliability of such Reporting Company's financial reporting and such Reporting Company's preparation of financial statements for external purposes in accordance with GAAP. Each Reporting Company has disclosed, based on its most recent evaluation prior to the date of this Agreement, to such Reporting Company's outside auditors and the audit committee of such Reporting Company's board of directors, (A) any significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that are reasonably likely to adversely affect such Reporting Company's ability to record, process, summarize and report financial information and (B) to the Knowledge of the Company, any fraud that involves management or other employees of such Reporting Company who have a significant role in such Reporting Company's internal control over financial reporting.

(iv) There are no liabilities or obligations of any Reporting Company or any Subsidiary of any Reporting Company of a nature that would be required under GAAP to be reflected or reserved on a balance sheet (consolidated, as applicable) of such Reporting Company, other than (A) liabilities or obligations reflected or reserved against in such Reporting Company's most recent balance sheet (including the notes thereto) included in the Applicable Company SEC Reports filed prior to the date hereof, (B) liabilities or obligations incurred in the ordinary course of business consistent with past practice since September 30, 2017, (C) liabilities or obligations incurred under or in accordance with this Agreement or in connection with the transactions contemplated by this Agreement and (D) liabilities or obligations that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(f) Absence of Certain Changes or Events.

(i) Since January 1, 2017, there have not been any changes, developments, circumstances, effects, events or occurrences (changes, developments, circumstances, effects, events and occurrences being collectively referred to as "Changes") that have had or would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(ii) Since January 1, 2017, except as contemplated or required by this Agreement, the Company and its Subsidiaries have conducted their respective businesses in all material respects in the ordinary course of business consistent with past practice.

(g) Litigation. There is no (i) material suit, action, arbitration, mediation or legal, arbitral, administrative or other proceeding (a "Proceeding") pending or, to the Knowledge of the Company, threatened against the Company or any of its Subsidiaries, (ii) to the Knowledge of the Company, pending or threatened material investigation or inquiry by a Governmental Entity of the Company or any of its Subsidiaries and (iii) Order, decree or writ of any Governmental Entity outstanding or, to the Knowledge of the Company, threatened to be imposed against the Company or any of its Subsidiaries.

(h) Contracts. Except for this Agreement and the Contracts set forth in Section 3.01(h) of the Company Disclosure Letter and Company Benefit Plans, as of the date of this Agreement, neither the Company nor any of its Subsidiaries is a party to any Company Material Contract. Each Company Material Contract required to be filed by the Company as a "material contract" pursuant to Item 601(b)(10) of Regulation S-K under the Securities Act has been so filed. Each of the Company Material Contracts is valid and binding on the Company or the Subsidiary of the Company party thereto and, to the Knowledge of the Company as of the date hereof, each other party thereto, and is in full force and effect, except for such failures to be valid and binding or to be in full force and effect that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. There is no default under any Company Material Contract by the Company or any of its Subsidiaries or, to the Knowledge of the Company as of the date hereof, by any other party thereto, in each case except for such defaults that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(i) Compliance with Law; Permits. Since January 1, 2016, the Company and each of its Subsidiaries have been in compliance with and have not been in default under or in violation of any applicable Law, except where such non-compliance, default or violation has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Since January 1, 2016, neither the Company nor any of its Subsidiaries has received any written notice from any Governmental Entity regarding any actual or possible violation of, or failure to comply with, any Law, except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. The Company and its Subsidiaries are in possession of all franchises, grants, permits, easements, variances, exceptions, Consents, certificates, permissions, qualifications and registrations and Orders of all Governmental Entities (collectively, "Permits"), and have filed all tariffs, reports, notices, and other documents with all Governmental Entities, necessary for the Company and its Subsidiaries to own, lease and operate their properties and assets and to carry on their businesses as currently conducted, except where the failure to possess any of such Permits or make any such filings has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. All such Permits are valid and in full force and effect and there are no pending or, to the Knowledge of the Company, threatened administrative or judicial Proceedings that would reasonably be expected to result in modification, termination or revocation thereof, except where the failure to be in full force and effect or any modification, termination or revocation thereof has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Since January 1, 2016, the Company and each of its Subsidiaries have been in compliance with the terms and requirements of such Permits, except where the failure to be in compliance has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(j) Labor and Employment Matters.

(i) Neither the Company nor any of its Subsidiaries is a party to any collective bargaining agreement or other similar agreement with a labor union, works council or similar organization. To the Knowledge of the Company, as of the date hereof, (A) there are no union or other labor organizing activities occurring concerning any employees of the Company or any of its Subsidiaries and (B) there are no labor strikes, slowdowns, work stoppages or lockouts pending or threatened in writing against the Company or any of its Subsidiaries, except, in each case, as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Since January 1, 2016, the Company and its Subsidiaries have not engaged in any action that required any notifications under the Workers Adjustment and Retraining Notification (WARN) Act of 1989, as amended, except as has not had and would not reasonably be expected to have, individually or in the aggregate a Company Material Adverse Effect.

(ii) The Company and its Subsidiaries are in compliance with all applicable Law respecting labor, employment, discrimination in employment, payroll, worker classification, wages and hours, occupational safety and health and employment practices, other than instances of non-compliance that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(iii) The list that has been provided by the Company to Parent prior to the date of this Agreement of each employee of the Company and its Subsidiaries setting forth (as applicable) each employee's annual base salary or base wage rate, target annual cash bonus, target long term incentive and other employee data is complete and accurate in all material respects as of the date of this Agreement.

(k) Employee Benefit Matters.

(i) Section 3.01(k)(i) of the Company Disclosure Letter sets forth a complete and accurate list of each material Company Benefit Plan. The Company has made available to Parent correct and complete copies of, to the extent applicable: (A) the current plan document for each material Company Benefit Plan, (B) the most recent annual report on Form 5500 required to be filed with the Department of Labor with respect to each material Company Benefit Plan, (C) the most recent summary plan description for each material Company Benefit Plan, (D) the most recent actuarial reports and financial statements for each material Company Benefit Plan, (E) each trust agreement relating to any material Company Benefit Plan, and (F) the most recent determination or opinion letter, as applicable, for each Qualified Plan.

(ii) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (A) each Company Benefit Plan (and any related trust or other funding vehicle) has been established, operated and administered in accordance with its terms and is in compliance with ERISA, the Code and all other applicable Law, (B) all contributions or other amounts payable by the Company or any Commonly Controlled Entity with respect to each Company Benefit Plan in respect of current or prior plan years have been paid or accrued in accordance with GAAP, (C) each Company Benefit Plan (and any related trust) that is intended to be qualified under Section 401(a) of the Code (each, a "Qualified Plan") is the subject of a favorable determination or opinion letter issued by the Internal Revenue Service, and, to the Knowledge of the Company, no condition exists that would reasonably be expected to result in the loss of any such Qualified Plan's qualified status and (D) to the Knowledge of the Company, there has been no non-exempt prohibited transaction (as defined in Section 4975 of the Code or Section 406 of ERISA) or breach of fiduciary duty under Section 404 of ERISA with respect to any Company Benefit Plan.

(iii) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, as of the date hereof, (A) no Proceedings (other than routine claims for benefits in the ordinary course of business) are pending or, to the Knowledge of the Company, threatened relating to or otherwise in connection with any Company Benefit Plan or the assets thereof and (B) to the Knowledge of the Company, there are no pending or threatened administrative investigations, audits or other administrative Proceedings by the Department of Labor, the Pension Benefit Guaranty Corporation, the Internal Revenue Service or other Governmental Entity relating to any Company Benefit Plan.

(iv) None of the Company or any Commonly Controlled Entity has, within the past six (6) years, sponsored, maintained, contributed to or been required to maintain or contribute to, or has any liability under, any employee benefit plan (within the meaning of Section 3(3) of ERISA) that is (and no Company Benefit Plan is) subject to Section 302 or Title IV of ERISA or Sections 412 or 4971 of the Code, or is otherwise a defined benefit plan (as defined in Section 4001 of ERISA). With respect to any plan set forth in Section 3.01(k)(iv) of the Company Disclosure Letter, the Pension Benefit Guaranty Corporation (the "PBGC") has not instituted Proceedings to terminate any such plan (and, to the Knowledge of the Company, no condition exists that would reasonably be expected to result in such Proceedings being instituted) and the Company and its Commonly Controlled Entities do not have any material liability to the PBGC with respect to such plan other than premium payments required by ERISA. Neither the Company nor any Commonly Controlled Entity has, within the past six (6) years, sponsored, maintained, contributed to or been required to maintain or contribute to, nor has any liability under, any multiemployer plan (as defined in Section 3(37) of ERISA).

(v) The Company has no liability for providing health, medical or life insurance or other welfare benefits after retirement or other termination of employment (other than for continuation coverage required under Section 4980(B)(f) of the Code or other similar applicable Law), except for such liabilities that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. With respect to any plan set forth in Section 3.01(k)(v) of the Company Disclosure Letter, to the Knowledge of the Company, the Company has the right to amend or terminate such plan in its discretion without the consent of any participant.

(vi) None of the execution and delivery of this Agreement, obtaining the Company Requisite Vote or the consummation of the Merger (alone or in conjunction with any other event, including any termination of employment on or following the Effective Time) would reasonably be expected to (A) entitle any current or former director, officer, employee or independent contractor of the Company or any of its Subsidiaries to any compensation or material benefit, (B) accelerate the time of payment or vesting, or trigger any payment or funding, of any compensation or material benefits or trigger any other material obligation under any Company Benefit Plan, (C) result in any material breach or violation of, or material default under, or limit the Company's right to amend, modify, terminate or transfer the assets of, any Company Benefit Plan, (D) directly or indirectly cause the Company to transfer or set aside any assets to fund any benefits, or otherwise give rise to any material liability, under any Company Benefit Plan or (E) result in payments to any "disqualified individual" (as defined for purposes of Section 280G(c) of the Code) which would not be deductible under Section 280G of the Code.

(l) Taxes.

(i) All material Tax Returns required to be filed by or with respect to the Company or any of its Subsidiaries have been timely filed (taking into account any extension of time within which to file) and all such Tax Returns are correct and complete in all material respects.

(ii) All material Taxes of the Company and its Subsidiaries that are required to be paid or discharged, other than Taxes being contested in good faith by appropriate proceedings, have been timely paid and discharged.

(iii) No material deficiency with respect to Taxes has been proposed, asserted or assessed against the Company or any of its Subsidiaries which has not been fully paid or adequately reserved in the SEC Reports filed or furnished by the applicable Reporting Company to the SEC.

(iv) There are no material Tax Liens, other than Permitted Liens, on any asset of the Company or any of its Subsidiaries.

(v) Neither the Company nor any of its Subsidiaries has executed any outstanding waiver of any statute of limitations for the assessment or collection of any material Tax.

(vi) As of the date hereof, no audit or other examination or Proceeding of, or with respect to, any material Tax Return or material amount of Taxes of the Company or any of its Subsidiaries is pending and, between January 1, 2016 and the date hereof, no written notice thereof has been received by the Company or any of its Subsidiaries.

(vii) None of the Company or any of its Subsidiaries (A) is a party to any material Tax allocation, Tax sharing, or Tax indemnity agreement (other than commercial Contracts the primary purpose of which is not Taxes) or (B) is under an obligation under Treasury Regulation Section 1.1502-6 (or any similar provision of state, local or non-U.S. Law) or as transferee or successor, such that, in each case, the Company or any of its Subsidiaries is, after the date hereof or after the Closing (as the case may be), liable for any material amount of Taxes of another Person (other than the Company or any of its Subsidiaries).

(viii) There are no material closing agreements, private letter rulings, technical advice memoranda or rulings that have been entered into or issued by any Tax authority with respect to the Company or any of its Subsidiaries which are still in effect as of the date of this Agreement.

(ix) Neither the Company nor any of its Subsidiaries has "participated" within the meaning of Treasury Regulation Section 1.6011-4(c)(3)(i)(A) in any "listed transaction" within the meaning of Section 6011 of the Code and the Treasury Regulations thereunder, as in effect and as amended by any guidance published by the Internal Revenue Service for the applicable period.

(x) Each of the Company and its Subsidiaries has properly and timely withheld or collected and timely paid over to the appropriate Governmental Entity (or each is properly holding for such timely payment) all material amounts of Taxes required to be withheld, collected and paid over by applicable Law.

(xi) To the Knowledge of the Company, the Company and its Subsidiaries have complied with the normalization rules described in Section 168(i)(9) of the Code and any other applicable provisions of the Code or the Treasury Regulations thereunder with respect to any "public utility property" (as defined in Section 168(i)(10) of the Code).

(xii) Neither the Company nor any of its Subsidiaries has taken any action or knows of any fact that would reasonably be expected to prevent the Merger from qualifying for the Intended Tax Treatment.

(m) Environmental Matters. Except for those matters that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (i) each of the Company and its Subsidiaries is, and since January 1, 2016 has been, in compliance with all applicable Environmental Law and, as of the date hereof, neither the Company nor any of its Subsidiaries has received any written notice from any Governmental Entity alleging that the Company or any of its Subsidiaries is in violation of, or has any liability under, any Environmental Law, (ii) each of the Company and its Subsidiaries possesses and is in compliance with all Permits required under applicable Environmental Law to conduct its business as currently conducted, and all such Permits are valid and in good standing and neither the Company nor any of its Subsidiaries has received notice from any Governmental Entity seeking to modify, revoke or terminate any such Environmental Permits, (iii) there are no Proceedings pursuant to any Environmental Law pending or, to the Knowledge of the Company, threatened against the Company or any of its Subsidiaries, (iv) there have been no releases of Hazardous Materials at or on any property owned, leased or operated by the Company or any of its Subsidiaries, in each case, in a manner that would reasonably be expected to result in any obligation to conduct any investigation, remediation or other corrective or responsive action by the Company or any of its Subsidiaries and (v) neither the Company nor any of its Subsidiaries is subject to any consent decrees, Orders, settlements or compliance agreements that impose any current or future obligations on the Company and its Subsidiaries under Environmental Law.

(n) Insurance. The Company and its Subsidiaries maintain, or are entitled to the benefits of, insurance in such amounts and against such risks as the Company believes to be customary for companies of a comparable size in the industries in which it and its Subsidiaries operate. Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, all material insurance policies carried by or covering the Company and its Subsidiaries with respect to their business, assets and properties are in full force and effect, and, to the Knowledge of the Company, no notice of cancellation has been given with respect to any such policy.

(o) Real Property.

(i) Subject, as to enforceability, to bankruptcy, insolvency and other Law of general applicability relating to or affecting creditors' rights and to general equity principles, each Contract under which the Company or any Subsidiary thereof is the tenant, subtenant or occupant (each, a "Company Real Property Lease") with respect to material real property leased, subleased, licensed or otherwise occupied (whether as tenant, subtenant or pursuant to other occupancy arrangements) by the Company or any of its Subsidiaries (collectively, including the improvements thereon, the "Company Leased Real Property") is valid and binding on the Company or the Subsidiary of the Company party thereto, and, to the Knowledge of the Company, each other party thereto, and is in full force and effect, except for such failures to be valid and binding or to be in full force and effect that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. There is no uncured default of any material provision of any Company Real Property Lease by the Company or any of its Subsidiaries or, to the Knowledge of the Company, by any other party thereto, and no event has occurred that with the lapse of time or the giving of notice or both would reasonably be expected to constitute a default thereunder by the Company or any of its Subsidiaries or, to the Knowledge of the Company, by any other party thereto, in each case except for such defaults and events that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(ii) The Company or one of its Subsidiaries has good and valid title to all material real property currently owned by the Company or any of its Subsidiaries (collectively, "Company Owned Real Property") free and clear of all Liens (other than Permitted Liens), except where absence of good and valid title or any such Lien has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(iii) Each of the Company and its Subsidiaries has such consents, easements, rights-of-way, permits and licenses with respect to any real property (collectively, "Rights-of-Way") as are sufficient to conduct its business in the manner described, and subject to the limitations, qualifications, reservations and encumbrances contained, in any Applicable Company SEC Report, except for such Rights-of-Way the absence of which has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. All pipelines and electric transmission assets owned or operated by the Company and its Subsidiaries are subject to Rights-of-Way, there are no encroachments or encumbrances or other Rights-of-Way that affect the use thereof and there are no gaps in the Rights-of-Way that are material for such pipelines or electric transmission assets, except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(iv) Each of the Company and its Subsidiaries have sufficient rights with respect to their Company Leased Real Property and Company Owned Real Property and under their Rights-of-Way to conduct its business as currently conducted, except where a failure to have such rights would not have and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(p) Intellectual Property, Privacy, and Information Technology.

(i) The Company and its Subsidiaries own or have the right to use all Intellectual Property necessary for the operation of the business of the Company and its Subsidiaries, except where the failure to own or have the right to use such Intellectual Property has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. To the Knowledge of the Company, the operation of the business of the Company and its Subsidiaries does not infringe upon or misappropriate any Intellectual Property of any other Person as of the date of this Agreement, except for such matters that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company

Material Adverse Effect. The Company and its Subsidiaries have taken commercially reasonable precautions to protect the secrecy and confidentiality of the trade secrets owned by the Company and its Subsidiaries, except where the failure to take reasonable precautions has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(ii) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (A) to the Knowledge of the Company, the Company has not suffered any security breach of its IT Systems that has caused any loss of data, disruption or damage to the Company's operations, (B) the Company has not experienced any security breaches of personal data or IT Systems that required or would require law enforcement or Governmental Entity notification or any remedial action under applicable Law or any Data Privacy Legal Requirement, (C) to the Knowledge of the Company, since January 1, 2016, there has been no unauthorized access to, or other misuse of, personal data or IT Systems and (D) there are no pending or expected complaints, claims, actions, fines, or other penalties facing the Company in connection with any of the foregoing.

(iii) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, the Company has security, back-ups, disaster recovery arrangements, and administrative, physical, and technical safeguards in place that are reasonably appropriate for a company in the business in which the Company is engaged and the Company has implemented security patches or upgrades that are reasonably available for the IT Systems where such patches or upgrades are reasonably required to maintain the security of such IT Systems.

(q) Regulatory Matters.

(i) All filings (other than immaterial filings) required to be made by the Company or any of its Subsidiaries since January 1, 2016 with the FERC, the Department of Energy (the "DOE"), the NRC, the FCC, the North American Electric Reliability Corporation (the "NERC"), the SCPSC, the SCORS, the NCUC, the GPSC, the United States Pipeline Hazardous Materials Safety Administration (the "PHMSA") and the United States Department of Transportation (the "DOT"), as the case may be, have been made, including all forms, notices, statements, reports, agreements and all documents, exhibits, amendments and supplements appertaining thereto, including all rates, tariffs and related documents, and all such filings complied, as of their respective dates, or, if amended or superseded by a subsequent filing made prior to the date of this Agreement, as of the date of the last such amendment or superseding filing prior to the date of this Agreement, with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, except for filings the failure of which to make or the failure of which to make in compliance with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(ii) Since January 1, 2016, none of the Company or any of its Subsidiaries has received any written notice or, to the Company's Knowledge, any other communication from the FERC, the DOE, the NRC, the FCC, the NERC, the SCPSC, the SCORS, the NCUC, the GPSC, the PHMSA or the DOT regarding any actual or possible material violation of, or material failure to comply with, any Law.

(iii) To the Knowledge of the Company, except as has not had and would not reasonably be expected to have a material impact on the Company and its Subsidiaries, the operations of the Virgil C. Summer Nuclear Station in Jenkinsville, South Carolina (the "Summer Station"), including the operation of the NND Project and the construction, and cessation of the construction, of such project, are and have been conducted in compliance with applicable health, safety, regulatory and other requirements under applicable Laws.

(iv) Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, the financial assurance for decommissioning relating to the Summer Station provided to comply with NRC's requirements in 10 CFR 50.75 and 72.30 consists of one or more trusts that are validly existing and in good standing under the Laws of their respective jurisdictions of formation with all requisite authority to conduct their affairs as currently conducted.

(r) Voting Requirements. Assuming the accuracy of the representations and warranties set forth in Section 3.02(n), the affirmative vote of holders of at least two-thirds of the outstanding Company Shares entitled to vote thereon at the Shareholders Meeting or any adjournment or postponement thereof to approve this Agreement (the "Company Requisite Vote") is the only vote of the holders of any class or series of capital stock of the Company necessary for the Company to approve this Agreement and approve and consummate the Merger and the other transactions contemplated by this Agreement.

(s) Brokers and Other Advisors. No broker, investment banker, financial advisor or other Person, other than Morgan Stanley & Co. LLC and RBC Capital Markets, LLC, is entitled to any broker's, finder's or financial advisor's fee or commission in connection with the Merger and the other transactions contemplated by this Agreement based upon arrangements made by or on behalf of the Company.

(t) Opinions of Financial Advisors. The Company Board has received the oral opinions of Morgan Stanley & Co. LLC and RBC Capital Markets, LLC to the effect that, as of the date of such opinions and based upon and subject to the various matters, limitations, qualifications and assumptions set forth therein, the Merger Consideration is fair, from a financial point of view, to the holders of Company Shares (other than Cancelled Shares). Signed, true and complete written copies of such opinions will be made available to Parent, which Parent and Merger Sub acknowledge and agree (i) are being provided to Parent for informational purposes only and (ii) may not be relied upon by Parent or Merger Sub.

(u) State Takeover Statutes. Assuming the accuracy of the representations and warranties set forth in Section 3.02(n), the Company Board has taken all action necessary to render inapplicable to this Agreement and the transactions contemplated by this Agreement all potentially applicable state anti-takeover statutes or regulations and any similar provisions in the Company Articles of Incorporation and the Company Bylaws. Assuming the accuracy of the representations and warranties set forth in Section 3.02(n), as of the date of this Agreement, no "fair price", "business combination", "moratorium", "control share acquisition" or other state takeover Law or similar Law (collectively, "Takeover Statutes") enacted by any state will prohibit or impair the consummation of the Merger or the other transactions contemplated by this Agreement.

(v) Information Supplied. None of the information supplied by the Company specifically for inclusion or incorporation by reference in the registration statement on Form S-4 in connection with the issuance by Parent of the aggregate Merger Consideration (the "Form S-4") or the Proxy Statement/Prospectus, at (i) the time the Form S-4 is declared effective, (ii) the date the Proxy Statement/Prospectus is first published or mailed to the holders of Company Shares or (iii) the time of the Shareholders Meeting (except, with respect to the foregoing clauses (i) through (iii), to the extent that any such information is amended or superseded by any subsequent SEC Reports of Parent or the Company), will contain any untrue statement of material fact or omit to state any material fact required to be stated therein or necessary to make the statements therein, in light of the circumstances under which they are made, not misleading.

SECTION 3.02. Representations and Warranties of Parent and Merger Sub. Except (x) as disclosed in the SEC Reports of Parent or its wholly-owned Subsidiaries filed with or furnished to the SEC since January 1, 2016 and publicly available at least twenty-four (24) hours prior to the date of this Agreement (excluding any disclosures set forth in any risk factor section or in any other section to the extent such disclosures are forward-looking statements or are cautionary, predictive or forward-looking in nature) or (y) as set forth in the Parent Disclosure Letter (it being agreed that disclosure of any item in any section or subsection of the Parent Disclosure Letter shall also be deemed disclosed with respect to any other section or subsection of this Agreement to which the relevance of such item is reasonably apparent), Parent and Merger Sub represent and warrant to the Company as follows:

(a) Organization, Standing and Corporate Power. Each of Parent and Merger Sub is a corporation duly incorporated, validly existing and in good standing (where such concept is recognized under applicable Law) under the Laws of the Commonwealth of Virginia, in the case of Parent, and the Laws of the State of South Carolina, in the case of Merger Sub, and has all requisite corporate power and authority to carry on its business as currently conducted and is duly qualified or licensed to do business and is in good standing (where such concept is recognized under applicable Law) in each jurisdiction where the nature of its business or the ownership, leasing or operation of its properties or assets makes such qualification or licensing necessary, other than where the failure to be so qualified, licensed or in good standing has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect. Each of Parent's Subsidiaries is a legal entity duly organized, validly existing and in good standing (where such concept is recognized under applicable Law) under the Law of its jurisdiction of organization and has all requisite corporate power and authority to carry on its business as currently conducted, and each of Parent's Subsidiaries is duly qualified or licensed to do business and is in good standing (where such concept is recognized under applicable Law) in each jurisdiction where the nature of its business or the ownership, leasing or operation of its properties or assets makes such qualification or licensing necessary, other than where the failure to be so qualified, licensed or in good standing has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect. Parent has made available to the Company a true and complete copy of the organizational documents of Parent (the "Parent Organizational Documents"), and the comparable organizational documents of Merger Sub, in each case as amended and in effect as of the date of this Agreement.

(b) Subsidiaries. All of the outstanding shares of capital stock of, or other equity interests in, each wholly-owned Subsidiary of Parent have, in all cases, been duly authorized and validly issued and are fully paid, non-assessable and not subject to preemptive rights, and are wholly-owned, directly or indirectly, by Parent free and clear of all Liens, other than transfer restrictions contained in the articles of incorporation, bylaws and limited liability company agreements (or any equivalent constituent documents) of such wholly-owned Subsidiary.

(c) Capital Structure.

(i) The authorized capital stock of Parent consists of 1,000,000,000 Parent Shares and 20,000,000 shares of preferred stock (such preferred stock, the "Parent Preferred Stock"). At the close of business on December 29, 2017, there were (A) 644,571,202 Parent Shares issued and outstanding and (B) no shares of Parent Preferred Stock issued or outstanding. Except as set forth in the immediately preceding sentence, at the close of business on December 29, 2017, no shares of capital stock or other voting securities of Parent were issued or outstanding. Since December 29, 2017 to the date of this Agreement, (x) there have been no issuances by Parent of shares of capital stock or other voting securities of Parent other than pursuant to the exercise or vesting of equity awards under any Parent equity award plans or pursuant to Parent's dividend reinvestment and direct stock purchase plan, in each case, outstanding as of December 29, 2017 and (y) there have been no issuances by Parent of options, warrants, other rights to acquire shares of capital stock of Parent or other rights that give the holder thereof any economic interest of a nature accruing to the holders of Parent Shares. All outstanding Parent Shares are, and all such Parent Shares that may be issued prior to the Effective Time will be when issued, duly authorized, validly issued, fully paid and non-assessable and not subject to preemptive rights.

(ii) No Subsidiary of Parent (it being understood and agreed that, for purposes of this Section 3.02(c)(ii), Subsidiaries of Parent shall not include (x) any benefit plan maintained by Parent or any of its Subsidiaries or (y) any nuclear decommissioning trusts maintained by Parent or any of its Subsidiaries) owns any Parent Shares or other shares of capital stock of Parent. There are no bonds, debentures, notes or other Indebtedness of Parent or of any of its Subsidiaries that give the holders thereof the right to vote (or that are convertible into, or exchangeable for, securities having the right to vote) on any matters on which holders of Parent Shares may vote ("Voting Parent Debt"). Except for any obligations pursuant to this Agreement or as otherwise set forth in Section 3.02(c)(i), as of December 29, 2017, there are no options, warrants, rights (including preemptive, conversion, stock appreciation, redemption or repurchase rights), convertible or exchangeable securities, stock-based performance units, Contracts or undertakings of any kind to which Parent or any of its Subsidiaries is a party or by which any of them is bound (A) obligating Parent or any of its Subsidiaries to issue, deliver or sell, or cause to be issued, delivered or sold, additional shares of capital stock or other securities of, or equity interests in, or any security convertible or exchangeable for any capital stock or other security of, or equity interest in, Parent or any of its wholly-owned Subsidiaries or any Voting Parent Debt, (B) obligating Parent or any of its wholly-owned Subsidiaries to issue, grant or enter into any such option, warrant, right, security, unit, Contract or undertaking to declare or pay any dividend or distribution or (C) that give any Person the right to subscribe for or acquire any securities of Parent or any of its wholly-owned Subsidiaries, or to receive any economic interest of a nature accruing to the holders of Parent Shares or otherwise based on the performance or value of shares of capital stock of Parent or any of its wholly-owned Subsidiaries. As of the date of this Agreement, there are no outstanding obligations of Parent or any of its wholly-owned Subsidiaries to repurchase, redeem or otherwise acquire any shares of capital stock or other equity interest, other than pursuant to any Parent equity award plans. There are no voting agreements, voting trusts, shareholders agreements, proxies or other agreements to which Parent or any of its Subsidiaries is bound with respect to the voting of the capital stock or other equity interests of Parent, or restricting the transfer of, or providing registration rights with respect to, such capital stock or equity interests.

(d) Authority; Noncontravention.

(i) Each of Parent and Merger Sub has all requisite corporate power and authority to execute and deliver, and perform its obligations under, this Agreement and to consummate the transactions contemplated by this Agreement, subject, in the case of the Merger, to the delivery by Parent of the written consent, as sole shareholder of Merger Sub, referenced in Section 5.11. The execution, delivery and performance of this Agreement by Parent and Merger Sub and the consummation by Parent and Merger Sub of the transactions contemplated by this Agreement have been duly authorized by all necessary corporate action on the part of each of Parent and Merger Sub, subject, in the case of the Merger, to the delivery by Parent of the written consent, as sole shareholder of Merger Sub, referenced in Section 5.11. This Agreement has been duly executed and delivered by each of Parent and Merger Sub and, assuming the due authorization, execution and delivery by the Company, constitutes a legal, valid and binding obligation of each of Parent and Merger Sub, enforceable against each of Parent and Merger Sub in accordance with its terms, subject, as to enforceability, to bankruptcy, insolvency and other Law of general applicability relating to or affecting creditors' rights and to general equity principles. The board of directors of Parent has duly and validly adopted resolutions approving this Agreement and the transactions contemplated by this Agreement, including the Merger, and the board of directors of Merger Sub has duly and validly adopted resolutions (A) determining that it is in the best interests of Merger Sub and its sole shareholder that Merger Sub enter into this Agreement and consummate the Merger and the other transactions contemplated by this Agreement on the terms and subject to the conditions set forth in this Agreement, (B) adopting this Agreement and approving the transactions contemplated by this Agreement, including the Merger and (C) recommending that the sole shareholder of Merger Sub approve this Agreement, which resolutions of Parent and Merger Sub, in each case, have not been rescinded, modified or withdrawn in any way.

(ii) The execution, delivery and performance by Parent and Merger Sub of this Agreement do not, and the consummation of the Merger and the other transactions contemplated by this Agreement and compliance with the provisions of this Agreement will not, conflict with, or result in any violation of, or default (with or without notice or lapse of time, or both) under, or give rise to any right (including a right of termination, cancellation or acceleration of any obligation or any right of first refusal, participation or similar right) under, or cause the loss of any benefit under, or result in the creation of any Lien (other than Permitted Liens) upon any of the properties or assets of Parent or Merger Sub or any of their respective Subsidiaries under, any provision of (A) the Parent Organizational Documents or the comparable organizational documents of any of Parent's Subsidiaries, including Merger Sub or (B) subject to the filings and other matters referred to in Section 3.02(d)(iii), (1) any Contract or (2) any Law, in each case, applicable to Parent or Merger Sub or any of their respective Subsidiaries or any of their respective properties or assets, other than, in the case of foregoing clause (B), any such conflicts, violations, defaults, rights, losses or Liens that have not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(iii) No Consent of, or registration, declaration or filing with, or notice to, any Governmental Entity is required to be obtained or made by or with respect to Parent or Merger Sub or any of their respective Subsidiaries in connection with the execution, delivery and performance of this Agreement by Parent and Merger Sub or the consummation by Parent and Merger Sub of the transactions contemplated by this Agreement, except for (A) the Regulatory Conditions and any other Consents of or under, and compliance with any other applicable requirements of, (1) the HSR Act, (2) the FERC, (3) the NRC, (4) the FCC, (5) the NCUC, and (6) the GPSC (the items set forth in this clause (A), collectively, the "Parent Regulatory Clearances" and together with the Company Regulatory Clearances, the "Regulatory Clearances"), (B) the filing with the SEC of such reports and other documents (including the filing of the Form S-4) under, and compliance with all other applicable requirements of, the Securities Act or the Exchange Act and the rules and regulations promulgated thereunder and any applicable state securities, takeover and "blue sky" Laws, (C) the filing of the Articles of Merger with the Secretary of State of the State of South Carolina, (D) any filings under, and compliance with all other applicable requirements of, the rules and regulations of the NYSE and (E) such other Consents, registrations, declarations, filings and notices, the failure of which to be obtained or made has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect and would not reasonably be expected to prevent, or materially impair or delay, the consummation of the Merger or any of the other material transactions contemplated by this Agreement.

(e) Applicable Parent SEC Reports; Financial Statements; Undisclosed Liabilities.

(i) Parent and its Subsidiaries have filed or furnished, as applicable, all SEC Reports such companies were required or otherwise obligated to file with or furnish to the SEC since June 30, 2016 (such SEC Reports, the "Applicable Parent SEC Reports"). As of their respective dates of filing, or, if amended or superseded by a subsequent filing made prior to the date of this Agreement, as of the date of the last such amendment or superseding filing prior to the date of this Agreement, the Applicable Parent SEC Reports complied in all material respects with the applicable requirements of the Securities Act, the Exchange Act and the Sarbanes-Oxley Act, as the case may be, and the applicable rules and regulations promulgated thereunder, each as in effect on the date of any such filing. As of the time of filing with the SEC (or, if amended prior to the date of this Agreement, as of the date of such amendment), none of the Applicable Parent SEC Reports so filed contained any untrue statement of a material fact or omitted to state a material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading, except to the extent that the information in such Applicable Parent SEC Reports has been amended or superseded by a later Applicable Parent SEC Report.

(ii) As of their respective dates, the audited and unaudited financial statements (consolidated, as applicable, and including any related notes thereto) of each of Parent and its Subsidiaries, as applicable, included in the Applicable Parent SEC Reports have been prepared in all material respects (except, as applicable, as permitted by Form 10-Q of the SEC or other applicable rules and regulations of the SEC) in accordance with GAAP applied on a consistent basis during the periods involved (except as may be indicated in the notes thereto) and fairly present in all material respects the consolidated financial position of Parent and its Subsidiaries, as applicable, as of the respective dates thereof (taking into account the notes thereto) and the consolidated results of their operations and cash flows for the periods indicated (taking into account the notes thereto) and subject, in the case of unaudited financial statements, to normal year-end adjustments.

(iii) Parent maintains disclosure controls and procedures required by Rule 13a-15(e) or Rule 15d-15(e) under the Exchange Act and such disclosure controls and procedures are effective in all material respects to ensure that information required to be disclosed by Parent in the SEC Reports it files or submits under the Exchange Act is recorded, processed, summarized and reported on a timely basis to the individuals responsible for the preparation of Parent's SEC Reports and other public disclosure documents. Parent maintains internal control over financial reporting required by Rule 13a-15(f) or Rule 15d-15(f) under the Exchange Act and such internal control is effective in all material respects in providing reasonable assurance regarding the reliability of Parent's financial reporting and Parent's preparation of financial statements for external purposes in accordance with GAAP. Parent has disclosed, based on its most recent evaluation prior to the date of this Agreement, to Parent's outside auditors and the audit committee of Parent's board of directors (A) any significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that are reasonably likely to adversely affect Parent's ability to record, process, summarize and report financial information and (B) to the Knowledge of Parent, any fraud that involves management or other employees of Parent who have a significant role in Parent's internal control over financial reporting.

(iv) There are no liabilities or obligations of Parent or any of its Subsidiaries of a nature that would be required under GAAP to be reflected or reserved on a financial statement (consolidated, as applicable) of Parent, other than (A) liabilities or obligations reflected or reserved against in such entity's most recent balance sheet (including the notes thereto) included in the Applicable Parent SEC Reports filed prior to the date hereof, (B) liabilities or obligations incurred in the ordinary course of business consistent with past practice since September 30, 2017, (C) liabilities or obligations incurred under or in accordance with this Agreement or in connection with the transactions contemplated by this Agreement and (D) liabilities or obligations that have not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(f) Absence of Certain Changes or Events.

(i) Since January 1, 2017, there have not been any Changes that have had or would reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(ii) Since January 1, 2017, except as contemplated or required by this Agreement, Parent and its wholly-owned Subsidiaries have conducted their respective businesses in all material respects in the ordinary course of business consistent with past practice.

(g) Litigation. Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect, there is no (i) Proceeding pending or, to the Knowledge of Parent, threatened against Parent or any of its Subsidiaries, (ii) to the Knowledge of Parent, pending or threatened material investigation or inquiry by a Governmental Entity of Parent or any of its Subsidiaries and (iii) Order, decree or writ of any Governmental Entity outstanding or, to the Knowledge of Parent, threatened to be imposed against Parent or any of its Subsidiaries.

(h) Compliance with Law. Since January 1, 2016, Parent and each of its Subsidiaries have been in compliance with and have not been in default under or in violation of any applicable Law, except where such non-compliance, default or violation has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect. Since January 1, 2016, neither Parent nor any of its Subsidiaries has received any written notice from any Governmental Entity regarding any violation of, or failure to comply with, any Law, except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(i) Taxes.

(i) All material Tax Returns required to be filed by or with respect to Parent or any of its wholly-owned Subsidiaries have been timely filed (taking into account any extension of time within which to file) and all such Tax Returns are correct and complete in all material respects.

(ii) All material Taxes of Parent and its wholly-owned Subsidiaries that are required to be paid or discharged, other than Taxes being contested in good faith by appropriate proceedings, have been timely paid and discharged.

(iii) There are no material Tax Liens, other than Permitted Liens, on any asset of Parent or any of its wholly-owned Subsidiaries.

(iv) Neither Parent nor any of its wholly-owned Subsidiaries has executed any outstanding waiver of any statute of limitations for the assessment or collection of any material Tax.

(v) As of the date hereof, no audit or other examination or Proceeding of, or with respect to, any material Tax Return or material amount of Taxes of Parent or any of its wholly-owned Subsidiaries is pending and, between January 1, 2016 and the date hereof, no written notice thereof has been received by Parent or any of its wholly-owned Subsidiaries.

(vi) None of Parent or any of its wholly-owned Subsidiaries (A) is a party to any material Tax allocation, Tax sharing, Tax indemnity or similar agreement or (B) is under an obligation under Treasury Regulation Section 1.1502-6 (or any similar provision of state, local or non-U.S. Law) or as transferee or successor, such that, in each case, Parent or any of its wholly-owned Subsidiaries is, after the date hereof or after the Closing (as the case may be), liable for any material amount of Taxes of another Person (other than Parent or any of its wholly-owned Subsidiaries).

(vii) There are no material closing agreements, private letter rulings, technical advice memoranda or rulings that have been entered into or issued by any Tax authority with respect to Parent or any of its wholly-owned Subsidiaries which are still in effect as of the date of this Agreement.

(viii) Neither Parent nor any of its wholly-owned Subsidiaries has “participated” within the meaning of Treasury Regulation Section 1.6011-4(c)(3)(i)(A) in any “listed transaction” within the meaning of Section 6011 of the Code and the Treasury Regulations thereunder, as in effect and as amended by any guidance published by the Internal Revenue Service for the applicable period.

(ix) Neither Parent nor any of its Subsidiaries has taken any action or knows of any fact that would reasonably be expected to prevent the Merger from qualifying for the Intended Tax Treatment.

(j) Regulatory Matters.

(i) All filings (other than immaterial filings) required to be made by Parent or any of its Subsidiaries since January 1, 2016 with the FERC, the DOE, the NRC, and the NERC, as the case may be, have been made, including all forms, notices, statements, reports, agreements and all documents, exhibits, amendments and supplements appertaining thereto, including all rates, tariffs and related documents, and all such filings complied, as of their respective dates, or, if amended or superseded by a subsequent filing made prior to the date of this Agreement, as of the date of the last such amendment or superseding filing prior to the date of this Agreement, with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, except for filings the failure of which to make or the failure of which to make in compliance with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(ii) Since January 1, 2016, none of Parent or any of its wholly-owned Subsidiaries has received any written notice or, to Parent’s Knowledge, any other communication from the FERC, the DOE, the NRC or the NERC regarding any actual or possible material violation of, or material failure to comply with, any Law.

(k) No Vote Required. Other than the approval of this Agreement by the sole shareholder of Merger Sub referenced in Section 5.11, no vote or consent of the holders of any class or series of capital stock of Parent or any of its Affiliates is necessary for Parent and Merger Sub to approve this Agreement and approve and consummate the Merger and the other transactions contemplated by this Agreement.

(l) Brokers and Other Advisors. Except for fees or commissions to be paid by Parent, no broker, investment banker, financial advisor or other Person is entitled to any broker's, finder's or financial advisor's fee or commission in connection with the Merger and the other transactions contemplated by this Agreement based upon arrangements made by or on behalf of Parent or Merger Sub.

(m) Ownership and Operation of Merger Sub. The authorized capital stock of Merger Sub consists solely of one thousand (1,000) shares of common stock, without par value, one hundred (100) of which are validly issued and outstanding as of the date hereof. All of the issued and outstanding capital stock of Merger Sub is, and at and immediately prior to the Effective Time will be, owned by Parent. Merger Sub has been formed solely for the purpose of engaging in the transactions contemplated by this Agreement and prior to the Effective Time will have engaged in no other business activities and will have no assets, liabilities or obligations of any nature other than those incident to its formation and its entry into this Agreement and the consummation of the Merger and the other transactions contemplated by this Agreement.

(n) Ownership of Shares. None of Parent, Merger Sub or any of their Subsidiaries (it being understood and agreed that, for purposes of this Section 3.02(n), Subsidiaries of Parent and Merger Sub shall not include (x) any benefit plan maintained by Parent or any of its Subsidiaries or (y) any nuclear decommissioning trusts maintained by Parent or any of its Subsidiaries) is, directly or indirectly, a "beneficial owner" (as such term is defined in Rule 13d-3 under the Exchange Act) of any (i) Company Shares, (ii) securities that are convertible into or exchangeable or exercisable for Company Shares, or (iii) any rights to acquire or vote any Company Shares, or any option, warrant, convertible security, stock appreciation right, swap agreement or other security, contract right or derivative position, whether or not presently exercisable, that provides Parent, Merger Sub, or any of their respective Subsidiaries with an exercise or conversion privilege or a settlement payment or mechanism at a price related to the value of Company Shares or a value determined in whole or part with reference to, or derived in whole or part from, the value of the Company Shares, in any case without regard to whether (A) such derivative conveys any voting rights in such securities to such Person, (B) such derivative is required to be, or capable of being, settled through delivery of securities or (C) such Person may have entered into other transactions that hedge the economic effect of such derivative, other than any Company Shares or securities, rights, options, warrants, agreements and derivatives with respect to any Company Shares in an amount equal to, in the aggregate, less than five percent (5%) of the total number of issued and outstanding Company Shares.

(o) Information Supplied. None of the information supplied by Parent specifically for inclusion or incorporation by reference in the Form S-4 or the Proxy Statement/Prospectus, at (i) the time the Form S-4 is declared effective, (ii) the date the Proxy Statement/Prospectus is first published or mailed to the holders of Company Shares or (iii) the time of the Shareholders Meeting (except, with respect to the foregoing clauses (i) through (iii), to the extent that any such information is amended or superseded by any subsequent SEC Reports of Parent or the Company), will contain any untrue statement of material fact or omit to state any material fact required to be stated therein or necessary to make the statements therein, in light of the circumstances under which they are made, not misleading.

(p) Financial Ability. Parent has, and at the Closing Parent will have, sufficient immediately available funds and the financial ability to pay all amounts payable to holders of Company Performance Share Awards and Company RSUs pursuant to Section 2.02 and any repayment or refinancing of then outstanding Indebtedness of the Company or any of its Subsidiaries, which repayment or refinancing is required as a result of the Merger, as set forth in Section 3.02(p) of the Company Disclosure Letter, after taking into account any consents or waivers obtained from any holder of such Indebtedness prior to the Effective Time.

ARTICLE IV

COVENANTS RELATING TO CONDUCT OF BUSINESS

SECTION 4.01. Conduct of Business Pending the Merger.

(a) Conduct of Business by the Company. From the date of this Agreement until the earlier of the Effective Time and the termination of this Agreement in accordance with Article VII, except as otherwise expressly contemplated by this Agreement, set forth in Section 4.01(a) of the Company Disclosure Letter, required by applicable Law, required by a Governmental Entity or with the prior written consent of Parent (such consent not to be unreasonably withheld, conditioned or delayed), (x) the Company shall, and shall cause each of its Subsidiaries to, conduct its business in all material respects in the ordinary course consistent with past practice and shall use commercially reasonable efforts to preserve substantially intact its current business organizations, maintain adequate and comparable insurance coverage, and preserve its relationships with its employees, counterparties, customers and suppliers and Governmental Entities with jurisdiction over the Company or any of its Subsidiaries and (y) without limiting the foregoing, the Company shall not, and shall not permit any of its Subsidiaries to:

(i) 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 (A) regular quarterly cash dividends payable by the Company in respect of Company Shares not in excess of the amount set forth in Section 4.01(a)(i) of the Company Disclosure Letter and (B) dividends or distributions by a Subsidiary of the Company to the Company or to any wholly-owned Subsidiary of the Company;

(ii) split, combine or reclassify any of its capital stock, other ownership interests or voting securities, or securities convertible into or exchangeable or exercisable for any such shares of capital stock, interests or securities, or issue or authorize the issuance of any other securities in respect of, in lieu of or in substitution for shares of its capital stock, other ownership interests or voting securities, other than transactions solely between or among the Company and its wholly-owned Subsidiaries or between or among the Company's wholly-owned Subsidiaries;

(iii) purchase, redeem or otherwise acquire any of its or its Subsidiaries' shares of capital stock, other ownership interests or voting securities, or securities convertible into or exchangeable or exercisable for any such shares of capital stock, interests or securities, or any rights, warrants or options to acquire any such shares of capital stock, interests or securities, other than (A) the withholding of Company Shares to satisfy Tax obligations or the exercise price with respect to awards granted pursuant to the Company Equity Award Plans or settlement of awards granted pursuant to the Company Equity Award Plans and (B) the acquisition by the Company of awards granted pursuant to the Company Equity Award Plans in connection with the forfeiture or settlement of such awards or rights, in each case, that are outstanding as of the date hereof and in accordance with their terms as of the date hereof or granted after the date hereof in accordance with this Agreement;

(iv) issue, deliver, sell, pledge, dispose of, encumber or subject to any Lien, any shares of its capital stock, other ownership interests or voting securities (other than the issuance of shares by a wholly-owned Subsidiary of the Company to the Company or another wholly-owned Subsidiary of the Company), or any securities convertible into, exercisable or exchangeable for, or any rights, warrants or options to acquire, any such shares of capital stock, interests or voting securities or any "phantom" stock, "phantom" stock rights, stock appreciation rights or stock-based performance units, other than upon the exercise, vesting or settlement of awards granted pursuant to the Company Equity Award Plans that are outstanding as of the date hereof or granted after the date hereof in accordance with this Agreement, in each case, exercised, vested or settled in accordance with their terms;

(v) amend (A) any of the Company Organizational Documents or (B) the comparable organizational documents of any Subsidiary of the Company, other than, in the case of this clause (B), amendments that effect solely ministerial changes to such documents;

(vi) acquire (whether by merger, consolidation, purchase of property or assets (including equity interests) or otherwise) any corporation, partnership or other business organization or division thereof or any material assets or interests in any Person with a value in excess of $50 million in the aggregate, other than transactions solely between or among the Company and its wholly-owned Subsidiaries or between or among the Company's wholly-owned Subsidiaries;

(vii) sell, license, lease, transfer, assign, divest, cancel, encumber, abandon or otherwise dispose of any of its properties, rights or assets which (A) are material to the Company and its Subsidiaries, taken as a whole, or (B) have a value in excess of $25 million, other than (1) sales, transfers and dispositions of obsolete, non-operating or worthless assets or properties and (2) sales, leases, transfers or other dispositions made in connection with (x) any immaterial transactions in the ordinary course of business consistent with past practice or (y) any transactions solely between or among the Company and its wholly-owned Subsidiaries or between or among the Company's wholly-owned Subsidiaries;

(viii) incur, redeem, prepay, defease, cancel, or, in any material respect, modify any indebtedness for borrowed money, issue or sell any debt securities or warrants or other rights to acquire any debt securities of the Company or any of its Subsidiaries, guarantee, assume or endorse or otherwise as an accommodation become responsible for any such indebtedness or any debt securities or other financial obligations of another Person or enter into any "keep well" or other agreement to maintain any financial statement condition of another Person (collectively, "Indebtedness"), other than (A) borrowings under existing revolving credit facilities (or replacements thereof on comparable terms, including in regards to maturity) or commercial paper programs in the ordinary course of business, (B) other than as set forth in the foregoing clause (A) and in Section 4.01(a)(viii) of the Company Disclosure Letter, incurring any Indebtedness in the ordinary course of business (including interest rate swaps on customary commercial terms consistent with past practice) not in excess of $200,000,000, (C) other than as set forth in Section 4.01(a)(viii) of the Company Disclosure Letter, redeeming, prepaying, defeasing, cancelling or modifying any Indebtedness in the ordinary course of business (including interest rate swaps on customary commercial terms consistent with past practice) not to exceed $200,000,000, (D) incurring, redeeming, prepaying, defeasing, cancelling or modifying any Indebtedness among the Company or any of its Subsidiaries, (E) incurring any Indebtedness to replace, renew, extend, refinance or refund any existing Indebtedness in the same principal amount of such existing Indebtedness and upon the maturity of such existing Indebtedness and to the extent such existing Indebtedness is Indebtedness of the Company, on terms that can be redeemed or prepaid at any time upon payment of the outstanding principal amount plus accrued interest without any make whole or similar prepayment penalty, and (F) providing guarantees and other credit support by the Company with respect to the obligations of any of its Subsidiaries; provided, however, no such Indebtedness shall contain any term that would accelerate the payment thereof or require its immediate repayment due to the transactions contemplated by this Agreement;

(ix) settle any claim, investigation or Proceeding with a Governmental Entity or third party, in each case, threatened, made or pending against the Company or any of its Subsidiaries, which (A) provides injunctive relief which is material to the Company or any of its Subsidiaries or (B) requires payment in excess of $10 million in the aggregate, other than the settlement of any claims, investigations or Proceedings made in the ordinary course of business or for an amount (excluding any amounts that are covered by any insurance policies of the Company or its Subsidiaries, as applicable) not in excess of the amount reflected or reserved therefor in the most recent financial statements (or the notes thereto) of the Company included in the Company's SEC Reports; provided, however, that neither the Company nor any of its Subsidiaries shall settle any claim, investigation or Proceeding with a Governmental Entity or third party, in each case, threatened, made or pending against the Company or any of its Subsidiaries relating to or arising out of (A) the construction (or cessation of the construction), abandonment or disposal of nuclear power Units 2 and 3 at the Summer Station, (B) the bankruptcy of Westinghouse Electric Company, LLC (including the settlement agreement entered into with Toshiba Corporation and any Contract relating to the proceeds thereof), or (C) any other aspect of the NND Project (collectively, the "NND Project Litigation") (it being understood and agreed that this proviso shall not apply to (x) the termination of any Contract related to the NND Project so long as such termination results in no additional liability of the Company or any of its Subsidiaries in excess of $5 million in the aggregate or (y) any immaterial amendment of any Contract related to the NND Project) other than as follows: (a) except as set forth in subclause (b) below, neither the Company nor any of its Subsidiaries shall settle any claim, investigation or Proceeding with a third party who is not a Governmental Entity relating to or arising out of the NND Project Litigation without prior consent of Parent (such consent not to be unreasonably withheld, conditioned or delayed), (b) the Company or its Subsidiaries may, after prior notice to Parent, settle any mechanic liens related to the cessation of construction of the NND Project including those more specifically described as item 1(y) of Section 3.01(g) of the Company Disclosure Letter (it being understood and agreed that the $10 million limitation referred to in the fourth line of this Section 4.01(a)(ix) shall not apply to such settlement of mechanic's liens) and (c) neither the Company nor its Subsidiaries may settle any claim, investigation or Proceeding with a Governmental Entity relating to or arising out of the NND Project Litigation without prior consent of Parent (such consent not to be unreasonably withheld, conditioned or delayed);

(x) make or agree to make any capital expenditure in any fiscal year, except (A) for capital expenditures made in accordance with the capital expenditures plan set forth in Section 4.01(a)(x) of the Company Disclosure Letter in an amount not to exceed $50 million in excess of the amounts set forth in such capital expenditure plan during any calendar year, (B) for capital expenditures related to operational emergencies, equipment failures or outages or expenditures that the Company reasonably determines are then necessary to maintain the safety and integrity of any asset or property in response to any unanticipated or unforeseen and subsequently discovered events, occurrences or developments, or (C) as required by Law or a Governmental Entity;

(xi) except as required pursuant to the terms of any Company Benefit Plan or other written agreement, in each case, in effect on the date hereof, (A) grant to any director or officer any increase in compensation or pay, or award any bonuses or incentive compensation, including in the case of any Company officer, any changes associated with promotions or other position changes, regardless of whether such promotions or changes were previously announced, (B) grant to any current or former director, officer or employee any increase in severance, retention or termination pay, (C) grant or amend any equity awards, (D) enter into any new, or modify any existing, employment or consulting agreement with any current or former director or officer or enter into any new, or modify any existing, employment or consulting agreement with any individual consultant pursuant to which the annual base salary of such individual under such agreement exceeds $250,000.00 or the term of which exceeds twelve (12) months, (E) establish, adopt, enter into or amend in any material respect any material collective bargaining agreement or material Company Benefit Plan, (F) take any action to accelerate any rights or benefits under any Company Benefit Plan, or (G) hire or promote any new officer (other than any officer whose hiring or promotion has previously been publicly announced, but that has not yet taken effect as of the date hereof); provided, however, that, other than as set forth in subclause (A), the foregoing shall not restrict the Company or any of its Subsidiaries from entering into or making available to newly hired employees or to employees in the context of promotions based on job performance or workplace requirements, in each case, in the ordinary course of business, plans, agreements, benefits and compensation arrangements (including incentive grants, whether cash or equity, but excluding any individual severance arrangements) that have a value that is consistent with its past practice of making compensation and benefits available to newly hired or promoted employees in similar positions and under similar circumstances;

(xii) other than as required (A) by GAAP (or any interpretation thereof), including pursuant to standards, guidelines and interpretations of the Financial Accounting Standards Board or any similar organization or (B) by a Governmental Entity or Law (including pursuant to any applicable SEC rule or policy), make any change in accounting methods, principles or practices where such changes would reasonably be expected to be material to the Company and its Subsidiaries, taken as a whole;

(xiii) (A) make, change or rescind any material Tax election, any Tax accounting period, or adopt or change any material method of Tax accounting, (B) settle or compromise any material Tax liability or consent to any material claim or assessment or obtain any material ruling relating Taxes, (C) file any amended material Tax Return or (D) enter into any material closing agreement relating to Taxes;

(xiv) other than in the ordinary course of business consistent with past practice, materially amend, modify or terminate, or waive any material rights under, or enter into any Contract which if entered into prior to the date of this Agreement would have been deemed, a Company Material Contract;

(xv) adopt or enter into a plan of complete or partial liquidation, dissolution, merger, consolidation, restructuring, recapitalization or other reorganization, other than the Merger and any other mergers, consolidations, restructurings, recapitalizations or other reorganizations solely between or among the Company and its wholly-owned Subsidiaries or between or among the Company's wholly-owned Subsidiaries;

(xvi) materially change or enter into any IT Systems or cyber-security Contracts that are material to the Company and its Subsidiaries (other than routine maintenance and upgrades to existing IT Systems); or

(xvii) authorize any of, or commit or agree to take any of, the foregoing actions prohibited pursuant to clauses (i) through (xvi) of this Section 4.01(a).

(b) Conduct of Business by Parent. From the date of this Agreement until the earlier of the Effective Time and the termination of this Agreement in accordance with Article VII, except as otherwise expressly contemplated by this Agreement, set forth in Section 4.01(b) of the Parent Disclosure Letter, required by applicable Law, required by a Governmental Entity or with the prior written consent of the Company (such consent not to be unreasonably withheld, conditioned or delayed), (x) Parent shall, and shall cause each of the Parent Significant Subsidiaries to, conduct its business in all material respects in the ordinary course of business consistent with past practice and shall use commercially reasonable efforts to preserve substantially intact its current business organizations, maintain adequate and comparable insurance coverage and preserve its relationships with its employees, counterparties, customers and suppliers and Governmental Entities with jurisdiction over Parent or any of the Parent Significant Subsidiaries and (y) without limiting the foregoing, Parent shall not:

(i) 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 payable by Parent in respect of Parent Shares;

(ii) split, combine or reclassify any of its capital stock, other ownership interests or voting securities, or securities convertible into or exchangeable or exercisable for any such shares of capital stock, interests or securities, or issue or authorize the issuance of any other securities in respect of, in lieu of or in substitution for shares of its capital stock, other ownership interests or voting securities, other than transactions solely between or among Parent and its wholly-owned Subsidiaries;

(iii) purchase, redeem or otherwise acquire any of its or the Parent Significant Subsidiaries' shares of capital stock, other ownership interests or voting securities, or securities convertible into or exchangeable or exercisable for any such shares of capital stock, interests or securities, or any rights, warrants or options to acquire any such shares of capital stock, interests or securities, other than (A) the withholding of Parent Shares or any of Parent's Subsidiaries' capital stock to satisfy Tax obligations or the exercise price with respect to awards granted pursuant to any of Parent's equity award plans or (B) purchasing, redeeming or acquiring any of Parent's equity awards pursuant to any of Parent's equity award plans;

(iv) except for any Parent Shares issued in an offering for cash at a price no lower than ninety-five percent (95%) of the market price for Parent Shares on the NYSE at the time of such offering, issue, deliver, sell, pledge, dispose of, encumber or subject to any Lien, any shares of its capital stock, other ownership interests or voting securities, or, except for equity units or mandatorily convertible securities issued in an offering for cash with a conversion premium, any securities convertible into, exercisable or exchangeable for, or any rights, warrants or options to acquire, any such shares of capital stock, interests or securities or any "phantom" stock, "phantom" stock rights, stock appreciation rights or stock-based performance units, other than upon the exercise, vesting or settlement of awards granted pursuant to any Parent equity award plans or pursuant to Parent's dividend reinvestment and direct stock purchase plan;

(v) amend (A) any of the Parent Organizational Documents or (B) the comparable organizational documents of any Parent Significant Subsidiary, in each case, in a manner that would materially adversely affect the holders of Company Shares whose Company Shares shall, pursuant to Section 2.01(a), convert in part into Parent Shares at the Effective Time; or

(vi) authorize any of, or commit or agree to take any of, the foregoing actions prohibited pursuant to clauses (i) through (v) of this Section 4.01(b).

(c) From the date of this Agreement until the earlier of the Effective Time and the termination of this Agreement in accordance with Article VII, neither the Company nor Parent shall take or permit any of their respective Subsidiaries to take any action that would reasonably be expected to prevent, or materially impair or delay, the consummation of the Merger or any of the other transactions contemplated by this Agreement.

SECTION 4.02. Acquisition Proposals.

(a) The Company agrees that, except as permitted by this Section 4.02, neither it nor any of its Subsidiaries, or any of their respective directors or officers, shall, and it shall instruct and use its reasonable best efforts to cause its and its Subsidiaries' employees, investment bankers, attorneys, accountants and other advisors or representatives (collectively, "Representatives") not to, directly or indirectly (i) initiate, solicit or knowingly encourage any Acquisition Proposal or the making of any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an Acquisition Proposal, (ii) engage in, continue or otherwise participate in any discussions or negotiations regarding any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an Acquisition Proposal, (iii) furnish or provide any information or data to any Person in connection with any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an Acquisition Proposal, (iv) otherwise knowingly facilitate any effort or attempt with respect to the foregoing. Any violation of the restrictions set forth in this Section 4.02 by any director, officer or investment banker of the Company or any of its Subsidiaries shall be deemed to be a breach of this Section 4.02 by the Company.

(b) The Company agrees that it and its Subsidiaries and their respective directors, officers, and employees, shall, and it shall instruct and use its reasonable best efforts to cause its and its Subsidiaries' Representatives to, immediately (i) cease and cause to be terminated any solicitation, discussions, negotiations or knowing facilitation or encouragement with any Person that may be ongoing with respect to any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, an Acquisition Proposal, (ii) terminate any such Person's access to any physical or electronic data rooms and (iii) request that any such Person and its Representatives promptly return or destroy all confidential information concerning the Company and its Subsidiaries theretofore furnished thereto by or on behalf of the Company or any of its Subsidiaries, and destroy all analyses and other materials prepared by or on behalf of such Person that contain, reflect or analyze such information, in each case, to the extent required by, and in accordance with, the terms of the applicable confidentiality agreement between the Company and such Person.

(c) The Company shall promptly (but in any event within forty-eight (48) hours) notify Parent in writing of the receipt of any inquiry, indication of interest, proposal or offer that constitutes, or could reasonably be expected to lead to, any Acquisition Proposal, indicating (i) the identity of the Person making such Acquisition Proposal and (ii) the material terms and conditions of such Acquisition Proposal and providing Parent with the most current version (if any) of such inquiry, indication of interest, proposal or offer and all related material documentation. With respect to any Acquisition Proposal described in the immediately preceding sentence, the Company shall keep Parent reasonably informed, on a prompt basis (but in any event within forty-eight (48) hours of any such event), of (x) any changes or modifications to the terms of any such Acquisition Proposal and (y) any communications from such Person to the Company or from the Company to such Person with respect to any changes or modifications to the terms of any such Acquisition Proposal. Except as required by applicable Law, the Company shall not terminate, amend, modify, waive or fail to enforce any provision of any standstill or similar obligation with respect to any class of equity securities of the Company or any of its Subsidiaries.

(d) Notwithstanding anything to the contrary contained in Section 4.02(a) or Section 4.02(b), prior to the Company Requisite Vote, in response to an unsolicited bona fide written Acquisition Proposal that did not result from a breach of this Section 4.02, if the Company Board determines in good faith (x) after consultation with the Company's financial advisors and outside legal counsel, that such Acquisition Proposal is, or could reasonably be expected to lead to, a Superior Proposal and (y) after consultation with the Company's outside legal counsel, that the failure to take such action would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law, the Company may, subject to providing Parent prior notice, (i) furnish or provide information (including non-public information or data) regarding, and afford access to, the business, properties, assets, books, records and personnel of, the Company and its Subsidiaries, to the Person making such Acquisition Proposal and its Representatives; provided, however, that the Company shall as promptly as is reasonably practicable make available to Parent any non-public information concerning the Company or its Subsidiaries that is provided to any Person pursuant to this clause (i) to the extent such information was not previously made available to Parent and (ii) engage in discussions and negotiations with such Person and its Representatives with respect to such Acquisition Proposal; provided, further, that, prior to taking any of the actions set forth in the foregoing clauses (i) or (ii) above, the Person making such Acquisition Proposal has entered into an Acceptable Confidentiality Agreement (it being understood that the negotiation of such Acceptable Confidentiality Agreement shall not be deemed to be a breach of Section 4.02(a) or Section 4.02(b)).

(e) Except as set forth in Section 4.02(f) and Section 4.02(g), the Company shall not, and the Company Board (and each committee thereof) shall not (i) (A) withdraw, change, qualify, withhold or modify, or propose to do any of the foregoing, in a manner adverse to Parent or Merger Sub, the Company Board Recommendation, (B) adopt, approve or recommend, or propose to adopt, approve or recommend, any Acquisition Proposal, (C) fail to include the Company Board Recommendation in the Proxy Statement/Prospectus, (D) fail to recommend against any Acquisition Proposal subject to Regulation 14D promulgated under the Exchange Act in any solicitation or recommendation statement made on Schedule 14D-9 within ten (10) Business Days after Parent so requests in writing, (E) if an Acquisition Proposal or any material modification thereof is made public or sent to the holders of Company Shares, fail to issue a press release that reaffirms the Company Board Recommendation within ten (10) Business Days after Parent so requests in writing or (F) agree or resolve to take any action set forth in the foregoing clauses (A) through (E) (any action set forth in this clause (i), a "Company Adverse Recommendation Change") or (ii) authorize, cause or permit the Company or any of its Affiliates to enter into any letter of intent, memorandum of understanding, agreement in principle, definitive agreement, or other similar commitment that would reasonably be expected to lead to an Acquisition Proposal (other than an Acceptable Confidentiality Agreement) (an "Alternative Acquisition Agreement").

(f) Notwithstanding anything to the contrary in this Agreement, at any time prior to obtaining the Company Requisite Vote, the Company Board may make a Company Adverse Recommendation Change (and, solely with respect to a Superior Proposal, terminate this Agreement pursuant to Section 7.01(c)(i)) if (i) the Company has received a Superior Proposal other than as a result of a breach of this Section 4.02 and the Company Board (or a duly authorized committee thereof) determines in good faith, after consultation with the Company's outside legal counsel, that the failure to make a Company Adverse Recommendation Change in response to the receipt of such Superior Proposal would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law and (ii) (A) the Company provides Parent prior written notice of its intent to make any Company Adverse Recommendation Change or terminate this Agreement pursuant to Section 7.01(c)(i) at least four (4) Business Days prior to taking such action to the effect that, absent any modification to the terms and conditions of this Agreement that would cause the Superior Proposal to no longer be a Superior Proposal, the Company Board has resolved to effect a Company Adverse Recommendation Change or to terminate this Agreement pursuant to Section 7.01(c)(i), which notice shall specify the basis for such Company Adverse Recommendation Change or termination, shall provide the material terms and conditions of such Superior Proposal and shall attach the most current draft of any Alternative Acquisition Agreement, and any other material documents with respect to the Superior Proposal that (x) include any terms and conditions of the Superior Proposal and (y) were not produced by the Company, any of its Subsidiaries or any of its or their Representatives solely for internal purposes, if applicable (a "Notice of Recommendation Change") (it being understood that such Notice of Recommendation Change shall not in itself be deemed a Company Adverse Recommendation Change and that any change in price or material revision or material amendment to the terms of a Superior Proposal, if applicable, shall require a new notice to which the provisions of clauses (A), (B) and (C) of this Section 4.02(f) shall apply *mutatis mutandis* except that, in the case of such a new notice, all references to four (4) Business Days in this Section 4.02(f) shall be deemed to be two (2) Business Days), (B) during such four (4) Business Day period, if requested by Parent, the Company shall make its Representatives reasonably available to negotiate in good faith with Parent and its Representatives regarding any modifications to the terms and conditions of this Agreement that Parent proposes to make and (C) at the end of such four (4) Business Day period and taking into account any modifications to the terms of this Agreement proposed by Parent to the Company in a written, binding and irrevocable offer, the Company Board determines in good faith (x) after consultation with the Company's financial advisors and outside legal counsel, that such Superior Proposal still constitutes a Superior Proposal and (y) after consultation with the Company's outside legal counsel, that the failure to make such a Company Adverse Recommendation Change would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law.

(g) Notwithstanding anything to the contrary in this Agreement, other than in connection with an Acquisition Proposal (which shall be governed by Section 4.02(f)), at any time prior to obtaining the Company Requisite Vote, the Company Board may make a Company Adverse Recommendation Change if (i) an Intervening Event occurs and in response thereto the Company Board determines in good faith, after consultation with the Company's outside legal counsel, that the failure to take such action would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law and (ii) (A) the Company provides Parent prior written notice of its intent to make any Company Adverse Recommendation Change at least four (4) Business Days prior to taking such action to the effect that the Company Board has resolved to effect a Company Adverse Recommendation Change, which notice shall specify the basis therefor and include a reasonably detailed description of the Intervening Event, (B) during such four (4) Business Day period, if requested by Parent, the Company shall make its Representatives reasonably available to negotiate in good faith with Parent and its Representatives regarding any modifications to the terms and conditions of this Agreement that Parent proposes to make and (C) at the end of such four (4) Business Day period and taking into account any modifications to the terms of this Agreement proposed by Parent to the Company in a written, binding and irrevocable offer, the Company Board determines in good faith, after consultation with the Company's outside legal counsel, that the failure to make such a Company Adverse Recommendation Change would reasonably be expected to be inconsistent with its fiduciary duties under applicable Law. Each time there is a material change to the facts or circumstances relating to the Intervening Event prior to obtaining the Company Requisite Vote, the Company will be required to deliver to Parent prompt written notice of such material change (which notice shall include a reasonably detailed description of such material change) and the Company will provide Parent with an additional two (2) Business Day period prior to making a Company Adverse Recommendation Change, such period shall begin upon the date of Parent's receipt of the notice of such material change.

(h) Nothing contained in this Section 4.02 or elsewhere in this Agreement shall prohibit the Company or any of its Subsidiaries from (i) complying with its disclosure obligations under U.S. federal or state Law, (ii) making any "stop, look or listen" communication to the shareholders of the Company pursuant to Rule 14d-9(f) promulgated under the Exchange Act (or any similar communications to the shareholders of the Company) or (iii) making any other disclosure to its shareholders if the Company Board determines in good faith after consultation with the Company's outside legal counsel that the failure to make such disclosure would be inconsistent with its fiduciary duties under applicable Law.

ARTICLE V

ADDITIONAL AGREEMENTS

SECTION 5.01. Proxy Statement/Prospectus; Shareholders Meeting.

(a) As soon as reasonably practicable following the date of this Agreement, but in any event within thirty (30) Business Days thereafter, (i) the Company and Parent shall jointly prepare and cause to be filed with the SEC the proxy statement/prospectus (together with any amendment or supplement thereto, the "Proxy Statement/Prospectus"), as part of the Form S-4, that includes (A) a proxy statement of the Company for use in the solicitation of proxies for the Shareholders Meeting and (B) a prospectus with respect to the issuance of Parent Shares in the Merger and (ii) Parent shall prepare and cause to be filed with the SEC the Form S-4. The Company and Parent shall use their respective reasonable best efforts to (A) have the Form S-4 declared effective under the Securities Act as promptly as practicable after the Form S-4 is filed, (B) ensure that the Form S-4 and the Proxy Statement/Prospectus complies in all material respects with the applicable provisions of the Securities Act, the Exchange Act and the rules and regulations thereunder and (C) keep the Form S-4 effective for as long as may be reasonably requested in connection with the preparation, filing and distribution of the Form S-4 and the Proxy Statement/Prospectus. As promptly as practicable after the date of this Agreement, each of the Company and Parent will furnish or cause to be furnished to the other party the information relating to itself and its Subsidiaries, and cooperate with the other party, as may reasonably be requested, in connection with the preparation, filing and distribution of the Form S-4 and the Proxy Statement/Prospectus. The Form S-4 and Proxy Statement/Prospectus shall include all information reasonably requested by the parties hereto pursuant to the immediately preceding sentence.

(b) Each party hereto shall promptly notify the other parties of the receipt of any comments of the SEC to the Form S-4 or the Proxy Statement/Prospectus and of any request by the SEC for any amendment or supplement thereto or for additional information in connection therewith. As promptly as practicable after receipt of any such comment or request from the SEC, the party that received such comment or request shall provide the other parties copies of all correspondence between the receiving party and its Representatives, on the one hand, and the SEC, on the other hand, regarding such comments or request. The Company and Parent shall each use its reasonable best efforts to promptly provide responses to the SEC with respect to all comments received on the Form S-4 or the Proxy Statement/Prospectus from the SEC.

(c) Notwithstanding the foregoing, prior to filing the Form S-4 (or any amendment or supplement thereto) or mailing the Proxy Statement/Prospectus (or any amendment or supplement thereto) or responding to any comments of the SEC with respect thereto, each of the Company and Parent shall (i) provide the other party an opportunity to review and comment on such document or response (including the proposed final version of such document or response) and shall consider such comments in good faith and (ii) promptly provide the other party with a copy of any such document or response.

(d) Each of the Company and Parent shall advise the other, promptly after receipt of notice thereof, of the time of effectiveness of the Form S-4, the issuance of any stop order relating thereto or the suspension of the qualification of the Parent Shares to be issued in connection with the consummation of the transactions contemplated by this Agreement for offering or sale in any jurisdiction. Each of the Company and Parent shall use its reasonable best efforts to have any such stop order or suspension lifted, reversed or otherwise terminated. Each of the Company and Parent shall also take any other action required to be taken under the Securities Act, the Exchange Act, any applicable foreign or state securities or "blue sky" laws and the rules and regulations thereunder in connection with the Merger and the issuance of the Parent Shares to be issued in connection with the consummation of the transactions contemplated by this Agreement.

(e) If, prior to the Effective Time, any event occurs with respect to any party hereto or any of its Subsidiaries, or any change occurs with respect to other information supplied by such party for inclusion in the Form S-4 or the Proxy Statement/Prospectus, which is required to be described in an amendment of, or a supplement to, the Form S-4 or the Proxy Statement/Prospectus, such party shall promptly notify the other parties hereto of such event, and the Company and Parent shall cooperate (i) in the prompt filing with the SEC of any necessary amendment or supplement to the Form S-4 or the Proxy Statement/Prospectus so that such documents would not include any misstatement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements made therein, in light of the circumstances under which they are made, not misleading and (ii) to the extent required by Law, in disseminating the information contained in such amendment or supplement to the holders of Company Shares.

(f) Subject to the fiduciary duties of the Company Board under applicable Law, the Company will take, in accordance with applicable Law and the Company Organizational Documents, all action necessary to call, give notice of, convene and hold a meeting of holders of Company Shares (the "Shareholders Meeting") as promptly as practicable after the Form S-4 is declared effective under the Securities Act, to consider and vote upon the approval of this Agreement. Subject to Section 4.02, the Company Board shall recommend such approval and shall take all lawful action to solicit and obtain the Company Requisite Vote. Notwithstanding anything to the contrary in this Agreement, the Company may, but shall not be required to, adjourn or postpone the Shareholders Meeting (i) to the extent necessary to ensure that any necessary supplement or amendment to the Proxy Statement/Prospectus (including with respect to an Acquisition Proposal) is provided to the holders of Company Shares a reasonable amount of time in advance of a vote on the approval of this Agreement, (ii) if the Company reasonably believes it is necessary and advisable to do so in order to solicit additional proxies in order to obtain the Company Requisite Vote, (iii) if, as of the time for which the Shareholders Meeting is originally scheduled, there are insufficient Company Shares represented (either in person or by proxy) to constitute a quorum necessary to conduct the business of such meeting or (iv) as required by applicable Law.

(g) Parent shall use its reasonable best efforts to cause to be delivered to the Company two (2) letters from Parent's independent accountants, one dated a date within two (2) Business Days before the date on which the Form S-4 shall become effective and one dated a date within two (2) Business Days before the Closing Date, each addressed to the Company, in form and substance reasonably satisfactory to the Company and customary in scope and substance for comfort letters delivered by independent public accountants in connection with registration statements similar to the Form S-4.

(h) The Company shall use its reasonable best efforts to cause to be delivered to Parent two (2) letters from the Company's independent accountants, one dated a date within two (2) Business Days before the date on which the Form S-4 shall become effective and one dated a date within two (2) Business Days before the Closing Date, each addressed to Parent, in form and substance reasonably satisfactory to Parent and customary in scope and substance for comfort letters delivered by independent public accountants in connection with registration statements similar to the Form S-4.

SECTION 5.02. Filings; Other Actions; Notification.

(a) Subject to the terms and conditions set forth in this Agreement, each of the Company, Parent and Merger Sub shall (and shall cause its respective Subsidiaries to) cooperate and use its respective reasonable best efforts to (i) promptly make any required submissions and filings under applicable Law or to Governmental Entities with respect to the Merger and the other transactions contemplated by this Agreement, (ii) promptly furnish information requested in connection with such submissions and filings to such Governmental Entities or under such applicable Law, (iii) keep the other parties reasonably informed with respect to the status of any such submissions and filings to such Governmental Entities or under such applicable Law, including with respect to: (A) the occurrence or receipt of any Consent under such applicable Law, (B) the expiration or termination of any waiting period, (C) the commencement or proposed or threatened commencement of any investigation, litigation or administrative or judicial action or proceeding under such applicable Law, and (D) the nature and status of any objections raised or proposed or threatened to be raised under such applicable Law with respect to the Merger or the other transactions contemplated by this Agreement, (iv) obtain all Consents and Permits from any Governmental Entity (including the Regulatory Clearances) or any other Person necessary to consummate the transactions contemplated by this Agreement as soon as practicable, and (v) take or cause to be taken all other actions, and do or cause to be done all other things, reasonably necessary to consummate and make effective the Merger and the other transactions contemplated by this Agreement as soon as practicable.

(b) In furtherance and not in limitation of the foregoing: each of the Company, Parent and Merger Sub shall (i) (A) make an appropriate filing of a Notification and Report Form pursuant to the HSR Act with respect to the transactions contemplated by this Agreement as promptly as reasonably practicable following the date of this Agreement (and in any event within fifteen (15) Business Days after the date hereof (unless the parties otherwise agree)), (B) furnish as soon as practicable any additional information and documentary material that may be required or requested pursuant to the HSR Act and (C) use its reasonable best efforts to take, or cause to be taken, all other actions consistent with this Section 5.02 necessary to cause the expiration or termination of the applicable waiting periods under the HSR Act (including any extensions thereof) as soon as practicable and (ii) (A) make or cause to be made the appropriate filings (including notice filings) as soon as practicable (and in any event by the date with respect to each such filing set forth in Section 5.02(b) of the Company Disclosure Letter (unless the parties otherwise agree)) with the FERC, the NRC, the FCC, the SCPSC, the NCUC and the GPSC relating to the transactions contemplated by this Agreement, (B) supply as soon as practicable any additional information and documentary material that may be required or requested by the FERC, the NRC, the FCC, the SCPSC, the SCORS, the NCUC and the GPSC, as applicable, in connection with the Regulatory Clearances and (C) use its reasonable best efforts to take or cause to be taken all other actions consistent with this Section 5.02 as necessary to obtain any necessary Consents and Permits from the FERC, the NRC, the FCC, the SCPSC, the NCUC and the GPSC, as applicable, in connection with the Regulatory Clearances as soon as practicable.

(c) In furtherance and not in limitation of the foregoing, as promptly as reasonably practicable following the date of this Agreement, the Company and Parent shall (i) work together in good faith the finalize the terms of the SCPCS Petition and (ii) jointly file the SCPSC Petition. Each of the Company, Parent and Merger Sub shall furnish as soon as practicable any additional information and documentary material that may be required by the SCPSC or any other Government Entity in connection with the SCPSC Petition and use its reasonable best efforts to take, or cause to be taken, all other actions consistent with this Section 5.02 and as set forth in the SCPSC Petition necessary to obtain the SCPSC Petition Approval as soon as practicable.

(d) The Company, Parent and Merger Sub shall, subject to applicable Law relating to the exchange of information: (i) promptly notify the other parties of (and if in writing, furnish the other parties with copies of) any communication to such Person from any third party (other than a Representative of any of the parties hereto or any of their respective Subsidiaries) or any Governmental Entity regarding the filings and submissions described in this Section 5.02 and permit the other parties to review and discuss in advance (and to consider in good faith any comments made by the others in relation to) any proposed written response to any communication from any third party (other than a Representative of any of the parties hereto or any of their respective Subsidiaries) or any Governmental Entity regarding such filings and submissions, (ii) keep the other parties reasonably informed of any developments, meetings or discussions with any third party (other than a Representative of any of the parties hereto or any of their respective Subsidiaries) or any Governmental Entity in respect of any filings, submissions, investigations, or inquiries concerning the transactions contemplated by this Agreement and (iii) not independently participate in any meeting or discussion with any third party (other than a Representative of any of the parties hereto or any of their respective Subsidiaries) or any Governmental Entity in respect of any filings, submissions, investigations or inquiries concerning the transactions contemplated by this Agreement without giving the other party or parties hereto prior notice of such meeting or discussions to the extent it is reasonably practical to do so and, unless prohibited by such third party or Governmental Entity or otherwise not reasonably practical, the opportunity to attend or participate; provided, however, that (x) the Company, Parent and Merger Sub shall be permitted to redact any correspondence, filing, submission or communication prior to furnishing it to the other parties to the extent such correspondence, filing, submission or communication contains competitively or commercially sensitive information, including information relating to the valuation of the transactions contemplated by this Agreement and (y) for the avoidance of doubt, the foregoing clause (iii) shall not prohibit the Company, Parent or Merger Sub from independently participating in meetings and discussions with third parties or Governmental Entities that solely relate to an explanation of the terms of this Agreement, including the conditions set forth in Article VI.

(e) In furtherance and not in limitation of the foregoing, but subject to the other terms and conditions of this Section 5.02, Parent, Merger Sub and the Company agree to take promptly any and all steps necessary to avoid, eliminate or resolve each and every impediment to and obtain all Consents under applicable Laws that may be required by any Governmental Entity (including any Regulatory Clearances and the SCPSC Petition Approval), so as to enable the parties to consummate the Merger and the other transactions contemplated by this Agreement as soon as practicable, including committing to and effecting, by consent decree, hold separate orders, trust, or otherwise, (i) selling, licensing, holding separate or otherwise disposing of assets or businesses of Parent or the Company or any of their respective Subsidiaries, (ii) terminating, relinquishing, modifying, or waiving existing relationships, ventures, contractual rights, obligations or other arrangements of Parent or the Company or any of their respective Subsidiaries and (iii) creating any relationships, ventures, contractual rights, obligations or other arrangements of Parent or the Company or any of their respective Subsidiaries (each, a "Remedial Action"); provided, however, that any Remedial Action may, at the discretion of the Company or Parent, be conditioned upon consummation of the transactions contemplated by this Agreement.

(f) In furtherance and not in limitation of the foregoing, but subject to the other terms and conditions of this Section 5.02, in the event that any Proceeding is commenced, threatened or is reasonably foreseeable challenging any of the transactions contemplated by this Agreement and such Proceeding seeks, or would reasonably be expected to seek, to prevent, materially impede or materially delay the consummation of such transactions, Parent shall use reasonable best efforts to take or cause to be taken any and all action, including a Remedial Action, to avoid or resolve any such Proceeding as promptly as practicable. In addition, each of the Company, Parent and Merger Sub shall cooperate with each other and use its respective reasonable best efforts to contest, defend and resist any such litigation, action or proceeding and to have vacated, lifted, reversed or overturned any Order, whether temporary, preliminary or permanent, that is in effect and that prohibits, prevents, delays, interferes with or restricts consummation of the transactions contemplated by this Agreement as promptly as practicable.

(g) From the date hereof until the earlier of the Effective Time and the date this Agreement is terminated pursuant to Article VII, neither Parent, Merger Sub, nor Company shall, nor shall they permit their respective Subsidiaries to, acquire or agree to acquire any rights, assets, business, Person or division thereof (through acquisition, license, joint venture, collaboration or otherwise), if such acquisition would reasonably be expected to materially increase the risk of not obtaining, or would reasonably be expected to prevent or prohibit, or materially impede, interfere with or delay, obtaining, any applicable Consent under applicable Laws (including any Regulatory Clearance and the SCPSC Petition Approval) with respect to the transactions contemplated by this Agreement. Section 5.02(g) of the Company Disclosure Letter sets forth the approach to the coordination of matters related to the Company's pending acquisition described as Item 3 of Section 3.01(f) of the Company Disclosure Letter and matters related to this Agreement.

(h) The Company and its Subsidiaries (as applicable) shall, to the extent reasonably practicable, subject to applicable Law relating to the exchange of information and except as would be in violation of, or result in a waiver or loss of, the attorney-client privilege or work-product doctrine: (i) within 48 hours of receipt thereof, notify Parent of (and if in writing, furnish Parent with copies of) any material communication to the Company or its Subsidiaries from any Governmental Entity related to or arising out of any material claim, hearing, investigation or Proceeding, whether criminal or civil in nature, relating to or arising out of the construction, or cessation of the construction, of nuclear power Units 2 and 3 at the Summer Station or the bankruptcy of Westinghouse Electric Company, LLC (including the settlement agreement entered into with Toshiba Corporation and any Contract relating to the proceeds thereof) (collectively, "Nuclear Litigation") and permit Parent to review and discuss in advance (and consider in good faith any comments made by Parent in relation to) any proposed written response to any material communication from any Governmental Entity related to or arising out of any Nuclear Litigation, (ii) keep Parent reasonably informed of any developments, meetings or discussions with any Governmental Entity related to or arising out of any Nuclear Litigation, and (iii) use good faith efforts to give Parent notice (which notice shall be prior notice to the extent providing prior notice is reasonably practical) of any material meetings or discussions relating to or arising out of any Nuclear Litigation (and consider in good faith any comments or guidance from Parent in relation to such meeting or discussions) and, if appropriate in the Company's reasonable judgment, provide Parent the opportunity to attend or participate in such meetings or discussions.

(i) Notwithstanding anything set forth in this Agreement, Parent and its Affiliates shall not be required to and the Company and its Affiliates shall not be required to, unless conditioned on the Closing, and without the prior written consent of Parent (which consent may be withheld at Parent's sole discretion) the Company shall not and shall cause its Subsidiaries not to, in connection with obtaining any Consent or Permit, or with respect to any actions required under this Section 5.02, offer or accept, or agree, commit to agree or consent to, any undertaking, term, condition, liability, obligation, commitment or sanction (including any Remedial Action), that constitutes a Burdensome Condition.

(j) Notwithstanding anything set forth in this Agreement, Parent and its Affiliates shall not be required to and the Company and its Affiliates shall not be required to, unless conditioned on the Closing, and without the prior written consent of Parent (which consent may be withheld at

Parent's sole discretion) the Company shall not and shall cause its Subsidiaries not to, in connection with the SCPSC Petition, offer or accept, or agree, commit to agree or consent to, any undertaking, term, condition, liability, obligation, commitment or sanction (including any Remedial Action) that (i) materially changes the proposed terms, conditions, or undertakings set forth in the SCPSC Petition or (ii) significantly changes the economic value of the proposed terms set forth in the SCPSC Petition, in each case, as reasonably determined by Parent in good faith.

SECTION 5.03. Access and Reports; Confidentiality.

(a) Subject to applicable Law relating to the exchange of information, upon reasonable notice, the Company and Parent shall, and shall cause each of their respective Subsidiaries to, afford to the other party's Representatives reasonable access, during normal business hours throughout the period prior to the Effective Time, to its employees, properties, books, contracts and records. During such period, the Company and Parent shall, and shall cause each of their respective Subsidiaries to, furnish promptly to the other party (i) to the extent not publicly available, a copy of each report, schedule, registration statement and other document (A) filed by it during such period pursuant to applicable Law or (B) filed with, furnished to or sent to the SEC, the FERC, the FCC, the NRC, the SCPSC, the SCORS, the NCUC, the GPSC or any other federal or state regulatory agency or commission and (ii) all information concerning its business, properties and personnel as may reasonably be requested by the other party; provided, however, that no investigation pursuant to this Section 5.03(a) shall affect or be deemed to modify any representation or warranty made herein; provided, further, that the foregoing shall not require the Company and Parent to (A) permit any inspection, or to disclose any information, that in the reasonable judgment of such party, would result in the disclosure of any trade secrets of third parties or violate any of its obligations to a third party with respect to confidentiality if the Company or Parent, as applicable, shall have used commercially reasonable efforts to obtain the consent of such third party to such inspection or disclosure, (B) disclose any privileged information of such party or any of its Subsidiaries, (C) permit any invasive environmental testing or sampling at any property or (D) take or allow any action that would unreasonably interfere with such party's or any of its Subsidiaries' business or operations. All requests for information made pursuant to this Section 5.03 shall be directed to the executive officer or other Person designated by the Company or Parent, as applicable. Notwithstanding the foregoing, with respect to Parent and its Subsidiaries, the access to and exchange of information described in this Section 5.03(a) shall be limited to the extent reasonably necessary or related to the consummation of the Merger and the other transactions contemplated by this Agreement.

(b) Each of the Company, Parent and Merger Sub will comply with the terms and conditions of that certain letter agreement, dated October 8, 2017, between Parent and the Company (as may be amended from time to time, the "Confidentiality Agreement"), and will hold and treat, and will cause their respective Representatives to hold and treat, in confidence all documents and information exchanged pursuant to Section 5.03(a) in accordance with the Confidentiality Agreement, which Confidentiality Agreement shall remain in full force and effect in accordance with its terms.

SECTION 5.04. Stock Exchange Delisting and Listing.

(a) Prior to the Closing Date, the Company shall cooperate with Parent and use its reasonable best efforts to take or cause to be taken all actions, and do or cause to be done all things, reasonably necessary, proper or advisable on its part under applicable Law and rules and policies of the NYSE to enable the delisting by the Surviving Corporation of the Company Shares from the NYSE and the deregistration of the Company Shares under the Exchange Act as promptly as practicable after the Effective Time and in accordance with applicable Law.

(b) Parent shall use its reasonable best efforts to cause the Parent Shares to be issued in connection with the transactions contemplated by this Agreement to be approved for listing on the NYSE, subject to official notice of issuance, prior to the Closing Date.

SECTION 5.05. Publicity. The initial news release regarding the Merger shall be a joint news release reasonably agreed between Parent and the Company and, except with respect to any action taken pursuant to Section 4.02 or Section 7.01, thereafter the Company and Parent each shall consult with each other prior to issuing, and give each other the opportunity to review and comment upon, any news releases or otherwise making public announcements with respect to the Merger and the other transactions contemplated by this Agreement, except as such party may reasonably conclude may be required by Law or by obligations pursuant to any listing agreement with or rules of any national securities exchange or interdealer quotation service or as may be requested by any Governmental Entity.

SECTION 5.06. Employee Matters.

(a) Following the Effective Time and until December 31, 2019 (the "Continuation Period"), Parent shall provide, or shall cause the Surviving Corporation to provide, the individuals who are employed by the Company or any of its Subsidiaries immediately before the Effective Time and not covered by any collective bargaining agreement (the "Company Non-Union Employees") with (i) annual base compensation no less than the annual base compensation provided to such Company Non-Union Employees immediately prior to the Effective Time, (ii) annual target cash incentive opportunities that are no less than the annual target cash incentive opportunities provided to such Company Non-Union Employees immediately prior to the Effective Time, subject to the satisfaction of performance criteria determined by Parent (consistent with the form and terms and conditions (including performance criteria) of such awards provided to other similarly situated employees of Parent) and other terms and conditions of Parent's annual incentive program, (iii) long-term target incentive award opportunities that are no less than the long-term target incentive award opportunities provided to such Company Non-Union Employees immediately prior to the Effective Time (such long-term incentive awards to be provided in such a form, and subject to such performance and vesting criteria and other terms and conditions, as Parent shall determine, consistent with the form and terms and conditions (including performance criteria) of such awards provided to other similarly situated employees of Parent), (iv) employment within a 50-mile radius from each such Company Non-Union Employee's location of employment immediately prior to the Effective Time and duties and responsibilities similar to what such Company Non-Union Employee had immediately prior to the Effective Time, (v) severance benefits that are no less favorable than those set forth in Section 5.06(a) of the Company Disclosure Letter and (vi) other employee benefits that are substantially comparable in the aggregate to the employee benefits provided to such Company Non-Union Employees immediately prior to the Effective Time. Further Parent shall provide, or shall cause the Surviving Corporation to provide, the individuals who are employed by the Company or any of its Subsidiaries immediately before the Effective Time and who are covered by a collective bargaining agreement with (A) compensation and benefits and other terms and conditions of employment in accordance with the terms of such collective bargaining agreement or any subsequently adopted collective bargaining agreement, as in effect from time to time, and (B) severance benefits that are no less favorable than those set forth in Section 5.06(a) of the Company Disclosure Letter.

(b) Without limiting the generality of Section 5.06(a) but subject to the obligations set forth in Section 5.06(a), from and after the Effective Time, Parent shall, or shall cause the Surviving Corporation to, assume, honor and continue during the Continuation Period or, if later, until all obligations thereunder have been satisfied, all of the Company's employment, severance, retention, termination, deferred compensation, and change in control plans, policies, programs, agreements and arrangements maintained by the Company or any of its Subsidiaries, in each case, as in effect at the Effective Time, including with respect to any payments, benefits or rights arising as a result of the transactions contemplated by this Agreement (either alone or in combination with any other event), and Parent or the Surviving Corporation may not amend, modify or terminate any such plan, policy, program, agreement or arrangement unless and solely to the extent permitted under the terms thereof as in effect at the Effective Time or otherwise as required to comply with applicable Law. In addition, to the extent required by the express terms of any Company Benefit Plan, Parent shall, or shall cause the Surviving Corporation to, expressly assume and agree to perform all obligations under and with respect to the terms of each such Company Benefit Plan. Notwithstanding anything to the contrary herein, Parent shall, or shall cause the Surviving Corporation to, maintain without amendment (other than as required to comply with applicable Law) for the duration of the Continuation Period each of the Company Benefit Plans listed on Section 5.06(b) of the Company Disclosure Letter. For avoidance of doubt, Parent shall assume, honor and continue the Company's change in control plans in accordance with the foregoing solely with respect to any payments, benefits or rights arising as a result of the transactions contemplated by this Agreement (either alone or in combination with any other event), and shall not be obligated to provide any additional payments, benefits or rights under such plans in connection with any subsequent change in control of Parent or the Surviving Corporation that may occur after the Merger.

(c) With respect to all plans maintained by Parent, the Surviving Corporation or their respective Subsidiaries in which the individuals who are employed by the Company or any of its Subsidiaries immediately before the Effective Time (the "Company Employees") are eligible to participate after the Closing Date (including any vacation, paid time-off and severance plans) for purposes of determining eligibility to participate, level of benefits and vesting (but not benefit accruals under any defined benefit pension plan), each Company Employee's service with the Company or any of its Subsidiaries (as well as service with any predecessor employer of the Company or any such Subsidiary, to the extent service with the predecessor employer is recognized by the Company or such Subsidiary) shall be treated as service with Parent, the Surviving Corporation or any of their respective Subsidiaries or any Commonly Controlled Entity, in each case, to the extent such service would have been recognized by the Company or its Subsidiaries under analogous Company Benefit Plans prior to the Effective Time; provided, however, that such service need not be recognized to the extent that such recognition would result in any duplication of benefits for the same period of service; and, provided further, that no Company Employee shall be entitled based on such prior credited service or otherwise to participate in any frozen or grandfathered plan or benefit formula of Parent or any of its Subsidiaries that would not be offered to employees first hired by Parent or its Subsidiaries after the Effective Time.

(d) Without limiting the generality of Section 5.06(a), Parent shall, or shall cause the Surviving Corporation to, waive any pre-existing condition limitations, exclusions, actively-at-work requirements and waiting periods under any welfare benefit plan maintained by Parent, the Surviving Corporation or any of their respective Subsidiaries in which Company Employees (and their eligible dependents) will be eligible to participate from and after the Effective Time, except to the extent that such pre-existing condition limitations, exclusions, actively-at-work requirements and waiting periods would not have been satisfied or waived under the comparable Company Benefit Plan immediately prior to the Effective Time; provided, however, that in the case of an insured plan, such waivers shall be made only to the extent the insurer consents thereto, and Parent and the Surviving Corporation shall use commercially reasonable efforts to obtain such consent. Parent shall, or shall cause the Surviving Corporation to, recognize the dollar amount of all co-payments, deductibles and similar expenses incurred by each Company Employee (and his or her eligible dependents) during the calendar year or plan year in which the Effective Time occurs for purposes of satisfying such year's deductible and co-payment limitations under the relevant welfare benefit plans in which they will be eligible to participate from and after the Effective Time; provided, however, that in the case of an insured plan, such amounts shall be taken into account only to the extent the insurer consents thereto, and Parent and the Surviving Corporation shall use commercially reasonable efforts to obtain such consent.

(e) The provisions of this Section 5.06 are solely for the benefit of the parties to this Agreement, and no other Person (including any current or former employee of the Company or its Subsidiaries or any beneficiary or dependent thereof) shall be regarded for any purpose as a third-party beneficiary of this Section 5.06, and no provision of this Section 5.06 shall create such rights in any such Persons. Except as set forth in Section 5.06(b), no provision of this Agreement shall be construed (i) as a guarantee of continued employment of any employee of the Company or its Subsidiaries, (ii) to prohibit Parent or its Subsidiaries (including the Surviving Corporation) from having the right to terminate the employment of any such employee, (iii) to require Parent or its Subsidiaries to continue to pay or provide any such employee any compensation or benefits after such termination of employment, other than any severance benefits that may be provided pursuant to Section 5.06(a)(v); (iv) to permit the amendment, modification or termination of any Company Benefit Plan or employee benefit plan of Parent or its Subsidiaries (in each case solely to the extent any such amendment, modification or termination is prohibited in accordance with the terms of the applicable plan) or (v) as an amendment or modification of the terms of any Company Benefit Plan or employee benefit plan or Parent or its Subsidiaries.

SECTION 5.07. Expenses. Except as set forth in Section 5.09(c), whether or not the Merger is consummated, all costs and expenses incurred in connection with this Agreement and the Merger and the other transactions contemplated by this Agreement shall be paid by the party incurring such expenses.

SECTION 5.08. Indemnification; Directors' and Officers' Insurance.

(a) From and after the Effective Time, Parent shall indemnify and hold harmless, to the fullest extent permitted under applicable Law, each present and former director and officer of the Company and its Subsidiaries (in each case, when acting in such capacity) (collectively, the "Indemnified Parties") from and against any and all costs and expenses (including reasonable attorneys' fees), judgments, fines, losses, claims, damages and liabilities (collectively, "Costs") incurred in connection with any Proceeding or investigation, whether civil, criminal, administrative or investigative, arising out of or pertaining to matters existing or occurring at or prior to the Effective Time, including the transactions contemplated by this Agreement. From and after the Effective Time, Parent shall advance expenses to each Indemnified Party claiming indemnification pursuant to this Section 5.08 as incurred to the fullest extent permitted under applicable Law; provided, however, that such Indemnified Party provides an undertaking to repay such advances if it is ultimately determined that such Indemnified Party is not entitled to such indemnification.

(b) From and after the Effective Time, Parent shall cause the Surviving Corporation to honor the provisions regarding (i) exculpation of directors, (ii) limitation of liability of directors and officers, (iii) advancement of expenses and (iv) indemnification, in each case, contained in the Company Organizational Documents (as in effect as of the date hereof), the comparable organizational documents of any of the Company's Subsidiaries (as in effect as of the date hereof) or any indemnification Contract set forth in Section 5.08(b) of the Company Disclosure Letter between the applicable Indemnified Party and the Company or any of its Subsidiaries existing immediately prior to the Effective Time (it being understood and agreed that, for the avoidance of doubt and without limiting the generality of the foregoing, the foregoing obligation of Parent shall apply with respect to, and remain in full force and effect as to any pending or future claim, hearing, investigation or Proceeding relating to or arising out of the construction, or cessation of the construction, of nuclear power Units 2 and 3 at the Summer Station or the bankruptcy of Westinghouse Electric Company, LLC (including the settlement agreement entered into with Toshiba Corporation and any Contract relating to the proceeds thereof)). For a period of three (3) years following the Effective Time, Parent shall cause the Surviving Corporation and its Subsidiaries not to amend, replace or otherwise modify the provisions regarding (A) exculpation of directors, (B) limitation of liability of directors and officers, (C) advancement of expenses and (D) indemnification, in each case, contained in their respective organizational documents; provided, however, that such three (3) year period shall be extended for so long as any Proceeding is pending or asserted against an Indemnified Party that implicates the rights set forth in the foregoing clauses (A) through (D); provided, further, that such prohibition on amendments, replacements and other modifications shall not apply to amendments, replacements and other modifications that are prospective in their application and exclude any effect on the Indemnified Parties.

(c) From and after the Effective Time, Parent shall cause the Surviving Corporation to maintain for a period of at least six (6) years following the Effective Time directors' and officers' liability insurance and fiduciary liability insurance policies (collectively, "D&O Insurance") from an insurance carrier with the same or better credit rating as the Company's current insurance carrier with benefits, levels of coverage and terms and conditions at least as favorable as the Company's D&O Insurance existing immediately prior to the Effective Time with respect to matters existing or occurring at or prior to the Effective Time, including for acts or omissions in connection with this Agreement and the consummation of the transactions contemplated by this Agreement. Notwithstanding the foregoing, in no event shall Parent or the Surviving Corporation be required to expend for such D&O Insurance coverage an annual premium amount greater than three hundred percent (300%) of the aggregate amount of the annual premiums currently paid by the Company for D&O Insurance immediately prior to the Effective Time (such aggregate amount of premiums currently paid, the "Maximum Annual Premium"). If the annual premiums of such D&O Insurance coverage exceed the Maximum Annual Premium, Parent and the Surviving Corporation shall obtain a policy with as much coverage as reasonably available for an annual cost not exceeding the Maximum Annual Premium.

(d) Notwithstanding Section 5.08(c), the Company may in its sole discretion obtain, prior to the Effective Time, six (6) year pre-paid "tail" insurance coverage, at an aggregate cost no greater than six times the Maximum Annual Premium, providing for D&O Insurance not materially less favorable than that described in Section 5.08(c). If the Company has obtained such policy pursuant to this Section 5.08(d), Parent will cause such policy to be maintained in full force and effect for its full term and cause all obligations thereunder to be honored by the Surviving Corporation, and Parent will have no further obligation to purchase or pay for insurance pursuant to Section 5.08(c).

(e) If Parent, the Surviving Corporation or any of their respective successors or assigns (i) consolidates or merges with or into any other Person and is not the continuing or surviving corporation or entity of such consolidation or merger or (ii) transfers all or substantially all of its properties and assets to any Person, then, and in each such case, proper provisions shall be made so that the successors and assigns of Parent or the Surviving Corporation, as applicable, shall assume and comply with all of the obligations applicable to Parent or the Surviving Corporation, respectively, set forth in this Section 5.08.

(f) The provisions of this Section 5.08 are intended to be for the benefit of, and shall be enforceable by, each of the Indemnified Parties. The obligations of Parent and the Surviving

Corporation in this Section 5.08 may not be terminated or modified in any manner that adversely affects any Indemnified Party without the consent of such Indemnified Party. Parent will honor, guaranty and stand as surety for, and will cause the Surviving Corporation and its Subsidiaries and successors to honor and comply with, the covenants contained in this Section 5.08.

(g) The rights of the Indemnified Parties under this Section 5.08 shall be in addition to, and not in limitation of, any rights such Indemnified Parties may have under the Company Organizational Documents or any of the comparable organizational documents of any of the Company's Subsidiaries, or under any applicable Contracts or Law.

SECTION 5.09. Financing.

(a) The Company shall, and shall cause its Subsidiaries to, (i) provide commercially reasonable assistance with the preparation of rating agency presentations and lender, underwriter and initial purchaser presentations, offering memoranda and prospectuses and any discussions regarding the business, financial statements, and management discussion and analysis of the Company and its Subsidiaries, all for use in connection with the financing activities of Parent, including any registration statement filed with the SEC where Parent determines that the inclusion of such information is required or desirable, and (ii) request that its independent accountants provide customary and reasonable assistance to Parent or any of its Subsidiaries, as applicable, in connection with providing customary comfort letters in connection with the financing activities of Parent; provided, further, that nothing in this Agreement shall require the Company to cause the delivery of (A) legal opinions or reliance letters or any certificate as to solvency or any other certificate necessary for such financing activities, other than as allowed by the preceding clause (ii), (B) any audited financial information or any financial information prepared in accordance with Regulation S-K or Regulation S-X under the Securities Act or any financial information in a form not customarily prepared by the Company with respect to any period or (C) any financial information with respect to a month or fiscal period that has not yet ended or has ended less than forty-five (45) days prior to the date of such request.

(b) Notwithstanding anything to the contrary contained in this Agreement (including this Section 5.09): (i) nothing in this Agreement (including this Section 5.09) shall require any such cooperation set forth in Section 5.09(a) to the extent that it would require the Company, any of its Subsidiaries or any of their respective Affiliates or Representatives to (A) pay any commitment or other fees, reimburse any expenses or otherwise incur any liabilities or give any indemnities prior to the Effective Time, (B) provide any cooperation that would unreasonably interfere with the ongoing business or operations of the Company, any of its Subsidiaries or any of their respective Affiliates or Representatives, (C) enter into or approve any agreement or other documentation effective prior to the Effective Time or agree to any change or modification of any existing agreement or other documentation that would be effective prior to the Effective Time, (D) require the Company to provide *pro forma* financial statements or *pro forma* adjustments reflecting the financing activities of Parent or any description of all or any component of such financing activities (it being understood that the Company shall use reasonable best efforts to assist in preparation of *pro forma* financial adjustments to the extent otherwise relating to the Company and required by the financing activities of Parent), (E) require the Company or the Subsidiaries of the Company to provide *pro forma* financial statements or *pro forma* adjustments reflecting transactions contemplated or required hereunder (it being understood that the Company shall use reasonable best efforts to assist in preparation of *pro forma* financial adjustments to the extent otherwise relating to the Company and required by the financing activities of Parent), (F) provide any cooperation or take any action that, in the reasonable judgment of the Company, would result in a violation of any confidentiality agreement or material agreement or the loss of any attorney-client or other similar privilege, (G) make any representation or warranty in connection with the financing activities of Parent or the marketing or arrangement thereof, (H) provide any cooperation, or take any action, that would cause any representation or warranty in this Agreement to be breached or any condition to the Closing set forth in this Agreement to fail to be satisfied or (I) cause the Company, any of its Subsidiaries or any of their respective boards of directors (or equivalent bodies) to approve or authorize the financing activities of Parent, and (ii) no action, liability or obligation (including any obligation to pay any commitment or other fees or reimburse any expenses) of the Company, any of its Subsidiaries or any of their respective Affiliates or Representatives under any certificate, agreement, arrangement, document or instrument relating to the financing activities of Parent shall be effective until the Effective Time.

(c) Parent shall (i) promptly reimburse the Company for all reasonable and out-of-pocket costs or expenses (including reasonable and documented costs and expenses of counsel and accountants) incurred by the Company, any of its Subsidiaries and any of their respective Representatives in connection with any cooperation provided for in Section 5.09(a) and (ii) indemnify and hold harmless the Company, each of its Subsidiaries and each of their respective Representatives against any claim, loss, damage, injury, liability, judgment, award, penalty, fine, Tax, cost (including cost of investigation), expense (including fees and expenses of counsel and accountants) or settlement payment incurred as a result of, or in connection with, any cooperation provided for in Section 5.09(a) or the financing activities of Parent and any information used in connection therewith, unless the Company acted in bad faith or engaged in willful misconduct and other than in the case of fraud.

(d) Without limiting the generality of the foregoing, promptly following Parent's request, the Company shall deliver to each of the lenders with respect to the Indebtedness set forth in Section 5.09(d) of the Parent Disclosure Letter (the "Existing Loan Lenders") a notice (an "Existing Loan Notice") prepared by Parent, in form and substance reasonably acceptable to the Company, notifying each of the Existing Loan Lenders of this Agreement and the contemplated Merger. At Parent's election, the Existing Loan Notice with respect to one or more of the Existing Loan Lenders may include a request for a consent, in form and substance reasonably acceptable to the Company (an "Existing Loan Consent"), to (i) the consummation of the Merger and the other transactions contemplated by this Agreement, and (ii) certain modifications of (or waivers under or other changes to) any agreement or documentation relating to the Company's or its Subsidiaries', as applicable, relationship with such Existing Loan Lender; provided, however, that no such modifications, waivers or changes shall be effective prior to the Effective Time.

(e) Parent and Merger Sub acknowledge and agree that the obtaining of any Existing Loan Consent is not a condition to the Closing.

SECTION 5.10. Rule 16b-3. Prior to the Effective Time, each of the Company and Parent shall take such steps as may be reasonably necessary or advisable to cause (a) any dispositions of Company equity securities (including derivative securities) pursuant to the transactions contemplated by this Agreement by each individual who is subject to the reporting requirements of Section 16(a) of the Exchange Act with respect to the Company to be exempt under Rule 16b-3 promulgated under the Exchange Act and (b) any acquisitions of Parent equity securities (including derivative securities) pursuant to the transactions contemplated by this Agreement by each individual who may become subject to the reporting requirements of Section 16(a) of the Exchange Act with respect to Parent to be exempt under Rule 16b-3 promulgated under the Exchange Act.

SECTION 5.11. Parent Consent. Within twenty-four (24) hours after the execution of this Agreement, Parent shall execute and deliver, in accordance with Chapter 11 of the SCBCA and in its capacity as the sole shareholder of Merger Sub, a written consent approving this Agreement.

SECTION 5.12. Merger Sub and Surviving Corporation Compliance. Parent shall cause Merger Sub or the Surviving Corporation, as applicable, to comply with all of its respective obligations under this Agreement, and prior to the Effective Time, Merger Sub shall not engage in any activities of any nature except as provided in or in furtherance of, or contemplated by this Agreement.

SECTION 5.13. Takeover Statutes. If any Takeover Statute is or may become applicable to the Merger or the other transactions contemplated by this Agreement, Parent, Merger Sub, the Company and the Company Board shall use reasonable best efforts to take such actions as are necessary so that such transactions may be consummated as promptly as practicable on the terms contemplated by this Agreement and otherwise act to eliminate or minimize the effects of such Takeover Statute on such transactions.

SECTION 5.14. Control of Operations. Without limiting any party's rights or obligations under this Agreement, the parties hereto understand and agree that (a) nothing contained in this Agreement will give any party hereto, directly or indirectly, the right to control, direct or influence any other party's operations prior to the Effective Time and (b) prior to the Effective Time, each party will exercise, consistent with the terms and conditions of this Agreement, complete control and supervision over its operations.

SECTION 5.15. Resignation of Directors. The Company will cause each of the directors of the Company to submit at the Closing a letter of resignation in form reasonably satisfactory to Parent and effective as of the Effective Time. Notwithstanding the foregoing, the Company will not be in breach of this Section 5.15 if it fails to obtain the resignation of any such director if Parent will have the power, directly or indirectly, to remove any such Person from his or her position as a director of the Company without cause immediately after the Effective Time with no liability in excess of $500,000 in the aggregate.

SECTION 5.16. Additional Matters. Parent hereby confirms that, subject to the occurrence of the Effective Time, it:

(a) intends to maintain South Carolina Electric & Gas Company's corporate headquarters in Cayce, South Carolina;

(b) will make a good faith commitment to give the employees of the Company and its Subsidiaries due and fair consideration for other employment and promotion opportunities within the larger Parent organization, both inside and outside of South Carolina, to the extent any employment positions are re-aligned, reduced or eliminated in the future as a result of the Merger;

(c) intends that Parent's board of directors will take all necessary action as soon as practical after the Effective Time to appoint a mutually agreeable current member of the Company Board or the Company's executive management as a director to serve on Parent's board of directors; and

(d) intends to increase the Company's historic level of corporate contributions to charities identified by the Company's leadership by $1,000,000.00 per year for at least five (5) years after the Effective Time and to maintain or increase historic levels of community involvement, low income funding and economic development efforts in the Company's current operating area.

SECTION 5.17. Shareholder Litigation. The Company shall advise Parent promptly in writing of any Proceeding brought by a holder of Company Shares or any other Person against the Company or its directors or officers arising out of or relating to this Agreement or the transactions contemplated by this Agreement (the "Shareholder Litigation") and shall keep Parent reasonably informed regarding any such matter. The Company shall not settle any such shareholder litigation without Parent's consent, not to be unreasonably withheld or delayed.

SECTION 5.18. Advice of Changes. Each of Parent and the Company will, to the extent not in violation of applicable Law, promptly advise the other of any Change of which it has Knowledge, (a) having or reasonably likely to have, individually or in the aggregate, a Parent Material Adverse Effect or a Company Material Adverse Effect, as the case may be, or (b) that would or would be reasonably likely to cause or constitute a material breach of any of its representations, warranties or covenants contained in this Agreement; provided, however, that (i) no such notification will operate as a waiver of or otherwise affect the representations, warranties or covenants of the parties or the conditions to the obligations of the parties under this Agreement, (ii) the delivery of any notice pursuant to this Section 5.18 shall not limit or otherwise affect the remedies available under this Agreement to the party receiving such notice and (iii) a failure to comply with this Section 5.18 shall not constitute the failure of any condition set forth in Article VI.

SECTION 5.19. Certain Tax Matters.

(a) Each of the parties shall use its reasonable best efforts to cause the Merger to qualify for the Intended Tax Treatment. None of the parties shall (and each of the parties shall cause their respective Subsidiaries not to) take any action (or fail to take any action) if taking (or failing to take) such action could reasonably be expected to cause the Merger to fail to qualify for the Intended Tax Treatment. The parties shall consider in good faith such amendments to this Agreement as may be reasonably required to cause the Merger to qualify for the Intended Tax Treatment.

(b) Each of the parties shall use its reasonable best efforts to obtain the Tax opinions to be attached as exhibits to the Proxy Statement/Prospectus and the Form S-4, including by (i) delivering to Morgan, Lewis & Bockius LLP and Mayer Brown LLP, prior to the filing of the Proxy Statement/Prospectus and the Form S-4, Tax representation letters in substantially the forms set forth in Section 5.19(b) of the Parent Disclosure Letter and Section 5.19(b) of the Company Disclosure Letter, respectively, and (ii) delivering to Morgan, Lewis & Bockius LLP and Mayer Brown LLP, dated and executed as of the Closing Date, Tax representation letters in substantially the forms set forth in Section 5.19(b) of the Parent Disclosure Letter and Section 5.19(b) of the Company Disclosure Letter, respectively. Each of the parties shall use its reasonable best efforts not to, and not permit any of its Affiliates to, take or cause to be taken any action that would cause to be untrue (or fail to take or cause not to be taken any action which inaction would cause to be untrue) any of the representations, warranties and covenants made to counsel in the Tax representation letters described in this Section 5.19(b).

(c) This Agreement is intended to constitute, and the parties hereto adopt this Agreement as, a "plan of reorganization" for purposes of Sections 354, 361 and 368 of the Code. The parties shall treat the Merger as a "reorganization" within the meaning of Section 368(a) of the Code for United States federal, state and other relevant Tax purposes.

ARTICLE VI

CONDITIONS

SECTION 6.01. Conditions to Each Party's Obligation to Effect the Merger. The respective obligation of each party hereto to effect the Merger is subject to the satisfaction or (to the extent permitted by Law) waiver at or prior to the Closing of each of the following conditions:

(a) Shareholder Approval. This Agreement shall have been duly approved by holders of Company Shares constituting the Company Requisite Vote;

(b) Orders. No Governmental Entity of competent jurisdiction shall have enacted, entered, promulgated or enforced any Law, executive order, ruling, judgment, injunction or other order (collectively, "Orders") that is in effect and restrains, enjoins, prevents or otherwise prohibits the consummation of the Merger or makes the consummation of the Merger illegal;

(c) Regulatory Conditions. Each of the conditions set forth in Section 6.01(c) of the Company Disclosure Letter with respect to the Consents described therein (the "Regulatory Conditions") shall have been satisfied;

(d) Approval of SCPSC Petition. The issuance by the SCPSC of an Order approving the SCPSC Petition (other than the request for the SCPSC to take the actions contemplated by Section 6.02(g), which actions are addressed in Section 6.02(g)), unless otherwise consented to by Parent in its sole discretion, without any (i) material changes to the proposed terms, conditions, or undertakings set forth in Section 3 of the key terms summarized in Appendix A attached to this Agreement and incorporated in the SCPSC Petition or (ii) a significant change to the economic value of proposed terms set forth in Section 3 of the key terms summarized in Appendix A attached to this Agreement and incorporated in the SCPSC Petition, in each case as reasonably determined by Parent in good faith (the "SCPSC Petition Approval") (it being understood and agreed that the condition set forth in this Section 6.01(d) shall be satisfied upon the issuance of such Order by the SCPSC without regard to any rehearing or appeals process (including the filing of any motion for reconsideration or petition for judicial review), or other judicial or administrative process, subsequent to the initial issuance of such Order);

(e) Listing. The Parent Shares to be issued in connection with the transactions contemplated by this Agreement shall have been approved for listing on the NYSE, subject to official notice of issuance; and

(f) Form S-4. The Form S-4 shall have been declared effective under the Securities Act and shall not be subject to any stop order or Proceeding seeking a stop order.

SECTION 6.02. Additional Conditions to Obligations of Parent and Merger Sub. The obligations of Parent and Merger Sub to effect the Merger are further subject to the satisfaction or (to the extent permitted by Law) waiver at or prior to the Closing of each of the following conditions:

(a) Representations and Warranties. (i) Each of the representations and warranties of the Company set forth in Section 3.01 (except for those contained in Section 3.01(c), Section 3.01(d)(i), Section 3.01(f)(i), Section 3.01(r) and Section 3.01(s)) shall be true and correct in all respects (disregarding all qualifications or limitations as to "materiality", "Company Material Adverse Effect" and words of similar import set forth therein) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date), except where the failure of such representations and warranties to be so true and correct has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (ii) each of the representations and warranties of the Company set forth in Section 3.01(c) shall be true and correct in all respects (except for de minimis inaccuracies) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date), (iii) each of the representations and warranties of the Company set forth in Section 3.01(d)(i) and Section 3.01(s) shall be true and correct in all material respects (disregarding all qualifications or limitations as to "materiality", "Company Material Adverse Effect" and words of similar import set forth therein) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date) and (iv) each of the representations and warranties of the Company set forth in Section 3.01(f)(i) and Section 3.01(r) shall be true and correct in all respects as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date);

(b) Performance of Obligations of the Company. The Company shall have performed in all material respects all obligations required to be performed by it under this Agreement on or prior to the Closing Date;

(c) Certificate. Parent shall have received a certificate of the Chief Executive Officer or the Chief Financial Officer of the Company, certifying that the conditions set forth in Section 6.02(a) and Section 6.02(b) have been satisfied;

(d) Absence of Burdensome Condition. No Regulatory Clearance, other approval of a Governmental Entity or other Consent, in each case in connection with the Merger, or Order related to any of the foregoing, shall impose or require any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions, or any structural or remedial actions (including a Remedial Action), that constitute a Burdensome Condition;

(e) No MAE. Since the date of this Agreement, there shall not have occurred any Change or Changes that have or would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect;

(f) No Actions Affecting SCPSC Petition. No Governmental Entity of competent jurisdiction shall have enacted any Order and no Change in Law (including no Change to the BLRA or the South Carolina Public Utility Laws) shall have been enacted, in each case which imposes any condition that would reasonably be expected to result in a (i) material change to the proposed terms, conditions, or undertakings set forth in the SCPSC Petition or (ii) a significant change to the economic value of the proposed terms set forth in the SCPSC Petition, in each case as reasonably determined by Parent in good faith;

(g) SCPSC Determination. The SCPSC shall have (i) approved the Merger with no material Changes to the terms of the Merger, (ii) made a finding that the Merger is in the public interest or (iii) made a finding that there is an absence of harm to South Carolina rate payers as a result of the Merger; and

(h) No Change in Law. Since the date of this Agreement, there shall not have occurred any (i) substantive Change in any applicable Law or any Order with respect to the BLRA, as in effect on the date of this Agreement, which has or would reasonably be expected to have an adverse effect on the Company or any of its Subsidiaries or (ii) substantive Change in any applicable Law or any Order with respect to any other South Carolina Public Utility Law, as in effect as of the date of this Agreement, which has or would reasonably be expected to have an adverse effect on the Company or any of its Subsidiaries (such Changes as set forth in (i) and (ii), the "SC Law Changes").

SECTION 6.03. Additional Conditions to Obligation of the Company. The obligation of the Company to effect the Merger is further subject to the satisfaction or (to the extent permitted by Law) waiver on or prior to the Closing of the following conditions:

(a) Representations and Warranties. (i) Each of the representations and warranties of Parent and Merger Sub set forth in Section 3.02 (except for those contained in Section 3.02(c), Section 3.02(d)(i), Section 3.02(f)(i), Section 3.02(k) and Section 3.02(l)) shall be true and correct in all respects (disregarding all qualifications or limitations as to "materiality", "Parent Material Adverse Effect" and words of similar import set forth therein) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date), except where the failure of such representations and warranties to be so true and correct has not had and would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect, (ii) each of the representations and warranties of Parent and Merger Sub set forth in Section 3.02(c) shall be true and correct in all respects (except for de minimis inaccuracies) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date), (iii) each of the representations and warranties of Parent and Merger Sub set forth in Section 3.02(d)(i) and Section 3.02(l) shall be true and correct in all material respects (disregarding all qualifications or limitations as to "materiality", "Parent Material Adverse Effect" and words of similar import set forth therein) as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date) and (iv) each of the representations and warranties of Parent and Merger Sub set forth in Section 3.02(f)(i) and Section 3.02(k) shall be true and correct in all respects as of the date of this Agreement and as of the Closing Date as though made on and as of such date (except for any such representation or warranty that is made as of a specified date (including the date of this Agreement), in which case such representation or warranty shall be true and correct only as of such specified date);

(b) Performance of Obligations of Parent and Merger Sub. Each of Parent and Merger Sub shall have performed in all material respects all obligations required to be performed by it under this Agreement at or prior to the Closing Date; and

(c) Certificate. The Company shall have received a certificate of the Chief Executive Officer or the Chief Financial Officer of Parent, certifying that the conditions set forth in Section 6.03(a) and Section 6.03(b) have been satisfied.

SECTION 6.04. Frustration of Closing Conditions. None of the Company, Parent or Merger Sub may rely on the failure of any condition set forth in Section 6.01, Section 6.02 or Section 6.03, as the case may be, to be satisfied if such failure was primarily caused by such party's breach of this Agreement.

ARTICLE VII

TERMINATION

SECTION 7.01. Termination. This Agreement may be terminated and the Merger may be abandoned at any time prior to the Effective Time, whether before or after (except as set forth below) the Company Requisite Vote is obtained:

(a) by mutual written consent of Parent and the Company;

(b) by either Parent or the Company:

(i) if the Merger shall not have been consummated on or before January 2, 2019 (the "Termination Date"); provided, however, that if any condition set forth in Section 6.01(b), Section 6.01(c) or Section 6.01(d) shall not have been satisfied at such time, the Termination Date shall automatically be extended to (and shall thereafter be deemed to be), without any action on the part of any party hereto, April 2, 2019; provided, further, that the right to terminate this Agreement pursuant to this Section 7.01(b)(i) shall not be available to any party if such party (or, in the case of Parent, Merger Sub) has breached its obligations under this Agreement in any manner that shall have been the principal cause of or resulted in the failure of a condition to any party's obligation to effect the Merger;

(ii) if at the Shareholders Meeting (or any adjournment or postponement thereof done in accordance with this Agreement), the Company Requisite Vote shall not have been obtained; or

(iii) if any Order permanently restraining, enjoining, preventing or otherwise prohibiting consummation of the Merger shall have become final and non-appealable; provided, however, that a party may not terminate this Agreement pursuant to this Section 7.01(b)(iii) if such party (or, in the case of Parent, Merger Sub) has breached its obligations under this Agreement in a manner that shall have been the principal cause of such Order;

(c) by the Company:

(i) if the Company Board has effected a Company Adverse Recommendation Change with respect to a Superior Proposal in accordance with Section 4.02(f) and shall have approved, and concurrently with the termination hereunder the Company shall have entered into, an Alternative Acquisition Agreement with respect to a Superior Proposal; provided, however, that such termination shall not be effective and the Company shall not enter into an Alternative Acquisition Agreement, unless (A) the Company shall have complied with the provisions of Section 4.02(f) and (B) the Company has paid the Company Termination Fee to Parent; provided, further, that the right to terminate this Agreement under this Section 7.01(c)(i) shall not be available after the Company Requisite Vote shall have been obtained; or

(ii) if Parent or Merger Sub shall have breached any of their respective representations or warranties or failed to perform any of their respective covenants or other agreements contained in this Agreement, where such breach or failure to perform (A) would give rise to the failure of a condition set forth in Section 6.03(a) or Section 6.03(b) and (B) cannot be cured by Parent or Merger Sub by the Termination Date, or if capable of being cured, is not cured prior to the earlier of (1) the thirtieth (30^{th}) day after written notice thereof is given by the Company to Parent and (2) the third (3^{rd}) Business Day immediately preceding the Termination Date; provided, however, that the Company shall not have the right to terminate this Agreement pursuant to this Section 7.01(c)(ii) if the Company is then in material breach of this Agreement;

(d) by Parent:

(i) if the Company Board (or a committee thereof) shall have effected a Company Adverse Recommendation Change; provided, however, that the right to terminate under this

Section 7.01(d)(i) shall not be available after the Company Requisite Vote shall have been obtained; or

(ii) if the Company shall have breached any of its representations or warranties or failed to perform any of its covenants or other agreements contained in this Agreement, where such breach or failure to perform (A) would give rise to the failure of a condition set forth in Section 6.02(a) or Section 6.02(b) and (B) cannot be cured by Company by the Termination Date, or if capable of being cured, is not cured prior to the earlier of (1) the thirtieth (30th) day after written notice thereof is given by Parent to the Company and (2) the third (3rd) Business Day immediately preceding the Termination Date; provided, however, that Parent shall not have the right to terminate this Agreement pursuant to this Section 7.01(d)(ii) if either Parent or Merger Sub is then in material breach of this Agreement.

SECTION 7.02. Effect of Termination and Abandonment.

(a) Except as provided in Section 7.02(b), in the event of termination of this Agreement and the abandonment of the Merger pursuant to this Article VII, this Agreement shall forthwith become void and of no effect and there shall be no liability or obligation on the part of any party hereto (or of any of its Representatives or Affiliates), except as provided in the last sentence of Section 5.02(c), Section 5.03(b), Section 5.07, Section 5.09(c), this Section 7.02 and Article VIII, which provisions shall survive such termination; provided, however, that subject to Section 7.02(b), Section 7.02(c), and Section 7.02(d), no such termination shall relieve any party hereto (treating Parent and Merger Sub as one party) of any liability for damages to any other party hereto resulting from any Willful Breach by the party (treating Parent and Merger Sub as one party) committing such Willful Breach prior to such termination, and the aggrieved party will be entitled to all rights and remedies available at law or in equity. The parties hereto acknowledge and agree that nothing in this Section 7.02 shall be deemed to affect their right to specific performance under Section 8.12.

(b) The Company shall pay or cause to be paid to Parent or its designee a non-refundable fee of $240,000,000 (the "Company Termination Fee") if:

(i) this Agreement is terminated by the Company pursuant to Section 7.01(c)(i);

(ii) (A) this Agreement is terminated (1) by Parent or the Company pursuant to Section 7.01(b)(i) or Section 7.01(b)(ii), or (2) by Parent pursuant to Section 7.01(d)(ii), (B) a bona fide Acquisition Proposal shall have been publicly announced or publicly disclosed and not have been withdrawn (1) in the case of a termination pursuant to Section 7.01(b)(i) or Section 7.01(d)(ii), prior to the date of such termination, and (2) in the case of a termination pursuant to Section 7.01(b)(ii), prior to the Shareholders Meeting, and (C) thereafter during the twelve (12) month period immediately following such termination, (1) the Company enters into an Alternative Acquisition Agreement or (2) an Acquisition Proposal is consummated; or

(iii) this Agreement is terminated by Parent pursuant to Section 7.01(d)(i);

If the Company Termination Fee becomes due pursuant to this Section 7.02(b), the Company shall pay Parent or its designee such Company Termination Fee by wire transfer of immediately available funds (x) in the case of a payment required by Section 7.02(b)(i), on the date of termination of this Agreement, (y) in the case of a payment required by Section 7.02(b)(ii), within two (2) Business Days after the earlier of the time when an Acquisition Proposal is consummated or an Alternative Acquisition Agreement is executed and (z) in the case of a payment required by Section 7.02(b)(iii), within two (2) Business Days of the date of termination of this Agreement, it being understood that in no event shall the Company be required to pay the Company Termination Fee on more than one occasion. Parent shall provide to the Company notice designating an account for purposes of payment of the Company Termination Fee within forty-eight (48) hours of a request by the Company to provide such information. For purposes of Section 7.02(b)(ii), the term "Acquisition Proposal" shall have the meaning assigned to such term in Exhibit A, except that all references to 15% therein shall be deemed to be references to 50%.

(c) Parent shall pay or cause to be paid to the Company or its designee a non-refundable fee of $280,000,000 (the "Parent Termination Fee") if:

(i) this Agreement is terminated by Parent or the Company pursuant to Section 7.01(b)(i) and, at the time of any such termination (A) the condition set forth in Section 6.02(d) shall not have been satisfied or waived with respect to one or more Regulatory Conditions and (B) the conditions set forth in Section 6.01(a), Section 6.01(b) – (d) (unless such condition was not satisfied solely due to the proposal of a Burdensome Condition to which Parent has not agreed), Section 6.01(f), Section 6.02(a), Section 6.02(b) and Section 6.02(e) shall have been satisfied or waived (except for any such conditions that have not been satisfied as a result of a breach by Parent or Merger Sub of any of their respective obligations under this Agreement);

(ii) this Agreement is terminated by Parent or the Company pursuant to Section 7.01(b)(iii) and, at the time of any such termination (A) the condition set forth in Section 6.02(d) shall not have been satisfied or waived with respect to one or more Regulatory Conditions and (B) the conditions set forth in Section 6.01(a), Section 6.01(b) – (d) (unless such condition was not satisfied solely due to the proposal of a Burdensome Condition to which Parent has not agreed), Section 6.01(f), Section 6.02(a), Section 6.02(b) and Section 6.02(e) shall have been satisfied or waived (except for any such conditions that have not been satisfied as a result of a breach by Parent or Merger Sub of any of their respective obligations under this Agreement); or

(iii) this Agreement is terminated by the Company pursuant to Section 7.01(c)(ii) due to a material breach by Parent or Merger Sub of its obligations under Section 5.02 which breach has caused the failure of a condition set forth in Section 6.01(b), Section 6.01(c), Section 6.01(d) , Section 6.02(d), Section 6.02(f), Section 6.02(g) or Section 6.02(h) to be satisfied.

If the Parent Termination Fee becomes due pursuant to this Section 7.02(c), Parent shall pay the Company or its designee the Parent Termination Fee by wire transfer of immediately available funds within two (2) Business Days of the date of termination of this Agreement, it being understood that in no event shall Parent be required to pay the Parent Termination Fee on more than one occasion. The Company shall provide to Parent notice designating an account for purposes of payment of the Parent Termination Fee within forty-eight (48) hours of a request by Parent to provide such information.

(d) Notwithstanding anything to the contrary in this Agreement, if this Agreement is terminated under circumstances in which the Company is required to pay the Company Termination Fee pursuant to Section 7.02(b) and the Company Termination Fee is paid, the payment of the Company Termination Fee shall be Parent's and Merger Sub's sole and exclusive remedy against the Company and its Affiliates, and their respective shareholders and Representatives, relating to or arising out of this Agreement, any agreement entered into in connection herewith or the transactions contemplated by this Agreement or thereby. Notwithstanding anything to the contrary in this Agreement, if this Agreement is terminated under circumstances in which Parent is required to pay the Parent Termination Fee pursuant to Section 7.02(c) and the Parent Termination Fee is paid, the payment of the Parent Termination Fee shall be the Company's sole and exclusive remedy against Parent, Merger Sub and their respective Affiliates, and their respective shareholders and Representatives, relating to or arising out of this Agreement, any agreement entered into in connection herewith or the transactions contemplated by this Agreement or thereby.

(e) Each party acknowledges that the agreements contained in Section 7.02(b) and Section 7.02(c) are an integral part of the transactions contemplated by this Agreement and that, without these agreements, such party would not enter into this Agreement. Accordingly, if the applicable party fails promptly to pay any amount due pursuant to Section 7.02(b) or Section 7.02(c), such party shall also pay any reasonable out-of-pocket costs, fees and expenses incurred by the other party (including reasonable legal fees and expenses) in connection with a Proceeding to enforce this Agreement that results in a final non-appealable Order for such amount against the party failing to promptly pay such amount. Any amount not paid when due pursuant to Section 7.02(b) or Section 7.02(c) shall bear interest from the date such amount is due until the date paid at a rate equal to the prime rate as published in *The Wall Street Journal*, *Eastern Edition*, in effect on the date of such payment.

ARTICLE VIII

MISCELLANEOUS

SECTION 8.01. Non-Survival. None of the representations, warranties, covenants and agreements in this Agreement or in any instrument delivered pursuant to this Agreement, including any rights arising out of any breach of such representations, warranties, covenants and agreements, shall survive the Effective Time, except for (a) those covenants and agreements contained herein that by their terms apply or are to be performed in whole or in part after the Effective Time and (b) those contained in this Article VIII.

SECTION 8.02. Modification or Amendment. Subject to the requirements of applicable Law, at any time prior to the Effective Time, the parties hereto (in the case of the Company or Merger Sub, by action of their respective boards of directors to the extent required by Law) may modify or amend this Agreement by written agreement, executed and delivered by duly authorized officers of the respective parties. No modification or amendment will be made which, pursuant to applicable Law or the rules of the NYSE, requires further approval by the holders of Company Shares or the holders of the Parent Shares, as applicable, without such further approval being obtained.

SECTION 8.03. Waiver. Subject to the requirements of applicable Law, at any time prior to the Effective Time, any party hereto may (a) extend the time for the performance of any of the obligations or other acts of the other parties, (b) waive any inaccuracies in the representations and warranties of the other parties contained herein or in any document delivered pursuant hereto, or (c) waive compliance by the other parties with any of the agreements or conditions contained herein; provided, however, that neither Parent nor Merger Sub may perform any of the actions set forth in the foregoing clauses (a), (b) or (c) with respect to Merger Sub or Parent, respectively. No extension or waiver will be made which, pursuant to applicable Law or the rules of the NYSE, requires further approval by the holders of Company Shares or the holders of the Parent Shares, as applicable, without such further approval being obtained. Any such extension or waiver shall be valid only if set forth in an instrument in writing signed by the party or parties to be bound thereby and specifically referencing this Agreement. The failure of any party hereto to assert any rights or remedies shall not constitute a waiver of such rights or remedies.

SECTION 8.04. No Other Representations or Warranties.

(a) Except for the representations and warranties set forth in Section 3.01, each of Parent and Merger Sub acknowledges and agrees that (i) none of the Company, its Subsidiaries or any other Person makes any other express or implied representation or warranty in connection with the transactions contemplated by this Agreement, (ii) it has relied solely on the representations and warranties of the Company expressly set forth in Section 3.01 and (iii) it has not been induced to enter into this Agreement by any representation, warranty or statement of or by the Company, any of its Subsidiaries or any other Person.

(b) Except for the representations and warranties set forth in Section 3.02, the Company acknowledges and agrees that (i) none of Parent, Merger Sub, any of Parent's other Subsidiaries or any other Person makes any other express or implied representation or warranty in connection with the transactions contemplated by this Agreement, (ii) it has relied solely on the representations and warranties of Parent and Merger Sub expressly set forth Section 3.02 and (iii) it has not been induced to enter into this Agreement by any representation, warranty or statement of or by Parent, Merger Sub, any of the other Subsidiaries of Parent or any other Person.

SECTION 8.05. Notices. All notices, requests, claims, demands and other communications hereunder shall be in writing and shall be deemed given if delivered personally, faxed (with confirmation), electronically mailed in portable document format (PDF) (with confirmation) or sent by overnight courier (providing proof of delivery) to the parties at the following addresses (or at such other address for a party as shall be specified by like notice):

if to Parent or Merger Sub, to:

Dominion Energy, Inc.
120 Tredegar Street
Richmond, Virginia 23219
Fax No.: (804) 819-2233
Attention: Mark O. Webb, Senior Vice President – Corporate Affairs and Chief Legal Officer
Carlos M. Brown, Vice President and General Counsel
Email: mark.webb@dominionenergy.com
carlos.m.brown@dominionenergy.com

with a copy to (which shall not constitute notice):

McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219
Fax No.: (804) 698-2090
Attention: Joanne Katsantonis
John L. Hughes, Jr.
Email: jkatsantonis@mcguirewoods.com
jhughes@mcguirewoods.com

if to the Company, to:

SCANA Corporation
220 Operation Way, Mail Code D-308
Cayce, South Carolina 29033

Fax No.: (803) 933-7676
Attention: Jim Stuckey, Senior Vice President and General Counsel
Email: jim.stuckey@scana.com

with a copy to (which shall not constitute notice):

Mayer Brown LLP
71 South Wacker Drive
Chicago, Illinois 60606
Fax No.: (312) 706-8183
Attention: Frederick B. Thomas
William R. Kucera
Email: fthomas@mayerbrown.com
wkucera@mayerbrown.com

SECTION 8.06. Definitions. Capitalized terms used in this Agreement have the meanings specified in Exhibit A.

SECTION 8.07. Interpretation.

(a) When a reference is made in this Agreement to an Article, a Section, an Appendix or an Exhibit, such reference shall be to an Article or a Section of, or an Appendix or an Exhibit to, this Agreement unless otherwise indicated. The table of contents and headings contained in this Agreement are for reference purposes only and shall not affect in any way the meaning or interpretation of this Agreement.

(b) Whenever the words "include", "includes" or "including" are used in this Agreement, they shall be deemed to be followed by the words "without limitation". The words "hereof", "herein" and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this Agreement. The word "or" when used in this Agreement is not exclusive.

(c) When a reference is made in this Agreement, the Company Disclosure Letter or the Parent Disclosure Letter to information or documents being "provided", "made available" or "disclosed" by a party hereto to another party or its Affiliates, such information or documents shall include any information or documents (i) included in the SEC Reports of such disclosing party which are publicly available at least twenty-four (24) hours prior to the date of this Agreement, (ii) furnished prior to the execution of this Agreement in the electronic "data room" maintained by such disclosing party and to which access has been granted to the other party and its Representatives at least twenty-four (24) hours prior to the date of this Agreement, or (iii) otherwise provided in writing (including electronically) to the other party or any of its Affiliates or Representatives at least twenty-four (24) hours prior to the date of this Agreement.

(d) The definitions contained in this Agreement are applicable to the singular as well as the plural forms of such terms and to the masculine as well as to the feminine and neuter genders of such term.

(e) Any agreement, instrument or statute defined or referred to herein means such agreement, instrument or statute as from time to time amended, modified or supplemented, including (in the case of agreements or instruments) by waiver or consent and (in the case of statutes) by succession of comparable successor statutes, and all attachments thereto and instruments incorporated therein.

(f) References to a Person are also to its permitted successors and permitted assigns.

(g) Where this Agreement states that a party "shall", "will" or "must" perform in some manner, it means that the party is legally obligated to do so under this Agreement.

(h) When calculating the period of time before which, within which or following which any act is to be done or step taken pursuant to this Agreement, (i) the date that is the reference date in calculating such period shall be excluded and (ii) if the last day of such period is not a Business Day, the period in question shall end on the next succeeding Business Day.

(i) Unless otherwise specifically indicated, any reference herein to $ means U.S. dollars.

(j) The parties hereto have participated jointly in the negotiation and drafting of this Agreement. If an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as jointly drafted by the parties hereto, and no presumption or burden of proof shall arise favoring or disfavoring any party by virtue of the authorship of any provision of this Agreement.

SECTION 8.08. Counterparts. This Agreement may be executed in one or more counterparts (including by facsimile or by attachment to electronic mail in portable document format (PDF)), and by the different parties hereto in separate counterparts, each of which when executed shall be deemed an original but all of which taken together shall be considered one and the same agreement and shall become effective when one or more counterparts have been signed by each of the parties hereto and delivered to the other parties hereto.

SECTION 8.09. Parties in Interest. This Agreement shall be binding upon and inure solely to the benefit of the parties hereto, and nothing in this Agreement, express or implied, is intended to or shall confer upon any other Person any rights, benefits or remedies of any nature whatsoever under or by reason of this Agreement, other than (a) after the Effective Time, with respect to the provisions of Section 5.08 which shall inure to the benefit of the Indemnified Parties who are intended to be third-party beneficiaries thereof, (b) after the Effective Time, the rights of the holders of Company Shares to receive the Merger Consideration in accordance with the terms and conditions of this Agreement, and (c) after the Effective Time, the rights of the holders of Company Performance Share Awards, Company RSUs and Company Deferred Units to receive the payments contemplated by the applicable provisions of Section 2.02, in each case, in accordance with the terms and conditions of this Agreement. The representations and warranties in this Agreement are the product of negotiations among the parties hereto and are for the sole benefit of such parties. Any inaccuracies in such representations and warranties are subject to waiver by the parties hereto in accordance with Section 8.03 without notice or liability to any other Person. In some instances, the representations and warranties in this Agreement may represent an allocation among the parties hereto of risks associated with particular matters regardless of the knowledge of any of the parties hereto. Consequently, Persons other than the parties hereto may not rely upon the representations and warranties in this Agreement as characterizations of actual facts or circumstances as of the date of this Agreement or as of any other date.

SECTION 8.10. Governing Law. This Agreement shall be governed by, and construed in accordance with, the internal Laws and judicial decisions of the State of Delaware applicable to agreements executed and performed entirely within such State, regardless of the Law that might otherwise govern under applicable principles of conflicts of law thereof, except that matters related to the obligations of the Company Board under the SCBCA and matters that are specifically required by the SCBCA in connection with the transactions contemplated by this Agreement shall be governed by the laws of the State of South Carolina.

SECTION 8.11. Entire Agreement; Assignment. This Agreement (including the Appendices and Exhibits hereto, the Company Disclosure Letter and the Parent Disclosure Letter) and the Confidentiality Agreement constitute the entire agreement among the parties hereto with respect to the subject matter hereof and supersede all prior and contemporaneous agreements and undertakings, both written and oral, among the parties, or any of them, with respect to the subject matter hereof. Neither this Agreement nor any of the rights, interests or obligations hereunder may be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of the other parties hereto. Any purported assignment in contravention of this Agreement is and shall be null and void. Subject to the immediately preceding two sentences, this Agreement will be binding upon, inure to the benefit of and be enforceable by the parties hereto and their respective successors and permitted assigns.

SECTION 8.12. Specific Enforcement; Consent to Jurisdiction.

(a) The parties hereto agree that irreparable damage for which monetary damages, even if available, would not be an adequate remedy, would occur in the event that any of the parties hereto do not perform the provisions of this Agreement (including failing to take such actions as are required of it hereunder in order to consummate the transactions contemplated by this Agreement) in accordance with its specified terms or otherwise breach such provisions. The parties hereto acknowledge and agree that each party hereto shall be entitled to seek an injunction, specific performance and other equitable relief to prevent breaches of this Agreement and to seek to enforce specifically the terms and provisions hereof, this being in addition to any other remedy to which it is entitled at law or in equity. Each of the parties hereto further agrees that it will not oppose the granting of an injunction, specific performance and other equitable relief as provided herein on the basis that (A) the other party has an adequate remedy at law or (B) an award of specific performance is not an appropriate remedy for any reason at law or equity. Any party hereto seeking an Order to prevent breaches of this Agreement and to enforce specifically the terms and provisions of this Agreement shall not be required to provide any bond or other security in connection with any such Order.

(b) Each of the parties hereto irrevocably (i) submits itself to the personal jurisdiction of the federal courts located in the State of Delaware and any appellate court therefrom, in connection with any claim or matter directly or indirectly based upon, arising out of or relating to this Agreement or any of the transactions contemplated by this Agreement or the actions of Parent, Merger Sub or the Company in the negotiation, administration, performance and enforcement of this Agreement, (ii) agrees that it will not attempt to deny or defeat such personal jurisdiction by motion or other request for leave from any such court, (iii) agrees that it will not bring any action relating to this Agreement or any of the transactions contemplated by this Agreement in any court other than the federal courts located in the State of Delaware and (iv) agrees that the service of any process, summons, notice or document through the notice procedures set forth in Section 8.05 or by U.S. registered mail to the respective addresses set forth in Section 8.05 shall be effective service of process for any Proceeding in connection with this Agreement or the transactions contemplated by this Agreement. Each party hereto hereby irrevocably waives, and agrees not to assert, by way of motion, as a defense, counterclaim or otherwise, in any Proceeding with respect to this Agreement, any claim that (A) it is not personally subject to the jurisdiction of the above-named courts for any reason other than the failure to serve process in accordance with this Section 8.12(b), (B) it or its property is exempt or immune from jurisdiction of any such court or from any legal process commenced in such courts (whether through service of notice, attachment prior to judgment, attachment in aid of execution of judgment, execution of judgment or otherwise), (C) the Proceeding in any such court is brought in an inconvenient forum, (D) the venue of such Proceeding is improper, or (E) this Agreement, or the subject matter hereof, may not be enforced in or by such courts. Furthermore, each of the Company, Parent and Merger Sub irrevocably waives, to the fullest extent permitted by applicable Law, the benefit of any defense that would hinder, fetter or delay the levy, execution or collection of any amount to which any party is entitled pursuant to the final judgment of any court having jurisdiction. Each party hereto expressly acknowledges that the foregoing waiver is intended to be irrevocable under the Law of the State of Delaware and of the United States of America; provided, however, that each such party's consent to jurisdiction and service contained in this Section 8.12 is solely for the purpose referred to in this Section 8.12 and shall not be deemed to be a general submission to said courts or to courts in the State of Delaware other than for such purpose.

SECTION 8.13. WAIVER OF JURY TRIAL. EACH PARTY HERETO ACKNOWLEDGES AND AGREES THAT ANY CONTROVERSY WHICH MAY ARISE UNDER THIS AGREEMENT IS LIKELY TO INVOLVE COMPLICATED AND DIFFICULT ISSUES, AND THEREFORE IT HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVES TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW ANY AND ALL RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY PROCEEDING (WHETHER BASED ON CONTRACT, TORT OR OTHERWISE) DIRECTLY OR INDIRECTLY BASED UPON, ARISING OUT OF OR RELATING TO THIS AGREEMENT OR ANY OF THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT OR THE ACTIONS OF PARENT, MERGER SUB OR THE COMPANY IN THE NEGOTIATION, ADMINISTRATION, PERFORMANCE AND ENFORCEMENT OF THIS AGREEMENT. EACH PARTY CERTIFIES AND ACKNOWLEDGES THAT (A) NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER, (B) IT UNDERSTANDS AND HAS CONSIDERED THE IMPLICATIONS OF SUCH WAIVER, (C) IT MAKES SUCH WAIVER VOLUNTARILY AND (D) IT HAS BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVER AND CERTIFICATIONS IN THIS SECTION 8.13.

SECTION 8.14. Severability. If any term or other provision of this Agreement is found by a court of competent jurisdiction to be invalid, illegal or incapable of being enforced by any rule of Law or public policy, all other terms and provisions of this Agreement shall nevertheless remain in full force and effect. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the parties hereto shall negotiate in good faith to modify this Agreement so as to effect the original intent of the parties hereto as closely as possible in an acceptable manner to the end that the transactions contemplated by this Agreement are fulfilled to the fullest extent possible.

SECTION 8.15. Transfer Taxes. All transfer, documentary, sales, use, stamp, registration and other Taxes and fees (including penalties and interest) incurred in connection with the Merger shall be paid by Parent and Merger Sub when due.

SECTION 8.16. Disclosure Letters. Certain items and matters are listed in the Company Disclosure Letter and the Parent Disclosure Letter for informational purposes only and may not be required to be listed therein by the terms of this Agreement. In no event shall the listing of items or matters in the Company Disclosure Letter or the Parent Disclosure Letter be deemed or interpreted to broaden, or otherwise expand the scope of, the representations and warranties or covenants and agreements contained in this Agreement. No reference to, or disclosure of, any item or matter in any Section of this Agreement or any section or subsection of the Company Disclosure Letter or the Parent Disclosure Letter shall be construed as an admission or indication that such item or matter is material or that such item or matter is required to be referred to or disclosed in this Agreement or in the Company

Disclosure Letter or the Parent Disclosure Letter, as applicable. Without limiting the foregoing, no reference to, or disclosure of, a possible breach or violation of any Contract or Law in the Company Disclosure Letter or the Parent Disclosure Letter shall be construed as an admission or indication that a breach or violation exists or has actually occurred. Each section or subsection of the Company Disclosure Letter and the Parent Disclosure Letter, as the case may be, shall be deemed to qualify the corresponding section or subsection of this Agreement, irrespective of whether or not any particular section or subsection of this Agreement specifically refers to the Company Disclosure Letter or the Parent Disclosure Letter, as the case may be.

[*Signature Pages Follow*]

IN WITNESS WHEREOF, the Company, Parent and Merger Sub have caused this Agreement to be signed by their respective officers thereunto duly authorized, all as of the date first written above.

SCANA CORPORATION

By: ______________________________
Name: Jimmy E. Addison
Title: Chief Executive Officer

DOMINION ENERGY, INC.

By: ______________________________
Name: Thomas F. Farrell, II
Title: President and Chief Executive Officer

SEDONA CORP.

By: ______________________________
Name: Mark F. McGettrick
Title: President

APPENDIX A

SCPSC PETITION

1. To meet commitments made by South Carolina Electric & Gas Company to the SCPSC, South Carolina Electric & Gas Company and Parent will jointly file the Petition on or before January 12, 2018.

2. The Petition will seek a ruling from the SCPSC (i) approving the Merger with no material changes to the terms of the Merger; (ii) making a finding that the Merger is in the public interest; or (iii) making a finding that there is an absence of harm to South Carolina rate payers as a result of the Merger.

3. The Petition will acknowledge that the Merger can only close if the SCPSC approves the jointly proposed NND Project cost recovery plan, with (x) no material change to the terms, conditions or undertakings set forth in the plan and (y) no significant change to the economic value of the plan, in each case as reasonably determined by Parent in good faith (except in each case unless otherwise consented to by Parent in its sole discretion), which shall include the following terms:

    a. There will be an aggregate up-front, one-time rate credit totaling $1.3 billion[1] to all current South Carolina Electric & Gas Company electric customers as of the date of Merger close. The rate credit will be apportioned to all retail electric customer classes based on their 2016 contribution to summer adjusted peak demand as prepared by South Carolina Electric & Gas Company. After the dollar apportionment per customer class and rate schedule is determined on this basis, a rate per kilowatt hour ($/kWh) will be derived by customer class and rate schedule by dividing the total kWh sales of electricity by customer class and rate schedule over a preceding 12-month period (the "Base Period") into the apportioned funding amount. The $/kWh rate will then be applied to each customer's kWh usage over the Base Period to determine the customer's up-front rate credit amount. The rate credit will be issued to eligible customers in the form of a check issued within 90 days of Merger close. Eligible customers shall be South Carolina Electric & Gas Company retail electric customers as of record on the date of the close of the Merger.

    b. South Carolina Electric & Gas Company will immediately upon Merger closing write down its investment in construction work in progress associated with the new nuclear development project by approximately $1.4 billion, which amount includes approximately $1.2 billion in assets that have not previously been subject to consideration in setting revised rates and approximately $200 million that have been so considered. The amounts written down would be permanently excluded from consideration in establishing retail electric rates going forward.

    c. South Carolina Electric & Gas Company will not seek recovery of the approximately $320 million in regulatory assets associated with the following items:

        i. The approximately $173 million regulatory asset associated with interest rate swap losses related to the debt that was not issued for the NND Project;

[1] The net proceeds of the Toshiba settlement were utilized by South Carolina Gas & Electric Company to repay indebtedness in 2017, and therefore those funds are unavailable for refund. A portion of the one time rate credit will be funded through issuance of debt and defeasement of the regulatory liability associated with the Toshiba settlement.

ii. The approximately $66 million regulatory asset associated with the NND Project Equity AFUDC;

iii. The approximately $52 million regulatory asset associated with the carrying costs on deferred tax assets related to nuclear construction; and

iv. The regulatory asset associated with foregone domestic production activities deductions will be written off and not be recovered from customers. The net regulatory asset associated with research and experimentation credit claims, interest, and legal costs expected to be incurred in defending these claims, will be borne by the shareholders and not returned to or collected from customers.

d. Parent will underwrite an approximately $575 million refund for amounts previously collected under the NND Project (regulatory liability) which is estimated to provide the 3.5% retail electric rate decrease from the 2017 rate level until accumulated amortization of the cost of abandoned plant lowers South Carolina Electric & Gas Company's revenue requirements. The refund amount is calculated to be sufficient to support the 3.5% retail electric rate reduction for approximately eight (8) years following the closing of the Merger. This amount of time is estimated to be sufficient to avoid a future retail electric rate increase resulting from new nuclear project costs when the refund amount is exhausted.

e. Parent will reduce retail electric rates further to reflect the impact of federal tax reform passed in December of 2017 which is estimated to lower rates an additional amount resulting in a total estimated rate reduction of approximately 5%.

f. An SCPSC finding, as necessary, that South Carolina Electric & Gas Company's investment in construction work in progress for new nuclear project in the amount of approximately $3.3 billion, which reflects the amount of that investment net of write-downs and offsets, was prudent; and that the capital costs and amortization of that $3.3 billion may be recovered through retail electric rates.

g. An SCPSC order directing that:

i. The approximately $3.3 billion of invested capital for the new nuclear development project shall be included in a regulatory asset and recovered through rates over a 20-year amortization and recovery period that is reflected in retail electric revenue requirements without offset or disallowance until the regulatory asset is fully recovered; and

ii. Until the balance in the regulatory asset is fully recovered, the capital costs associated with the unrecovered balance in that account shall be reflected in South Carolina Electric & Gas Company's cost of capital devoted to retail electric operations at a rate that reflects a return on common equity of 10.25%,[2] a weighted average cost of debt of 5.85%, and a capital structure consisting of 52.81% equity and 47.19% debt, with these percentages fixed over the 20-year amortization period.

---

[2] The current allowed blended ROE for NND is approximately 10.9% but the proposal is to adjust the rate down to South Carolina Gas & Electric Company's base ROE of 10.25%.

h. The deferred tax liability associated with the tax abandonment of the NND Project shall reduce the NND Project cost to be recovered from South Carolina Electric & Gas Company customers. The deferred tax asset for the net operating loss carryforward resulting from the tax abandonment of the NND Project shall be reflected as a rate base offset, dollar for dollar, to the deferred tax liability. Reductions in the deferred tax asset shall be subject to Parent's ability to use the net operating loss in filing its consolidated income tax returns and shall not be computed on a separate company basis.

i. Adjustments to the deferred tax liability and the deferred tax asset described in item (h) of this subsection resulting from a change in tax laws or tax treatment of the abandonment and/or Parent's ability to use the net operating loss will be returned to or recovered from South Carolina Electric & Gas Company customers in the following manner:

   i. The regulatory liability resulting from excess deferred tax liabilities on the tax abandonment will be returned to customers over the book recovery period of the property (*i.e.*, 20 years);

   ii. The regulatory asset resulting from excess deferred tax assets on the net operating loss will be recovered from customers in a manner that coincides with Parent's ability to use the net operating loss in filing its consolidated income tax returns and not on a separate company basis; and

   iii. As adjusted for any impacts related to the tax treatment of the abandonment loss

j. The approximately $180 million initial capital investment in the Columbia Energy Center, a 540-megawatt combined-cycle, natural gas-fired power plant located in Gaston, S.C., will be excluded from rate base and rate recovery, with only the ongoing costs such as fuel costs, operations and maintenance expense, and maintenance or improvement capital investments associated with the plant to be recovered in future base and fuel rates.

k. Transmission projects associated with the new nuclear project will be closed to rate base and removed from BLRA project costs. The revenue of approximately $32 million per year currently being recovered in base rates will continue to be recovered through base rates notwithstanding the Merger. The associated depreciation and operating and maintenance costs will be captured in a regulatory asset for future rate recovery.

l. Except for rate adjustments for fuel and environmental costs, demand side management costs and other rates routinely adjusted on an annual or biannual basis, retail electric base rates will remain frozen at current levels until January 1, 2021.

4. The parties shall request approval of the SCPSC Petition, including the NND Project cost recovery plan, within 6 months from the date of filing.

5. South Carolina Electric & Gas Company and Parent commit to support and advocate for SCPSC approval or adoption of the terms, both individually and collectively, and without modification, identified and described in Paragraphs (2) and (3) above (the "Merger Terms") and will take no action inconsistent with this commitment. In the Petition to be jointly filed on January 12, 2018, South Carolina Electric & Gas Company may also present alternative terms for NND Project cost recovery, consistent with and based on the terms publically disclosed by Mr. Kissam on November

16, 2017 and previously provided to Parent in a more comprehensive form in a proposed draft of the Petition (the "Alternative Terms"). South Carolina Electric & Gas Company may provide any necessary testimony, exhibits or supporting materials in order to meet prior commitments to the SCPSC concerning the substance of South Carolina Electric & Gas Company's January 12, 2018 filing or to show that the Alternative Terms, as a disfavored alternative to the Merger Terms, are nonetheless just, reasonable, lawful, fair and non-confiscatory and should be adopted by the SCPSC if the Merger is not approved. However, South Carolina Electric & Gas Company will not support or advocate for the Alternative Terms except as an expressly disfavored alternative to the Merger Terms and in each case where it discusses the Alternative Terms in testimony, exhibits or otherwise, will expressly state South Carolina Electric & Gas Company's overriding commitment to the Merger Terms as being in the best interest of customers and the State of South Carolina, and that the Alternative Terms are a disfavored alternative to be considered only if the Merger is disapproved. South Carolina Electric & Gas Company will not otherwise advocate for any other terms for NND cost recovery differing from those identified in Paragraphs (2) and (3) above (without prior consent of Parent), unless and until the Merger Agreement is terminated.

EXHIBIT A

DEFINITIONS

(a) The following terms have the following meanings:

"Acceptable Confidentiality Agreement" means a confidentiality agreement having provisions as to confidential treatment of the Company's information that are not materially less favorable to those contained in the Confidentiality Agreement.

"Acquisition Proposal" means any bona fide proposal or offer from any Person or group of Persons (other than Parent, Merger Sub or their respective Affiliates) relating to (i) any acquisition or purchase directly or indirectly, in a single transaction or series of transactions, of a business that constitutes more than 15% of the net revenues, net income or consolidated assets of the Company and its Subsidiaries, taken as a whole, or more than 15% of the total voting power of the equity securities of the Company, (ii) any tender offer or exchange offer that if consummated would result in any Person beneficially owning more than 15% of the total voting power of the equity securities of the Company or (iii) any merger, reorganization, consolidation, share exchange, business combination, recapitalization, liquidation, joint venture, partnership, dissolution or similar transaction involving directly or indirectly, in a single transaction or series of transactions, the Company (or any Subsidiary or Subsidiaries of the Company whose business constitutes more than 15% of the net revenues, net income or consolidated assets of the Company and its Subsidiaries, taken as a whole).

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such first Person.

"Atomic Energy Act" means the Atomic Energy Act of 1954, as amended.

"Average Price" means the volume-weighted average price, rounded to four decimal places, of Parent Shares for the ten (10) consecutive trading days ending on and including the second (2^{nd}) trading day prior to the Effective Time.

"BLRA" means the South Carolina Base Load Review Act of 2007 as amended, S.C. Code Ann. § 58-33-210 *et seq*.

"Burdensome Condition" shall mean any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions (including any Remedial Action) that, in the aggregate, would have or would reasonably be expected to have, a material adverse effect on the business, financial condition, assets, liabilities or results of operations of the Company and its Subsidiaries, taken as a whole, or of Parent and its Subsidiaries, taken as a whole; provided, however, that, for this purpose, Parent and its Subsidiaries, and after giving effect to the Merger, Parent and its Subsidiaries, shall be deemed to be a consolidated group of entities of the size and scale of a hypothetical company that is 100% of the size and scale of the Company and its Subsidiaries, taken as a whole as of immediately prior to the Effective Time; and provided, further, that any undertakings, terms, conditions, liabilities, obligations, commitments or sanctions relating to implementing, or otherwise arising or resulting from or imposed by, the Social Commitments, or any relief or other matters contemplated by the SCPSC Petition or the SCPSC Petition Approval, shall not constitute or be taken into account in determining whether there has been or is such a material adverse effect.

"Business Day" means any day other than a Saturday or Sunday or a day on which banks in the City of New York are required or authorized to be closed.

"Byproduct Material" means any radioactive material (except Special Nuclear Material) yielded in, or made radioactive by, exposure to radiation in the process of producing or utilizing Special Nuclear Material.

"Code" means the Internal Revenue Code of 1986, as amended.

"Commonly Controlled Entity" means, with respect to the Company, any other Person that, together with the Company, is treated as a single employer under Section 414 of the Code.

"Company Benefit Plan" means any (i) "employee benefit plan" (within the meaning of Section 3(3) of ERISA), (ii) bonus, incentive or deferred compensation or equity or equity-based compensation plan, program, policy or arrangement (including the Company Equity Award Plans), (iii) severance, change in control, employment, consulting, retirement, retention or termination plan, program, agreement, policy or arrangement or (iv) other compensation or benefit plan, program, agreement, policy, practice, Contract, arrangement or other obligation, whether or not in writing and whether or not subject to ERISA, in each case, sponsored, maintained, contributed to or required to be maintained or contributed to by the Company or any Commonly Controlled Entity or with respect to which the Company or any Commonly Controlled Entity had or has any present or future liability, in any case other than any (A) "multiemployer plan" (within the meaning of Section 3(37) of ERISA) or (B) plan, program, policy or arrangement mandated by applicable Law.

"Company Disclosure Letter" means the confidential disclosure letter dated as of the date of this Agreement delivered by the Company to Parent and Merger Sub.

"Company Equity Award Plans" means the 2015 Long-Term Equity Compensation Plan, the 2000 Long-Term Equity Compensation Plan, and the Director Compensation and Deferral Plan, each as amended and restated from time to time.

"Company Material Adverse Effect" means any Change that has a material adverse effect on the business, financial condition, assets, liabilities or results of operations of the Company and its Subsidiaries, taken as a whole; provided, however, that none of the following shall, either alone or in combination, constitute or contribute to a Company Material Adverse Effect: (i) Changes in the economy in the United States or elsewhere in the world, including as a result of changes in geopolitical conditions, (ii) Changes that affect any of the industries in which the Company or any of its Subsidiaries operate, (iii) Changes in the financial, debt, capital, credit or securities markets generally in the United States or elsewhere in the world, including changes in interest rates, (iv) any Change in the stock price, trading volume or credit rating of the Company or any of its Subsidiaries or any failure by the Company to meet published analyst estimates or expectations of its revenue, earnings or other financial performance or results of operations for any period, or any failure by the Company to meet its internal or published projections, budgets, plans or forecasts of its revenues, earnings or other financial performance or results of operations for any period (it being understood that the Changes underlying any such Change or failure described in this clause (iv) to the extent not otherwise excluded from the definition of a "Company Material Adverse Effect" may be considered in determining whether there has been a Company Material Adverse Effect), (v) Changes in Law, legislative or political conditions or policy or practices of any Governmental Entity (other than SC Law Changes), (vi) Changes in applicable accounting regulations or principles or interpretations thereof, (vii) an act of terrorism or an outbreak or escalation of hostilities or war (whether declared or not declared) or earthquakes, any weather-related or other force majeure events or other natural disasters or any national or international calamity or crisis, (viii) the announcement, execution or delivery of this Agreement or the public announcement or pendency of the Merger or the other transactions contemplated by this Agreement, in each case, including any impact thereof on relationships, contractual or otherwise, with Governmental Entities or customers, suppliers, distributors, lenders, partners or employees of the Company and its Subsidiaries, (ix) actions taken or requirements imposed by any Governmental Entities, in connection with obtaining the Regulatory Clearances or the SCPSC Petition Approval, (x) any Shareholder Litigation or Changes with respect thereto and (xi) any Proceedings, claims, investigations or inquiries set forth in Section 3.01(g) of the Company Disclosure Letter (other than with respect to SC Law Changes) or any Changes with respect thereto , provided, further, that any Change set forth in the foregoing clauses (i), (ii), (iii), (v) or (vi), to the extent not otherwise excluded hereunder, may be taken into account in determining whether a Company Material Adverse Effect has occurred solely to the extent that such Change has a materially disproportionate adverse effect on the Company and its Subsidiaries, taken as a whole, as compared to other Persons engaged in the relevant business affected by such Change.

"Company Material Contract" means any Contract (i) required to be filed by the Company as a "material contract" pursuant to Item 601(b)(10) of Regulation S-K under the Securities Act, (ii) that provides for Indebtedness of the Company or any of its Subsidiaries of more than $50,000,000, (iii) that resulted in expenditures, receipts, liabilities, or payments by the Company or any of its Subsidiaries of more than $80,000,000 in the 2016 fiscal year or 2017 fiscal year or (iv) that requires the Company or any of its Subsidiaries to incur Indebtedness or liabilities, or to make payments or expenditures, of more than $80,000,000 in any one future fiscal year, in the case of the foregoing clauses (ii) and (iii), excluding (A) any Contracts that can be terminated for convenience on less than ninety (90) days' notice without material payment or penalty and (B) any Contracts for the supply of natural gas capacity or commodity.

"Company Share" means a share of common stock, without par value, of the Company.

"Consent" means any consent, clearance, approval, Order, authorization, waiver, license, notice filing, action or non-action.

"Contract" means a contract, purchase order, license, sublicense, lease, sublease, option, warrant, guaranty, indenture, note, bond, mortgage or other legally binding agreement or instrument, whether written or unwritten.

"control" (including in the terms "controlling", "controlled", "controlled by" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of a Person, whether through the ownership of voting securities, by Contract or otherwise.

"Data Privacy Legal Requirements" mean (i) all applicable requirements imposed by applicable Laws relating to (A) the security or privacy of information systems, networks, or data; (B) the use, collection, recording, storing, altering, retrieving, transferring, disclosing (whether authorized or unauthorized) or otherwise processing of data owned or used by the Company or its Subsidiaries; (C) the unauthorized access, acquisition, use, modification, disclosure or misuse of data; (D) the notification to affected parties, regulators, or credit reporting agencies as a result of any breach of systems, networks or data; or (E) any other cybersecurity or data privacy incident requiring reporting outside of the Company; (ii) all contractual standards, rules and requirements that the Company or any of its Subsidiaries is or has been contractually obligated to comply with; and (iii) each published external or internal, past or present Company privacy policy or security policy applicable to any information systems, networks, or data, including personal data and any published policy of the Company or its Subsidiaries relating to: (A) the privacy of any Person, (B) financial records or information pertaining to any Person, (C) the collection, storage, disclosure, transfer, disposal, other processing or security of any personal data, or (D) personally identifying information, sensitive customer information, financial records, security records and associated information, about Persons.

"Director Compensation and Deferral Plan" means the Company Director Compensation and Deferral Plan.

"Environmental Law" means any Law relating to pollution or protection of the environment or natural resources, including ambient air, soil, surface water or groundwater, sediment, flora and fauna, or, as it relates to the exposure to hazardous, deleterious or toxic materials, human health or safety.

"Equity Award Consideration" means an amount in cash, without interest, equal to the product of (i) the Merger Consideration multiplied by (ii) the Average Price.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Executive Deferred Compensation Plan" means the Company Executive Deferred Compensation Plan.

"Governmental Entity" means any federal, state, local, or non-United States government, any court or tribunal of competent jurisdiction, any administrative, regulatory (including any stock exchange) or other governmental or quasi-governmental agency, commission, branch or authority or other governmental entity or body (it being understood and agreed that no reference to "Governmental Entity" in this Agreement shall be deemed to include Santee Cooper in its capacity as a commercial counterparty of the Company in connection with the NND Project or otherwise).

"Hazardous Materials" means any substance, waste or material defined or regulated as hazardous, acutely hazardous or toxic or that could reasonably be expected to result in liability under any applicable Environmental Law currently in effect, including petroleum, petroleum products, High-Level Waste, Spent Nuclear Fuel, by-products and distillates, pesticides, dioxin, polychlorinated biphenyls, mold, biological hazards, asbestos and asbestos-containing materials.

"High-Level Waste" means (i) irradiated nuclear reactor fuel, (ii) liquid wastes resulting from the operation of the first cycle solvent extraction system, or its equivalent, and the concentrated wastes from subsequent extraction cycles, or their equivalent, in a facility for reprocessing irradiated reactor fuel and (iii) solids into which such liquid wastes have been converted.

"HSR Act" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

"Intellectual Property" means all intellectual property and proprietary rights, and applications with respect thereto, including (i) patents and patent applications, (ii) trademarks, service marks, trade dress, logos, Internet domain names, trade names and corporate names, whether registered or unregistered, and the goodwill associated therewith, together with any registrations and applications for registration thereof, (iii) copyrights and rights under copyrights, whether registered or unregistered, and any registrations and applications for registration thereof, (iv) trade secrets and other rights in know-how and confidential or proprietary information, including any technical data, specifications, techniques, inventions and discoveries, in each case, to the extent that it qualifies as a trade secret under applicable Law and (v) all other intellectual property rights recognized by applicable Law.

"Intervening Event" means any material event, development or change in circumstances that materially affects the business, assets or operations of the Company and its Subsidiaries, taken as a whole, that first becomes known to the Company Board or any of the Persons set forth in Section 8.06 of the Company Disclosure Letter or their successors after the date of this Agreement but before the Company Requisite Vote is obtained, to the extent that such event, development or change in circumstances was not reasonably foreseeable as of or prior to the date of this Agreement or which would not reasonably be expected to have become known after reasonable investigation or inquiry as of or prior to the date of this Agreement; provided, however, that in no event will (i) the receipt, existence or terms of an Acquisition Proposal or any matter relating thereto or consequence thereof, (ii) any action taken by the parties pursuant to or in compliance with this Agreement, including any action taken in connection with seeking any Regulatory Clearances, (iii) any changes in Law or the settlement of any lawsuits, investigations, inquiries or Proceedings, (iv) changes in the market price or trading volume of the Company Shares or Parent Shares, or the Company or Parent or any their respective Subsidiaries meeting or exceeding internal or published projections, forecasts or revenue or earnings predictions for any period, (v) changes in the energy markets or industry or to rates, or (vi) any event, development or change relating solely to Parent or its Affiliates, in each case, constitute an "Intervening Event" or be taken into account in determining whether an Intervening Event has occurred or would reasonably be expected to result.

"IT Systems" means all computer systems, computer programs, networks, hardware, software, software engines, electronic databases and websites used to process, store, maintain and operate data, information and control systems owned, used or provided by the Company.

"Knowledge" means (i) with respect to the Company, the actual knowledge, after reasonable inquiry, of any of the Persons set forth in Section 8.06 of the Company Disclosure Letter and their successors and (ii) with respect to Parent or Merger Sub, the actual knowledge, after reasonable inquiry, of any of the Persons set forth in Section 8.06 of the Parent Disclosure Letter and their successors.

"Law" means any federal, state, local or non-United States law, statute, regulation, rule, ordinance, Order or decree of any Governmental Entity.

"Low-Level Waste" means radioactive material that (i) is not High-Level Waste, Mixed Waste, Spent Nuclear Fuel or Byproduct Material as defined in section 11e.(2) of the Atomic Energy Act, and (ii) the NRC classifies as low-level radioactive waste.

"Mixed Waste" means waste that (i) contains both a hazardous waste component regulated under the Resource Conservation and Recovery Act (42 U.S.C. § 6901 *et seq*.) and a radioactive component of Source Material, Byproduct Material or Special Nuclear Material and (ii) the NRC classifies as mixed waste or that constitutes "mixed waste" as defined in 42 U.S.C. § 6903(41).

"NND Project" means the New Nuclear Development Project under which the Company and Santee Cooper undertook to construct two Westinghouse AP1000 Advanced Passive Safety nuclear units in Jenkinsville, South Carolina.

"Nuclear Material" means Source Material, Special Nuclear Material, Low-Level Waste, High-Level Waste, the radioactive component of Mixed Waste, Byproduct Material and Spent Nuclear Fuel.

"NYSE" means the New York Stock Exchange.

"Parent Disclosure Letter" means the confidential disclosure letter dated as of the date of this Agreement delivered by Parent to the Company.

"Parent Material Adverse Effect" means any Change that has a material adverse effect on the business, financial condition, assets, liabilities or results of operations of Parent and its Subsidiaries, taken as a whole; provided, however, that none of the following shall, either alone or in combination, constitute or contribute to a Parent Material Adverse Effect: (i) Changes in the economy in the United States or elsewhere in the world, including as a result of changes in geopolitical conditions, (ii) Changes that affect any of the industries in which Parent or any of its Subsidiaries operate, (iii) Changes in the financial, debt, capital, credit or securities markets generally in the United States or elsewhere in the world, including changes in interest rates, (iv) any Change in the stock price, trading volume or credit rating of Parent or any of its Subsidiaries or any failure by Parent to meet published analyst estimates or expectations of its revenue, earnings or other financial performance or results of operations for any period, or any failure by Parent to meet its internal or published projections, budgets, plans or forecasts of its revenues, earnings or other financial performance or results of operations for any period (it being understood that the Changes underlying any such Change or failure described in this clause (iv) to the extent not otherwise excluded from the definition of a "Parent Material Adverse Effect" may be considered in determining whether there has been a Parent Material Adverse Effect), (v) Changes in Law, legislative or political conditions or policy or practices of any Governmental Entity (other than SC Law Changes), (vi) Changes in applicable accounting regulations or principles or interpretations thereof, (vii) an act of terrorism or an outbreak or escalation of hostilities or war (whether declared or not declared) or earthquakes, any weather-related or other force majeure events or other natural disasters or any national or international calamity or crisis, (viii) the announcement, execution or delivery of this Agreement or the public announcement or pendency of the Merger or the other transactions contemplated by this Agreement, in each case, including any impact thereof on relationships, contractual or otherwise, with Governmental Entities or customers, suppliers, distributors, lenders, partners or employees of Parent and its Subsidiaries, (ix) actions taken or requirements imposed by any Governmental Entities, in connection with obtaining the Regulatory Clearances or the SCPSC Petition Approval, (x) any Shareholder Litigation or any Changes with respect thereto, and (xi) any Proceedings, claims, investigations or inquiries set forth in Section 3.02(g) of the Parent Disclosure Letter or any Changes with respect thereto, provided, further, that any Change set forth in the foregoing clauses (i), (ii), (iii), (v) or (vi), to the extent not otherwise excluded hereunder, may be taken into account in determining whether a Parent Material Adverse Effect has occurred solely to the extent that such Change has a materially disproportionate adverse effect on the Parent and its Subsidiaries, taken as a whole, as compared to other Persons engaged in the relevant business affected by such Change.

"Parent Severance Program" means the severance program sponsored by Parent and described in the summary plan description attached as Section 5.06 of the Parent Disclosure Letter.

"Parent Share" means a share of common stock, without par value, of Parent.

"Parent Significant Subsidiaries" means the significant subsidiaries (as defined in Rule 1-02(w) of Regulation S-X) of Parent, excluding, if otherwise included, Dominion Energy Midstream Partners LP.

"Permitted Liens" means, with respect to any Person, (i) mechanics', materialmen's, carriers', workmen's, repairmen's, vendors', operators' or other like Liens, if any, that do not materially detract from the value of or materially interfere with the use of any of the assets of such Person and its Subsidiaries as currently conducted, (ii) Liens arising under original purchase price conditional sales

Contracts and equipment leases with third parties entered into in the ordinary course of business, (iii) title defects or Liens (other than those constituting Liens for the payment of Indebtedness), if any, that do not or would not, individually or in the aggregate, impair in any material respect the use or occupancy of the assets of such Person and its Subsidiaries, taken as a whole, (iv) Liens for Taxes that are not yet due or payable or that may thereafter be paid without penalty, (v) Liens supporting surety bonds, performance bonds and similar obligations issued in connection with the businesses of such Person and its Subsidiaries, (vi) Liens not created by such Person or its Subsidiaries that affect the underlying fee interest of a Company Leased Real Property, (vii) Liens that are disclosed on the most recent consolidated balance sheet of such Person included in its SEC Reports or notes thereto or securing liabilities reflected on such balance sheet, (viii) Liens arising under or pursuant to the organizational documents of such Person or any of its Subsidiaries, (ix) grants to others of rights-of-way, surface leases or crossing rights and amendments, modifications, and releases of rights-of-way, surface leases or crossing rights in the ordinary course of business, (x) with respect to rights-of-way, restrictions on the exercise of any of the rights under a granting instrument that are set forth therein or in another executed agreement, that is of public record or to which such Person or any of its Subsidiaries otherwise has access, between the parties thereto, (xi) Liens which an accurate up-to-date survey would show, (xii) Liens resulting from any facts or circumstances relating to, if such Person is the Company, Parent, Merger Sub or any of their Affiliates or, if such Person is Parent or Merger Sub, the Company or any of its Affiliates and (xiii) Liens that do not and would not reasonably be expected to materially impair the continued use of a Company Owned Real Property or a Company Leased Real Property as currently operated.

"Person" means an individual, corporation (including not-for-profit), Governmental Entity, general or limited partnership, limited liability company, joint venture, estate, trust, association, organization, unincorporated organization, other entity of any kind or nature or group (as defined in Section 13(d)(3) of the Exchange Act).

"Santee Cooper" means the South Carolina Public Service Authority, a body corporate and politic and agency of the State of South Carolina established under Chapter 31 of Title 58 of the Code of Laws of South Carolina, Annotated, as amended from time to time.

"Sarbanes-Oxley Act" means the Sarbanes-Oxley Act of 2002, as amended.

"SCBCA" means the South Carolina Business Corporation Act of 1988, as amended.

"SCORS" means the South Carolina Office of Regulatory Staff, the administrative and regulatory body established under Title 58, Chapter 4 of the Code of Laws of South Carolina, Annotated, as amended from time to time.

"SCPSC" means the South Carolina Public Service Commission, the regulatory commission established under Title 58, Chapter 3 of the Code of Laws of South Carolina, Annotated, as amended from time to time.

"SCPSC Petition" means a petition to be filed jointly by the Company and Parent with the SCPSC for approval of the Merger and for approval of terms for cost recovery and other regulatory matters with respect to the NND Project, including the key terms summarized in Appendix A attached to this Agreement.

"SEC" means the United States Securities and Exchange Commission.

"SEC Reports" means all forms, statements, certifications, reports and other documents a Person is required or otherwise obligated to file or furnish with the SEC, including (i) those filed or furnished subsequent to the date of this Agreement and (ii) all exhibits and other information incorporated therein and all amendments and supplements thereto.

"Securities Act" means the Securities Act of 1933, as amended.

"Social Commitments" means the undertakings, terms, conditions, liabilities, obligations, commitments and sanctions set forth in Section 5.16.

"Source Material" means (i) uranium or thorium, or any combination thereof, in any physical or chemical form or (ii) ores that contain by weight one-twentieth of one percent (0.05%) or more of (A) uranium, (B) thorium or (C) any combination thereof.

"South Carolina Public Utility Laws" means the Laws of the State of South Carolina governing public utilities as contained in Title 58 of the Code of Laws of South Carolina, Annotated, as they may be amended from time, including the BLRA, the Laws providing for the organization, powers and terms of officials and members of the SCPSC and the SCORS, and the Laws providing for the establishment, review and adjustment of retail electric and natural gas rates and terms of conditions of service, as found in Title 58 of the Code of Laws of South Carolina, Annotated, in each case, as they may be amended from time to time.

"Special Nuclear Material" means plutonium, uranium-233, uranium enriched in the isotope-233 or in the isotope-235, and any other material that the NRC determines to be "Special Nuclear Material." Special Nuclear Material also refers to any material artificially enriched by any of the foregoing materials or isotopes. Special Nuclear Material does not include Source Material.

"Spent Nuclear Fuel" means fuel that has been withdrawn from a nuclear reactor following irradiation, and has not been chemically separated into its constituent elements by reprocessing. Spent Nuclear Fuel includes Special Nuclear Material, Byproduct Material, Source Material and other radioactive materials associated with nuclear fuel assemblies.

"Subsidiary" means, with respect to any Person, (i) any other Person (other than a partnership, joint venture or limited liability company) of which 50% or more of the total voting power of shares of stock or other equity interests entitled to vote in the election of directors, managers or trustees is at the time of determination owned or controlled, directly or indirectly, by such first Person and (ii) any partnership, joint venture or limited liability company of which (A) 50% or more of the capital accounts, distribution rights, total equity or voting interests or general or limited partnership interests, as applicable, are owned or controlled, directly or indirectly, by such Person, whether in the form of membership, general, special or limited partnership interests or otherwise or (B) such Person or any Subsidiary of such Person is a controlling general partner or otherwise controls such entity.

"Superior Proposal" means an unsolicited bona fide written Acquisition Proposal relating to any direct or indirect acquisition or purchase of (i) assets that generate more than 50% of the consolidated total revenues or operating income of the Company and its Subsidiaries, taken as a whole, (ii) assets that constitute more than 50% of the consolidated total assets of the Company and its Subsidiaries, taken as a whole or (iii) more than 50% of the total voting power of the equity securities of the Company, in each case, that the Company Board determines in good faith after consultation with the Company's financial advisors and outside legal counsel is more favorable to the Company's shareholders than the Merger, taking into account the Person making the Acquisition Proposal and all legal, financial and regulatory aspects of the Acquisition Proposal (including the likelihood that such Acquisition Proposal would be consummated in accordance with its terms) and all other relevant circumstances.

"Tax Return" means any return, declaration, report, election, claim for refund or information return or any other statement or form filed or required to be filed with any Governmental Entity relating to Taxes, including any schedule or attachment thereto, and including any amendment thereof.

"Taxes" means all forms of taxes or duties imposed by any Governmental Entity, or required by any Governmental Entity to be collected or withheld, including charges, together with any related interest, penalties and other additional amounts.

"Willful Breach" means, with respect to any breach or failure to perform any of the covenants or other agreements contained in this Agreement, a breach that is a consequence of an act or failure to act undertaken by the breaching party with actual knowledge that such party's act or failure to act would result in or constitute a breach of this Agreement. For the avoidance of doubt, the failure of a party hereto to consummate the Closing when required pursuant to Section 1.02, or, on the Closing Date, cause the Effective Time to occur pursuant to Section 1.03, shall be a Willful Breach of this Agreement.

(b) Each of the following terms is defined in the Section set forth opposite such term:

Term	Section
Agreement	Preamble
Alternative Acquisition Agreement	4.02(e)
Applicable Company SEC Reports	3.01(e)(i)
Applicable Parent SEC Reports	3.02(e)(i)
Articles of Merger	1.03
Book-Entry Share	2.01(a)
Cancelled Shares	2.01(b)
Certificate	2.01(a)
Changes	3.01(f)(i)
Closing	1.02
Closing Date	1.02
Company	Preamble
Company Adverse Recommendation Change	4.02(e)
Company Articles of Incorporation	3.01(a)
Company Board	Recitals
Company Board Recommendation	3.01(d)(i)
Company Bylaws	3.01(a)
Company Deferred Unit	2.02(c)
Company Employees	5.06(c)
Company Leased Real Property	3.01(o)(i)
Company Non-Union Employees	5.06(a)
Company Organizational Documents	3.01(a)
Company Owned Real Property	3.01(o)(ii)
Company Performance Share Award	2.02(a)
Company Real Property Lease	3.01(o)(i)
Company Regulatory Clearances	3.01(d)(iii)
Company Requisite Vote	3.01(r)
Company RSU	2.02(b)
Company Termination Fee	7.02(b)
Confidentiality Agreement	5.03(b)
Continuation Period	5.06(a)

SCANA CORPORATION

President, Chief Executive Officer And Chief Operating Officer	Jimmy E. Addison
Senior Vice President	Jeffrey B. Archie
Senior Vice President, Risk Management Officer, Corporate Compliance Officer	Sarena D. Burch
Senior Vice President, Chief Financial Officer and Treasurer	Iris N. Griffin
Senior Vice President	D. Russell Harris
Senior Vice President	Kenneth R. Jackson
Senior Vice President	W. Keller Kissam
Senior Vice President	Randal M. Senn
Senior Vice President, General Counsel and Assistant Secretary	Jim O. Stuckey
Vice President and Secretary	Gina S. Champion
Vice President and Controller	James E. Swan, IV
Vice President and Chief Information Officer	Stacy O. Shuler, Jr.

January 1, 2018

FORM 10-K

SOUTH CAROLINA ELECTRIC & GAS CO - SCG

Filed: February 24, 2017 (period: December 31, 2016)

Annual report with a comprehensive overview of the company

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2016

Commission File Number		Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809		**SCANA Corporation** (a South Carolina corporation)	57-0784499
1-3375		**South Carolina Electric & Gas Company** (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	57-0248695

Securities registered pursuant to Section 12(b) of the Act:
SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

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.
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Exchange Act Rule 12b-2).

SCANA Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
South Carolina Electric & Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
SCANA Corporation Yes ☐ No ☒ South Carolina Electric & Gas Company Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $10.8 billion at June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $75.66 per share. South Carolina Electric & Gas Company is a wholly-owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 20, 2017
SCANA Corporation	Without Par Value	142,916,917
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Specified sections of SCANA Corporation's Proxy Statement, in connection with its 2017 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. South Carolina Electric & Gas Company makes no representation as to information relating to SCANA Corporation or its subsidiaries (other than South Carolina Electric & Gas Company and its consolidated affiliates).

South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;
(2) legislative and regulatory actions, particularly changes related to electric and gas services, rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations, and actions affecting the construction of new nuclear units;
(3) current and future litigation;
(4) changes in the economy, especially in areas served by subsidiaries of SCANA;
(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;
(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;
(7) the loss of sales to distributed generation, such as solar photovoltaic systems or energy storage systems;
(8) growth opportunities for SCANA's regulated and other subsidiaries;
(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;
(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA's subsidiaries;
(11) changes in SCANA's or its subsidiaries' accounting rules and accounting policies;
(12) payment and performance by counterparties and customers as contracted and when due;
(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission, including nuclear generating facilities;
(14) the results of efforts to operate the Company's electric and gas systems and assets in accordance with acceptable performance standards, including the impact of additional distributed generation and nuclear generation;
(15) maintaining creditworthy joint owners for SCE&G's new nuclear generation project;
(16) the creditworthiness and/or financial stability of contractors for SCE&G's new nuclear generation project, particularly in light of adverse financial developments disclosed by Toshiba;
(17) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon quality and prices, for our construction program, operations and maintenance;
(18) the results of efforts to ensure the physical and cyber security of key assets and processes;
(19) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;
(20) the availability of skilled, licensed and experienced human resources to properly manage, operate, and grow the Company's businesses;
(21) labor disputes;
(22) performance of SCANA's pension plan assets and the effect(s) of associated discount rates;
(23) changes in tax laws and realization of tax benefits and credits, including production tax credits for new nuclear units, and the ability or inability to realize credits and deductions;
(24) inflation or deflation;
(25) changes in interest rates;
(26) compliance with regulations;
(27) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and
(28) the other risks and uncertainties described from time to time in the reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CB&I	Chicago Bridge & Iron Company N.V.
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGT	Carolina Gas Transmission Corporation
CO_2	Carbon Dioxide
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of WEC and Stone and Webster
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker (decoupling mechanism)
CWA	Clean Water Act
DCGT	Dominion Carolina Gas Transmission LLC
DER	Distributed Energy Resource
DHEC	South Carolina Department of Health and Environmental Control
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
DRB	Dispute Resolution Board
DSM Programs	Demand Side Management Programs
ELG Rule	Federal effluent limitation guidelines for steam electric generating units
EMANI	European Mutual Association for Nuclear Insurance
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fluor	Fluor Corporation
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
IRC	Internal Revenue Code
IRS	United States Internal Revenue Service
KVA	Kilovolt ampere
kWh	Kilowatt-hour
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability

LNG	Liquefied Natural Gas
LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MCF	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NASDAQ	The NASDAQ Stock Market, Inc.
NAV	Net Asset Value
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NO_X	Nitrogen Oxide
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
October 2015 Amendment	Amendment, dated October 27, 2015, to the EPC Contract
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act
PSNC Energy	Public Service Company of North Carolina, Incorporated
ROE	Return on Common Equity
RSA	Natural Gas Rate Stabilization Act
RTO/ISO	Regional Transmission Organization/Independent System Operator
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	SCANA Energy Marketing, Inc.
SCANA Services	SCANA Services, Inc.
SCE&G	South Carolina Electric & Gas Company
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Southern Natural	Southern Natural Gas Company
Spirit Communications	SCTG, LLC and its wholly-owned subsidiary SCTG Communications, Inc.
Stone & Webster	Prior to December 31, 2015, CB&I Stone & Webster, a subsidiary of CB&I. Effective December 31, 2015, Stone & Webster, a subsidiary of WECTEC, LLC, a wholly-owned subsidiary of WEC
Summer Station	V.C. Summer Nuclear Station
Supreme Court	United States Supreme Court
Toshiba	Toshiba Corporation, parent company of WEC
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
Unit 1	Nuclear Unit 1 at Summer Station
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
WEC	Westinghouse Electric Company LLC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

INVESTOR INFORMATION

SCANA's and SCE&G's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA's internet website at *www.scana.com* (which is not intended as an active hyperlink; the information on SCANA's website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC) as soon as reasonably practicable after these reports are filed or furnished.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G's new nuclear project and other matters of interest to investors on SCANA's website. On SCANA's homepage, there is a yellow box containing links to the Nuclear Development and Other Investor Information sections of the website. The Nuclear Development section contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor-related information that cannot be found at other areas of the website. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the new nuclear project, may be deemed to be material information that has not otherwise become public. Investors, media and other interested persons are encouraged to review this information and can sign up, under the Investor Relations Section of the website, for an email alert when there is a new posting in the Nuclear Development and Other Investor Information yellow box.

CORPORATE STRUCTURE AND SEGMENTS OF BUSINESS

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees of 5,910 as of February 20, 2017 and 5,829 as of February 19, 2016. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries, including the subsidiaries described below.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 709,000 customers and the purchase, sale and transportation of natural gas to approximately 358,000 customers (each as of December 31, 2016). SCE&G's business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 16,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 23,000 square miles. More than 3.4 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products, automotive and tire and fabricated metal products.

GENCO owns Williams Station and sells electricity, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a unit power sales agreement and related operating agreement. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances.

PSNC Energy purchases, sells and transports natural gas to approximately 550,000 residential, commercial and industrial customers (as of December 31, 2016). PSNC Energy serves 28 franchised counties covering approximately 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food products, health services, automotive, chemicals, non-woven textiles, electrical generation and construction.

Nonregulated Businesses

SCANA Energy markets natural gas in the southeast and provides energy-related services. A division of SCANA Energy sells natural gas to approximately 450,000 customers (as of December 31, 2016) in Georgia's deregulated natural gas market.

SCANA Services, Inc. provides administrative and management services to SCANA's other subsidiaries.

For information with respect to major segments of business, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 12 of the consolidated financial statements. All such information is incorporated herein by reference.

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity and margins earned from those sales by customer classification as percentages of electric revenues were as follows:

	Sales		Margins	
Customer Classification	**2016**	**2015**	**2016**	**2015**
Residential	46%	45%	50%	50%
Commercial	33%	33%	33%	33%
Industrial	17%	17%	14%	14%
Sales for resale	2%	2%	1%	1%
Other	2%	3%	2%	2%
Total	100%	100%	100%	100%

Sales for resale include sales to three municipalities and one electric cooperative. Short-term system sales and margins were not significant for either period presented.

During 2016 SCE&G experienced a net increase of approximately 11,000 electric customers (growth rate of 1.6%), increasing its total number of electric customers to approximately 709,000 at year end.

The following projections assume normal weather where applicable. For the period 2016 to 2017, SCE&G projects a retail kWh sales decrease of approximately 0.1% and customer growth of 1.5%. For the period 2017-2019, SCE&G projects total territorial kWh sales of electricity to increase 0.3% annually, total retail sales to grow 0.3% annually, total electric customer base to increase 1.6% annually and territorial peak load (summer, in MW) to increase 1.6% annually. SCE&G's goal is to maintain a planning reserve margin of between 14% and 20%; however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a unit power sales agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G's transmission system extends over a large part of the central, southern and southwestern portions of South Carolina. The system interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Santee Cooper, Georgia Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) were as follows:

	Cost of Fuel Used		
	2016	2015	2014
Per MMBTU:			
Nuclear	$ 0.98	$ 0.95	$ 1.01
Coal	3.41	3.81	3.90
Natural Gas	3.02	3.26	5.19
All Fuels (weighted average)	2.41	3.01	3.62
Per Ton: Coal	84.62	95.69	96.74
Per MCF: Gas	3.11	3.35	5.30

For a listing of the Company's generating facilities, see the Electric Properties section within Item 2. Properties. For information on actual and projected sources and percentages of total MWh generation by each category of fuel, see Electric Operations - Environmental within the Overview section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

In 2016, coal was primarily obtained through long-term contracts with suppliers located in eastern Kentucky, Tennessee, Virginia, and West Virginia. These contracts provide for approximately 1.4 million tons annually. Sulfur restrictions on the contract coal range from 1.0% to 1.6%. These contracts expire at various times through 2018. Spot market purchases may occur when needed or when prices are believed to be favorable. The Company relies on unit trains and, in some cases, trucks and barges for coal deliveries.

SCANA and SCE&G believe that electric operations comply with all applicable regulations relating to the discharge of SO_2 and NO_X . See additional discussion at Environmental Matters in Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

SCE&G, for itself and as agent for Santee Cooper, and WEC are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G supplies enriched products to WEC and WEC supplies nuclear fuel assemblies for Unit 1 and is under contract to supply assemblies for the New Units. WEC will be SCE&G’s exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Unit 1 and the New Units through 2033. SCE&G is dependent upon WEC for providing fuel assemblies for the new AP1000 reactors in the New Units in the current and anticipated future absence of other commercially viable sources.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of its nuclear generating units.

SCE&G stores spent nuclear fuel in its on-site spent-fuel pool, and has constructed a dry cask storage facility to accommodate the spent fuel output for the life of Unit 1. In addition, Unit 1 has sufficient on-site capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see the Environmental section of Note 10 to the consolidated financial statements.

SCE&G also uses long-term power purchase agreements to ensure that adequate power supply resources are in place to meet load obligations and reserve requirements. As of January 1, 2017, SCE&G had such agreements in place for 325 MW of capacity (expiring at various times through 2020). In addition, SCE&G had the ability to purchase an additional 204 MW of capacity under these agreements.

GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported were as follows:

	SCANA		SCE&G	
Customer Classification	**2016**	**2015**	**2016**	**2015**
Residential	57.9%	57.0%	48.3%	47.9%
Commercial	26.4%	26.8%	28.6%	28.0%
Industrial	10.4%	11.0%	19.5%	20.6%
Transportation Gas	5.3%	5.2%	3.6%	3.5%
Total	100.0%	100.0%	100.0%	100.0%

For the period 2017-2019, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 4.1% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.5%, commercial of 0.8% and industrial of 10.7%.

For the period 2017-2019, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 2.7% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.4%, commercial of 0.7% and industrial of 4.3%.

For the period 2017-2019, each of SCANA's and SCE&G's total regulated natural gas customer base is projected to increase 2.6% annually. During 2016, SCANA recorded a net increase of approximately 26,000 regulated gas customers (growth rate of 2.9%), increasing the number of its regulated gas customers to approximately 907,000. Of this increase, SCE&G recorded a net increase of approximately 10,000 gas customers (growth rate of 2.9%), increasing the number of its total gas customers to approximately 358,000 (as of December 31, 2016).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost and Supply

SCE&G purchases natural gas under contracts with producers and marketers on both a short-term and long-term basis at market based prices. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2018), Transco (expiring at various times through 2031) and DCGT (expiring at various times through 2036). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 212,194 MMBTU from Southern Natural, 104,652 MMBTU from Transco and 461,727 MMBTU from DCGT. Additional natural gas volumes may be delivered to SCE&G's system as capacity is available through interruptible transportation.

The daily volume of gas that SCANA Energy is entitled to transport under its service agreements (expiring at various times through 2023) on a firm basis is 771,627 MMBTU. Additional natural gas volumes may be delivered as capacity is available through interruptible transportation.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $3.46 per MMBTU during 2016 and $3.67 per MMBTU during 2015.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G has 5,502,600 MMBTU of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 3,806,800 MMBTU of gas were in storage on December 31, 2016. SCE&G supplements its supplies of natural gas with two LNG storage facilities, one of which has liquefaction capability. Approximately 1,833,400 MMBTU (liquefied equivalent) of gas were in storage on December 31, 2016. For a discussion of SCE&G's natural gas storage capacity, see Item 2. Properties.

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2031. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 710,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $3.73 per MMBTU during 2016 compared to $4.12 per MMBTU during 2015.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Transmission, Inc., Columbia Gas Transmission, Transco and Spectra Energy provide for storage capacity of approximately 13,000,000 MMBTU. Approximately 9,000,000 MMBTU of gas were in storage under these agreements at December 31, 2016. PSNC Energy also maintains LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG which provides 1,300,000 MMBTU (liquefied equivalent) of storage space. Approximately 1,100,000 MMBTU (liquefied equivalent) were in storage under these agreements at December 31, 2016. Approximately 900,000 MMBTU (liquefied equivalent) of gas were in storage at PSNC Energy's LNG storage facility at December 31, 2016. For a discussion of PSNC Energy's LNG storage capacity, see Item 2. Properties.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SCANA Energy markets natural gas and provides energy-related services in the Southeast. In addition, a division of SCANA Energy markets natural gas to approximately 450,000 customers (as of December 31, 2016) in Georgia’s natural gas market. Georgia’s natural gas market includes approximately 1.6 million customers.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements.

REGULATION

Regulatory jurisdictions to which SCANA and its subsidiaries are subject are described in the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	**License Expiration**
Saluda (Lake Murray)	*
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

* SCE&G operates the Saluda hydroelectric project under an annual license while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, or may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 2 to the consolidated financial statements.

Fuel Cost Recovery Procedures

The SCPSC's fuel cost recovery procedure determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions, and the cost of emission allowances used for SO_2, NO_X, mercury and particulates. In addition, the statutory definition of fuel cost allows electric utilities to recover avoided costs under the Public Utility Regulatory Policy Act of 1978, as well as costs incurred as a result of offering DER and net metering programs to its customers. SCE&G may request a formal proceeding concerning its fuel costs at any time.

Fuel cost recovery procedures related to the Company's natural gas operations along with related rate proceedings by the SCPSC and NCUC are described in Note 2 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of any new or pending regulations or standards upon existing operations cannot be predicted. For a discussion of how these regulations and standards may impact SCANA and SCE&G (including capital expenditures necessitated thereby), see the Environmental Matters section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements.

OTHER MATTERS

Insurance coverage for SCE&G's nuclear units is described in Note 10 to the consolidated financial statements.

For a discussion of the impact of competition, see the Overview section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to the Company, and where indicated the risk factors also relate to Consolidated SCE&G.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction for environmental compliance and its construction of the New Units and associated transmission infrastructure, are significant and these projects are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of these projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in energy generation and in other internal infrastructure projects, including projects for environmental compliance. In particular, SCE&G and Santee Cooper have agreed to jointly own, contract the design and construction of, and operate the New Units, which will be two 1,250 MW (1,117 MW, net) nuclear units at SCE&G's Summer Station, in pursuit of which they have committed and are continuing to commit significant resources. In addition, construction of significant new transmission infrastructure is necessary to support the New Units and is under way as an integral part of the project. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and construction schedules may be affected by many variables, such as the regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness and/or financial stability, unforeseen difficulties meeting critical regulatory requirements, contract disputes and litigation, and changes in key contractors or subcontractors. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects (including new baseload generation) as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, adverse changes in applicable laws and regulations, new or enhanced environmental or regulatory requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. Some of the foregoing issues have been experienced in the construction of the New Units. A discussion of certain of those matters can be found under New Nuclear Construction in Note 10 to the consolidated financial statements.

Should the construction of the New Units materially and adversely deviate from the SCPSC-approved schedules (by more than 18 months), estimates, and projections, the SCPSC could disallow the additional capital costs that result from the deviations to the extent that it is deemed that the Company's failure to anticipate or avoid the deviation, or to minimize the resulting expenses, was imprudent, considering the information available at the time that the Company could have acted to avoid the deviation or minimize its effect. Depending upon the magnitude of any such disallowed capital costs, the Company could be moved to evaluate the prudency of continuation, adjustment to, or termination of the project.

Furthermore, jointly owned projects, such as the current construction of the New Units, are subject to risks including that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments, that new joint owners cannot be secured at equivalent financial terms, or that changes in the joint ownership make-up will increase project costs and/or delay the completion.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows and financial condition, as well as our qualifications for applicable governmental programs and benefits, such as production tax credits, may be adversely affected.

Recent announcements by Toshiba, the parent company of WEC and the guarantor of WEC's payment obligations with respect to the above construction project for New Units at SCE&G's Summer Station, related to deterioration in its financial position and liquidity indicate heightened risks and substantial uncertainties with respect to the cost, timing, construction and/or completion of the New Units.

Following several announcements and related media reports, on February 14, 2017, Toshiba, the parent company of WEC and the guarantor of its payment obligations with respect to the EPC Contract, announced that it expects to record a multi-billion dollar impairment loss associated with the construction of the New Units and the two additional AP1000 units being constructed by WEC for another company in the United States.

In December 2015, WEC acquired 100% of the shares of Stone & Webster from CB&I. On December 27, 2016, Toshiba announced the possibility that the goodwill resulting from the transaction would reach a level of several billion U.S. dollars and would be impaired, leaving Toshiba with negative shareholders' equity. The increase to the amount of goodwill resulted from WEC's analysis that demonstrated the cost to complete the four Westinghouse AP1000 new nuclear plants in the United States would far surpass the original estimates for construction. In public statements in 2017, Toshiba attributed the cost overruns to, among other things, higher labor costs arising from lower than anticipated work efficiency and the inability to improve such work efficiency over time. While the final figures related to the impairment remain subject to adjustment, Toshiba's February 14, 2017 announcement indicated it anticipates it will record a loss in excess of $6 billion.

Toshiba's credit ratings, already below investment grade following disclosures of accounting and internal control irregularities in 2015, were further reduced in January 2017, and the Company and Consolidated SCE&G expect that Toshiba will continue to experience negative financial repercussions resulting from these developments. In response, Toshiba has announced, among other things, its plan to monetize portions of its businesses to generate cash. It has also indicated that it will not take on future nuclear construction projects and that it will significantly alter its risk management oversight of its nuclear business. The ability of WEC and Toshiba to successfully respond to these developments will continue to impact Toshiba's credit ratings, creditworthiness, financial stability and viability. There can be no assurance that Toshiba's or WEC's actions will be sufficient such that Toshiba's lenders and creditors will continue to provide necessary liquidity. In particular, these losses raise uncertainty with respect to Toshiba's ability to perform under its guaranty of WEC's payment obligations to the Company and Consolidated SCE&G, and further highlight the risks to the Company and Consolidated SCE&G related to the construction schedule and WEC's ability to continue with and/or complete the construction of the New Units. Adverse changes in contracts, contractors and subcontractors, and to the project schedule could result. Additionally, contractual disputes and litigation could follow.

In addition to the project risks highlighted in Toshiba's disclosures surrounding the large losses described above, additional risks and uncertainties regarding the project schedule are evident. In February 2017, WEC notified the Company and Consolidated SCE&G that the contractual guaranteed substantial completion dates of August 2019 and 2020 for Unit 2 and Unit 3, respectively, which were reflected in the October 2015 Amendment, are not likely to be met. Instead, revised substantial completion dates of April 2020 and December 2020 are reflected within WEC's revised project schedule. While these later dates remain within the SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits, there remains substantial uncertainty as to WEC's ability to meet these dates given its historical inability to meet forecasted productivity and work force efficiency levels.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under any of several arrangements with other contractors or, were it determined to be prudent, halting the project, leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA. Any significant delay in the timing of construction or any determination by the SCPSC to disallow the recovery of costs would adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition.

Commodity price changes, delays in delivery of commodities, commodity availability and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs), availability and deliverability. Any such changes could affect the prices these businesses charge, their operating costs, and the competitive position of their products and services. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to result in the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial condition.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternate forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers on a volumetric rate structure unable to switch to alternate fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G. A regulatory mechanism applies to residential and commercial customers at PSNC Energy to mitigate the earnings impact of an increase or decrease in gas usage.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e., natural gas) market risk. We could be required to provide cash collateral or recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract.

The Company strives to manage commodity price exposure by establishing risk limits and utilizing various financial instruments (exchange traded and over-the-counter instruments) to hedge physical obligations and reduce price volatility. We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be adversely impacted.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, the Department of Homeland Security, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental agencies, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our businesses. In addition to many other aspects of our businesses, these requirements impact the services mandated or offered to our customers, and the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. Non-compliance with these requirements by third parties, such as our contractors, vendors and agents, may subject the Company and Consolidated SCE&G to operational risks and to liability. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's or Consolidated SCE&G's businesses. Non-compliance with these laws and regulations could result in fines, litigation, loss of licenses or permits, mandated capital expenditures and other adverse business outcomes, as well as reputational damage, which could adversely affect the cash flows, results of operations, and financial condition of the Company and Consolidated SCE&G.

Furthermore, changes in or uncertainty in monetary, fiscal, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G could be adversely impacted by changes in tax policy, such as the loss of production tax credits related to the construction of the New Units.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects, results of DSM Programs, results of DER programs, and/or increases in operating costs may lead to requests for regulatory relief, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits.

SCE&G's electric operations in South Carolina and the Company's gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the construction of the New Units by SCE&G is subject to rate regulation by the SCPSC via the BLRA. Consolidated SCE&G's generating facilities are subject to extensive regulation and oversight from the NRC and SCPSC. SCE&G's electric transmission system is subject to extensive regulations and oversight from the SCPSC, NERC and FERC. Implementing and maintaining compliance with the NERC's mandatory reliability standards, enforced by FERC, for bulk electric systems could result in higher operating costs and capital expenditures. Non-compliance with these standards could subject SCE&G to substantial monetary penalties. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as market conditions evolve.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement, many of which are still pending final action by those federal agencies. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers and major swap participants, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers or major swap participants, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated

SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Although we believe that we have constructive relationships with the regulators, our ability to obtain rate treatment that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing NO_X, SO_2, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh. No new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company and Consolidated SCE&G are monitoring the final rule, but do not plan to construct new coal-fired units in the foreseeable future. In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national CO_2 emissions by 32% from 2005 levels by 2030. However, on February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. Also, a number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none has yet been enacted. In April 2012, the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. The EPA's rule for cooling water intake structures to meet the best technology available became effective in October 2014, and the EPA also issued a final rule in December 2014 regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA finalized new standards under the CWA governing effluent limitation guidelines for electric generating units in September 2015.

Compliance with these environmental laws and regulations requires us to commit significant resources toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as the clean-up of MGP sites or additional emission allowances) or require us to incur additional expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our businesses and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are imposed.

Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. In June 2014 the State of South Carolina enacted legislation known as Act 236 with the stated goal for each investor-owned utility to supply up to 2% of its 5-year average retail peak demand with renewable electric generation resources by the end of 2020. A utility, at its option, may supply an additional 1% during this period. Such renewable energy may not be readily available in our service territories and could be costly to build, finance, acquire, integrate, and/or operate. Resulting increases in the price of electricity to recover the cost of these types of generation, as approved by regulatory commissions, could result in lower usage of electricity by our customers. In addition, DER generation at customers' facilities could result in the loss of sales to those customers. Compliance with potential future portfolio standards could significantly impact our capital expenditures and our results of operations and financial condition. Utility scale solar development companies are currently working in South Carolina to develop projects in SCE&G's service territory. The integration of those resources at high penetration levels may be challenging.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In effecting compliance with MATS, SCE&G has retired three of its oldest and smallest coal-fired units and converted three others such that they may be gas-fired.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and we may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company's and Consolidated SCE&G's business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company's and Consolidated SCE&G's ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and its actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA's pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In addition, a significant decline in the market value of the investments may adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition, including its shareholders' equity.

A downgrade in the credit rating of SCANA or any of SCANA's subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Various rating agencies currently rate SCANA's long-term senior unsecured debt, SCE&G's long-term senior secured debt, and the long-term senior unsecured debt of PSNC Energy as investment grade. In addition, rating agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of our rated companies' commonly monitored financial credit metrics and adverse developments with respect to nuclear construction could negatively affect their debt ratings. If these rating agencies were to downgrade any of these ratings, particularly to below investment grade for long-term ratings, borrowing costs on new issuances would increase, which could adversely impact financial results, and the potential pool of investors and funding sources could decrease.

The Company and Consolidated SCE&G are engaged in activities for which they have claimed, and expect to claim in the future, research and experimentation tax deductions and credits which are the subject of uncertainty and which may be considered controversial by the taxing authorities. The outcome of those uncertainties could adversely impact cash flows and financial condition.

The Company and Consolidated SCE&G have claimed significant research and experimentation tax deductions and credits related to the ongoing design and construction activities of the New Units. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. (See also Uncertain income tax positions within the Critical Accounting Policies and Estimates section of Item 7.

Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 5 to the consolidated financial statements.)

These tax claims primarily involve the timing of recognition of tax deductions rather than permanent tax attributes. The permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to them, have been deferred within regulatory assets. As such, these claims have not had, and are not expected to have in the future, significant direct effects on the Company's and Consolidated SCE&G's results of operations. Nonetheless, the claims have contributed significantly to the Company's and Consolidated SCE&G's cash flows and are expected to continue to do so through the remainder of the New Units' construction period. Also, the claims have provided a significant source of capital and have lessened the level of debt and equity financing that the Company and Consolidated SCE&G have needed to raise in the financial markets. Future claims are expected to provide similar tax benefits.

However, the claims made to date are under examination, and may be considered controversial, by the IRS. It is expected that the IRS will also examine future claims. To the extent that the claims are not sustained on examination or through any subsequent appeal, the Company and Consolidated SCE&G will be required to repay any cash received for tax benefit claims which are ultimately disallowed, along with interest on those amounts. Such amounts could be significant and could adversely affect the Company's and Consolidated SCE&G's cash flows and financial condition. In certain circumstances, which management considers to be remote, penalties for underpayment of income taxes could also be assessed. Additionally, in such circumstances, the Company and Consolidated SCE&G may need to access the capital markets to fund those tax and interest payments, which could in turn adversely impact their ability to access financial markets for other purposes.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and, in deregulated markets, received lower prices for natural gas when weather conditions have been milder than normal, and as a consequence earned less income from those operations. Mild weather in the future could adversely impact the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as hurricanes or other significant weather events, electromagnetic events or the 2011 earthquake and tsunami in Japan) or man-made mishaps (such as the San Bruno, California natural gas transmission pipeline failure, electric utility companies' ash pond failures, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial condition, operating expenses, and cash flows.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via an RTO/ISO is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should an RTO/ISO-market be implemented in the Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new delivery transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina or North Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company's and Consolidated SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets could be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems, which systems have undergone a rapid decline in their costs. As a result of federal and state subsidies, potential regulations allowing third-party retail sales, and advances in distributed generation technology, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and will slow growth, potentially causing higher rates to customers.

The Company and SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and SCE&G, which may be affected by regional, national or even international economic factors. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in higher costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally, legislative actions (including tax reform), or regulatory actions. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company's and SCE&G's products and adversely affect sales, sales growth, and customer usage patterns. For instance, improvements in energy storage technology, if realized, could have dramatic impacts on the viability of and growth in distributed generation.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms that are attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be adversely impacted.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company's or Consolidated SCE&G's operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission equipment failure, information systems failure or security breach, operator error, natural disasters, and the effects of a pandemic, terrorist attack or cyber attack on our workforce or facilities or on vendors and suppliers necessary to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The operation of the New Units or the integration of a significant amount of distributed generation into our systems may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G's territory or elsewhere in the region. Similarly, a natural gas line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company's and Consolidated SCE&G's revenues, results of operations, cash flows, and financial condition. Insurance may not be available or adequate to mitigate the adverse impacts of these events.

A failure of the Company and Consolidated SCE&G to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's and Consolidated SCE&G's financial condition, results of operations and cash flows.

The Company and Consolidated SCE&G depend on maintaining the physical and cyber security of their operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our businesses could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's and Consolidated SCE&G's operations are dependent in some manner upon our cyber systems, which encompass electric and gas operations, nuclear and fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company and Consolidated SCE&G, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, vendor, shareholder, employee, or corporate information. The Company and Consolidated SCE&G may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to mitigate the adverse impacts of these events. As a result, the Company's and Consolidated SCE&G's financial condition, results of operations, and cash flows may be adversely affected.

SCANA's ability to pay dividends and to make payments on SCANA's debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital.

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SCANA Energy, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

A significant portion of Consolidated SCE&G's generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition. These risks will increase as the New Units are developed.

In 2016, Unit 1 provided approximately 5.8 million MWh, or 25% of our generation. When the New Units are completed, our generating capacity and the percentage of total generating capacity represented by nuclear sources are expected to increase. Hence, SCE&G is subject to various risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and suppliers thereof, fabrication of nuclear fuel and related vendors, and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. In today's environment, there is a heightened risk of terrorist attack on the nation's nuclear facilities, which has resulted in increased security costs at our nuclear plant. Although we have no reason to anticipate a serious nuclear incident, a major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit, resulting in costly changes to units under construction or in operation and adversely impacting our results of operations, cash flows and financial condition. Furthermore, a major incident at a domestic nuclear facility could result in retrospective premium assessments under our nuclear insurance coverages.

Failure to retain and attract key personnel could adversely affect the Company's and Consolidated SCE&G's operations and financial performance.

As with many other utilities, a significant portion of our workforce will be eligible for retirement during the next few years. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our businesses. Competition for these employees is high, and in some cases we must compete for these employees on a regional or national basis. We may be unable to attract and retain these personnel. In particular, the timely hiring, training, licensing and retention of personnel needed for the operation of the New Units is necessary to maintain the schedule for their operation. Further, the Company's or Consolidated SCE&G's ability to construct or maintain generation or other assets including the New Units requires the availability of suitable skilled contractor personnel. We may be unable to obtain appropriate contractor personnel at the times and places needed. Labor disputes with employees or contractors covered by collective bargaining agreements also could adversely affect implementation of our strategic plan and our operational and financial performance. Furthermore, increased medical benefit costs of employees and retirees could adversely affect the results of operations of the Company and Consolidated SCE&G. Medical costs in this country have risen significantly over the past number of years and are expected to continue to increase at unpredictable rates. Such increases, unless satisfactorily managed by the Company and Consolidated SCE&G, could adversely affect results of operations.

***The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial condition, and access to capital*.**

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes, including customers' concerns regarding rate increases, such as those periodic rate increases under the BLRA, may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously supported by legislation or approved by regulators), to the detriment of the Company or Consolidated SCE&G (e.g., revision or repeal of the BLRA). Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company's or Consolidated SCE&G's interests, may have a negative effect on our results of operations, cash flows and financial condition, as well as limit our ability to access capital.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards related to compliance with laws and regulations, ethical conduct, operational effectiveness, customer service and the safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company's and Consolidated SCE&G's access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to assure reliability of provided services, to focus on the safety of employees, customers and the public, to ensure environmental compliance, to maintain the privacy of information related to our customers and employees, and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. Traditional news media and social media can very rapidly convey information, whether factual or not, to large numbers of people, including customers, investors, regulators, legislators and other stakeholders, and the failure to effectively manage timely, accurate communication through these channels could adversely impact our reputation. The Company and Consolidated SCE&G also are committed to operational excellence, to quality customer service, and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments may subject the Company and Consolidated SCE&G not only to fraud, regulatory action, litigation and financial loss, but also to reputational risk that could adversely affect the valuation of SCANA's stock, adversely affect the Company's and Consolidated SCE&G's access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds, directly or indirectly, all of the capital stock of each of its subsidiaries.

SCE&G's bond indenture, which secures its First Mortgage Bonds, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which secures certain outstanding debt of GENCO.

Electric Properties

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2016.

	In-Service Date	Net Generating Capacity Summer (MW)
Coal-Fired Steam:		
Wateree - Eastover, SC	1970	684
Williams - Goose Creek, SC	1973	605
Cope - Cope, SC	1996	415
Kapstone - Charleston, SC	1999	85
Gas-Fired Steam:		
McMeekin - Irmo, SC	1958	250
Urquhart Unit 3 - Beech Island, SC	1953	95
Nuclear:		
Summer Station Unit 1 - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647
Summer Station Unit 2 and Unit 3 - Parr, SC		*
Internal Combustion Turbines:		
Jasper Combined Cycle - Jasper, SC	2004	852
Urquhart Combined Cycle - Beech Island, SC	2002	458
Peaking units - various locations in SC	1968-2010	348
Hydro:		
Fairfield Pumped Storage - Parr, SC	1978	576
Saluda - Irmo, SC	1930	200
Other - various locations in or bordering SC	1905-1914	18

* SCE&G presently owns 55% of Unit 2 and Unit 3, which are being constructed at Summer Station.

SCE&G owns 433 substations having an aggregate transformer capacity of 31.5 million KVA. The transmission system consists of 3,442 miles of lines, and the distribution system consists of 18,522 pole miles of overhead lines and 7,441 trench miles of underground lines.

Natural Gas Distribution and Transmission Properties

SCE&G's natural gas system includes 447 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and DCGT. SCE&G’s distribution system consists of 17,375 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6,180 MMBTU per day and store the liquefied equivalent of 1,009,400 MMBTU of natural gas. The Salley facility can store the liquefied equivalent of 927,000 MMBTU of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 61,800 MMBTU per day at Charleston and 92,700 MMBTU per day at Salley.

PSNC Energy’s natural gas system consists of 606 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy’s distribution system consists of 21,686 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000,000 MMBTU, the capacity to liquefy up to 4,000 MMBTU per day and the capacity to regasify approximately 100,000 MMBTU per day.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G are subject to various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on their respective results of operations, cash flows or financial condition. In addition, certain material regulatory and environmental matters and uncertainties, some of which remain outstanding at December 31, 2016, are described in the Rate Matters section of Note 2 and in the Environmental section of Note 10 to the consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all wholly-owned subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	61	Chairman of the Board and Chief Executive Officer	*-present
		President and Chief Operating Officer-SCANA	*-present
Jimmy E. Addison	56	Executive Vice President-SCANA	*-present
		Chief Financial Officer	*-present
		President and Chief Operating Officer-SCANA Energy	2014-present
Jeffrey B. Archie	59	Senior Vice President and Chief Nuclear Officer-SCE&G	*-present
		Senior Vice President-SCANA	*-present
Sarena D. Burch	59	Senior Vice President-Risk Management and Corporate Compliance Senior Vice President-Fuel Procurement and Asset Management-SCANA, SCE&G and PSNC Energy	2016-present *-2015
Stephen A. Byrne	57	President-Generation and Transmission and Chief Operating Officer-SCE&G	*-present
		Executive Vice President-SCANA	*-present
D. Russell Harris	52	President-Gas Operations-SCE&G	2013-present
		President and Chief Operating Officer-PSNC Energy	*-present
		Senior Vice President-Gas Distribution-SCANA	2013-present
		Senior Vice President-SCANA	2012-2013
Kenneth R. Jackson	60	Senior Vice President-Economic Development, Governmental and Regulatory Affairs	2014-present
		Vice President-Rates and Regulatory Services	*-2014
W. Keller Kissam	50	President-Retail Operations-SCE&G	*-present
		Senior Vice President-SCANA	*-present
Ronald T. Lindsay	66	Senior Vice President, General Counsel and Assistant Secretary	*-present
Randal M. Senn	60	Senior Vice President-Administration-SCANA	2016-present
		Vice President and Chief Information Officer	2016
		Chief Information Officer	*-2016

*Indicates positions held at least since February 24, 2012.

PART II
ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

SCANA:

Price Range (NYSE Composite Listing):

	2016				2015			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$ 74.94	$ 76.41	$ 75.67	$ 70.35	$ 61.95	$ 57.73	$ 56.26	$ 65.57
Low	$ 67.31	$ 69.04	$ 66.02	$ 59.46	$ 54.84	$ 50.17	$ 47.77	$ 52.03

SCANA common stock trades on the NYSE using the ticker symbol SCG. At February 20, 2017 there were 142,916,917 shares of SCANA common stock outstanding which were held by approximately 25,000 shareholders of record. For a summary of equity securities issuable under SCANA's compensation plans at December 31, 2016, see Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

SCANA declared quarterly dividends on its common stock of $0.575 per share in 2016 and $0.545 per share in 2015. On February 16, 2017, SCANA increased the quarterly cash dividend rate on SCANA common stock to $0.6125 per share, an increase of approximately 6.5%. The next quarterly dividend is payable April 1, 2017 to shareholders of record on March 10, 2017. For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

The following table provides information about purchases by or on behalf of SCANA or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934, as amended (Exchange Act)) of shares or other units of any class of SCANA's equity securities that are registered pursuant to Section 12 of the Exchange Act:

Issuer Purchases of Equity Securities

	(a)	(b)	(c)	(d)
Period	Total number of shares (or units) purchased	Average price paid per share (or unit)	Total number of shares (or units) purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 1-31, 2016	7,583	$ 69.29	7,583	
November 1-30, 2016	—	—	—	
December 1-31, 2016	—	—	—	
Total	7,583		7,583	*

*The above table represents shares acquired for non-employee directors under the Director Compensation and Deferral Plan. On December 16, 2014, SCANA announced a program to convert from original issue to open market purchase of SCANA common stock for all applicable compensation and dividend reinvestment plans. This program took effect in the first quarter of 2015 and has no stated maximum number of shares that may be purchased and no stated expiration date.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2016 and 2015, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount	Declaration Date	Amount
February 18, 2016	$ 72.2 million	February 20, 2015	$ 69.0 million
April 28, 2016	73.3 million	April 30, 2015	67.8 million
July 28, 2016	74.0 million	July 30, 2015	68.4 million
October 27, 2016	77.5 million	October 29, 2015	72.3 million

On February 16, 2017, SCE&G declared a quarterly dividend on its common stock of $76.9 million.

For a discussion of provisions that could limit the payment of cash dividends, see Financing Limits and Related Matters in the Liquidity and Capital Resources section of Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 to the consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2016	2015	2014	2013	2012
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Income Data					
Operating Revenues	$ 4,227	$ 4,380	$ 4,951	$ 4,495	$ 4,176
Operating Income	$ 1,153	$ 1,308	$ 1,007	$ 910	$ 859
Net Income	$ 595	$ 746	$ 538	$ 471	$ 420
Common Stock Data					
Weighted Avg Common Shares Outstanding (Millions)	142.9	142.9	141.9	138.7	131.1
Basic Earnings Per Share	$ 4.16	$ 5.22	$ 3.79	$ 3.40	$ 3.20
Diluted Earnings Per Share	$ 4.16	$ 5.22	$ 3.79	$ 3.39	$ 3.15
Dividends Declared Per Share of Common Stock	$ 2.30	$ 2.18	$ 2.10	$ 2.03	$ 1.98
Balance Sheet Data					
Utility Plant, Net	$ 14,324	$ 13,145	$ 12,232	$ 11,643	$ 10,896
Total Assets	$ 18,707	$ 17,146	$ 16,818	$ 15,127	$ 14,568
Total Equity	$ 5,725	$ 5,443	$ 4,987	$ 4,664	$ 4,154
Short-term and Long-term Debt	$ 7,431	$ 6,529	$ 6,581	$ 5,788	$ 5,707
Other Statistics					
Electric:					
Customers (Year-End)	709,418	698,372	687,800	678,273	669,966
Total sales (Million kWh)	23,458	23,102	23,319	22,313	23,879
Generating capability-Net MW (Year-End)	5,233	5,234	5,237	5,237	5,533
Territorial peak demand-Net MW	4,807	4,970	4,853	4,574	4,761
Regulated Gas:					
Customers, excluding transportation (Year-End)	906,883	881,295	859,186	837,232	818,983
Sales, excluding transportation (Thousand Therms)	890,113	875,218	973,907	921,533	798,978
Transportation customers (Year-End)	632	627	656	667	663
Transportation volumes (Thousand Therms)	674,999	791,402	1,786,897	1,729,399	1,559,542

For information on the impact of certain dispositions on SCANA's selected financial data, see Note 1 to the consolidated financial statements.

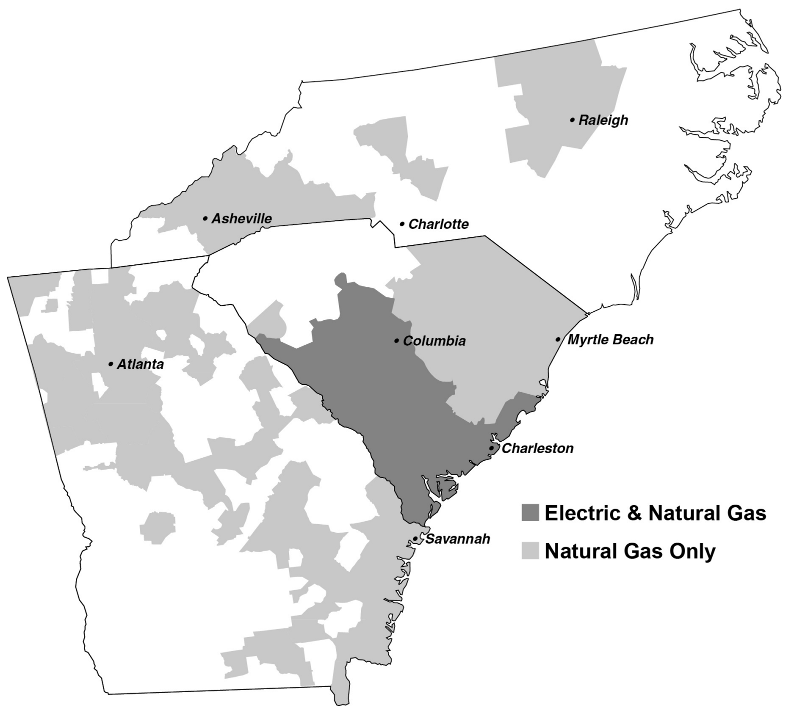
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pursuant to General Instruction I of Form 10-K, SCE&G is permitted to omit certain information related to itself and its consolidated affiliates called for by Item 7 of Form 10-K, and instead provide a management's narrative explanation of its consolidated results of operation and other information described therein. Such information is presented hereunder specifically for Consolidated SCE&G, but may be presented alongside information presented for the Company generally. Consolidated SCE&G makes no representation as to information relating solely to SCANA Corporation and its subsidiaries (other than Consolidated SCE&G).

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers in the southeast. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

The following map indicates areas where the Company's significant business segments conduct their activities, as further described in this overview section.



The following percentages reflect amounts attributable to the Company's regulated and nonregulated operations and other nonregulated (including the holding company and the services company).

	2016	2015	2014
Net Income			
Regulated	98 %	72%	98 %
Nonregulated operations	5 %	4%	7 %
Other nonregulated	(3)%	24%	(5)%
Assets			
Regulated	97 %	97%	95 %
Nonregulated operations	1 %	1%	2 %
Other nonregulated	2 %	2%	3 %

In the first quarter of 2015, SCANA closed on the sales of its interstate natural gas pipeline and telecommunications subsidiaries. Gains from these sales are included within Other. See Dispositions in Note 1 to the consolidated financial statements.

Key Earnings Drivers and Outlook

In 2016, companies announced plans to invest over $1.8 billion, with the expectation of creating approximately 7,000 jobs in the Company's South Carolina and North Carolina service territories. At December 31, 2016, South Carolina's unemployment rate was 4.3%, which is approximately 1.2% lower than the prior year. In addition, each of the Company's regulated businesses experienced positive customer growth year over year.

Over the next five years, key earnings drivers for the Company are expected to be additions to rate base at its regulated subsidiaries, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage in each of the regulated utility businesses, earnings in the natural gas marketing business and the level of growth of operation and maintenance, interest and other expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generate electricity and provide for its transmission, distribution and sale to approximately 709,000 customers (as of December 31, 2016) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity compared to other energy sources.

Embedded in the rates charged to customers is an allowed regulatory ROE. SCE&G's allowed ROE in 2016 was 10.25% for non-BLRA rate base and 10.5% for BLRA-related rate base. For BLRA-related rate base existing prior to 2016, SCE&G's allowed ROE was 11.0%.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and SCE&G has agreed to acquire an additional 5% ownership from Santee Cooper in increments beginning with the commercial operation date of Unit 2.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding certain disputes, and the EPC Contract was amended. The October 2015 Amendment became effective on December 31, 2015, and among other things, it resolved by settlement and release substantially all then-outstanding disputes between SCE&G and the Consortium. The October 2015 Amendment also provided SCE&G and Santee Cooper an option, subject to regulatory approvals, to fix the total amount to be paid to the Consortium for its entire scope of work on the project after June 30, 2015, subject to certain exceptions. In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units developed as a result of the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively, although recent communications from WEC indicate substantial completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. These later dates remain within SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits. However, there is substantial uncertainty as to WEC's ability to meet these dates given its historical inability to meet forecasted productivity and work force efficiency levels.

The approved capital cost schedule includes incremental capital costs. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under any of several arrangements with other contractors or, were it determined to be prudent, halting the project, leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA. Any significant delay in the timing of construction or any determination by the SCPSC to disallow the recovery of costs would adversely impact results of operations, cash flows and financial condition.

The information summarized above, as well as additional information regarding uncertainties concerning WEC's ability to continue to fulfill its performance and financial commitments and Toshiba's ability to perform under its payment guaranty with respect to the project and other related matters, is further discussed in Note 2 and Note 10 to the consolidated financial statements.

Environmental

The results of recent elections may affect the pace at which federal environmental laws and regulations are enacted or how stringently their provisions are interpreted in the future. However, public sentiment surrounding air quality and water quality remains strong and is expected to continue unabated.

Over several years, SCE&G has made significant investments in constructing non-emitting generation (the New Units previously mentioned) and retiring certain coal-fired plants or converting them to burn natural gas. In addition, SCE&G expects to add the renewable energy from six new solar generating facilities at locations throughout its electric service territory over the next few years. The impact of these investments is expected to result in a significant shift toward non-emitting sources of fuel used to generate electricity in the future.

Generation Type	2016 Actual	2021 Projected
Nuclear	24.7%	56.7%
Hydro	3.3%	3.4%
Solar	—%	2.2%
Total Non-emitting	**28.0%**	**62.3%**
Biomass	1.7%	—%
Natural Gas	33.5%	17.9%
Coal	36.8%	19.8%
Total Generation	100.0%	100.0%

In addition, SCE&G and GENCO have made significant investments to install pollution control equipment at their remaining coal-fired plants. These investments, together with investments in non-emitting generation, have reduced their air emissions and are expected to result in additional reductions in the future.

Emissions, measured in thousands of tons			
Year	**NO_X**	**SO_2**	**CO_2**
2005	27.0	107.9	18,778.7
2013	7.0	19.3	12,507.9
2014	7.6	16.8	13,984.6
2015	5.7	5.1	12,891.8
2016	5.4	2.7	11,567.4
2021*	3.2	1.2	7,062.5
% decrease from 2005 to 2021*	**88.1%**	**98.9%**	**62.4%**

* Projected

The status of significant environmental laws and regulations and certain initiatives undertaken to ensure compliance with them are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. In addition, uncertainties with respect to the New Units are described in Note 10 to the consolidated financial statements.

Gas Distribution

The local distribution operations of SCE&G and PSNC Energy purchase, transport and sell natural gas to approximately 907,000 retail customers (as of December 31, 2016) in portions of South Carolina and North Carolina in areas covering approximately 35,000 square miles. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory ROE for SCE&G of 10.25% and for PSNC Energy of 10.60% through October 31, 2016 and 9.7% thereafter.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company’s ability to retain large commercial and industrial customers.

The production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at generally low levels for several years. The supply of natural gas from the Marcellus shale basin has prompted companies unaffiliated with SCANA to propose a 550-mile pipeline that would bring natural gas from West Virginia to Virginia and North Carolina. This pipeline is expected to be completed in late 2019 and, if successful, it may drive economic development along its path, including areas within PSNC Energy's service territory, and may serve to assist in keeping natural gas competitively priced in the region.

Gas Marketing

SCANA Energy markets natural gas in the southeast and provides energy-related services to customers, including, notably, retail customers in Georgia. Operating results for energy marketing are influenced by customer demand for natural gas and the ability to control costs. The price of alternate fuels and customer growth significantly affect demand for natural gas. In addition, the availability of certain pipeline capacity to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the Georgia retail market. SCANA Energy sells natural gas to approximately 450,000 customers (as of December 31, 2016) throughout Georgia. This market is mature, resulting in lower margins and stiff competition. Competitors include affiliates of large energy companies as well as electric membership cooperatives, among others. SCANA Energy’s ability to maintain its market share primarily depends on the prices it charges customers relative to the prices charged by its competitors and its ability to provide high levels of customer service. In addition, SCANA Energy's operating results are sensitive to weather.

RESULTS OF OPERATIONS

Earnings and Dividends

Earnings and dividends were as follows:

	2016	2015	2014
The Company			
Earnings per share	$ 4.16	$ 5.22	$ 3.79
Cash dividends declared per share	$ 2.30	$ 2.18	$ 2.10
Consolidated SCE&G			
Net income (millions of dollars)	$ 525.8	$ 479.5	$ 457.7

On February 16, 2017, SCANA declared a quarterly cash dividend on its common stock of $0.6125 per share.

2016 vs 2015

Earnings per share decreased primarily due to the sales of CGT and SCI in 2015, higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense. These decreases were partially offset by higher electric and gas distribution margins, higher other income net of other expenses and higher energy marketing net income, as further described below.

Consolidated SCE&G's net income increased primarily due to higher electric and gas distribution margins, partially offset by higher operation and maintenance expense, higher depreciation expense, higher property taxes, higher interest cost, and higher income taxes, as further described below.

2015 vs 2014

Earnings per share increased due to the sales of CGT and SCI in 2015, higher electric margins, lower operation and maintenance expenses and lower depreciation expense. These increases were partially offset by lower gas margins, higher property taxes, lower other income, higher interest expense, a higher effective tax rate and dilution from additional shares outstanding, as further described below.

The sales of CGT and SCI were closed in the first quarter of 2015. These subsidiaries operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. Therefore, CGT and SCI were not a part of the Company's core business. See Note 12 to the consolidated financial statements.

Consolidated SCE&G's net income increased primarily due to higher electric and gas distribution margins and lower depreciation expense, partially offset by lower other income, higher operation and maintenance expense, higher property taxes, higher interest cost, and higher income taxes, as further described below.

Electric Operations

Electric Operations for the Company and for Consolidated SCE&G is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric Operations operating income (including transactions with affiliates) was as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Operating revenues	$ 2,619.4	$ 2,557.1	$ 2,629.4	$ 2,619.4	$ 2,557.1	$ 2,629.4
Fuel used in electric generation	576.1	660.6	799.3	576.1	660.6	799.3
Purchased power	63.7	52.1	80.7	63.7	52.1	80.7
Margin	1,979.6	1,844.4	1,749.4	1,979.6	1,844.4	1,749.4
Other operation and maintenance	526.1	497.1	494.8	540.2	509.6	507.5
Depreciation and amortization	286.5	277.3	300.3	274.9	266.9	289.5
Other taxes	210.4	194.5	186.7	207.9	192.4	184.8
Operating Income	$ 956.6	$ 875.5	$ 767.6	$ 956.6	$ 875.5	$ 767.6

Electric operations can be significantly impacted by the effects of weather. SCE&G estimates the effects on its electric business of actual temperatures in its service territory as compared to historical averages to develop an estimate of electric margin revenue attributable to the effects of abnormal weather. Results in 2016 reflect warmer than normal weather in the second and third quarters and milder than normal weather in the first and fourth quarters. Results in 2015 reflect colder than normal weather in the first quarter, warmer than normal weather in the second and third quarters and milder than normal weather in the fourth quarter. Results in 2014 reflect colder than normal weather in the first quarter, hotter than normal weather in the second and third quarters and milder than normal weather in the fourth quarter.

2016 vs 2015

- Margin increased due to base rate increases under the BLRA of $60.7 million, the effects of weather of $22.1 million, residential and commercial customer growth of $22.1 million, higher industrial margin of $7.6 million and higher collections under the rate rider for pension costs of $13.5 million. These margin increases were partially offset by lower residential and commercial average use. The higher pension rider collections had no effect on net income as they were fully offset by the recognition, within other operation and maintenance expenses, of higher pension costs. Margin also increased due to downward revenue adjustments in 2015, pursuant to orders from the SCPSC, to apply $14.5 million as an offset to fuel cost recovery upon the adoption of new (lower) electric depreciation rates and by $5.2 million related to DSM Programs. These adjustments had no effect on net income in 2015 as they were fully offset by the recognition of $14.5 million of lower depreciation expense and by the recognition, within other income, of $5.2 million of gains realized upon the settlement of certain interest rate contracts.
- Other operation and maintenance expenses increased due to higher labor costs of $25.4 million, primarily due to increased pension cost associated with the higher pension rider collections and higher incentive compensation costs. Other operation and maintenance expenses also increased due to higher amortization of DSM program costs of $2.0 million.
- Depreciation and amortization increased primarily due to net plant additions.
- Other taxes increased primarily due to higher property taxes on net plant additions.

2015 vs 2014

- Margin increased due to downward adjustments of $69.0 million in 2014, compared to downward adjustments of $19.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and DSM Programs. These adjustments had no effect on net income as they were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts, lower depreciation expense upon the adoption and implementation of revised depreciation rates as a result of an updated depreciation study and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve. Margin also increased due to base rate increases under the BLRA of $65.7 million and residential and commercial customer growth of $21.4 million. These increases were partially offset by $25.6 million due to the effects of weather, lower industrial margins of $14.6 million primarily due to variable price contracts, and lower collections under the rate rider for pension costs of $3.0 million. See Note 2 to the consolidated financial statements.

- Other operation and maintenance expenses increased due to the application of $5.0 million in 2014 of the storm damage reserve to offset downward revenue adjustments related to DSM Programs and the amortization of $3.7 million of DSM Programs cost. These increases were partially offset by lower labor costs of $2.0 million primarily due to lower pension cost recognition as a result of lower rate rider collections.
- Depreciation and amortization decreased by $28.7 million in 2015 due to the implementation of the above mentioned revised depreciation rates, $14.5 million of which was offset by downward revenue adjustments. This decrease in depreciation expense was partially offset by increases associated with net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric operations margin above, by class, were as follows:

Classification	2016	2015	2014
Residential	8,140	7,978	8,156
Commercial	7,506	7,386	7,371
Industrial	6,265	6,201	6,234
Other	600	595	600
Total retail sales	22,511	22,160	22,361
Wholesale	947	942	958
Total Sales	23,458	23,102	23,319

2016 vs 2015

Retail sales volumes increased primarily due to the effects of weather and customer growth.

2015 vs 2014

Retail sales volumes decreased primarily due to the effects of weather, partially offset by customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G, and for the Company, also includes PSNC Energy. Gas Distribution operating income (including transactions with affiliates) was as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	2016	2015	2014	2016	2015	2014
Operating revenues	$ 789.8	$ 811.7	$ 1,014.0	$ 366.8	$ 372.7	$ 462.2
Gas purchased for resale	345.9	383.7	592.5	182.9	192.5	283.1
Margin	443.9	428.0	421.5	183.9	180.2	179.1
Other operation and maintenance	172.7	161.4	154.8	73.6	69.8	67.7
Depreciation and amortization	82.0	77.5	72.4	27.3	26.8	25.7
Other taxes	41.5	37.5	34.8	26.8	24.9	23.1
Operating Income	$ 147.7	$ 151.6	$ 159.5	$ 56.2	$ 58.7	$ 62.6

The effect of abnormal weather conditions on gas distribution margin is mitigated by the WNA at SCE&G and the CUT at PSNC Energy as further described in Revenue Recognition in Note 1 of the consolidated financial statements. The WNA and CUT affect margins but not sales volumes.

2016 vs 2015

- Margin increased $11.5 million at the Company, including $6.0 million at SCE&G, due to residential and commercial customer growth, $5.0 million due to an NCUC-approved rate increase effective November 2016 at PSNC Energy, and $1.1 million due to an SCPSC-approved increase in base rates under the RSA effective November 2016 at SCE&G. These increases were partially offset by lower average use of $4.1 million at SCE&G.
- Other operation and maintenance expenses increased due to higher labor costs of $6.7 million at the Company, including $2.1 million at SCE&G, due primarily to higher incentive compensation costs.
- Depreciation and amortization increased at the Company and SCE&G due to net plant additions, partially offset by the implementation of SCPSC-approved revised (lower) depreciation rates at SCE&G of $1.1 million.
- Other taxes increased at the Company and SCE&G due to net plant additions.

2015 vs 2014

- Margin increased due to residential and commercial customer growth of $7.8 million at the Company, including $4.3 million at SCE&G, partially offset by a decrease of $3.1 million due to an SCPSC-approved decrease in base rates at SCE&G under the RSA effective November 2014.
- Other operation and maintenance expenses increased at the Company and SCE&G due to higher labor costs, primarily due to incentive compensation.
- Depreciation and amortization increased at the Company and SCE&G due to net plant additions.
- Other taxes increased at the Company and SCE&G due primarily to higher property taxes associated with net plant additions.

Sales volumes (in MMBTU) related to gas distribution margin by class, including transportation, were as follows:

	The Company			Consolidated SCE&G		
Classification (in thousands)	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Residential	40,142	39,090	46,207	12,420	12,086	14,917
Commercial	29,078	28,064	30,701	12,879	12,580	13,936
Industrial	19,364	20,101	20,343	17,228	17,901	18,307
Transportation gas	49,769	49,297	45,506	5,250	4,781	4,286
Total	138,353	136,552	142,757	47,777	47,348	51,446

2016 vs 2015

Residential and commercial firm sales volumes increased primarily due to customer growth. Commercial and industrial interruptible volumes decreased, and firm volumes increased, due to customers switching from interruptible to firm service at SCE&G. Industrial volumes decreased and transportation volumes increased due to customers switching to transportation only service.

2015 vs 2014

Residential and commercial firm sales volumes decreased due to the effects of weather and lower average use, partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to a shift to transportation service from system supply and the impact of curtailments, partially offset at the Company by lower curtailments at PSNC Energy. Transportation volumes increased due to customers shifting to transportation-only service at SCE&G, and at the Company, included increased sales for natural gas fired electric generation in PSNC Energy's territory.

Gas Marketing

Gas Marketing is comprised of the Company’s nonregulated marketing operation, SCANA Energy, which operates in the southeast and includes Georgia’s retail natural gas market. Gas Marketing operating revenues and net income were as follows:

Millions of dollars	**2016**	**2015**	**2014**
Operating revenues	$ 936.7	$ 1,146.7	$ 1,496.4
Net Income	29.8	27.6	31.0

2016 vs 2015

Operating revenues decreased due to the lower market price of natural gas and lower industrial sales volume. Net income increased primarily due to a weather-related increase in demand.

2015 vs 2014

Operating revenues decreased due to the lower market price of natural gas, weather-related changes in demand, lower industrial sales volume and lower market prices. Net income decreased primarily due to weather-related changes in demand, partially offset by lower cost of gas and lower costs of transportation to serve customers.

Other Operating Expenses

Other operating expenses were as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Other operation and maintenance	$ 755.6	$ 715.3	$ 728.3	$ 613.8	$ 579.4	$ 575.2
Depreciation and amortization	370.9	357.5	383.7	302.2	293.7	315.2
Other taxes	253.9	234.2	228.8	234.7	217.3	207.9

Changes in other operating expenses are largely attributable to the electric operations and gas distribution segments and are addressed in those discussions. Additional information is provided below.

2016 vs 2015

In addition to factors discussed in the electric operations and gas distribution segments, overall increases in other operating expenses were partially offset by the Company's sale of CGT in early 2015, which resulted in decreases in other operation and maintenance expenses of $2.2 million, depreciation and amortization of $0.7 million and other taxes of $0.5 million.

2015 vs 2014

In addition to factors discussed in the electric operations and gas distribution segments, the Company's sale of CGT in early 2015 resulted in decreases in other operation and maintenance expenses of $24.2 million, depreciation and amortization of $7.8 million and other taxes of $8 million.

Net Periodic Benefit Cost

Other operation and maintenance expense includes net periodic benefit cost, which was recorded on the income statements and balance sheets as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Income Statement Impact:						
Employee benefit costs	$ 19.2	$ 5.3	$ 5.0	$ 16.4	$ 2.8	$ 4.0
Other expense	0.9	1.1	0.2	0.2	0.2	0.1
Balance Sheet Impact:						
Increase in capital expenditures	5.3	3.9	0.5	4.7	3.4	0.3
Component of amount receivable from Summer Station co-owner	2.1	1.5	0.1	2.1	1.5	0.1
Increase (decrease) in regulatory assets	(4.6)	6.2	(3.2)	(4.6)	6.2	(3.2)
Net periodic benefit cost	$ 22.9	$ 18.0	$ 2.6	$ 18.8	$ 14.1	$ 1.3

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were $2.0 million for retail electric operations and $1.0 million for gas operations for each period presented.

Other Income (Expense)

Other income (expense) includes the results of certain incidental non-utility activities of regulated subsidiaries, the activities of certain of the Company's non-regulated subsidiaries, and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. An equity portion of AFC is included in nonoperating income and a debt portion of AFC is included in interest charges (credits), both of which have the effect of increasing reported net income. Components of other income (expense) and AFC were as follows:

Millions of dollars	The Company 2016	The Company 2015	The Company 2014	Consolidated SCE&G 2016	Consolidated SCE&G 2015	Consolidated SCE&G 2014
Other income	$ 64.4	$ 74.5	$ 121.8	$ 29.3	$ 31.1	$ 79.8
Other expense	(38.5)	(60.1)	(64.3)	(24.1)	(31.1)	(33.8)
Gain on sale of SCI, net of transaction costs	—	106.6	—	—	—	—
AFC - equity funds	29.4	27.0	32.7	26.1	24.8	27.7

2016 vs 2015

Other income at the Company and Consolidated SCE&G decreased by $3.5 million due to lower gains on the sale of land and due to the recognition in 2015 of $5.2 million of gains realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). At the Company, other income also decreased by $3.9 million and other expenses decreased by $2.3 million due to the sale of SCI, and other income and other expenses decreased by $10.5 million for billings to DCGT for transition services provided at cost pursuant to the terms of the sale of CGT. Other expenses at the Company and Consolidated SCE&G decreased by $5.2 million due to lower contribution expenses. In 2015, the Company's other income included the gain on the sale of SCI (see Dispositions in Note 1 to the consolidated financial statements). AFC increased due to construction activity.

2015 vs 2014

Other income decreased at the Company and Consolidated SCE&G due primarily to the recognition of $64.0 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). At the Company, other income also decreased by $18.3 million and other expenses decreased by $10.9 million due to the sale of SCI, and other income and other expenses increased by $12.7 million for billings to DCGT for transition services provided at cost pursuant to the terms of the sale of CGT. In 2015, the Company's other income included the gain on the sale of SCI (see Dispositions in Note 1 to the consolidated financial statements). AFC decreased due to lower AFC rates.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	The Company 2016	The Company 2015	The Company 2014	Consolidated SCE&G 2016	Consolidated SCE&G 2015	Consolidated SCE&G 2014
Interest on long-term debt, net	$ 330.3	$ 311.3	$ 306.7	$ 253.8	$ 236.0	$ 217.6
Other interest expense	12.0	6.5	5.7	16.2	12.1	10.4
Total	$ 342.3	$ 317.8	$ 312.4	$ 270.0	$ 248.1	$ 228.0

Interest expense increased in each year primarily due to increased borrowings.

Income Taxes

At the Company, income tax expense decreased from 2015 to 2016 primarily due to lower income before taxes. Income tax expense increased from 2014 to 2015 primarily due to higher income before taxes. Income before taxes, income taxes and the effective tax rate were all higher in 2015 primarily due to the sales of CGT and SCI. At Consolidated SCE&G, income tax expense increased each year primarily due to increases in income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to meet contractual cash obligations in 2017 through internally generated funds and additional short- and long-term borrowings. The Company may also meet such obligations through the sale of equity securities. The Company expects that, barring a future impairment of the capital markets or its access to such markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Cash requirements for SCANA’s regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

Due primarily to the availability of proceeds from the sale of two subsidiaries in the first quarter of 2015, the Company began using open market purchases for its stock plans at the end of January 2015. Prior to the use of open market purchases, SCANA common stock was acquired on behalf of participants in SCANA's Investor Plus Plan and Stock Purchase-Savings Plan through the original issuance of shares. This provided additional equity of approximately $14 million in 2015.

Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of the Company's or its rated operating companies' commonly monitored financial credit metrics and adverse developments with respect to nuclear construction could negatively affect the Company's debt ratings. This could cause the Company to pay higher interest rates on its long- and short-term indebtedness, and could limit the Company's access to capital markets and liquidity.

Cash provided from operating activities in 2015 reflects lower tax payments arising from Congress' extension of bonus deprecation provisions in 2014. Cash provided from operating activities in 2016 reflects significant tax benefits (reductions in income tax payments) arising from the deduction under Section 174 of the IRC of certain expenditures related to the design and construction of the New Units and the related claim of credits under Section 41 of the IRC. Similar tax benefits are expected to be claimed in the next several years as design and construction continues, and these cash flows are expected to continue to supplant portions of financing which would otherwise be obtained in the capital markets.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.6 billion in 2016. Estimates of capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2017	2018	2019
SCE&G - Normal			
Generation	$ 138	$ 124	$ 148
Transmission & Distribution	180	205	207
Other	10	16	26
Gas	74	85	76
Common	4	3	9
Total SCE&G - Normal	406	433	466
PSNC Energy	332	242	182
Other	31	21	28
Total Normal	769	696	676
New Nuclear (including transmission) - SCE&G*	1,222	1,165	501
Cash Requirements for Construction*	1,991	1,861	1,177
Nuclear Fuel - SCE&G	80	89	111
Total Estimated Capital Expenditures*	$ 2,071	$ 1,950	$ 1,288

*Excludes the impact of the updated integrated project schedule which reflects WEC's revised estimated completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. See Note 10 to the consolidated financial statements.

Contractual cash obligations as of December 31, 2016 are summarized as follows:

Contractual Cash Obligations		Payments due by periods			
Millions of dollars	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long- and short-term debt, including interest	$ 13,976	$ 1,292	$ 2,002	$ 1,257	$ 9,425
Capital leases	26	5	14	2	5
Operating leases	116	30	59	6	21
Purchase obligations	3,869	2,387	1,481	1	—
Other commercial commitments	3,639	899	1,532	613	595
Total	$ 21,626	$ 4,613	$ 5,088	$ 1,879	$ 10,046

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent. SCE&G has agreed to acquire an additional 5% ownership in the New Units and has included $850 million for this purpose in other commercial commitments. See also New Nuclear Construction in Note 10 to the consolidated financial statements.

Purchase obligations include customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Such forward contracts include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a "take-and-pay" contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases.

Unrecognized tax benefits of approximately $219 million have been excluded from the table above due to uncertainty as to the timing of future payments. For additional information, see Note 5 to the consolidated financial statements.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $11.1 million in 2016, and such annual payments are expected to be the same or increase to as much as $15.9 million in the future.

The Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. The Company, including Consolidated SCE&G, is also party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash collateral. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 6 to the consolidated financial statements. As of December 31, 2016, the Company had posted $29.0 million in cash collateral related to interest rate derivative contracts.

The Company has a legal obligation associated with the decommissioning and dismantling of Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements.

Financing Limits and Related Matters

Issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor (pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million.

GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2018.

At December 31, 2016 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $400 million, $1.2 billion, of which $500 million relates to Fuel Company, and $200 million, respectively, which expire in December 2020. In addition, at December 31, 2016 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2016, the Company had no outstanding borrowings under its credit facilities, had approximately $941 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC-supported letters of credit, and held approximately $208 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. The Company's average short-term borrowings outstanding during 2016 were approximately $857 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2016, the Company’s long-term debt portfolio has a weighted average maturity of approximately 20 years and bears an average cost of 5.8%. Substantially all long-term debt bears fixed interest rates or is swapped to fixed.

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture (relating to the hereinafter defined Bonds) and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2016, approximately $79.0 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2016, the Bond Ratio was 5.12.

Financing Activities

During 2016, net cash inflows related to financing activities totaled approximately $560 million, primarily associated with the proceeds from the issuance of long-term debt and short-term borrowings, partially offset by the payment of dividends.

On November 1, 2016, Consolidated SCE&G paid at maturity $100 million related to a nuclear fuel financing which had an imputed interest rate of 0.78%.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of the $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G’s construction program, to finance capital expenditures, and for general corporate purposes.

In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from this sale were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

On February 2, 2015, SCANA redeemed prior to maturity $150 million of its 7.70% junior subordinated notes at their face value.

Investing Activities

To settle interest rate derivative contracts, the Company paid approximately $113 million in 2016, $253 million, net, in 2015 and approximately $95 million in 2014.

For additional information, see Note 4 to the consolidated financial statements.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2016, were as follows:

December 31,	2016	2015	2014	2013	2012
The Company	3.38	4.40	3.39	3.22	2.93
Consolidated SCE&G	3.66	3.69	3.77	3.48	3.29

The Company's ratio for 2015 reflects the impact of gains recorded upon the sale of certain subsidiaries. See Note 1 to the consolidated financial statements.

NEW NUCLEAR CONSTRUCTION MATTERS

For a discussion of developments related to new nuclear construction, see Note 2 and Note 10 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

The operations of the Company are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on financial condition, results of operations and cash flows. In addition, the conditions or requirements that will be imposed by regulatory or legislative proposals often cannot be predicted. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, recovery of such expenditures and costs are expected through existing ratemaking provisions.

For the three years ended December 31, 2016, capital expenditures for environmental control equipment at fossil fuel generating stations totaled $39.5 million. During this same period, expenditures were made for the construction and retirement of landfills and ash ponds, net of disposal proceeds, of approximately $32.8 million. In addition, expenditures were made to operate and maintain environmental control equipment at fossil plants of $9.5 million in 2016, $8.7 million in 2015 and $9.1 million in 2014, which are included in other operation and maintenance expense, and expenditures were made to handle waste ash, net of disposal proceeds, of $2.4 million in 2016, $1.3 million in 2015 and $1.6 million in 2014, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2016, 2015 and 2014 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $38.3 million for 2017 and $120 million for the four-year period 2018-2021. These expenditures are included in the Estimated Capital Expenditures table, discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to the Company's electric and gas systems, as well as impacts on employees and customers, the supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow for the protection of assets and the return of systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC, under Dodd-Frank, concerning recordkeeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCANA and any of its subsidiaries engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and other matters, including accounting; the DOE under the Federal Power Act as to use of emergency authority and coordination of all applicable federal authorizations and related environmental reviews to site an electric transmission facility; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings); the FERC as to issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters; and the DOE under the Federal Power Act as to use of emergency authority.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.

SCE&G and PSNC Energy	The PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively. The ORS and the NCUC are responsible for enforcement of federal and state pipeline safety requirements in South Carolina (SCE&G) and North Carolina (PSNC Energy), respectively.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

SCE&G's electric transmission system and certain facilities related to generation and distribution are subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Accounting for Rate Regulated Operations

Regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the criteria of accounting for rate-regulated utilities may no longer be met, and the write off of regulatory assets and liabilities could be required. Such an event could have a material effect on the results of operations, liquidity or financial position of the Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the regulatory assets and liabilities.

Generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write down in those assets could be required. It is not possible to predict whether any write-downs would be necessary and, if they were, the extent to which they would affect results of operations in the period in which they would be recorded. As of December 31, 2016, net investments in fossil/hydro and nuclear generation assets were approximately $2.2 billion and $5.0 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, estimates are recorded for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. The Company's accounts receivable included unbilled revenues of $178.9 million at December 31, 2016 and $129.1 million at December 31, 2015, compared to total revenues of $4.2 billion in 2016 and $4.4 billion in 2015.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates, less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Asset Retirement Obligations

AROs are accrued for legal obligations associated with the retirement of long-lived tangible assets that result from acquisition, construction, development and normal operation in accordance with applicable accounting guidance. These obligations are recognized at present value in the period in which they are incurred, and associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2016, the Company has recorded AROs of $199 million for nuclear plant decommissioning (as discussed above) and AROs of $359 million for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of precision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. Net pension cost of $22.9 million recorded in 2016 reflects the use of a 4.68% discount rate derived using a cash flow matching technique, and an assumed 7.50% long-term rate of return on plan assets. The Company believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2016 would have increased the Company's pension cost by $1.6 million and increased the pension obligation by $23.2 million. Further, had the assumed long-term rate of return on assets been 7.25%, the Company's pension cost for 2016 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2016, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.3%, 4.6%, 7.2% and 8.7%, respectively. The 2016 expected long-term rate of return of 7.50% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2017, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.1%, 5.4%, 6.9% and 8.2%, respectively. For 2017, it is anticipated that the long-term expected rate of return will be 7.25%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's and PSNC Energy's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after 2023. As a result, the significance of pension costs and the criticality of the related estimates will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future based on current market conditions and assumptions.

The Company accounts for the cost of its postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 4.78%, derived using a cash flow matching technique, and recorded a net cost for 2016 of $17.3 million. Had the selected discount rate been 4.53% (25 basis points lower than the discount rate referenced above), the expense for 2016 would have been $0.7 million higher and increased the obligation by $8.3 million. Because the plan provisions include “caps” on company per capita costs, and because employees hired after 2010 are responsible for the full cost of retiree medical benefits elected by them, health care cost inflation rate assumptions do not materially impact the net expense recorded.

Uncertain Income Tax Positions

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In September 2016, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the ongoing design and construction activities of the New Units, in its 2015 income tax returns. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models. See also Note 5 to the consolidated financial statements.

These income tax deductions and credits are considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities are required to be recorded as unrecognized tax benefits in the financial statements. As of December 31, 2016, such estimated unrecognized tax benefits totaled $350 million ($219 million net of the impact of state deductions on federal returns, and net of certain operating loss and tax credit carryforwards and receivables related to the uncertain tax positions). The estimates of unrecognized tax benefits were computed with consideration as to whether the claims are (or are not) more likely than not to be sustained and with consideration of analyses of cumulative probabilities regarding potential outcomes. Such estimates involve significant management judgment and varying levels of precision. Changes in such estimates are required to be recorded as circumstances change and additional information regarding the claims and potential outcomes becomes available, and these changes could be significant.

However, as these uncertain tax positions primarily involve the timing of recognition of tax deductions rather than permanent tax attributes, the estimates regarding their recognition do not significantly impact the Company's effective tax rate. Further, the permanent attributes (net), as well as most of the interest accruals required to be recorded with respect to the unrecognized tax benefits, have been deferred within regulatory assets. As such, the impacts of these significant accounting estimates, and changes therein, are primarily reflected on the balance sheet rather than in results of operations.

Upon resolution of the uncertainties, the Company will be required to re-pay any tax benefits claimed which are ultimately disallowed, along with interest on those amounts. In certain circumstances, which the Company considers to be remote, penalties for underpayment of income taxes could also be assessed. Such amounts could be significant and adversely affect cash flow and financial condition.

OTHER MATTERS

Off-Balance Sheet Arrangements

SCANA holds insignificant investments in securities and business ventures. The Company does not engage in significant off-balance sheet financing or similar transactions, although it is party to various operating leases in the normal course of business for land, office space, furniture, vehicles, equipment, rail cars, a purchase power agreement, and airplanes.

Claims and Litigation

For a description of claims and litigation, see Note 10 to the consolidated financial statements.

Other

As Georgia's regulated provider, SCANA Energy provides service to customers considered to be low-income or that are otherwise unable to obtain natural gas service from other marketers. SCANA Energy provides this service at rates approved by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA's natural gas distribution and gas marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating commodity natural gas prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or placed under contract.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

Interest Rate Risk

The tables below provide information about long-term debt issued by the Company and Consolidated SCE&G and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

The Company **December 31, 2016**	**Expected Maturity Date**							
Millions of dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	12.5	721.7	11.1	360.2	489.0	4,789.7	6,384.3	7,040.6
Average Fixed Interest Rate (%)	4.21	6.01	4.40	6.33	4.64	5.73	5.70	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	125.0	147.0	142.7
Average Variable Interest Rate (%)	1.63	1.63	1.63	1.63	1.63	1.16	1.23	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	554.4	704.4	4.4	4.4	4.4	128.6	1,400.6	12.3
Average Pay Interest Rate (%)	2.91	2.22	6.17	6.17	6.17	4.57	2.74	—
Average Receive Interest Rate (%)	1.00	1.00	1.63	1.63	1.63	1.08	1.02	—

December 31, 2015	Expected Maturity Date							
Millions of dollars	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	111.5	10.6	719.8	9.1	358.3	4,673.0	5,882.3	6,336.2
Average Fixed Interest Rate (%)	1.16	4.42	6.02	4.73	6.35	5.63	5.63	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	129.4	151.4	145.5
Average Variable Interest Rate (%)	1.11	1.11	1.11	1.11	1.11	0.55	0.63	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	654.4	554.4	4.4	4.4	4.4	133.0	1,355.0	(72.1)
Average Pay Interest Rate (%)	2.89	2.91	6.17	6.17	6.17	4.62	3.10	—
Average Receive Interest Rate (%)	0.62	0.62	1.11	1.11	1.11	0.52	0.61	—

Consolidated SCE&G

December 31, 2016	Expected Maturity Date							
Millions of dollars	2017	2018	2019	2020	2021	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	12.0	721.7	11.1	10.2	39.0	4,339.7	5,133.7	5,687.3
Average Fixed Interest Rate (%)	4.27	6.01	4.40	4.54	3.60	5.75	5.76	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	64.9
Average Variable Interest Rate (%)	—	—	—	—	—	0.76	0.76	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	550.0	700.0	—	—	—	71.4	1,321.4	31.7
Average Pay Interest Rate (%)	2.88	2.19	—	—	—	3.29	2.54	—
Average Receive Interest Rate (%)	1.00	1.00	—	—	—	0.64	0.98	—

December 31, 2015	Expected Maturity Date							
Millions of dollars	2016	2017	2018	2019	2020	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	110.4	10.1	719.8	9.1	8.3	3,873.0	4,730.7	5,095.0
Average Fixed Interest Rate (%)	1.13	4.50	6.02	4.73	4.94	5.71	5.64	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	63.7
Average Variable Interest Rate (%)	—	—	—	—	—	0.03	0.03	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	650.0	550.0	—	—	—	71.4	1,271.4	(49.8)
Average Pay Interest Rate (%)	2.87	2.88	—	—	—	3.28	2.90	—
Average Receive Interest Rate (%)	0.61	0.61	—	—	—	0.01	0.58	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of long-term debt and interest rate derivatives, see the Liquidity and Capital Resources section in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes 4 and 6 to the consolidated financial statements.

Commodity Price Risk

The following table provides information about the Company's financial instruments, which are limited to financial positions of Energy Marketing and PSNC Energy, that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity	2017	2018	2019
Futures - Long			
Settlement Price (a)	3.65	3.43	—
Contract Amount (b)	92.6	15.4	—
Fair Value (b)	102.3	16.5	—
Futures - Short			
Settlement Price (a)	3.65	3.43	—
Contract Amount (b)	49.7	8.0	—
Fair Value (b)	51.6	8.3	—
Options - Purchased Call (Long)			
Strike Price (a)	1.95	—	—
Contract Amount (b)	13.7	—	—
Fair Value (b)	2.6	—	—
Swaps - Commodity			
Pay fixed/receive variable (b)	13.9	8.0	1.0
Average pay rate (a)	3.4075	3.4326	2.9667
Average received rate (a)	3.6240	3.2042	3.0954
Fair Value (b)	14.8	7.5	1.1
Pay variable/receive fixed (b)	30.4	11.3	0.8
Average pay rate (a)	3.6234	3.2431	3.1277
Average received rate (a)	3.2387	3.3488	2.9851
Fair Value (b)	27.1	11.7	0.8
Swaps - Basis			
Pay variable/receive variable (b)	1.5	0.8	0.3
Average pay rate (a)	3.7218	3.4697	3.1904
Average received rate (a)	3.6529	3.4218	3.1234
Fair Value (b)	1.5	0.8	0.3

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows, and changes in common equity for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

SCANA Corporation and Subsidiaries
Consolidated Balance Sheets

December 31, (Millions of dollars)	2016	2015
Assets		
Utility Plant In Service	$ 13,444	$ 12,883
Accumulated Depreciation and Amortization	(4,446)	(4,307)
Construction Work in Progress	4,845	4,051
Nuclear Fuel, Net of Accumulated Amortization	271	308
Goodwill	210	210
Utility Plant, Net	14,324	13,145
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $138 and $124	276	280
Assets held in trust, net-nuclear decommissioning	123	115
Other investments	76	71
Nonutility Property and Investments, Net	475	466
Current Assets:		
Cash and cash equivalents	208	176
Receivables:		
Customer, net of allowance for uncollectible accounts of $6 and $5	616	505
Income taxes	142	—
Other	127	227
Inventories:		
Fuel	136	164
Materials and supplies	155	148
Prepayments	105	115
Other current assets	17	43
Total Current Assets	1,506	1,378
Deferred Debits and Other Assets:		
Regulatory assets	2,130	1,937
Other	272	220
Total Deferred Debits and Other Assets	2,402	2,157
Total	$ 18,707	$ 17,146

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2016	2015
Capitalization and Liabilities		
Common Stock - no par value, 142.9 million shares outstanding for all periods presented	$ 2,390	$ 2,390
Retained Earnings	3,384	3,118
Accumulated Other Comprehensive Loss	(49)	(65)
Total Common Equity	5,725	5,443
Long-Term Debt, Net	6,473	5,882
Total Capitalization	12,198	11,325
Current Liabilities:		
Short-term borrowings	941	531
Current portion of long-term debt	17	116
Accounts payable	404	590
Customer deposits and customer prepayments	168	137
Taxes accrued	201	242
Interest accrued	84	83
Dividends declared	80	76
Derivative financial instruments	35	50
Other	135	127
Total Current Liabilities	2,065	1,952
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	2,159	1,907
Asset retirement obligations	558	520
Pension and postretirement benefits	373	315
Unrecognized tax benefits	219	44
Regulatory liabilities	930	855
Other	205	228
Total Deferred Credits and Other Liabilities	4,444	3,869
Commitments and Contingencies (Note 10)	—	—
Total	$ 18,707	$ 17,146

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Income

Years Ended December 31, (Millions of dollars, except per share amounts)	2016	2015	2014
Operating Revenues:			
Electric	$ 2,614	$ 2,551	$ 2,622
Gas-regulated	788	811	1,028
Gas-nonregulated	825	1,018	1,301
Total Operating Revenues	4,227	4,380	4,951
Operating Expenses:			
Fuel used in electric generation	576	660	793
Purchased power	64	52	81
Gas purchased for resale	1,054	1,287	1,729
Other operation and maintenance	755	715	728
Depreciation and amortization	371	358	384
Other taxes	254	234	229
Total Operating Expenses	3,074	3,306	3,944
Gain on sale of CGT, net of transaction costs	—	234	—
Operating Income	1,153	1,308	1,007
Other Income (Expense):			
Other income	64	75	122
Other expense	(38)	(60)	(64)
Gain on sale of SCI, net of transaction costs	—	107	—
Interest charges, net of allowance for borrowed funds used during construction of $19, $15 and $16	(342)	(318)	(312)
Allowance for equity funds used during construction	29	27	33
Total Other Expense	(287)	(169)	(221)
Income Before Income Tax Expense	866	1,139	786
Income Tax Expense	271	393	248
Net Income	$ 595	$ 746	$ 538
Earnings Per Share of Common Stock	$ 4.16	$ 5.22	$ 3.79
Weighted Average Common Shares Outstanding (millions)	142.9	142.9	141.9
Dividends Declared Per Share of Common Stock	$ 2.30	$ 2.18	$ 2.10

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31, (Millions of dollars)	2016	2015	2014
Net Income	$ 595	$ 746	$ 538
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $2, $(7) and $(9)	4	(12)	(14)
Cash flow hedging activities reclassified to interest expense, net of tax of $4, $4 and $4	7	7	7
Cash flow hedging activities reclassified to gas purchased for resale, net of tax of $4, $9 and $(2)	6	15	(4)
Net unrealized gains (losses) on cash flow hedging activities	17	10	(11)
Deferred Costs of Employee Benefit Plans:			
Deferred costs of employee benefit plans, net of tax of $-, $- and $(3)	—	—	(5)
Amortization of deferred employee benefit plan costs reclassified to net income (see Note 8), net of tax of $-, $- and $-	(1)	—	1
Net deferred costs of employee benefit plans	(1)	—	(4)
Other Comprehensive Income (Loss)	16	10	(15)
Total Comprehensive Income	$ 611	$ 756	$ 523

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2016	2015	2014
Cash Flows From Operating Activities:			
Net Income	$ 595	$ 746	$ 538
Adjustments to reconcile net income to net cash provided from operating activities:			
Gain on sale of subsidiaries	—	(355)	—
Deferred income taxes, net	242	(31)	235
Depreciation and amortization	389	368	403
Amortization of nuclear fuel	57	46	45
Allowance for equity funds used during construction	(29)	(27)	(33)
Carrying cost recovery	(17)	(12)	(9)
Changes in certain assets and liabilities:			
Receivables	(112)	188	(33)
Income tax receivable	(142)	—	—
Inventories	(43)	(16)	(62)
Prepayments	11	211	(235)
Regulatory assets	(114)	(31)	(138)
Regulatory liabilities	(2)	(1)	(104)
Accounts payable	44	(78)	36
Unrecognized tax benefits	175	31	10
Taxes accrued	(41)	61	(24)
Pension and other postretirement benefits	51	(6)	133
Derivative financial instruments	(9)	(9)	18
Other assets	(44)	(3)	(35)
Other liabilities	81	(23)	(15)
Net Cash Provided From Operating Activities	1,092	1,059	730
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,579)	(1,153)	(1,092)
Proceeds from sale of subsidiaries	—	647	—
Proceeds from investments (including derivative collateral returned)	860	1,117	347
Purchase of investments (including derivative collateral posted)	(788)	(1,018)	(475)
Payments upon interest rate derivative contract settlement	(113)	(263)	(95)
Proceeds from interest rate derivative contract settlement	—	10	—
Net Cash Used For Investing Activities	(1,620)	(660)	(1,315)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	—	14	98
Proceeds from issuance of long-term debt	592	491	294
Repayments of long-term debt	(117)	(166)	(54)
Dividends	(325)	(309)	(294)
Short-term borrowings, net	410	(387)	542
Deferred financing costs	—	(3)	—
Net Cash Provided From (Used For) Financing Activities	560	(360)	586
Net Increase in Cash and Cash Equivalents	32	39	1
Cash and Cash Equivalents, January 1	176	137	136
Cash and Cash Equivalents, December 31	$ 208	$ 176	$ 137
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $19, $15 and $16)	$ 328	$ 306	$ 301
—Income taxes paid	229	184	299
—Income taxes received	166	—	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures	109	244	180
Capital leases	15	6	5

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Changes in Common Equity

	Common Stock				Accumulated Other Comprehensive Income (Loss)			
Millions	**Shares**	**Outstanding Amount**	**Treasury Amount**	**Retained Earnings**	**Gains (Losses) Cash Flow Hedges**	**Deferred Employee Benefit Plans**	**Total AOCI**	**Total**
Balance as of January 1, 2014	141	$ 2,289	$ (9)	$ 2,444	$ (52)	$ (8)	$ (60)	$ 4,664
Net Income				538				538
Other Comprehensive Income (Loss)								
Losses arising during the period					(14)	(5)	(19)	(19)
Losses/amortization reclassified from AOCI					3	1	4	4
Total Comprehensive Income (Loss)				538	(11)	(4)	(15)	523
Issuance of Common Stock	2	99	(1)					98
Dividends Declared				(298)				(298)
Balance as of December 31, 2014	143	$ 2,388	(10)	2,684	(63)	(12)	(75)	4,987
Net Income				746				746
Other Comprehensive Income (Loss)								
Losses arising during the period					(12)	—	(12)	(12)
Losses/amortization reclassified from AOCI					22	—	22	22
Total Comprehensive Income				746	10	—	10	756
Issuance of Common Stock	—	14	(2)					12
Dividends Declared				(312)				(312)
Balance as of December 31, 2015	143	$ 2,402	(12)	3,118	(53)	(12)	(65)	5,443
Net Income				595				595
Other Comprehensive Income (Loss)								
Losses arising during the period					4	(1)	3	3
Losses/amortization reclassified from AOCI					13	—	13	13
Total Comprehensive Income (Loss)				595	17	(1)	16	611
Issuance of Common Stock	—	—	—					—
Dividends Declared				(329)				(329)
Balance as of December 31, 2016	143	$ 2,402	$ (12)	$ 3,384	$ (36)	$ (13)	$ (49)	$ 5,725

Dividends declared per share of common stock were $2.30, $2.18 and $2.10 for 2016, 2015 and 2014, respectively.

See Notes to Consolidated Financial Statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of comprehensive income, cash flows, and changes in equity for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

South Carolina Electric & Gas Company and Affiliates
Consolidated Balance Sheets

December 31, (Millions of dollars)	2016	2015
Assets		
Utility Plant In Service	$ 11,510	$ 11,153
Accumulated Depreciation and Amortization	(3,991)	(3,869)
Construction Work in Progress	4,813	3,997
Nuclear Fuel, Net of Accumulated Amortization	271	308
Utility Plant, Net ($756 and $700 related to VIEs)	12,603	11,589
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	69	68
Assets held in trust, net-nuclear decommissioning	123	115
Other investments	3	1
Nonutility Property and Investments, Net	195	184
Current Assets:		
Cash and cash equivalents	164	130
Receivables:		
Customer, net of allowance for uncollectible accounts of $3 and $3	378	324
Affiliated companies	16	22
Income taxes	53	—
Other	94	202
Inventories:		
Fuel	83	98
Materials and supplies	143	136
Prepayments	88	92
Other current assets	1	15
Total Current Assets ($85 and $88 related to VIEs)	1,020	1,019
Deferred Debits and Other Assets:		
Regulatory assets	2,030	1,857
Other	243	116
Total Deferred Debits and Other Assets ($52 and $53 related to VIEs)	2,273	1,973
Total	$ 16,091	$ 14,765

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2016	2015
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$ 2,860	$ 2,760
Retained Earnings	2,481	2,265
Accumulated Other Comprehensive Loss	(3)	(3)
Total Common Equity	5,338	5,022
Noncontrolling interest	134	129
Total Equity	5,472	5,151
Long-Term Debt, net	5,154	4,659
Total Capitalization	10,626	9,810
Current Liabilities:		
Short-term borrowings	804	420
Current portion of long-term debt	12	110
Accounts payable	247	469
Affiliated payables	122	113
Customer deposits and customer prepayments	126	93
Taxes accrued	195	299
Interest accrued	68	66
Dividends declared	79	75
Derivative financial instruments	28	34
Other	55	61
Total Current Liabilities	1,736	1,740
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,939	1,732
Asset retirement obligations	522	488
Pension and postretirement benefits	232	186
Unrecognized tax benefits	236	44
Regulatory liabilities	695	635
Other	89	113
Other - affiliate	16	17
Total Deferred Credits and Other Liabilities	3,729	3,215
Commitments and Contingencies (Note 10)	—	—
Total	$ 16,091	$ 14,765

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Comprehensive Income

For the Years Ended December 31, (Millions of dollars)	2016	2015	2014
Operating Revenues:			
Electric	$ 2,614	$ 2,551	$ 2,621
Electric - nonconsolidated affiliate	5	6	8
Gas	366	372	461
Gas - nonconsolidated affiliate	1	1	1
Total Operating Revenues	2,986	2,930	3,091
Operating Expenses:			
Fuel used in electric generation	472	559	644
Fuel used in electric generation - nonconsolidated affiliate	104	102	155
Purchased power	64	52	81
Gas purchased for resale	174	162	210
Gas purchased for resale - nonconsolidated affiliate	9	31	73
Other operation and maintenance	403	380	382
Other operation and maintenance - nonconsolidated affiliate	211	199	193
Depreciation and amortization	302	294	315
Other taxes	227	211	202
Other taxes - nonconsolidated affiliate	7	6	6
Total Operating Expenses	1,973	1,996	2,261
Operating Income	1,013	934	830
Other Income (Expense):			
Other income	29	31	80
Other expenses	(24)	(31)	(34)
Interest charges, net of allowance for borrowed funds used during construction of $18, $14 and $14	(270)	(248)	(228)
Allowance for equity funds used during construction	26	25	28
Total Other Expense	(239)	(223)	(154)
Income Before Income Tax Expense	774	711	676
Income Tax Expense	248	231	218
Net Income and Total Comprehensive Income	526	480	458
Less Net Income and Total Comprehensive Income Attributable to Noncontrolling Interest	13	14	12
Earnings and Comprehensive Income Available to Common Shareholder	$ 513	$ 466	$ 446
Dividends Declared on Common Stock	$ 305	$ 285	$ 272

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2016	2015	2014
Cash Flows From Operating Activities:			
Net income	$ 526	$ 480	$ 458
Adjustments to reconcile net income to net cash provided from operating activities:			
Deferred income taxes, net	207	8	187
Depreciation and amortization	310	294	318
Amortization of nuclear fuel	57	46	45
Allowance for equity funds used during construction	(26)	(25)	(28)
Carrying cost recovery	(17)	(12)	(9)
Changes in certain assets and liabilities:			
Receivables	(47)	85	51
Receivables - affiliate	(3)	16	(90)
Income tax receivable	(53)	—	—
Inventories	(35)	(24)	(52)
Prepayments	(4)	70	(89)
Regulatory assets	(94)	(29)	(116)
Other regulatory liabilities	(5)	(3)	(103)
Accounts payable	8	11	(49)
Accounts payable - affiliate	13	(17)	63
Unrecognized tax benefits	192	31	10
Taxes accrued	(104)	129	(53)
Pension and other postretirement benefits	39	(5)	106
Other assets	(99)	57	(15)
Other liabilities	58	(28)	16
Other liabilities - affiliate	(1)	(6)	(9)
Net Cash Provided From Operating Activities	922	1,078	641
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,399)	(1,008)	(934)
Proceeds from investments and sales of assets (including derivative collateral returned)	794	975	275
Purchase of investments (including derivative collateral posted)	(740)	(887)	(381)
Payments upon interest rate derivative contract settlement	(113)	(263)	(95)
Proceeds from interest rate derivative contract settlement	—	10	—
Proceeds from investment in affiliate	9	71	—
Investment in affiliate	—	—	(80)
Net Cash Used For Investing Activities	(1,449)	(1,102)	(1,215)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	494	491	294
Repayment of long-term debt	(112)	(11)	(48)
Dividends	(301)	(285)	(260)
Short-term borrowings, net	384	(289)	458
Short-term borrowings-nonconsolidated affiliate, net	(4)	(50)	56
Contribution from parent	100	204	89
Return of capital to parent	—	(4)	(7)
Deferred financing costs	—	(2)	—
Net Cash Provided From Financing Activities	561	54	582
Net Increase in Cash and Cash Equivalents	34	30	8
Cash and Cash Equivalents, January 1	130	100	92
Cash and Cash Equivalents, December 31	$ 164	$ 130	$ 100
Supplemental Cash Flow Information:			
Cash for—Interest paid (net of capitalized interest of $18, $14 and $14)	$ 251	$ 228	$ 210
—Income taxes paid	289	89	177
—Income taxes received	189	84	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures	95	230	151
Capital leases	14	6	5

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Changes in Equity

	Common Stock					
Millions	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total Equity
Balance at January 1, 2014	40	$ 2,479	$ 1,896	$ (3)	$ 117	$ 4,489
Earnings available for common shareholder			446		12	458
Deferred cost of employee benefit plans, net of tax $-				—		—
Total Comprehensive Income			446	—	12	458
Capital contributions from parent		81			1	82
Cash dividends declared			(265)		(7)	(272)
Balance at December 31, 2014	40	2,560	2,077	(3)	123	4,757
Earnings Available for Common Shareholder			466		14	480
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income			466	—	14	480
Capital contributions from parent		200			—	200
Cash dividends declared			(278)		(8)	(286)
Balance at December 31, 2015	40	2,760	2,265	(3)	129	5,151
Earnings Available for Common Shareholder			513		13	526
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income			513	—	13	526
Capital contributions from parent		100			—	100
Cash dividends declared			(297)		(8)	(305)
Balance at December 31, 2016	40	$ 2,860	$ 2,481	$ (3)	$ 134	$ 5,472

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
South Carolina Electric & Gas Company and Affiliates
Notes to Consolidated Financial Statements

The following notes to the consolidated financial statements are a combined presentation. Except as otherwise indicated herein, each note applies to the Company and Consolidated SCE&G; however, Consolidated SCE&G makes no representation as to information relating solely to SCANA Corporation or its subsidiaries (other than Consolidated SCE&G).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

The Company

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina, the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia and conducts other energy-related business.

The accompanying consolidated financial statements reflect the accounts of SCANA, the following wholly-owned subsidiaries, and subsidiaries that formerly were wholly-owned during the periods presented.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	ServiceCare, Inc.
South Carolina Generating Company, Inc.	SCANA Services, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Corporate Security Services, Inc.
	SCANA Communications Holdings, Inc.

SCANA reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance. Discussions regarding the Company's financial results necessarily include the results of Consolidated SCE&G.

Consolidated SCE&G

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs) and accordingly, Consolidated SCE&G's consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G's parent. As a result, GENCO's and Fuel Company's equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G's consolidated financial statements. Intercompany balances and transactions between SCE&G, Fuel Company and GENCO have been eliminated in consolidation.

GENCO owns a coal-fired electric generating station with a 605 MW net generating capacity (summer rating). GENCO's electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $485 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Dispositions

In the first quarter of 2015, SCANA sold CGT and SCI. CGT was an interstate natural gas pipeline regulated by FERC that transported natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provided fiber optic communications and other services and built, managed and leased communications towers in several southeastern states, and it was sold to Spirit Communications. These sales resulted in recognition of pre-tax gains totaling approximately $342 million. The pre-tax gain from the sale of CGT is included within Operating Income and the pre-tax gain from the sale of SCI is included within Other Income (Expense) on the Company's consolidated statement of income.

CGT and SCI operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI met accounting criteria for disclosure as a reportable segment and were included within All Other in Note 12. The sales of CGT and SCI did not represent a strategic shift that had a major effect on the Company's operations; therefore, these sales did not meet the criteria for classification as discontinued operations.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current presentation, as follows:

Statements of Cash Flows - For the Company and Consolidated SCE&G, non-cash changes in fair value of interest rate swaps were reclassified as an offset to the changes in certain assets and liabilities section within the reconciliations of Net Income to Net Cash Provided From Operating Activities as follows:

	December 31,	
Millions of dollars	2015	2014
Derivative financial instruments	$ (174)	$ 207
Regulatory assets	179	(234)
Regulatory liabilities	4	(29)
Other assets	(15)	32
Other liabilities	6	24

In addition, due to insignificance, the caption for Losses from equity method investments has been eliminated, and the amounts have been reclassified and included within the caption of Changes in Other assets.

The reclassifications above had no effect on Net Cash Provided From Operating Activities or on any other subtotal in the consolidated statements of cash flows.

Statements of Comprehensive Income - For Consolidated SCE&G, operating revenues and operating expenses from transactions with nonconsolidated affiliates are presented separately. A detail of such transactions are included in Note 11.

Segment of Business Information Disclosure - For the Company, the Gas Marketing segment includes the information formerly reported in two separate marketing segments. See Note 12 for the required disclosures.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset’s life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company's regulated subsidiaries calculated AFC using average composite rates of 5.3% for 2016, 6.1% for 2015, and 7.2% for 2014. Consolidated SCE&G calculated AFC using average composite rates of 4.7% for 2016, 5.6% for 2015, and 6.5% for 2014. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. In addition, CGT was sold in the first quarter of 2015 (see Dispositions herein) and excluded from the 2015 calculation of composite weighted average depreciation rates. The composite weighted average depreciation rates for utility plant assets were as follows:

	2016	2015	2014
SCE&G	2.56%	2.55%	2.85%
GENCO	2.66%	2.66%	2.66%
CGT	—	—	2.11%
PSNC Energy	2.90%	2.94%	2.98%
Weighted average of above	2.61%	2.61%	2.84%
Consolidated SCE&G	2.56%	2.56%	2.84%

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in Fuel used in electric generation and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2016		2015	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.3 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 634.4 million	—	$ 620.4 million	—
Construction work in progress	$ 167.7 million	$ 4.2 billion	$ 214.6 million	$ 3.4 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Unit 1 and the New Units. These amounts totaled $76.2 million at December 31, 2016 and $178.8 million at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2016, and 2015, SCE&G incurred $23.8 million and $16.5 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, SCE&G accrues $17.2 million annually for its portion of the nuclear refueling outages scheduled from the spring of 2014 through the spring of 2020. Refueling outage costs incurred for which SCE&G was responsible totaled $26.8 million for the Fall 2015 outage and $1.8 million in 2016 in preparation for the Spring 2017 outage.

Goodwill

The Company considers certain amounts categorized by FERC as acquisition adjustments to be goodwill. The Company tests goodwill for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. Accounting guidance adopted by the Company gives it the option to perform a qualitative assessment of impairment ("step zero"). Based on this qualitative assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with a two-step quantitative assessment. If the quantitative assessment becomes necessary, step one requires estimation of the fair value of the reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. Should a write-down be required, such a charge would be treated as an operating expense.

For each period presented, assets with a carrying value of $210 million for PSNC Energy (Gas Distribution segment), net of a writedown of $230 million taken in 2002, were classified as goodwill. The Company utilized the step zero qualitative assessment in its evaluation as of January 1, 2017 and was not required to use the two-step quantitative assessment. In evaluations for preceding periods, the Company's step one assessment utilized the assistance of an independent appraisal in determining its estimate of fair value. In such evaluations, step one indicated no impairment, and no impairment charges were recorded.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $786.4 million, stated in 2016 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, SCE&G transfers to an external trust fund the amounts collected through rates ($3.2 million pre-tax in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Temporary cash investments having original maturities of three months or less at time of purchase are considered to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.
Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable.

PSNC Energy utilizes an asset management and supply service agreement with a counterparty for certain natural gas storage facilities. The counterparty held, through an agency relationship, 40% and 46% of PSNC Energy's natural gas inventory at December 31, 2016 and December 31, 2015, respectively, with a carrying value of $9.8 million and $17.7 million, respectively. Under the terms of this agreement, PSNC Energy receives storage asset management fees of which 75% are credited to rate payers. PSNC Energy expects to replace this agreement when it expires on March 31, 2017.

Income Taxes

SCANA files consolidated federal income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

Consolidated SCE&G is included in the consolidated federal income tax returns of SCANA. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

The Company's rate-regulated utilities, including Consolidated SCE&G, record costs that have been or are expected to be allowed in the ratemaking process in periods different from the periods in which the costs would be charged to expense, or record revenues in periods different from the periods in which the revenues would be recorded, by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations for refunds to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as Receivables - Customer or Customer deposits and customer prepayments, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Premiums, discounts and debt issuance costs are presented within long-term debt and are amortized as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

Revenues and expenses arising from regulated businesses and, in the case of the Company, retail natural gas marketing businesses (including those activities of segments described in Note 12) are presented within Operating Income, and all other activities are presented within Other Income (Expense). Consistent with this presentation, the Company presents the 2015 gain on the sale of CGT within Operating Income and the 2015 gain on the sale of SCI within Other Income (Expense).

Revenue Recognition

Revenues are recorded during the accounting period in which services are provided to customers and include estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $178.9 million at December 31, 2016 and $129.1 million at December 31, 2015 for the Company. Unbilled revenues totaled $117.6 million at December 31, 2016 and $101.5 million at December 31, 2015 for Consolidated SCE&G.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy’s PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings Per Share

Basic earnings per share are computed by dividing net income by the weighted average number of common shares outstanding for the period. When applicable, diluted earnings per share are computed using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method.

New Accounting Matters

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most earlier revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2018. The guidance permits adoption using a retrospective method, with options to elect certain practical expedients, or recognition of a cumulative effect in the year of initial adoption. The Company and Consolidated SCE&G have not determined which method of adoption will be employed or what practical expedients may be elected. The Company and Consolidated SCE&G have not determined the impact this guidance will have on their respective financial statements. However, the identification of implementation project team members and the analysis of contracts with customers to which the guidance might be applicable, particularly large customer contracts, have begun. In addition, activities of the FASB's Transition Resource Group for Revenue Recognition are being monitored, particularly as they relate to the required treatment under the standard of contributions in aid of construction, alternative revenue programs and the collectibility of revenue of utilities subject to rate regulation.

In May 2015, the FASB issued accounting guidance removing the requirement to categorize within the fair value hierarchy investments for which fair values are estimated using the NAV practical expedient. Disclosures about investments in certain entities that calculate NAV per share are limited under this guidance to those investments for which the entity has elected to estimate the fair value using the NAV practical expedient. The Company and Consolidated SCE&G elected to adopt this guidance on a retrospective basis. The adoption resulted in the reclassification of fair value related to the pension plan's investment in the common collective trust, joint venture interest, and limited partnership as of December 31, 2015. See Note 8.

In July 2015, the FASB issued accounting guidance intended to simplify the measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. The Company and Consolidated SCE&G expect to adopt this guidance in the first quarter of 2017 and do not expect it to have a significant impact on their respective financial statements.

In January 2016, the FASB issued accounting guidance that will change how entities measure certain equity investments and financial liabilities, among other things. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2018 and have determined adoption of this guidance will not have a significant impact on their respective financial statements.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over 12 months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily on the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for years beginning in 2019. The Company and Consolidated SCE&G have not determined what impact this guidance will have on their respective financial statements. However, the identification of implementation project team members and the initial identification and analysis of leasing and related contracts to which the guidance might be applicable have begun. In addition, the Company and Consolidated SCE&G have begun evaluating certain third party software tools that may assist with this implementation and ongoing compliance.

In March 2016, the FASB issued accounting guidance changing how companies account for certain aspects of share-based payments to employees. Entities are required to recognize the income tax effects of awards in the income statement when the awards vest or are settled. The Company and Consolidated SCE&G adopted this guidance in the fourth quarter of 2016 and, based on the nature of their share-based awards practices, the adoption had no impact on their respective financial statements.

In June 2016, the FASB issued accounting guidance requiring the use of a current expected credit loss impairment model for certain financial instruments. The new model is applicable to trade receivables and most debt instruments, among other financial instruments, and is intended to result in certain impairment losses being recognized earlier than under current guidance. The Company and Consolidated SCE&G must adopt this guidance beginning in 2020, including interim periods, though the guidance may be adopted in 2019. The Company and Consolidated SCE&G have not determined when this guidance will be adopted or what impact it will have on their respective financial statements.

In August 2016, the FASB issued accounting guidance to reduce diversity in cash flow classification related to certain transactions. The Company and Consolidated SCE&G expect to adopt this guidance when required in the first quarter of 2018 and do not anticipate that its adoption will impact their respective financial statements.

In October 2016, the FASB issued accounting guidance related to the tax effects of intra-entity asset transfers of assets other than inventory. An entity will be required to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The Company and Consolidated SCE&G expect to adopt this guidance in the first quarter 2017 and it is not expected to have a material impact on their respective financial statements.

In November 2016, the FASB issued accounting guidance related to the presentation of restricted cash on the statement of cash flows. The guidance is effective for years beginning in 2018 and the Company and Consolidated SCE&G expect no impact on their respective financial statements.

In January 2017, the FASB issued accounting guidance to simplify the accounting for goodwill impairment. The guidance removes Step 2 of the goodwill impairment test. The same one-step impairment test will be applied to goodwill at all reporting units, even those with zero or negative carrying amounts. The guidance is effective for years beginning in 2020, though early adoption after January 1, 2017 is allowed. The Company and Consolidated SCE&G have not determined when this guidance will be adopted but do not anticipate that adoption will have a material impact on their respective financial statements.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments were fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G, ORS, and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million ($.12 per share) in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million ($.06 per share) with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, SCE&G's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

By order dated April 29, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties to decrease the total fuel cost component of retail electric rates. SCE&G reduced the total fuel cost component of retail electric rates to reflect lower projected fuel costs and to eliminate over-collected balances of approximately $61 million for base fuel and environmental costs over a 12-month period beginning with the first billing cycle of May 2016. SCE&G also began to recover projected DER program costs of approximately $6.9 million beginning with the first billing cycle of May 2016.

In October 2016, the SCPSC initiated its 2017 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 6, 2017.

Electric - Base Rates

Pursuant to an SCPSC order, SCE&G removes from rate base certain deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $14.0 million and $9.5 million during 2016 and 2015, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these deferred income tax assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2016	First billing cycle of May	$37.6 million
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G's request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G's DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

By order dated April 29, 2016, the SCPSC approved SCE&G's request to increase its pension costs rider. The increased pension rider is designed to allow SCE&G to recover projected pension costs, including under-collections, over a 12-month period, beginning with the first billing cycle in May 2016.

In January 2017, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved the filing would allow recovery of $37.0 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric - BLRA

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed ROE. The SCPSC has approved recovery of the following amounts.

Year	Increase	Effective for bills rendered on and after	Amount	Allowed ROE
2016	2.7%	November 27	$64.4 million	10.50% *
2015	2.6%	October 30	$64.5 million	11.00%
2014	2.8%	October 30	$66.2 million	11.00%

*Applied prospectively for purposes of calculating revised rates under the BLRA on and after January 1, 2016.

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time. See also New Nuclear Construction in Note 10.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued. SCE&G cannot determine when the SCPSC will issue its order in this matter or if that order will be appealed.

Gas - SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2016	1.2% Increase	$4.1 million
2015	No change	—
2014	0.6% Decrease	$2.6 million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2016, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Gas - PSNC Energy

PSNC Energy's Rider D rate mechanism allows it to recover from customers all prudently incurred gas costs and certain related uncollectible expenses as well as losses on negotiated gas and transportation sales.

PSNC Energy establishes rates using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

On October 28, 2016, the NCUC granted PSNC Energy a net annual increase of approximately $19.1 million, or 4.39%, in rates and charges to customers, and set PSNC Energy's authorized ROE at 9.7%. In addition, PSNC Energy was authorized to implement a tracker that provides for biannual rate adjustments to recover the revenue requirement associated with integrity management plant investment and associated costs resulting from prevailing federal standards for pipeline integrity and safety that are not otherwise included in current base rates. The new rates are effective for services rendered on or after November 1, 2016.

In November 2016, in connection with PSNC Energy's 2016 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2016.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, the Company and Consolidated SCE&G have recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

Millions of dollars	The Company December 31, 2016	The Company December 31, 2015	Consolidated SCE&G December 31, 2016	Consolidated SCE&G December 31, 2015
Regulatory Assets:				
Accumulated deferred income taxes	$ 316	$ 298	$ 307	$ 291
AROs and related funding	425	405	403	384
Deferred employee benefit plan costs	342	325	309	295
Deferred losses on interest rate derivatives	620	535	620	535
Unrecovered plant	117	127	117	127
Environmental remediation costs	32	42	26	35
DSM Programs	59	61	59	61
Pipeline integrity management costs	33	19	6	4
Carrying costs on deferred tax assets related to nuclear construction	32	18	32	18
Deferred storm damage costs	20	—	20	—
Deferred costs related to uncertain tax position	15	—	15	—
Other	119	107	116	107
Total Regulatory Assets	$ 2,130	$ 1,937	$ 2,030	$ 1,857
Regulatory Liabilities:				
Asset removal costs	$ 755	$ 732	$ 529	$ 519
Deferred gains on interest rate derivatives	151	96	151	96
Other	24	27	15	20
Total Regulatory Liabilities	$ 930	$ 855	$ 695	$ 635

Accumulated deferred income tax liabilities that arise from utility operations that have not been included in customer rates are recorded as a regulatory asset. A substantial portion of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

AROs and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 11 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G or PSNC Energy, and are expected to be recovered over periods of up to approximately 18 years.

DSM Programs represent SCE&G's deferred costs associated with such programs, and such deferred costs are currently being recovered over approximately five years through an approved rate rider.

Pipeline integrity management costs represent costs incurred to comply with regulatory requirements related to natural gas pipelines located near moderate to high density populations. PSNC Energy will recover costs totaling $20.3 million over a five-year period beginning November 2016, and remaining costs of $7.0 million have been deferred pending future approval of rate recovery. SCE&G began amortizing $1.9 million of such costs annually in November 2015.

Carrying costs on deferred tax assets related to nuclear construction are calculated on accumulated deferred income tax assets associated with the New Units which are not part of electric rate base using the weighted average long-term debt cost of capital. These carrying costs will be amortized over ten years beginning in approximately 2020.

Deferred storm damage costs represent costs incurred in excess of amounts previously collected through SCE&G’s SCPSC-approved storm damage reserve, and for which SCE&G expects to receive future recovery through customer rates.

Deferred costs related to uncertain tax position primarily represent the estimated amounts of domestic production activities deductions foregone as a result of the deduction of certain research and experimentation expenditures for income tax purposes, net of related tax credits, as well as accrued interest expense and other costs arising from this uncertain tax position. SCE&G's current customer rates reflect the availability of domestic production activities deductions. These net deferred costs are expected to be recovered through utility rates following ultimate resolution of the claims. See also Note 5.

Various other regulatory assets are expected to be recovered through rates over periods up to 2047.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company or Consolidated SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's and Consolidated SCE&G's financial statements in the period the write-off would be recorded.

3. COMMON EQUITY

SCANA’s articles of incorporation do not limit the dividends that may be paid on its common stock, and the articles of incorporation of each of SCANA's subsidiaries contain no such limitations on their respective common stock. However, SCE&G’s bond indenture and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances, which the Company and, in the case of SCE&G, Consolidated SCE&G consider to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2016 and 2015, retained earnings of approximately $79.0 million and $72.4 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

Authorized shares of common stock were 200 million as of December 31, 2016 and 2015.

SCANA issued no common stock during the year ended December 31, 2016. SCANA issued common stock valued at $14.3 million (when issued) during the year ended December 31, 2015, to satisfy the requirements of deferred compensation and dividend reinvestment plans.

Authorized shares of SCE&G common stock were 50 million as of December 31, 2016 and 2015. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2016 and 2015.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

The Company

December 31, Dollars in millions	Maturity	2016 Balance	2016 Rate	2015 Balance	2015 Rate
SCANA Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.42%
SCANA Senior Notes (unsecured) (a)	2017 - 2034	79	1.63%	84	1.11%
SCE&G First Mortgage Bonds (secured)	2018 - 2065	4,840	5.79%	4,340	5.78%
GENCO Notes (secured)	2017 - 2024	213	5.93%	220	5.92%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.51%	122	3.51%
PSNC Energy Senior Debentures and Notes	2020 - 2046	450	5.53%	350	5.93%
Nuclear Fuel Financing	2016	—	—%	100	0.78%
Other	2017 - 2027	27	2.76%	18	2.72%
Total debt		6,531		6,034	
Current maturities of long-term debt		(17)		(116)	
Unamortized discount, net		(1)		—	
Unamortized debt issuance costs		(40)		(36)	
Total long-term debt, net		$ 6,473		$ 5,882	

Consolidated SCE&G

December 31, Dollars in millions	Maturity	2016 Balance	2016 Rate	2015 Balance	2015 Rate
First Mortgage Bonds (secured)	2018 - 2065	$ 4,840	5.79%	$ 4,340	5.78%
GENCO Notes (secured)	2017 - 2024	213	5.93%	220	5.92%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.51%	122	3.51%
Nuclear Fuel Financing	2016	—	—%	100	0.78%
Other	2017 - 2027	26	2.76%	17	2.63%
Total debt		5,201		4,799	
Current maturities of long-term debt		(12)		(110)	
Unamortized premium, net		1		2	
Unamortized debt issuance costs		(36)		(32)	
Total long-term debt, net		$ 5,154		$ 4,659	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.17%).
(b) Includes variable rate debt of $67.8 million at December 31, 2016 (rate of 0.76%) and 2015 (rate of 0.03%) which are hedged by fixed swaps.

In June 2016, SCE&G issued $425 million of 4.1% first mortgage bonds due June 15, 2046. In addition, SCE&G issued $75 million of 4.5% first mortgage bonds due June 1, 2064, which constituted a reopening of $300 million of 4.5% first mortgage bonds issued in May 2014. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In June 2016, PSNC Energy issued $100 million of 4.13% senior notes due June 22, 2046. Proceeds from this sale were used to repay short-term debt, to finance capital expenditures, and for general corporate purposes.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

The Company's long-term debt maturities will be $17 million in 2017, $726 million in 2018, $15 million in 2019, $365 million in 2020 and $493 million in 2021. These amounts include, for Consolidated SCE&G, $12 million in 2017, $722 million in 2018, $11 million in 2019, $10 million in 2020 and $39 million in 2021.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2016, the Bond Ratio was 5.12.

Lines of Credit and Short-Term Borrowings

At December 31, 2016 and 2015, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

December 31, 2016 **Millions of dollars**	**Total**	**SCANA**	**SCE&G**	**PSNC Energy**
Lines of credit:				
Five-year, expiring December 2020	$ 1,300.0	$ 400.0	$ 700.0	$ 200.0
Fuel Company five-year, expiring December 2020	$ 500.0	—	$ 500.0	—
Three-year, expiring December 2018	$ 200.0	—	$ 200.0	—
Total committed long-term	$ 2,000.0	$ 400.0	$ 1,400.0	$ 200.0
Outstanding commercial paper (270 or fewer days)	$ 940.5	$ 64.4	$ 804.3	$ 71.8
Weighted average interest rate		1.43%	1.04%	1.07%
Letters of credit supported by LOC	$ 3.3	$ 3.0	$ 0.3	—
Available	$ 1,056.2	$ 332.6	$ 595.4	$ 128.2
December 31, 2015				
Lines of credit:				
Five-year, expiring December 2020	$ 1,300.0	$ 400.0	$ 700.0	$ 200.0
Fuel Company five-year, expiring December 2020	$ 500.0	—	$ 500.0	—
Three-year, expiring December 2018	$ 200.0	—	$ 200.0	—
Total committed long-term	$ 2,000.0	$ 400.0	$ 1,400.0	$ 200.0
Outstanding commercial paper (270 or fewer days)	$ 531.4	$ 37.4	$ 420.2	$ 73.8
Weighted average interest rate		1.19%	0.74%	0.77%
Letters of credit supported by LOC	$ 3.3	$ 3.0	$ 0.3	—
Available	$ 1,465.4	$ 359.6	$ 979.6	$ 126.2

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to credit agreements in the amounts and for the terms described above. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

Each of the Company and Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2016 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $29 million. At December 31, 2015 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $33 million and money pool investments due from an affiliate of $9 million. On SCE&G's consolidated balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense are as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current taxes:						
Federal	$ 36	$ 382	$ 38	$ 50	$ 208	$ 39
State	13	57	(4)	13	32	(6)
Total current taxes	49	439	34	63	240	33
Deferred tax (benefit) expense, net:						
Federal	203	(36)	184	167	(3)	157
State	21	(7)	34	20	(3)	32
Total deferred taxes	224	(43)	218	187	(6)	189
Investment tax credits:						
Amortization of amounts deferred-state	—	(1)	(1)	—	(1)	(1)
Amortization of amounts deferred-federal	(2)	(2)	(3)	(2)	(2)	(3)
Total investment tax credits	(2)	(3)	(4)	(2)	(3)	(4)
Total income tax expense	$ 271	$ 393	$ 248	$ 248	$ 231	$ 218

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Net income	$ 595	$ 746	$ 538	$ 513	$ 466	$ 446
Income tax expense	271	393	248	248	231	218
Noncontrolling interest	—	—	—	13	14	12
Total pre-tax income	$ 866	$ 1,139	$ 786	$ 774	$ 711	$ 676
Income taxes on above at statutory federal income tax rate	$ 303	$ 399	$ 275	$ 271	$ 249	$ 237
Increases (decreases) attributed to:						
State income taxes (less federal income tax effect)	27	38	24	26	24	21
State investment tax credits (less federal income tax effect)	(5)	(6)	(5)	(5)	(6)	(5)
Allowance for equity funds used during construction	(10)	(9)	(11)	(9)	(9)	(10)
Deductible dividends—401(k) Retirement Savings Plan	(10)	(10)	(10)	—	—	—
Amortization of federal investment tax credits	(2)	(2)	(3)	(2)	(2)	(3)
Section 41 tax credits	—	1	(3)	—	1	(3)
Section 45 tax credits	(8)	(9)	(9)	(8)	(9)	(9)
Domestic production activities deduction	(23)	(18)	(7)	(23)	(18)	(7)
Realization of basis differences upon sale of subsidiaries	—	7	—	—	—	—
Other differences, net	(1)	2	(3)	(2)	1	(3)
Total income tax expense	$ 271	$ 393	$ 248	$ 248	$ 231	$ 218

The tax effects of significant temporary differences comprising net deferred tax liability are as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	**2016**	**2015**	**2016**	**2015**
Deferred tax assets:				
Nondeductible accruals	$ 148	$ 135	$ 53	$ 52
Asset retirement obligation, including nuclear decommissioning	213	199	200	187
Financial instruments	22	35	—	2
Unamortized investment tax credits	15	16	15	16
Deferred fuel costs	17	8	17	7
Other	10	5	8	2
Total deferred tax assets	425	398	293	266
Deferred tax liabilities:				
Property, plant and equipment	2,159	1,906	1,856	1,644
Deferred employee benefit plan costs	105	96	93	85
Regulatory asset, asset retirement obligation	143	135	135	127
Regulatory asset, unrecovered plant	45	49	45	49
Demand side management costs	23	23	23	23
Prepayments	32	31	30	29
Other	77	65	50	41
Total deferred tax liabilities	2,584	2,305	2,232	1,998
Net deferred tax liability	$ 2,159	$ 1,907	$ 1,939	$ 1,732

The State of North Carolina lowered its corporate income tax rate from 6.9% to 6.0% in 2014, 5.0% in 2015, 4% in 2016 and 3% effective January 1, 2017. In connection with these changes in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The changes in income tax rates did not and are not expected to have a material impact on the Company’s financial position, results of operations or cash flows.

The Company files consolidated federal income tax returns which includes Consolidated SCE&G, and the Company and its subsidiaries file various applicable state and local income tax returns. The IRS has completed examinations of the Company’s federal returns through 2004, and the Company’s federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2015 as a result of claims discussed below in Changes in Unrecognized Tax Benefits. With few exceptions, the Company, including Consolidated SCE&G, is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes in Unrecognized Tax Benefits

	The Company			Consolidated SCE&G		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Unrecognized tax benefits, January 1	$ 49	$ 16	$ 3	$ 49	$ 16	$ 3
Gross increases—uncertain tax positions in prior period	94	33	—	94	33	—
Gross decreases—uncertain tax positions in prior period	—	(2)	—	—	(2)	—
Gross increases—current period uncertain tax positions	207	2	13	207	2	13
Unrecognized tax benefits, December 31	$ 350	$ 49	$ 16	$ 350	$ 49	$ 16

During 2013 and 2014, SCANA amended certain of its income tax returns to claim additional tax-defined research and experimentation deductions (under IRC Section 174) and credits (under IRC Section 41) and to reflect related impacts on other items such as domestic production activities deductions (under IRC Section 199). SCANA also made similar claims in filing its original 2013 and 2014 returns in 2014 and 2015, respectively. In September 2016, SCANA claimed significant research and experimentation deductions and credits (offset by reductions in its domestic production activities deductions), related to the ongoing design and construction activities of the New Units, in its 2015 income tax returns. These claims followed the issuance of final IRS regulations in 2014 regarding such treatment with respect to expenditures related to the design and construction of pilot models.

The IRS examined the claims in the amended returns, and as the examination progressed without resolution, the Company and Consolidated SCE&G evaluated and recorded adjustments to unrecognized tax benefits; however, none of these changes materially affected the Company's and Consolidated SCE&G's effective tax rate. In October 2016, the examination of the amended tax returns progressed to the IRS Office of Appeals. In addition, the IRS has begun an examination of SCANA's 2013 through 2015 income tax returns.

These income tax deductions and credits are considered to be uncertain tax positions, and under relevant accounting guidance, estimates of the amounts of related tax benefits which may not be sustained upon examination by the taxing authorities are required to be recorded as unrecognized tax benefits in the financial statements. As of December 31, 2016, the Company and Consolidated SCE&G have recorded an unrecognized tax benefit of $350 million ($219 million and $236 million for the Company and Consolidated SCE&G, respectively, net of the impact of state deductions on federal returns, and net of certain operating loss and tax credit carryforwards and receivables related to the uncertain tax positions). If recognized, $17 million of the tax benefit would affect the Company’s and Consolidated SCE&G's effective tax rate (see discussion below regarding deferral of benefits related to 2015 forward). It is reasonably possible that these unrecognized tax benefits may increase by an additional $292 million within the next 12 months as additional expenditures giving rise to pilot model tax benefits are incurred. It is also reasonably possible that these unrecognized tax benefits may decrease by $49 million within the next 12 months if the claims on the amended returns which are currently in appeals are resolved and that resolution were also applied to the 2013 and 2014 returns. No other material changes in the status of the Company’s or Consolidated SCE&G's tax positions have occurred through December 31, 2016.

In connection with the research and experimentation deduction and credit claims reflected on the 2015 income tax returns and the expectation of similar claims to be made in determining 2016’s taxable income, the Company and Consolidated SCE&G have recorded regulatory assets for estimated foregone domestic production activities deductions, offset by estimated tax credits, and expect that such (net) deferred costs, along with any interest (see below) and other related deferred costs, will be recoverable through customer rates in future years. SCE&G's current customer rates reflect the availability of domestic production activities deductions (see Note 2).

Estimated interest expense accrued with respect to the unrecognized tax benefits related to the research and experimentation deductions in the 2015 income tax returns has been deferred as a regulatory asset and is expected to be recoverable through customer rates in future years. See also Note 2. Otherwise, the Company and Consolidated SCE&G recognize interest accrued related to unrecognized tax benefits within interest expense or interest income and recognize tax penalties within other expenses. In 2016, the amount recorded for such interest income is $1.8 million and interest expense is $0.9 million. Such amounts were not significant in 2015 or 2014. No amounts have been recorded for tax penalties for any periods presented.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Derivative instruments are recognized either as assets or liabilities in the statement of financial position and are measured at fair value. Changes in the fair value of derivative instruments are recognized either in earnings, as a component of other comprehensive income (loss) or, for regulated operations, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures, and in some cases risk limits, are established to control the level of market, credit, liquidity and operational and administrative risks. SCANA’s Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Risk Management Officer and other senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statements of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and NYMEX futures and options. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the under- or over-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SCANA Energy, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

Interest rate swaps may be used to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which swaps designated as cash flow hedges are used to synthetically convert variable rate debt to fixed rate debt, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

Forward starting swap agreements that are designated as cash flow hedges may be used in anticipation of the issuance of debt. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For SCANA and its nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest rate derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts related to them are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be amortized to interest expense or may be applied as otherwise directed by the SCPSC.

Cash payments made or received upon termination of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)		
Hedge designation	**Gas Distribution**	**Gas Marketing**	**Total**
As of December 31, 2016			
Commodity	4,510,000	11,947,000	16,457,000
Energy Management (a)	—	67,447,223	67,447,223
Total (a)	4,510,000	79,394,223	83,904,223
As of December 31, 2015			
Commodity	7,530,000	11,842,500	19,372,500
Energy Management (a)	—	38,857,480	38,857,480
Total (a)	7,530,000	50,699,980	58,229,980

(a) Includes amounts related to basis swap contracts totaling 730,721 MMBTU in 2016 and 1,842,048 MMBTU in 2015.

The aggregate notional amounts of the interest rate swaps were as follows:

	The Company		Consolidated SCE&G	
Millions of dollars	**December 31, 2016**	**December 31, 2015**	**December 31, 2016**	**December 31, 2015**
Designated as hedging instruments	$ 115.6	$ 120.0	$ 36.4	$ 36.4
Not designated as hedging instruments	1,285.0	1,235.0	1,285.0	1,235.0

The following table shows the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the consolidated balance sheet, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Fair Values of Derivative Instruments

		The Company		Consolidated SCE&G	
Millions of dollars	**Balance Sheet Location**	**Asset**	**Liability**	**Asset**	**Liability**
As of December 31, 2016					
Designated as hedging instruments					
Interest rate contracts					
	Derivative financial instruments		$ 4		$ 1
	Other deferred credits and other liabilities		24		8
Commodity contracts					
	Prepayments	$ 5			
	Other current assets	1			
Total		$ 6	$ 28	—	$ 9
Not designated as hedging instruments					
Interest rate contracts					
	Other deferred debits and other assets	$ 71		$ 71	
	Derivative financial instruments		$ 27		$ 27
	Other deferred credits and other liabilities		3		3
Commodity contracts					
	Other current assets	3			
Energy management contracts					
	Prepayments	6	2		
	Other current assets	2	1		
	Other deferred debits and other assets	2			
	Derivative financial instruments		4		
	Other deferred credits and other liabilities		2		
Total		$ 84	$ 39	$ 71	$ 30
As of December 31, 2015					
Designated as hedging instruments					
Interest rate contracts					
	Derivative financial instruments		$ 4		$ 1
	Other deferred credits and other liabilities		28		9
Commodity contracts					
	Other current assets		1		
	Derivative financial instruments		4		
Total		—	$ 37	—	$ 10

Not designated as hedging instruments				
Interest rate contracts				
Other current assets	$ 10		$ 10	
Other deferred debits and other assets	5		5	
Derivative financial instruments		$ 33		$ 33
Other deferred credits and other liabilities		22		22
Commodity contracts				
Other current assets	1			
Energy management contracts				
Other current assets	11	2		
Other deferred debits and other assets	3			
Derivative financial instruments		9		
Other deferred credits and other liabilities		3		
Total	$ 30	$ 69	$ 15	$ 55

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the consolidated statements of income is as follows:

The Company and Consolidated SCE&G:	**Loss Deferred in Regulatory Accounts**	**Loss Reclassified from Deferred Accounts into Income (Effective Portion)**	
Millions of dollars	**(Effective Portion)**	**Location**	**Amount**
Year Ended December 31, 2016			
Interest rate contracts	—	Interest expense	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (3)	Interest expense	$ (3)
Year Ended December 31, 2014			
Interest rate contracts	$ (9)	Interest expense	$ (3)

The Company:	**Gain or (Loss) Recognized in OCI, net of tax**	**Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion)**	
Millions of dollars	**(Effective Portion)**	**Location**	**Amount**
Year Ended December 31, 2016			
Interest rate contracts	$ (1)	Interest expense	$ (7)
Commodity contracts	5	Gas purchased for resale	(6)
Total	$ 4		$ (13)
Year Ended December 31, 2015			
Interest rate contracts	$ (2)	Interest expense	$ (7)
Commodity contracts	(10)	Gas purchased for resale	(15)
Total	$ (12)		$ (22)
Year Ended December 31, 2014			
Interest rate contracts	$ (6)	Interest expense	$ (7)
Commodity contracts	(8)	Gas purchased for resale	4
Total	$ (14)		$ (3)

As of December 31, 2016, the Company expects that during the next 12 months reclassifications from AOCI to earnings arising from cash flow hedges will include approximately $5.4 million as a decrease to gas cost, assuming natural gas markets remain at their current levels, and approximately $7.2 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of December 31, 2016, all of the Company's commodity cash flow hedges settle by their terms before the end of the second quarter of 2019.

As of December 31, 2016, each of the Company and Consolidated SCE&G expects that during the next 12 months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $1.8 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

For the Company and Consolidated SCE&G, ineffectiveness on interest rate hedges designated as cash flow hedges was insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

The Company and Consolidated SCE&G:		**Gain (Loss) Reclassified from Deferred Accounts into Income**	
Millions of dollars	**Loss Deferred in Regulatory Accounts**	**Location**	**Amount**
Year Ended December 31, 2016			
Interest rate contracts	$ (34)	Interest Expense	$ (2)
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2016, the Company and Consolidated SCE&G expect that during the next 12 months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $2.4 million as an increase to interest expense.

Credit Risk Considerations

Certain derivative contracts contain contingent credit features. These features may include (i) material adverse change clauses or payment acceleration clauses that could result in immediate payments or (ii) the posting of letters of credit or termination of the derivative contract before maturity if specific events occur, such as a credit rating downgrade below investment grade or failure to post collateral.

Derivative Contracts with Credit Contingent Features

	The Company		**Consolidated SCE&G**	
Millions of dollars	**December 31, 2016**	**December 31, 2015**	**December 31, 2016**	**December 31, 2015**
in Net Liability Position				
Aggregate fair value of derivatives in net liability position	$ 50.3	$ 95.2	$ 30.3	$ 57.0
Fair value of collateral already posted	29.2	50.4	9.2	13.4
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	21.1	44.8	21.1	43.6
in Net Asset Position				
Aggregate fair value of derivatives in net asset position	$ 62.9	$ 7.3	$ 62.0	$ 7.3
Fair value of collateral already posted	—	—	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	62.9	7.3	62.0	7.3

In addition, for fixed price supply contracts offered to certain of SCANA Energy's customers, the Company could have called on letters of credit in the amount of $1.5 million related to $9.0 million in commodity derivatives that are in a net asset position at December 31, 2016, compared to letters of credit of $3.0 million related to derivatives of $14.0 million at December 31, 2015, if all the contingent features underlying these instruments had been fully triggered.

Information related to the offsetting derivative assets follows:

Derivative Assets	The Company				Consolidated SCE&G
Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total	Interest Rate Contracts
As of December 31, 2016					
Gross Amounts of Recognized Assets	$ 71	$ 9	$ 10	$ 90	$ 71
Gross Amounts Offset in Statement of Financial Position			(4)	(4)	
Net Amounts Presented in Statement of Financial Position	71	9	6	86	71
Gross Amounts Not Offset - Financial Instruments	(9)			(9)	(9)
Gross Amounts Not Offset - Cash Collateral Received					
Net Amount	$ 62	$ 9	$ 6	$ 77	$ 62
Balance sheet location					
Prepayments				$ 9	
Other current assets				5	
Other deferred debits and other assets				72	$ 71
Total				$ 86	$ 71
As of December 31, 2015					
Gross Amounts of Recognized Assets	$ 15	$ 1	$ 15	$ 31	$ 15
Gross Amounts Offset in Statement of Financial Position			(1)	(1)	
Net Amounts Presented in Statement of Financial Position	15	1	14	30	15
Gross Amounts Not Offset - Financial Instruments	(8)			(8)	(8)
Gross Amounts Not Offset - Cash Collateral Received					
Net Amount	$ 7	$ 1	$ 14	$ 22	$ 7
Balance sheet location					
Other current assets				$ 22	$ 10
Other deferred debits and other assets				8	5
Total				$ 30	$ 15

Information related to the offsetting of derivative liabilities follows:

Derivative Liabilities	The Company				Consolidated SCE&G
Millions of dollars	Interest Rate Contracts	Commodity Contracts	Energy Management Contracts	Total	Interest Rate Contracts
As of December 31, 2016					
Gross Amounts of Recognized Liabilities	$ 58		$ 9	$ 67	$ 39
Gross Amounts Offset in Statement of Financial Position			(3)	(3)	
Net Amounts Presented in Statement of Financial Position	58	—	6	64	39
Gross Amounts Not Offset - Financial Instruments	(9)			(9)	(9)
Gross Amounts Not Offset - Cash Collateral Posted	(29)			(29)	(9)
Net Amount	$ 20	—	$ 6	$ 26	$ 21
Balance sheet location					
Derivative financial instruments				$ 35	$ 28
Other deferred credits and other liabilities				29	11
Total				$ 64	$ 39

As of December 31, 2015					
Gross Amounts of Recognized Liabilities	$ 87	$ 5	$ 15	$ 107	$ 65
Gross Amounts Offset in Statement of Financial Position			(1)	(1)	
Net Amounts Presented in Statement of Financial Position	87	5	14	106	65
Gross Amounts Not Offset - Financial Instruments	(8)			(8)	(8)
Gross Amounts Not Offset - Cash Collateral Posted	(36)	(5)	(9)	(50)	(13)
Net Amount	$ 43	$ —	$ 5	$ 48	$ 44
Balance sheet location					
Other current assets				$ 3	
Derivative financial instruments				50	$ 34
Other deferred credits and other liabilities				53	31
Total				$ 106	$ 65

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Available for sale securities are valued using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2016			As of December 31, 2015		
	The Company		Consolidated SCE&G	The Company		Consolidated SCE&G
Millions of dollars	**Level 1**	**Level 2**	**Level 2**	**Level 1**	**Level 2**	**Level 2**
Assets:						
Available for sale securities	$ 14	—	—	$ 11	—	—
Held to maturity securities	—	$ 7	—	—	—	—
Interest rate contracts	—	71	$ 71	—	$ 15	$ 15
Commodity contracts	8	1	—	1	—	—
Energy management contracts	6	4	—	—	14	—
Liabilities:						
Interest rate contracts	—	58	39	—	87	65
Commodity contracts	—	—	—	1	4	—
Energy management contracts	2	10	—	4	12	—

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2016 and December 31, 2015 were as follows:

	As of December 31, 2016		As of December 31, 2015	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
The Company	$ 6,489.8	$ 7,183.3	$ 5,997.6	$ 6,445.7
Consolidated SCE&G	5,166.0	5,752.3	4,769.0	5,129.1

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. SCE&G participates in SCANA's pension plan. SCANA’s policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee’s average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. SCE&G participates in these programs. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	The Company				Consolidated SCE&G			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2016	2015	2016	2015	2016	2015	2016	2015
Benefit obligation, January 1	$ 855.4	$ 919.5	$ 253.6	$ 268.2	$ 724.0	$ 773.7	$ 191.7	$ 204.1
Service cost	20.7	24.1	4.4	5.3	16.9	19.3	3.6	4.4
Interest cost	39.4	38.2	12.1	11.4	33.4	32.2	9.9	9.4
Plan participants’ contributions	—	—	1.7	2.4	—	—	1.3	1.9
Actuarial (gain) loss	45.0	(62.4)	14.0	(21.2)	41.8	(47.0)	11.5	(15.7)
Benefits paid	(56.2)	(64.0)	(11.1)	(12.5)	(47.7)	(54.2)	(9.1)	(10.3)
Amounts Funded to parent	n/a	n/a	n/a	n/a	—	—	(1.7)	(2.1)
Benefit obligation, December 31	$ 904.3	$ 855.4	$ 274.7	$ 253.6	$ 768.4	$ 724.0	$ 207.2	$ 191.7

In 2015, based on an evaluation of the mortality experience of the pension plan, a custom mortality table was adopted for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations for the Company of approximately $21.5 million and $2.4 million, respectively. This change resulted in an actuarial gain for pension and other postretirement benefit obligations for Consolidated SCE&G of approximately $18.2 million and $2.0 million, respectively.

The accumulated benefit obligation for pension benefits for the Company was $874.3 million at the end of 2016 and $829.3 million at the end of 2015. The accumulated benefit obligation for pension benefits for Consolidated SCE&G was $742.9 million at the end of 2016 and $702.0 million at the end of 2015.The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	2016	2015
Annual discount rate used to determine benefit obligation	4.22%	4.68%	4.30%	4.78%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 6.6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate for the Company would increase the postretirement benefit obligation by $0.8 million at December 31, 2016 and by $0.8 million at December 31, 2015. A one percent decrease in the assumed health care cost trend rate for the Company would decrease the postretirement benefit obligation by $0.7 million at December 31, 2016 and by $0.7 million at December 31, 2015. A one percent increase in the assumed health care cost trend rate for Consolidated SCE&G would increase the postretirement benefit obligation by $0.6 million at December 31, 2016 and by $0.6 million at December 31, 2015. A one percent decrease in the assumed health care cost trend rate for Consolidated SCE&G would decrease the postretirement benefit obligation by $0.6 million at December 31, 2016 and by $0.6 million at December 31, 2015.

Funded Status

	The Company				Consolidated SCE&G			
Millions of Dollars	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015	2016	2015	2016	2015
Fair value of plan assets	$ 793.6	$ 781.7	—	—	$ 732.9	$ 720.1	—	—
Benefit obligation	904.3	855.4	$ 274.7	$ 253.6	768.4	724.0	$ 207.2	$ 191.7
Funded status	$ (110.7)	$ (73.7)	$ (274.7)	$ (253.6)	$ (35.5)	$ (3.9)	$ (207.2)	$ (191.7)

Amounts recognized on the consolidated balance sheets were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015	2016	2015	2016	2015
Current liability	—	—	$ (12.6)	$ (11.9)	—	—	$ (10.4)	$ (9.8)
Noncurrent liability	$ (110.7)	$ (73.7)	(262.1)	(241.7)	$ (35.5)	$ (3.9)	(196.8)	(181.9)

Amounts recognized in accumulated other comprehensive loss were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015	2016	2015	2016	2015
Net actuarial loss	$ 10.4	$ 10.4	$ 2.5	$ 1.7	$ 1.9	$ 2.0	$ 1.0	$ 0.7
Prior service cost	0.1	0.2	—	—	—	—	—	—
Total	$ 10.5	$ 10.6	$ 2.5	$ 1.7	$ 1.9	$ 2.0	$ 1.0	$ 0.7

Amounts recognized in regulatory assets were as follows:

	The Company				Consolidated SCE&G			
Millions of Dollars	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
December 31,	2016	2015	2016	2015	2016	2015	2016	2015
Net actuarial loss	$ 236.1	$ 219.4	$ 34.7	$ 24.0	$ 208.8	$ 193.7	$ 29.3	$ 20.4
Prior service cost	2.5	5.9	—	0.3	2.2	5.2	—	0.2
Total	$ 238.6	$ 225.3	$ 34.7	$ 24.3	$ 211.0	$ 198.9	$ 29.3	$ 20.6

In connection with the joint ownership of Summer Station, pension costs attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $23.4 million and $20.3 million, respectively, and was recorded within deferred debits. The unfunded postretirement benefit obligation attributable to Santee Cooper as of December 31, 2016 and 2015 totaled $15.8 million and $13.8 million, respectively, and also was recorded within deferred debits.

Changes in Fair Value of Plan Assets

	The Company		Consolidated SCE&G	
	Pension Benefits		Pension Benefits	
Millions of dollars	**2016**	**2015**	**2016**	**2015**
Fair value of plan assets, January 1	$ 781.7	$ 861.8	$ 720.1	$ 783.6
Actual return (loss) on plan assets	68.1	(16.1)	60.5	(9.3)
Benefits paid	(56.2)	(64.0)	(47.7)	(54.2)
Fair value of plan assets, December 31	$ 793.6	$ 781.7	$ 732.9	$ 720.1

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. SCANA uses a dynamic investment strategy for the management of the pension plan assets. This strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2016 and 2015 and the target allocation for 2017 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	**2017**	**2016**	**2015**
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	32%
Hedge Funds	9%	11%	11%

For 2017, the expected long-term rate of return on assets will be 7.25%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan’s historical cumulative actual returns over several periods, considers the expected active and passive returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2016 and 2015, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

Millions of dollars	The Company 2016	The Company 2015	Consolidated SCE&G 2016	Consolidated SCE&G 2015
Investments with fair value measure at Level 2:				
Mutual funds	$ 125	$ 125	$ 115	$ 115
Short-term investment vehicles	16	14	15	12
US Treasury securities	18	22	17	20
Corporate debt securities	82	78	76	72
Municipals	14	14	13	13
Total assets in the fair value hierarchy	255	253	236	232
Investments at net asset value:				
Common collective trust	453	413	418	381
Joint venture interests	86	83	79	77
Limited partnership	—	33	—	30
Total investments at fair value	$ 794	$ 782	$ 733	$ 720

For all periods presented, assets with fair value measurements classified as Level 1 were insignificant, and there were no assets with fair value measurements classified as Level 3. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2016 or 2015. In addition, in 2015 the fair value of pension plan assets totaling $413 million for the Company and $381 million for Consolidated SCE&G were previously depicted as mutual funds but have been reclassified as Common collective trust for the current presentation.

Mutual funds held by the plan are open-ended mutual funds registered with the SEC. The price of the mutual funds' shares is based on its NAV, which is determined by dividing the total value of portfolio investments, less any liabilities, by the total number of shares outstanding. For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. US Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Common collective trust assets and limited partnerships are valued at NAV, which has been determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such trust funds by dividing the trust funds' net assets at fair value by the units outstanding at each valuation date. Joint venture interests assets are invested in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and not traded on a daily basis. The valuation of such multi-strategy hedge fund of funds is estimated based on the NAV of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may influence their fair value.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	The Company Pension Benefits	The Company Other Postretirement Benefits	Consolidated SCE&G Pension Benefits	Consolidated SCE&G Other Postretirement Benefits
2017	$ 63.1	$ 12.9	$ 63.1	$ 10.6
2018	65.1	13.7	65.1	11.2
2019	64.5	14.5	64.5	11.9
2020	64.7	15.3	64.7	12.5
2021	67.1	15.9	67.1	13.1
2022-2026	324.4	86.0	324.4	70.5

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals at the end of 2023, no significant contributions to the pension plan are expected to be made for the foreseeable future based on current market conditions and assumptions.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

The Company	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Service cost	$ 20.7	$ 24.1	$ 20.0	$ 4.4	$ 5.3	$ 4.6
Interest cost	39.4	38.2	40.4	12.1	11.4	12.0
Expected return on assets	(55.9)	(62.0)	(66.7)	n/a	n/a	n/a
Prior service cost amortization	3.9	4.1	4.1	0.3	0.4	0.3
Amortization of actuarial losses	14.8	13.6	4.8	0.5	2.1	—
Net periodic benefit cost	$ 22.9	$ 18.0	$ 2.6	$ 17.3	$ 19.2	$ 16.9

Consolidated SCE&G	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Service cost	$ 16.9	$ 19.3	$ 16.0	$ 3.6	$ 4.4	$ 3.6
Interest cost	33.4	32.2	34.1	9.9	9.4	9.4
Expected return on assets	(47.4)	(52.2)	(56.3)	n/a	n/a	n/a
Prior service cost amortization	3.4	3.4	3.5	0.3	0.3	0.3
Amortization of actuarial losses	12.5	11.4	4.0	0.4	1.7	—
Net periodic benefit cost	$ 18.8	$ 14.1	$ 1.3	$ 14.2	$ 15.8	$ 13.3

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

The Company	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	$ 0.6	$ 2.7	$ 3.1	$ 0.8	$ (1.2)	$ 1.3
Amortization of actuarial losses	(0.6)	(0.4)	(0.2)	—	(0.1)	—
Amortization of prior service cost	(0.1)	(0.1)	(0.2)	—	(0.1)	—
Total recognized in OCI	$ (0.1)	$ 2.2	$ 2.7	$ 0.8	$ (1.4)	$ 1.3

Consolidated SCE&G	**Pension Benefits**			**Other Postretirement Benefits**		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	—	$ 0.2	$ 0.2	$ 0.3	$ (0.3)	$ 0.4
Amortization of actuarial losses	$ (0.1)	(0.1)	(0.1)	—	—	—
Amortization of prior service cost	—	(0.1)	(0.1)	—	—	—
Total recognized in OCI	$ (0.1)	$ —	$ —	$ 0.3	$ (0.3)	$ 0.4

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

The Company	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	$ 29.4	$ 9.2	$ 101.3	$ 11.1	$ (18.0)	$ 19.4
Amortization of actuarial losses	(12.7)	(11.9)	(4.0)	(0.4)	(1.8)	—
Amortization of prior service cost	(3.4)	(3.7)	(3.2)	(0.3)	(0.3)	(0.3)
Total recognized in regulatory assets	$ 13.3	$ (6.4)	$ 94.1	$ 10.4	$ (20.1)	$ 19.1

Consolidated SCE&G	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current year actuarial (gain) loss	$ 26.3	$ 12.2	$ 87.7	$ 9.2	$ (14.0)	$ 15.8
Amortization of actuarial losses	(11.2)	(10.4)	(3.5)	(0.3)	(1.5)	—
Amortization of prior service cost	(3.0)	(3.1)	(2.8)	(0.2)	(0.3)	(0.2)
Total recognized in regulatory assets	$ 12.1	$ (1.3)	$ 81.4	$ 8.7	$ (15.8)	$ 15.6

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2016	**2015**	**2014**	**2016**	**2015**	**2014**
Discount rate	4.68%	4.20%	5.03%	4.78%	4.30%	5.19%
Expected return on plan assets	7.50%	7.50%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.00%	3.00%	3.00%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.00%	7.40%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2021	2020	2020

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 are as follows for the Company. For Consolidated SCE&G such amounts are insignificant:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 0.6	$ 0.1
Prior service cost	0.1	—
Total	$ 0.7	$ 0.1

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2017 are as follows:

	The Company		Consolidated SCE&G	
Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 13.6	$ 1.2	$ 12.0	$ 1.0
Prior service cost	1.4	—	1.3	—
Total	$ 15.0	$ 1.2	$ 13.3	$ 1.0

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCANA sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. SCE&G participates in this plan. Contributions are matched 100% up to 6% of an employee's eligible earnings. Such matching contributions made by the Company totaled $27.5 million in 2016, $26.2 million in 2015 and $25.8 million in 2014. These matching contributions included those made by Consolidated SCE&G, which totaled $22.9 million in 2016, $21.8 million in 2015 and $20.7 million in 2014. Employee deferrals, matching contributions, and earnings on all contributions are fully vested and nonforfeitable at all times.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2014-2016 performance cycle provides for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 and 2016-2018 awards are based on performance over a single three-year cycle. In the performance cycle for the 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash, and 80% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For each of the 2015-2017 and 2016-2018 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. At the Company's discretion, awards under the 2014-2016 performance cycle were paid in cash in February 2017 totaling $28.0 million for the Company, of which $20.2 million was attributable to Consolidated SCE&G (including amounts allocated from SCANA Services). Cash-settled liabilities related to earlier performance cycles totaled approximately $18.4 million in 2016, $20.8 million in 2015 and $11.8 million in 2014 for the Company and approximately $13.2 million in 2016, $6.3 million in 2015 and $1.9 million in 2014 for Consolidated SCE&G.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $25.6 million in 2016, $18.0 million in 2015 and $20.3 million in 2014 for the Company, of which approximately $17.3 million in 2016, $12.2 million in 2015 and $12.6 million in 2014 for Consolidated SCE&G (including amounts allocated from SCANA Services). Such fair value adjustments also resulted in capitalized compensation costs of $3.3 million in 2016, $2.3 million in 2015 and $3.1 million in 2014 for the Company and $3.1 million in 2016, $0.6 million in 2015 and $0.6 million in 2014 for Consolidated SCE&G. At December 31, 2016, unrecognized compensation cost, which is expected to be recognized over a weighted-average period of 18 months, was $23.4 million for the Company and $17.2 million for Consolidated SCE&G.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at SCE&G's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin and up to $2.33 billion resulting from an event of a non-nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of total coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $45.8 million. SCE&G currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with EMANI. The policy provides coverage to Unit 1 for property damage and outage costs up to $415 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, SCE&G's portion of the retrospective premium assessment would not exceed $1.8 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G's rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on the Company's and Consolidated SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium in 2008 for the design and construction of the New Units. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Estimated operating costs, including the depreciation of the utility plant costs, are then to be recovered through rates beginning when the construction of each New Unit is completed and placed into service. The BLRA also provides that, in the event of abandonment prior to plant completion, construction work in progress costs incurred, including AFC, and a return on those costs may be recoverable through rates, so long as SCE&G demonstrates by a preponderance of the evidence that its decision to abandon the New Unit(s) was prudent. As of December 31, 2016, SCE&G's investment in the New Units, including related transmission, totaled $4.5 billion, for which the financing costs on $3.8 billion have been reflected in rates under the BLRA. See Note 2 for a description of rate changes which have occurred under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. The Consortium has experienced delays throughout much of the project to date, and forecasted work crew efficiency and productivity metrics have not been met. In response, in November 2012, and again in September 2015 and November 2016 (see discussion below), the SCPSC approved SCE&G's requested updates to the milestone schedule, revised contractual substantial completion dates, and increases in capital and other costs. Some of these increased costs were the result of the schedule delays and were the subject of dispute.

October 2015 Amendment and WEC's Engagement of Fluor

On October 27, 2015, SCE&G, Santee Cooper and the Consortium amended the EPC Contract. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from CB&I. Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor as a subcontracted construction manager.

Among other things, the October 2015 Amendment provided SCE&G and Santee Cooper an irrevocable option to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G's 55% portion being approximately $3.345 billion). This total amount to be paid would be reduced by amounts paid since June 30, 2015. SCE&G, on behalf of itself and as agent for Santee Cooper, executed the fixed price option, subject to SCPSC approval, on July 1, 2016.

The October 2015 Amendment:

(i) resolved by settlement and release most outstanding disputes between SCE&G and the Consortium,

(ii) revised the contractual guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn Internal Revenue Code Section 45J production tax credits (see also below), resulting in escalating liquidated damages that are capped at an aggregate of $338 million per New Unit (SCE&G's 55% portion being approximately $186 million per New Unit),

(iv) provided for payment to the Consortium of a completion bonus of $150 million per New Unit (SCE&G's 55% portion being approximately $83 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provided for development of a revised construction milestone payment schedule,

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project,

(vii) provided for an explicit definition of Change in Law designed to reduce the likelihood of certain future commercial disputes, with the Consortium also acknowledging and agreeing that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19, and

(viii) eliminated the requirement or ability of any party to bring suit regarding disputes before substantial completion of the project.

As part of its responsibility as a subcontracted construction manager, Fluor has reviewed and assisted in the development of an updated integrated project schedule which reflects WEC's revised estimated completion dates of April 2020 and December 2020 for Units 2 and 3, respectively. These later dates remain within the SCPSC-approved 18-month contingency periods provided for under the BLRA, and achievement of such dates would also allow the output of both units to qualify, under current law, for federal production tax credits (see below). However, there is substantial uncertainty as to WEC's ability to meet these dates given its historical inability to achieve forecasted productivity and work force efficiency levels.

November 2016 SCPSC Order

In May 2016, SCE&G petitioned the SCPSC for approval of updated construction and capital cost schedules for the New Units which were developed in connection with the October 2015 Amendment. On November 9, 2016, the SCPSC approved a settlement agreement among SCE&G, ORS and certain other parties concerning this petition. The SCPSC also approved SCE&G's election of the fixed price option. See also Note 2.

The approved construction schedule designates contractual guaranteed substantial completion dates of August 31, 2019 and August 31, 2020 for Units 2 and 3, respectively. The approved capital cost schedule includes incremental capital costs that total $831 million. SCE&G's total project capital cost is now estimated at approximately $6.8 billion including owner's costs and transmission, or $7.7 billion with escalation and AFC. In addition, the SCPSC approved revising SCE&G's allowed ROE for new nuclear construction from 10.5% to 10.25%. This revised ROE will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2017. In addition, SCE&G may not file future requests to amend capital cost schedules prior to January 28, 2019, unless its annual revised rate request is denied because SCE&G is out of compliance with its approved capital cost schedule or BLRA construction milestone schedule. In most circumstances, if the projected commercial operation date for Unit 2 is extended, the expiration of the January 28, 2019 moratorium will be extended by an equal amount of time.

On December 14, 2016, the SCPSC denied Petitions for Rehearing filed by certain parties that were not included in the settlement. These parties may appeal this decision to the South Carolina Supreme Court once the SCPSC's order has been issued. SCE&G cannot determine when the SCPSC will issue its order in this matter or if that order will be appealed.

Construction Milestone Payment Schedule and Related DRB Activity

The October 2015 Amendment established a DRB process for resolving certain commercial claims and disputes. The DRB is comprised of three members chosen by the parties, and amounts in dispute of less than $5 million will be resolved by the DRB without recourse. Amounts in dispute greater than $5 million will be resolved by the DRB for the remainder of the construction of the New Units, with a reserved right to further arbitrate or to litigate such issues at the conclusion of construction.

On December 2, 2016 the DRB issued an order establishing a construction milestone payment schedule (see (v) in October 2015 Amendment above) on which SCE&G and WEC had been unable to agree subsequent to the October 2015 Amendment. The dispute related only to the timing of payments; the total amount to be paid was not in dispute. The DRB order provides that certain subcontractor and other supplier-related costs incurred by the Consortium will be reimbursed by the owners regardless of payment-milestone completion, but that other payments will be made only upon documented achievement of the agreed-upon payment-milestones. Such subcontractor and other supplier-related costs comprised approximately $873 million of the $3.345 billion of fixed option payments that were the subject of the DRB order.

Payment and Performance Obligations and Certain Related Uncertainties

Payment and performance obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba, WEC's parent company, reaffirmed its guaranty of WEC's payment obligations. Additionally, the EPC Contract provides the owners the right, exercisable upon certain conditions, to obtain payment and performance bonds from WEC equal to 15% of the highest projected three months billings during the applicable year, and their aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bonds.

In late 2015, Toshiba's credit ratings declined to below investment grade following disclosures regarding its operating and financial performance and near-term liquidity. As a result, pursuant to the above-described terms of the EPC Contract, SCE&G has obtained standby letters of credit in lieu of payment and performance bonds from WEC totaling $45 million (or approximately $25 million for SCE&G's 55% share). These standby letters of credit expire annually in February, and they automatically renew for successive one-year periods until their final expiration date of August 31, 2020, unless the issuer provides a minimum 60-day notice that it will not renew. If the issuer provides notice that it will not renew, SCE&G may draw upon the standby letter of credit prior to its expiration. In the event that WEC would be unable to meet its payment and performance obligations under the EPC Contract, it is anticipated this funding would provide a source of liquidity to assist in an orderly transition. In addition, the EPC Contract provides that upon the request of SCE&G, and at owners' cost, the Consortium must escrow certain intellectual property and software for the owners' benefit to assist in completion of the New Units. An escrow arrangement has been established, and certain intellectual property and software have been deposited. Additional deposits are anticipated.

In December 2016 through February 2017, Toshiba and WEC announced further deterioration in their financial position and liquidity related to write-downs arising from WEC's acquisition of Stone and Webster from CB&I (discussed above). The announcements noted that WEC and Toshiba have determined that significant losses will be incurred under the EPC Contract for the New Units and under a similar engineering, procurement and construction agreement for other units currently being constructed in the United States. This determination has impacted their allocation of the CB&I purchase price, resulting in recognition of a large amount of goodwill which has in turn been determined to be impaired. Preliminary recognition of this impairment loss (in excess of $6 billion) has left Toshiba with negative shareholders' equity and threatened its liquidity. In January 2017, Toshiba's credit ratings were further reduced. In response, Toshiba has indicated its interest in monetizing portions of its business as it attempts to restructure and restore its financial position. Toshiba has also indicated that it will withdraw from the nuclear construction business prospectively and that it will significantly alter its risk management oversight of its nuclear power business. WEC has told the Company that it and Toshiba are committed to completing the New Units. Toshiba has acknowledged its parental guaranty to the project, but it has informed the Company that no specific commitment regarding completion of the New Units has been agreed to by it so far.

Toshiba also announced that it had requested (and successfully received) a one-month extension of the deadline for submitting its securities report to Japanese securities regulators for the quarter ended December 31, 2016 to allow an internal investigation into the adequacy of internal controls relating to the purchase price allocation process for WEC's acquisition of Stone & Webster and concerns that senior management at WEC may have exerted inappropriate pressure in order to advance the purchase price allocation process. As part of the announcement, it was stated that Toshiba's audit committee was concerned that an invalidation of internal controls (or even the possibility thereof) might affect Toshiba's quarterly financial statements, and that two law firms had been separately retained by the audit committee and WEC to assist with this investigation.

Although progress on the project was seen in December 2016 and January 2017, including the placement of the first of Unit 2's two steam generators, significant risks and uncertainties remain concerning WEC's ability to improve work force efficiency and productivity performance and to continue to fulfill its performance and financial commitments and Toshiba's ability to perform under its payment guaranty with respect to the project. In particular, there can be no assurance that their creditors will continue to provide support or that other sources of liquidity will emerge or continue to be available. In the event that WEC were to fail to complete the project in breach of its obligations under the EPC Contract, its payment obligations for damages would increase substantially above the amount of the liquidated damages described above, but would still be subject to limitations.

SCE&G and Santee Cooper, the co-owner of the New Units, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include completing the work under possible arrangements with other contractors or, were it determined to be prudent, halting the project and leaving SCE&G to pursue cost recovery under the abandonment provisions of the BLRA.

Also, in response to these developments and in light of the DRB-established construction milestone payment schedule, in February 2017, SCE&G initiated its solicitation for increased levels of standby letters of credit in lieu of payment and performance bonds referred to above. However, it is uncertain whether such additional levels of standby letters of credit will be available at reasonable cost or whether any letters of credit will continue to be renewed by their issuers.

Finally, additional claims by the Consortium or SCE&G involving the project schedule, budget and performance may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues, and SCE&G expects to resolve disputes through those means. SCE&G expects to seek recovery through rates of any project costs that arise through such dispute resolution processes, as well as other project costs identified from time to time; however, any such request would be subject to the provisions of the November 2016 SCPSC order discussed above. There can be no assurance that recovery would be granted.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction is subject to customary closing conditions, including receipt of necessary regulatory approvals. This transaction will not affect the payment obligations between the parties during construction of the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. SCE&G's current projected cost for the additional 5% interest being acquired from Santee Cooper is approximately $850 million.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the IRC to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on current tax law and the contractual guaranteed substantial completion dates (and the recently revised forecasted dates of completion) provided above, both New Units would be operational and would qualify for the nuclear production tax credits; however, any further delays in the schedule or changes in tax law could adversely impact these conclusions. See also the Payment and Performance Obligations and Certain Related Uncertainties discussion above. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan remains under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's and Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, the Company and Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company and Consolidated SCE&G expect to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the SO_2 and NO_X emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of CO_2 from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds CO_2 per MWh and new natural gas units to meet 1,000 pounds CO_2 per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company and Consolidated SCE&G are monitoring the final rule, but do not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national CO_2 emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives each state from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. The Company and Consolidated SCE&G expect any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of SO_2 and NO_X from power plants in the eastern half of the United States. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual SO_2 emissions and annual and ozone season NO_X emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for SO_2 and NO_X and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. The State of South Carolina has chosen to remain in the CSAPR program, even though recent court rulings exempted the state. This allows the state to remain compliant with regional haze standards. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any costs incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The MATS rule has been the subject of ongoing litigation even while it remains in effect. Rulings on this litigation are not expected to have an impact on SCE&G or GENCO due to plant retirements, conversions, and enhancements. SCE&G and GENCO are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule became effective on January

4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. The Company and Consolidated SCE&G expect that wastewater treatment technology retrofits will be required at Williams and Wateree Stations. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications to ensure compliance with this rule. Any costs incurred to comply with this rule are expected to be recoverable through rates.

The EPA's final rule for CCR became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities. SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. The Company and Consolidated SCE&G do not expect the incremental compliance costs associated with this rule to be significant and expect to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2016, the federal government has not accepted any spent fuel from Unit 1, and it remains unclear when the repository may become available. SCE&G has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2018 and will cost an additional $10.2 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2016, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $25.7 million and are included in regulatory assets.

Claims and Litigation

The Company and Consolidated SCE&G are subject to various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on the Company’s and Consolidated SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

The Company and Consolidated SCE&G are obligated under various operating leases for land, office space, furniture, vehicles, equipment, rail cars, a purchase power agreement, and for the Company, airplanes. Leases expire at various dates through 2057.

Millions of dollars	Rent Expense 2016	2015	2014
The Company	$ 10.2	$ 11.1	$ 12.3
Consolidated SCE&G	12.2	12.3	12.1

Millions of dollars	Future Minimum Rental Payments 2017	2018	2019	2020	2021	Thereafter
The Company	$ 31	$ 29	$ 28	$ 3	$ 3	$ 23
Consolidated SCE&G	25	23	22	1	—	17

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is remote; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2016, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.7 billion.

Asset Retirement Obligations

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2016, SCE&G has recorded AROs of approximately $199 million for nuclear plant decommissioning (see Note 1). In addition, the Company has recorded AROs of approximately $359 million, including $323 million for Consolidated SCE&G, for other conditional obligations primarily related to other generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	The Company 2016	The Company 2015	Consolidated SCE&G 2016	Consolidated SCE&G 2015
Beginning balance	$ 520	$ 563	$ 488	$ 536
Liabilities incurred	—	—	—	—
Liabilities settled	(11)	(16)	(11)	(16)
Accretion expense	23	25	22	23
Revisions in estimated cash flows	26	(52)	23	(55)
Ending balance	$ 558	$ 520	$ 522	$ 488

Revisions in estimated cash flows in 2016 primarily related to changes in projected costs, based on a nuclear decommissioning cost study. Such revisions in 2015 related to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study.

11. AFFILIATED TRANSACTIONS

The Company:

The Company received cash distributions from equity-method investees of $3.7 million in 2016, $4.0 million in 2015 and $7.8 million in 2014. The Company made investments in equity-method investees of $5.5 million in 2016, $4.1 million in 2015 and $5.7 million in 2014.

The Company and Consolidated SCE&G:

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. Consolidated SCE&G’s total purchases from this affiliate were $161.8 million in 2016, $233.2 million in 2015 and $260.3 million in 2014. Consolidated SCE&G’s total sales to this affiliate were $160.8 million in 2016, $232.0 million in 2015 and $259.0 million in 2014. The net of the total purchases and total sales are recorded in Other expenses on the consolidated statements of income (for the Company) and of comprehensive income (for Consolidated SCE&G). Consolidated SCE&G’s payable to this affiliate was $16.1 million at December 31, 2016 and $12.9 million at December 31, 2015. Consolidated SCE&G’s receivable from this affiliate was $16.0 million at December 31, 2016 and $12.8 million at December 31, 2015.

Consolidated SCE&G:

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $111.5 million in 2016, $128.5 million in 2015 and $195.7 million in 2014. SCE&G’s payables to SCANA Energy for such purchases were $8.8 million and $7.5 million as of December 31, 2016 and 2015, respectively.

SCANA Services, on behalf of itself and its parent company, provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems, telecommunications, customer support, marketing and sales, human resources, corporate compliance, purchasing, financial, risk management, public affairs, legal, investor relations, gas supply and capacity management, strategic planning, general administrative and retirement benefits. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services, including amounts capitalized, totaled $337.7 million in 2016, $300.0 million in 2015 and $292.2 million in 2014. Amounts expensed are recorded in Other operation and maintenance - nonconsolidated affiliate and Other expenses on the consolidated statements of comprehensive income. Consolidated SCE&G's payables to SCANA Services for these services were $63.5 million and $57.0 million at December 31, 2016 and 2015, respectively.

Prior to January 31, 2015, CGT was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in 2015 and $30.0 million in 2014.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs is described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein. Intersegment sales and transfers of electricity and gas are recorded based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, purchases and sells natural gas, primarily at retail. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively. Gas Marketing is comprised of the marketing operations of SCANA Energy, which markets natural gas to retail customers in Georgia and to industrial and large commercial customers and municipalities in the Southeast.

All Other includes the parent company, a services company and other nonreportable segments that were insignificant for all periods presented. In addition, All Other includes gains from the sales of CGT and SCI (see Note 1) and their operating results and assets prior to their sale in the first quarter of 2015. CGT and SCI were nonreportable segments during all periods presented. External revenue and intersegment revenue for All Other related to CGT and SCI were not significant during any period presented.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. Gas Marketing operates in a deregulated environment.

Management uses operating income to measure segment profitability for its regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, no allocation is made to segments for interest charges, income tax expense or assets other than utility plant. For nonregulated operations, management uses net income as the measure of segment profitability and evaluates total assets for financial position. Intersegment revenue for SCE&G was not significant. Interest income is not reported by segment and is not material. Deferred tax assets are netted with deferred tax liabilities for consolidated reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense, Expenditures for Assets and Deferred Tax Assets include primarily the amounts that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs, and totals not allocated to other segments. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

Reportable segments have changed from what was reported as of December 31, 2015 to combine the former Retail Gas Marketing and Energy Marketing segments into a single Gas Marketing segment. This change in reportable segments occurred due to changes in the structure of the Company's internal organization which included the integration of strategic planning and reporting for these business units and the related integration of the chief operating decision maker's assessment of performance and resource allocation. Corresponding amounts in prior periods have been revised to conform to the current presentation.

Disclosure of Reportable Segments

The Company:

Millions of dollars	**Electric Operations**	**Gas Distribution**	**Gas Marketing**	**All Other**	**Adjustments/ Eliminations**	**Consolidated Total**
2016						
External Revenue	$ 2,614	$ 788	$ 825	—	—	$ 4,227
Intersegment Revenue	5	2	111	$ 414	$ (532)	—
Operating Income	957	148	n/a	—	48	1,153
Interest Expense	17	25	1	—	299	342
Depreciation and Amortization	287	82	2	16	(16)	371
Income Tax Expense	8	32	19	—	212	271
Net Income (Loss)	n/a	n/a	30	(18)	583	595
Segment Assets	11,929	2,892	230	1,124	2,532	18,707
Expenditures for Assets	1,275	276	2	11	15	1,579
Deferred Tax Assets	9	32	11	—	(52)	—

2015						
External Revenue	$ 2,551	$ 810	$ 1,018	$ 5	$ (4)	$ 4,380
Intersegment Revenue	6	2	128	413	(549)	—
Operating Income	876	152	n/a	236	44	1,308
Interest Expense	17	23	1	1	276	318
Depreciation and Amortization	277	77	2	16	(14)	358
Income Tax Expense	9	32	18	1	333	393
Net Income	n/a	n/a	28	185	533	746
Segment Assets	10,883	2,606	201	998	2,458	17,146
Expenditures for Assets	1,087	203	2	15	(154)	1,153
Deferred Tax Assets	5	29	15	—	(49)	—
2014						
External Revenue	$ 2,622	$ 1,012	$ 1,301	$ 37	$ (21)	$ 4,951
Intersegment Revenue	7	2	196	437	(642)	—
Operating Income	768	159	n/a	27	53	1,007
Interest Expense	19	22	1	5	265	312
Depreciation and Amortization	300	72	2	24	(14)	384
Income Tax Expense	7	33	19	12	177	248
Net Income (Loss)	n/a	n/a	31	(6)	513	538
Segment Assets	10,182	2,487	290	1,474	2,385	16,818
Expenditures for Assets	936	200	2	52	(98)	1,092
Deferred Tax Assets	11	29	20	15	(75)	—

Consolidated SCE&G:

Millions of dollars	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2016				
External Revenue	$ 2,619	$ 367	—	$ 2,986
Operating Income	957	56	—	1,013
Interest Expense	17	—	$ 253	270
Depreciation and Amortization	287	28	(13)	302
Segment Assets	11,929	825	3,337	16,091
Expenditures for Assets	1,275	78	46	1,399
Deferred Tax Assets	9	n/a	(9)	—
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	876	58	—	934
Interest Expense	17	—	$ 231	248
Depreciation and Amortization	277	28	(11)	294
Segment Assets	10,883	757	3,125	14,765
Expenditures for Assets	1,087	57	(136)	1,008
Deferred Tax Assets	5	n/a	(5)	—
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	768	62	—	830
Interest Expense	19	—	$ 209	228
Depreciation and Amortization	300	27	(12)	315
Segment Assets	10,182	721	3,175	14,078
Expenditures for Assets	936	55	(57)	934
Deferred Tax Assets	11	n/a	(11)	—

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

The Company

Millions of dollars, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2016					
Total operating revenues	$ 1,172	$ 905	$ 1,093	$ 1,057	$ 4,227
Operating income	331	221	348	253	1,153
Net income	176	105	189	125	595
Earnings per share	1.23	.74	1.32	.87	4.16
2015					
Total operating revenues	$ 1,389	$ 967	$ 1,068	$ 956	$ 4,380
Operating income	586	216	292	214	1,308
Net income	400	99	149	98	746
Earnings per share	2.80	.69	1.04	.69	5.22

Consolidated SCE&G

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2016					
Total operating revenues	$ 717	$ 692	$ 882	$ 695	$ 2,986
Operating income	236	222	359	196	1,013
Net Income	116	113	204	93	526
Earnings Available to Common Shareholder	113	110	201	89	513
2015					
Total operating revenues	$ 772	$ 709	$ 806	$ 643	$ 2,930
Operating income	237	218	307	172	934
Net Income	126	111	167	76	480
Earnings Available to Common Shareholder	122	107	164	73	466

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2016, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCANA's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2016, SCANA's disclosure controls and procedures were effective.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2016, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCANA's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2016. There has been no change in SCANA's internal controls over financial reporting during the quarter ended December 31, 2016 that has materially affected or is reasonably likely to materially affect SCANA's internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA's internal control system was designed by or under the supervision of SCANA's management, including its CEO and CFO, to provide reasonable assurance to SCANA's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA's management assessed the effectiveness of SCANA's internal control over financial reporting as of December 31, 2016. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (2013)*. Based on this assessment, SCANA's management believes that, as of December 31, 2016, internal control over financial reporting is effective based on those criteria.

SCANA's independent registered public accounting firm has issued an attestation report on SCANA's internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company'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 Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2016, of the Company and our report dated February 24, 2017, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2016, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCE&G’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2016, SCE&G's disclosure controls and procedures were effective.

Management’s Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2016, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCE&G's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2016. There has been no change in SCE&G’s internal controls over financial reporting during the quarter ended December 31, 2016 that has materially affected or is reasonably likely to materially affect SCE&G’s internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G’s internal control system was designed by or under the supervision of SCE&G’s management, including its CEO and CFO, to provide reasonable assurance to SCE&G’s management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G’s management assessed the effectiveness of SCE&G’s internal control over financial reporting as of December 31, 2016. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013).* Based on this assessment, SCE&G’s management believes that, as of December 31, 2016, internal control over financial reporting is effective based on those criteria.

ITEM 9B. OTHER INFORMATION

SCANA:

The following information is included herein in lieu of filing it in Item 1.01 of Form 8-K:

On February 22, 2017, consistent with its past practice, SCANA entered into an indemnification agreement with Randal M. Senn in connection with his promotion in 2016.

The indemnification agreement generally provides that SCANA will indemnify the covered person for claims arising in such person's capacity as a director, officer, employee or other agent of SCANA or its subsidiaries, provided that, among other things, such person acted in good faith and with a view to the best interests of SCANA and, with respect to any criminal proceeding, had no reasonable grounds for believing that person's conduct was unlawful. The indemnification agreement also provides for payment for or reimbursement of reasonable expenses incurred by an indemnitee who is a party to a proceeding in advance of final disposition of the proceeding under certain circumstances.

The above description of the indemnification agreement is qualified in its entirety by reference to the form of indemnification agreement that was filed as Exhibit 10.01 to SCANA's Quarterly Report on Form 10-Q for the period ended June 30, 2012 and that is incorporated herein by reference.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report at page 23. The other information required by Item 10 is incorporated herein by reference to the captions "INFORMATION ABOUT EXPERIENCE AND QUALIFICATION OF DIRECTORS AND NOMINEES," "NOMINEES FOR DIRECTOR," "CONTINUING DIRECTORS," "BOARD MEETINGS-COMMITTEES OF THE BOARD", "GOVERNANCE INFORMATION-SCANA's Code of Conduct & Ethics" and "OTHER INFORMATION-Section 16(a) Beneficial Ownership Reporting Compliance" in SCANA's definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information required by Item 11 is incorporated herein by reference to the captions "Compensation Committee Interlocks and Insider Participation," "Compensation Risk Assessment," "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table," "2016 Grants of Plan-Based Awards," "Outstanding Equity Awards at 2016 Fiscal Year-End," "2016 Option Exercises and Stock Vested," "Pension Benefits," "2016 Nonqualified Deferred Compensation," and "Potential Payments Upon Termination or Change in Control," under the heading "EXECUTIVE COMPENSATION" and the heading "DIRECTOR COMPENSATION" in SCANA's definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: Information required by Item 12 is incorporated herein by reference to the caption "SHARE OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT" in SCANA's definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

Equity securities issuable under SCANA's compensation plans at December 31, 2016 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
2015 Long-Term Equity Compensation Plan	306,428 (1)	n/a	4,963,572
Prior Long-Term Equity Compensation Plan	296,732 (2)	n/a	—
Non-Employee Director Compensation Plan	n/a	n/a	179,248
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	603,160	n/a	5,142,820

(1) Represents unearned non-vested performance share awards from the 2015-2017 and 2016-2018 performance periods assuming a target level payout.
(2) Represents performance shares related to vested grants from the 2014-2016 performance period which were settled in cash rather than shares in February 2017.

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: The information required by Item 13 is incorporated herein by reference to the captions “RELATED PARTY TRANSACTIONS” and “GOVERNANCE INFORMATION - Director Independence” in SCANA’s definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA’s fiscal year.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA: The information required by Item 14 is incorporated herein by reference to “PROPOSAL 4-APPROVAL OF THE APPOINTMENT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM” in SCANA’s definitive proxy statement for the 2017 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities and Exchange Act of 1934 within 120 days after the end of SCANA’s fiscal year.

SCE&G: The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm’s Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to SCE&G and its consolidated affiliates for the fiscal years ended December 31, 2016 and 2015 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	2016	2015
Audit Fees (1)	$ 2,316,288	$ 2,032,222
Audit-Related Fees (2)	117,146	114,832
Total Fees	$ 2,433,434	$ 2,147,054

(1) Fees for audit services billed in 2016 and 2015 consisted of audits of annual financial statements, comfort letters for securities underwriters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

(2) Fees primarily for employee benefit plan audits and non-statutory audit services.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under Item 8 herein. The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under Item 8 herein. The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA's employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts

			Additions			
Description (in millions)		Beginning Balance	Charged to Income	Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2016	$ 5	$ 12	—	$ 11	$ 6
	2015	7	12	—	14	5
	2014	6	16	—	15	7
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2016	$ 6	$ 5	—	$ 2	$ 9
	2015	5	11	—	10	6
	2014	6	7	—	8	5
SCE&G:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2016	$ 3	$ 6	—	$ 6	$ 3
	2015	4	6	—	7	3
	2014	3	8	—	7	4
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2016	$ 5	$ 5	—	$ 2	$ 8
	2015	3	11	—	9	5
	2014	5	1	—	3	3

SIGNATURES

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

DATE: February 24, 2017

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 and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

(Principal Executive Officer)

/s/ J. E. Addison

J. E. Addison
Executive Vice President and Chief Financial Officer

(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Vice President and Controller

(Principal Accounting Officer)

Other Directors*:

G. E. Aliff	J. M. Micali
J. A. Bennett	L. M. Miller
J. F. A. V. Cecil	J. W. Roquemore
S. A. Decker	M. K. Sloan
D. M. Hagood	A. Trujillo

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 24, 2017

SIGNATURES

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director

DATE: February 24, 2017

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 and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.

/s/ K. B. Marsh

K. B. Marsh Chairman of the Board, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ J. E. Addison

J. E. Addison
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV

J. E. Swan, IV
Vice President and Controller
(Principal Accounting Officer)

Other Directors*:

G. E. Aliff	J. M. Micali
J. A. Bennett	L. M. Miller
J. F. A. V. Cecil	J. W. Roquemore
S. A. Decker	M. K. Sloan
D. M. Hagood	A. Trujillo

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 24, 2017

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of SCANA	Applicable to Form 10-K of SCE&G	Description
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File No. 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of December 30, 2016 (Filed herewith)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
4.01	X	X	Articles of Exchange of SCE&G and SCANA (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein)
4.02	X		Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N. A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein)
4.03	X		First Supplemental Indenture dated as of November 1, 2009 to Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 99.01 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.04		X	Indenture dated as of April 1, 1993 from SCE&G to The Bank of New York Mellon Trust Company, N. A. (as successor to NationsBank of Georgia, National Association), as Trustee (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein)
4.05		X	First Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein)
4.06		X	Second Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein)
4.07		X	Third Supplemental Indenture to Indenture referred to in Exhibit 4.04 dated as of September 1, 2013 (Filed as Exhibit 4.12 to Post-Effective Amendment to Registration Statement No. 333-184426-01 and incorporated by reference herein)
10.01	X	X	Engineering, Procurement and Construction Agreement, dated May 23, 2008, between SCE&G, for itself and as Agent for the South Carolina Public Service Authority and a Consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2008 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.02	X	X	Contract for AP1000 Fuel Fabrication and Related Services between Westinghouse Electric Company LLC and SCE&G for V. C. Summer AP1000 Nuclear Plant Units 2 & 3 (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2011 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.03	X	X	Amendment to EPC Contract referred to in Exhibit 10.01 dated October 27, 2015 (Filed as Exhibit 10.05 to Form 10-Q for the quarter ended September 30, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)

*10.04	X	X	SCANA Executive Deferred Compensation Plan (including amendments through November 25, 2014) (Filed as Exhibit 10.03 to Form 10-K for the year ended December 31, 2014 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.05	X	X	SCANA Supplemental Executive Retirement Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.06	X	X	SCANA Director Compensation and Deferral Plan (including amendments through November 30, 2014) (Filed as Exhibit 10.05 to Form 10-K for the year ended December 31, 2014 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.07	X	X	SCANA Long-Term Equity Compensation Plan effective February 19, 2015 (Filed as Exhibit 4.05 to Registration Statement No. 333-204218 and incorporated by reference herein)
*10.08	X	X	SCANA Supplementary Executive Benefit Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.07 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.09	X	X	SCANA Short-Term Annual Incentive Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.08 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.10	X	X	SCANA Supplementary Key Executive Severance Benefits Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.09 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.11	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F for the year ended December 31, 1991, under cover of Form SE (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.12		X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 99.10 to Registration Statement No. 333-174796 and incorporated by reference herein)
10.13	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q dated June 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.14	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCANA; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.1 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
10.15	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A., as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.2 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.16	X	X	Amended and Restated Three-Year Credit Agreement dated as of December 17, 2015, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Morgan Stanley Bank, N.A., as Issuing Bank; Bank of America, N.A. as Issuing Bank and Co-Syndication Agent; Morgan Stanley Senior Funding, Inc., as Co-Syndication Agent; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.3 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)

10.17	X	X	Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among Fuel Company; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.4 to Form 8-K on December 22, 2015 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.18	X		Second Amended and Restated Five-Year Credit Agreement dated as of December 17, 2015, by and among PSNC Energy; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, LTD., MUFG Union Bank, N.A., TD Bank N.A. and UBS Securities, LLC, as Documentation Agents (Filed as Exhibit 99.5 to Form 8-K on December 22, 2015 (File No. 001-08809) and incorporated by reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
21.01	X		Subsidiaries of the registrant (Filed herewith)
23.01	X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
23.02		X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
24.01	X		Power of Attorney (Filed herewith)
24.02		X	Power of Attorney (Filed herewith)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02		X	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS**	X	X	XBRL Instance Document
101. SCH**	X	X	XBRL Taxonomy Extension Schema
101. CAL**	X	X	XBRL Taxonomy Extension Calculation Linkbase
101. DEF**	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB**	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE**	X	X	XBRL Taxonomy Extension Presentation Linkbase

* Management Contract or Compensatory Plan or Arrangement

** Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

Exhibit 3.05

AMENDED AND RESTATED

BYLAWS

OF

SCANA CORPORATION

Adopted on December 30, 2016

ARTICLE I. SHAREHOLDERS

Section 1. _Annual Meeting_. An annual meeting of the shareholders shall be held each fiscal year for the purpose of electing Directors and for the transaction of such other business as may properly come before the meeting. The exact time and place of the annual meeting shall be determined by the Board of Directors.

Section 2. _Special Meetings_. Special meetings of the shareholders may be called by the Chief Executive Officer, or by the Chairman of the Board of Directors, or by a majority of the Board of Directors. Business transacted at a special meeting shall be confined to the specific purpose or purposes of the persons authorized to request such special meeting as set forth in this Section and only such purpose or purposes shall be set forth in the notice of such meeting.

Section 3. _Place of Meeting_. The Board of Directors may designate any place, either within or without the State of South Carolina, as the place of meeting for any annual meeting or for any special meeting.

Section 4. _Conduct of Meetings_. Meetings of shareholders shall be presided over by the Chairman of the Board or, in the absence of the Chairman of the Board, the Chairman of the Executive Committee, or in the absence of the Chairman of the Executive Committee, a chairman designated by the Board of Directors or, in the absence of such designation, by a chairman chosen at the meeting by the vote of a majority in interest of the shareholders present in person or represented by proxy and entitled to vote thereat. The Secretary or, in the Secretary's absence, an Assistant Secretary or, in the absence of the Secretary and all Assistant Secretaries, a person whom the chairman of the meeting shall appoint shall act as secretary of the meeting and keep a record of the proceedings thereof.

The Board of Directors shall be entitled to make such rules, regulations and procedures for the conduct of meetings of shareholders as it shall deem necessary, appropriate or convenient. Subject to such rules, regulations and procedures of the Board of Directors, if any, the chairman of the meeting shall have the right and authority to prescribe such rules, regulations and procedures and to do all such acts as, in the judgment of such chairman, are necessary, appropriate or convenient for the proper conduct of the meeting, including, without limitation, establishing (a) an agenda or order of business for the meeting, (b) rules, regulations and procedures for maintaining order at the meeting and the safety of those present, (c) limitations on participation in such meeting to shareholders of record of the Corporation and their duly authorized and constituted proxies and such other persons as the chairman shall permit, (d) restrictions on entry to the meeting after the time fixed for the commencement thereof, (e) limitations on the time allotted to questions or comments by participants and (f) rules, regulations and procedures governing the opening and closing of the polls for balloting and matters which are to be voted on by ballot. Unless and to the extent determined by the Board of Directors or the chairman of the meeting, meetings of shareholders shall not be required to be held in accordance with rules of parliamentary procedure.

Section 5. *Nominations by Shareholders and Shareholder Proposals – Annual Meeting* . Nominations of persons for election to the Board of Directors and the proposal of business to be considered by the shareholders may be made at an annual meeting of shareholders (a) by or at the direction of the Board of Directors or (b) by any shareholder of the Corporation who was a shareholder of record at the time of giving of notice by such shareholder provided for in this Section, who is entitled to vote at the meeting and who complied with the notice procedures set forth below in this Section.

For nominations or other business to be properly brought before an annual meeting by a shareholder pursuant to clause (b) of the foregoing paragraph of this Section 5, the shareholder must have given timely notice thereof in writing to the Secretary of the Corporation. To be timely, a shareholder's notice shall be delivered to and received by the Secretary at the principal office of the Corporation not less than 120 days prior to the first anniversary of the date of the proxy statement sent to shareholders in connection with the preceding year's annual meeting; provided, however, that if the date of the annual meeting is advanced by more than 30 days or delayed by more than 60 days from the anniversary date of the preceding year's annual meeting, notice by the shareholder to be timely must be so delivered not later than the close of business on the later of (i) the 120th day prior to such annual meeting or (ii) the 10th day following the day on which public announcement of the date of such meeting is first made.

Notwithstanding anything in the second sentence of the preceding paragraph to the contrary, if the number of directors to be elected to the Board of Directors is increased and there is no public announcement naming all of the nominees for director or specifying the size of the increased Board of Directors made by the Corporation at least 120 days prior to the first anniversary of the date of the proxy statement sent to shareholders in connection with the preceding year's annual meeting, a shareholder's notice required by this Bylaw shall also be considered timely, but only with respect to nominees for any new positions created by such increase, if it shall be delivered to and received by the Secretary at the principal office of the Corporation not later than the close of business on the 10th day following the day on which such public announcement is first made by the Corporation.

Such shareholder's notice shall set forth (a) as to each person whom the shareholder proposes to nominate for election or reelection as a director all information relating to such person that is required to be disclosed in solicitations of proxies for election of directors, or is otherwise required, in each case pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) (including such person’s written consent to being named in the proxy statement as a nominee and to serving as a director if elected) and a description of all arrangements and understandings between the nominating shareholder and the nominee or any other person (naming such person) relating to the nomination; (b) as to any other business that the shareholder proposes to bring before the meeting, a brief description of the business desired to be brought before the meeting, the reasons for conducting such business at the meeting and any material interest in such business of such shareholder and the beneficial owner, if any, on whose behalf the proposal is made; (c) as to the shareholder giving the notice and the beneficial owner, if any, on whose behalf the nomination or proposal is made (i) the name and address of such shareholder, as they appear on the Corporation’s books, and of such beneficial owner and (ii) the class and number of shares of the Corporation which are owned beneficially and of record by such shareholder and such beneficial owner.

Only such persons who are nominated in accordance with the procedures set forth in these Bylaws shall be eligible to serve as directors and only such business shall be conducted at an annual meeting of shareholders as shall have been brought before the meeting in accordance with the procedures set forth in this Section. The chairman of the meeting shall have the power and duty to determine whether a nomination or any business proposed to be brought before the meeting was made in accordance with the procedures set forth in this Section and, if any proposed nomination or business is not in compliance with this Section, to declare that such defective proposal shall be disregarded.

For purposes of this Section, “public announcement” shall mean disclosure in a press release reported by the Dow Jones News Service, Associated Press or comparable national news service, or in a document mailed to all shareholders of record.

Section 6. _Nominations at Special Meetings_. Directors are to be elected at a special meeting of shareholders only (a) if the Board of Directors so determines or (b) to fill a vacancy created by the removal of a director at such special meeting. Nominations of persons for election to the Board of Directors may be made at a special meeting of shareholders at which directors are to be elected (a) by or at the direction of the Board of Directors or (b) by any shareholder of the Corporation who was a shareholder of record at the time of giving of notice by such shareholder provided for in this Section, who is entitled to vote at the meeting and who complied with the notice procedures set forth below in this Section.

Nominations by a shareholder of persons for election to the Board of Directors may be made at such a special meeting of shareholders at which directors are to be elected if the shareholder's notice required by the fourth paragraph of Section 5 of Article I of these Bylaws shall be delivered to and received by the Secretary of the Corporation at the principal office of the Corporation not earlier than the 120th day prior to such special meeting and not later than the close of business on the later of the 90th day prior to such special meeting or the 10th day following the day on which public announcement (as defined in Section 5 of Article I of these Bylaws) is first made of the date of the special meeting and of the nominees proposed by the Board of Directors to be elected at such meeting.

Only such persons who are nominated in accordance with the procedures set forth in these Bylaws shall be eligible to serve as directors and only such business shall be conducted at a special meeting of shareholders as shall have been brought before the meeting in accordance with the procedures set forth in Section 2 of this Article I. The chairman of the meeting shall have the power and duty to determine whether a nomination or any business proposed to be brought before the special meeting was made in accordance with the procedures set forth in this Section and, if any proposed nomination or business is not in compliance with this Section, to declare that such defective proposal shall be disregarded.

Section 7. _*Proxy Access for Director Nominations*_.

(a) Subject to the terms and conditions of these Bylaws, the Corporation shall include in its proxy statement and on its form of proxy for an annual meeting of shareholders the name of, and shall include in its proxy statement the Required Information (as defined below) relating to, any nominee for election to the Board delivered pursuant to this Section 7 (a "Shareholder Nominee") who satisfies the eligibility requirements in this Section 7, and who is identified in a timely and proper notice that both complies with this Section 7 (the "Shareholder Notice") and is given by a shareholder on behalf of one or more shareholders or on behalf of any affiliate, associate of, or any other party acting in concert with or on behalf of one or more shareholders nominating a Shareholder Nominee or beneficial owners on whose behalf such shareholder(s) is acting (an "Associated Person"), but in no case more than twenty shareholders or beneficial owners, that:

(i) expressly elect at the time of the delivery of the Shareholder Notice to have such Shareholder Nominee included in the Corporation's proxy materials,

(ii) as of the date of the Shareholder Notice, own and continuously have owned during the three prior years at least three percent (3%) of the outstanding shares of common stock of the Corporation entitled to vote in the election of directors (the "Required Shares"), and

(iii) satisfy the additional requirements in these Bylaws (an "Eligible Shareholder").

(b) For purposes of qualifying as an Eligible Shareholder and satisfying the ownership requirements under Section 7(a):

(i) the outstanding shares of common stock of the Corporation owned by one or more shareholders and beneficial owners that each shareholder and/or beneficial owner has owned continuously for at least three years as of the date of the Shareholder Notice may be aggregated, provided that the number of shareholders and Associated Persons whose ownership of shares is aggregated for such purpose shall not exceed twenty (20) and that any and all requirements and obligations for an Eligible Shareholder set forth in this Section 7 are satisfied by and as to each such shareholder and Associated Persons (except as noted with respect to aggregation or as otherwise provided in this Section 7), and

(ii) a group of funds that are (1) under common management and investment control, (2) under common management and funded primarily by the same employer, or (3) a “group of investment companies,” as such term is defined in Section 12(d)(1)(G)(ii) of the Investment Company Act of 1940, as amended (a “Qualifying Fund”) shall be treated as one shareholder, provided that each fund included within a Qualifying Fund otherwise meets the requirements set forth in this Section 7.

(c) For purposes of this Section 7:

(i) A shareholder or beneficial owner shall be deemed to own only those outstanding shares of common stock of the Corporation as to which such person possesses both (i) the full voting and investment rights pertaining to the shares and (ii) the full economic interest in (including the opportunity for profit and risk of loss on) such shares; provided that the number of shares calculated in accordance with clauses (i) and (ii) shall not include any shares (A) sold by such person or any of its affiliates in any transaction that has not been settled or closed, including any short sale, (B) borrowed by such person or any of its affiliates for any purposes or purchased by such person or any of its affiliates pursuant to an agreement to resell, or (C) subject to any option, warrant, forward contract, swap, contract of sale, or other derivative or similar agreement entered into by such person or any of its affiliates, whether any such instrument or agreement is to be settled with shares or with cash based on the notional amount or value of outstanding shares of Common Stock, in any such case which instrument or agreement has, or is intended to have the purpose or effect of (1) reducing in any manner, to any extent or at any time in the future, such person's or its affiliates' full right to vote or direct the voting of any such shares, and/or (2) hedging, offsetting, or altering to any degree any gain or loss arising from the full economic ownership of such shares by such person or its affiliate.

(ii) A shareholder or beneficial owner shall be deemed to own shares held in the name of a nominee or other intermediary so long as the shareholder or beneficial owner retains the right to instruct how the shares are voted with respect to the election of directors and possesses the full economic interest in the shares. A person's ownership of shares shall be deemed to continue during any period in which the person has delegated any voting power by means of a proxy, power of attorney, or other instrument or arrangement that is revocable at any time by the person.

(iii) A shareholder or beneficial owner's ownership of shares shall be deemed to continue during any period in which the person has loaned such shares provided that the person has the power to recall such loaned shares on five business days' notice and has recalled such loaned shares as of the date of the Shareholder Notice and through the date of the annual meeting.

Whether outstanding shares of the Corporation are owned for these purposes shall be determined by the Board.

(d) No shareholder or beneficial owner, alone or together with any Associated Person, may be a member of more than one group constituting an Eligible Shareholder under this Section 7.

(e) For purposes of this Section 7, the "Required Information" that the Corporation will include in its proxy statement is:

(i) the information concerning the Shareholder Nominee and the Eligible Shareholder that is required to be disclosed in the Corporation's proxy statement by the applicable requirements of the Exchange Act and the rules and regulations thereunder; and

(ii) if the Eligible Shareholder so elects, a written statement of the Eligible Shareholder, not to exceed 500 words, in support of each Shareholder Nominee, which must be provided at the same time as the Shareholder Notice for inclusion in the Corporation's proxy statement for the annual meeting (the "Statement").

Notwithstanding anything to the contrary contained in this Section 7, the Corporation may omit from its proxy materials any information or Statement (or portion thereof) that the Corporation, in good faith, believes (i) would violate any applicable law, rule, regulation or listing standard, or (ii) is not true and correct in all material respects or omits to state a material fact necessary in order to make the statements made, in light of the circumstances under which they were made, not misleading. Nothing in this Section 7 shall limit the Corporation's ability to solicit against and include in its proxy materials its own statements relating to any Eligible Shareholder or Shareholder Nominee.

(f) The Shareholder Notice shall include the following information:

(i) the written consent of each Shareholder Nominee to being named in the Corporation's proxy materials as a nominee and to serving as a director if elected;

(ii) a copy of the Schedule 14N that has been or concurrently is filed with the SEC under Exchange Act Rule 14a-18;

(iii) a description of all arrangements or understandings between the Eligible Shareholder and each Shareholder Nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the Eligible Shareholder;

(iv) such information about the Shareholder Nominee as would have been required to be included in a proxy statement filed pursuant to the proxy rules of the SEC had each Shareholder Nominee been nominated, or intended to be nominated, by the Board;

(v) the written agreement of the Eligible Shareholder (in the case of a group, each shareholder or beneficial owner whose shares are aggregated for purposes of constituting an Eligible Shareholder) addressed to the Corporation, setting forth the following additional agreements, representations, and warranties:

(A) certifying to the number of shares of common stock of the Corporation it owns and has owned (as defined in Section 7(c) of these Bylaws) continuously for at least three years as of the date of the Shareholder Notice and agreeing to continue to own such shares through the annual meeting, which statement shall also be included in the Schedule 14N filed by the Eligible Shareholder with the SEC;

(B) the Eligible Shareholder's agreement to provide written statements from the record holder and intermediaries as required under Section 7(h) verifying the Eligible Shareholder's continuous ownership of the Required Shares through and as of the business day immediately preceding the date of the annual meeting;

(C) The Eligible Shareholder's agreement to appear in person or by legal proxy at the annual meeting to nominate the Shareholder Nominee; and

(D) the Eligible Shareholder's representation and warranty that the Eligible Shareholder (including each member of any group of shareholders and/or Associated Persons that together is an Eligible Shareholder) (1) acquired the Required Shares in the ordinary course of business and not with the intent to change or influence control of the Corporation, and does not presently have any such intent, (2) has not nominated and will not nominate for election to the Board at the annual meeting any person other than the Shareholder Nominee(s) being nominated pursuant to this Section 7, (3) has not engaged and will not engage in, and has not been and will not be a participant (as defined in Item 4 of Exchange Act Schedule 14A) in, a solicitation within the meaning of Exchange Act Rule 14a-1(l), in support of the election of any individual as a director at the annual meeting other than its Shareholder Nominee or a nominee of the Board, and (4) will not distribute any form of proxy for the annual meeting other than the form distributed by the Corporation; and

(vi) the Eligible Shareholder's agreement to (1) assume all liability stemming from any legal or regulatory violation arising out of the Eligible Shareholder's communications with the shareholders of the Corporation or out of the information that the Eligible Shareholder provided to the Corporation, (2) indemnify and hold harmless the Corporation and each of its directors, officers and employees individually against any liability, loss or damages in connection with any threatened or pending action, suit or proceeding, whether legal, administrative or investigative, against the Corporation or any of its directors, officers or employees arising out of any nomination submitted by the Eligible Shareholder pursuant to this Section 7, (3) comply with all other laws, rules, regulations and listing standards applicable to any solicitation in connection with the annual meeting, (4) file all materials described in Section 7(h)(iii) with the SEC, regardless of whether any such filing is required under Exchange Act Regulation 14A, or whether any exemption from filing is available for such materials under Exchange Act Regulation 14A, and (5) provide to the Corporation promptly and prior to the annual meeting such additional information as necessary or reasonably requested by the Corporation, and in the case of a nomination by a group of shareholders or beneficial owners that together is an Eligible Shareholder, the designation by all group members of one group member that is authorized to act on behalf of all such members with respect to the nomination and matters related thereto, including withdrawal of the nomination.

(g) To be timely under this Section 7, the Shareholder Notice must be received by the Secretary of the Corporation at the principal executive offices of the Corporation not later than the 120th day nor earlier than the 150th day prior to the first anniversary of the date the definitive proxy statement was first sent to shareholders in connection with the preceding year's annual meeting of shareholders; provided, however, that in the event the date of the annual meeting is advanced by more than 30 days or delayed by more than 60 days from such anniversary date, or if no annual meeting was held in the preceding year, to be timely the Shareholder Notice must be so delivered not later than the close of business on the later of (i) the 120th day prior to the date of such annual meeting or (ii) the 10th day following the day on which the date of such meeting is first publicly announced by the Corporation. In no event shall an adjournment or recess of an annual meeting, or a postponement of an annual meeting for which notice has been given or with respect to which there has been a public announcement of the date of the meeting, commence a new time period (or extend any time period) for the giving of the Shareholder Notice.

(h) An Eligible Shareholder must:

(i) within five business days after the date of the Shareholder Notice, provide one or more written statements from the record holder(s) of the Required Shares and from each intermediary through which the Required Shares are or have been held, in each case during the requisite three year holding period, specifying the number of shares that the Eligible Shareholder owns, and has owned continuously, in compliance with this Section 7;

(ii) include in the Schedule 14N filed with the SEC a statement certifying that it owns and continuously has owned the Required Shares for at least three years;

(iii) file with the SEC any solicitation or other communication by or on behalf of the Eligible Shareholder relating to the Corporation's annual meeting of shareholders, one or more of the Corporation's directors or director nominees or any Shareholder Nominee, regardless of whether any such filing is required under Exchange Act Regulation 14A or whether any exemption from filing is available for such solicitation or other communication under Exchange Act Regulation 14A; and

(iv) as to any group of funds whose shares are aggregated for purposes of constituting an Eligible Shareholder, within five business days after the date of the Shareholder Notice, provide documentation reasonably satisfactory to the Corporation that demonstrates that the funds satisfy Section 7(b)(ii).

The information provided pursuant to this Section 7(h) shall be deemed part of the Shareholder Notice for purposes of this Section 7.

(i) Within the time period prescribed in Section 7(g) for delivery of the Shareholder Notice, the Eligible Shareholder must also deliver to the Secretary of the Corporation at the principal executive offices of the Corporation a written representation and agreement (which shall be deemed part of the Shareholder Notice for purposes of this Section 7) signed by each Shareholder Nominee and representing and agreeing that such Shareholder Nominee:

(i) is not and will not become a party to any agreement, arrangement, or understanding with, and has not given any commitment or assurance to, any person or entity as to how such Shareholder Nominee, if elected as a director, will act or vote on any issue or question;

(ii) is not and will not become a party to any agreement, arrangement, or understanding with any person with respect to any direct or indirect compensation, reimbursement, or indemnification in connection with service or action as a director that has not been disclosed to the Corporation;

(iii) if elected as a director, will comply with all of the Corporation's corporate governance, conflict of interest, confidentiality, and stock ownership and trading policies and guidelines, and any other Corporation policies and guidelines applicable to directors; and

(iv) will not provide any non-public information regarding the Corporation to any third party other than the Corporation's auditors, legal counsel or the SEC.

At the request of the Corporation, the Shareholder Nominee must promptly, but in any event within five business days after such request, submit (i) all completed and signed questionnaires required of the Corporation's directors, (ii) a written consent to the Corporation's following such processes for evaluation as the Corporation follows in evaluating any other potential Board Nominee, and (iii) such other information as the Corporation may reasonably request. The Corporation may request such additional information as necessary to permit the Board to determine if each Shareholder Nominee satisfies this Section 7.

(j) In the event that any information or communications provided by the Eligible Shareholder or any Shareholder Nominees to the Corporation or its shareholders is not, when provided, or thereafter ceases to be, true, correct and complete in all material respects (including omitting a material fact necessary to make the statements made, in light of the circumstances under which they were made, not misleading), each Eligible Shareholder or Shareholder Nominee, as the case may be, shall promptly notify the Secretary of the Corporation and provide the information that is required to make such information or communication true, correct, complete and not misleading; it being understood that providing any such notification shall not be deemed to cure any such defect or limit the Corporation's right to omit a Shareholder Nominee from its proxy materials pursuant to this Section 7.

Notwithstanding anything to the contrary contained in this Section 7, a Shareholder Nominee shall be disqualified from serving as a director of the Corporation, and the Corporation may omit any such Shareholder Nominee from its proxy materials, and such nomination shall be disregarded and no vote on such Shareholder Nominee will occur, notwithstanding that proxies in respect of such vote may have been received by the Corporation, if:

(i) the Eligible Shareholder or Shareholder Nominee breaches any of its respective agreements, representations, or warranties set forth in the Shareholder Notice (or otherwise submitted pursuant to this Section 7), any of the information in the Shareholder Notice (or otherwise submitted pursuant to this Section 7) was not, when provided, true, correct and complete, or the requirements of this Section 7 have otherwise not been met;

(ii) the Shareholder Nominee is not independent under the listing standards of the principal U.S. exchange upon which the shares of the Corporation are listed, any applicable rules of the SEC, and the Corporation's Governance Principles;

(iii) the Shareholder Nominee is or has been, within the past three (3) years, an officer or director of a competitor, as defined in Section 8 of the Clayton Antitrust Act of 1914;

(iv) the Shareholder Nominee is a named subject of a pending criminal proceeding (excluding traffic violations and other minor offenses) or has been convicted in such a criminal proceeding within the past ten years;

(v) a notice is delivered to the Corporation (whether or not subsequently withdrawn) indicating that a shareholder intends to nominate any candidate for election to the Board pursuant to the Board's director nomination process;

(vi) the election of the Shareholder Nominee to the Board would cause the Corporation to be in violation of the Articles of

Incorporation, these Bylaws, or any applicable state or federal law, rule, or regulation or any applicable listing standard.

(vii) the Shareholder Nominee has any interlocking relationships or affiliations prohibited by the rules and regulations of the Federal Energy Regulatory Commission.

(k) The maximum number of Shareholder Nominees that may be included in the Corporation's proxy materials pursuant to this Section 7 shall not exceed the greater of (i) two or (ii) twenty percent (20%) of the number of directors in office as of the last day on which a Shareholder Notice may be delivered pursuant to this Section 7 with respect to the annual meeting, or if such amount is not a whole number, the closest whole number below twenty percent (20%). If directors are to be elected at an annual meeting for terms of office longer than one year or until the next annual meeting, the maximum number of Shareholder Nominees that may be included in the Corporation's proxy materials pursuant to this Section 7 shall not exceed the greater of (i) one or (ii) twenty percent (20%) of the number of directors to be elected at such annual meeting, or if such amount is not a whole number, the closest whole number below twenty percent (20%). However, the maximum number of Shareholder Nominees that may be included in the Corporation's proxy materials pursuant to this Section 7 shall be reduced by any (i) Shareholder Nominee whose name was submitted for inclusion in the Corporation's proxy materials pursuant to this Section 7 but either is subsequently withdrawn or that the Board of Directors decides to nominate as a Board nominee and (ii) any Shareholder Nominee elected to the Board of Directors at either of the two preceding annual meetings who are standing for reelection at the nomination of the Board of Directors. In the event that one or more vacancies for any reason occurs after the deadline in Section 7(g) for delivery of the

Shareholder Notice but before the annual meeting and the Board resolves to reduce the size of the Board in connection therewith, the maximum number shall be calculated based on the number of directors in office as so reduced. In the event that the number of Shareholder Nominees submitted by Eligible Shareholders pursuant to this Section 7 exceeds this maximum number, the Corporation shall determine which Shareholder Nominees shall be included in the Corporation's proxy materials in accordance with the following provisions: each Eligible Shareholder (or in the case of a group, each group constituting an Eligible Shareholder) will select one Shareholder Nominee for inclusion in the Corporation's proxy materials until the maximum number is reached, going in order of the amount (largest to smallest) of shares of the Corporation each Eligible Shareholder disclosed as owned in its respective Shareholder Notice submitted to the Corporation. If the maximum number is not reached after each Eligible Shareholder (or in the case of a group, each group constituting an Eligible Shareholder) has selected one Shareholder Nominee, this selection process will continue as many times as necessary, following the same order each time, until the maximum number is reached. Following such determination, if any Shareholder Nominee who satisfies the eligibility requirements in this Section 7 is thereafter nominated by the Board, and thereafter is not included in the Corporation's proxy materials or thereafter is not submitted for director election for any reason (including the Eligible Shareholder's or Shareholder Nominee's failure to comply with this Section 7), no other nominee or nominees shall be included in the Corporation's proxy materials or otherwise submitted for director election in substitution thereof.

(l) Any Shareholder Nominee who is included in the Corporation's proxy materials for a particular annual meeting of shareholders but either (i) withdraws from or becomes ineligible or unavailable for election at the annual meeting for any reason, including for the failure to comply with any provision of these Bylaws or (ii) does not receive votes at least equal to twenty-five percent (25%) of the shares voting for director candidates, will be ineligible to be a Shareholder Nominee pursuant to this Section 7 for the next two annual meetings.

(m) The Board (and any other person or body authorized by the Board) shall have the power and authority to interpret this Section 7 and to make any and all determinations necessary or advisable to apply this Section 7 to any persons, facts or circumstances, including the power to determine (i) whether one or more shareholders or beneficial owners qualifies as an Eligible Shareholder, (ii) whether a Shareholder Notice complies with this Section 7 and has otherwise met the requirements of this Section 7, (iii) whether a Shareholder Nominee satisfies the qualifications and requirements in this Section 7, and (iv) whether any and all requirements of this Section 7 (or any applicable requirements of the Board's director nomination process) have been satisfied. Any such interpretation or determination adopted in good faith by the Board (or any other person or body authorized by the Board) shall be binding on all persons, including the Corporation and its shareholders (including any beneficial owners). Notwithstanding the foregoing provisions of this Section 7, unless otherwise required by law or otherwise determined by the chairman of the meeting or the Board, if (i) the Eligible Shareholder or (ii) a qualified representative of the shareholder does not appear at the annual meeting of shareholders of the Corporation to present its Shareholder Nominee or Shareholder Nominees, such nomination or nominations shall be disregarded, notwithstanding that proxies in respect of the election of the Shareholder Nominee or Shareholder Nominees may have been received by the Corporation. This Section 7 shall be the exclusive method for shareholders to include nominees for director election in the

Corporation's proxy materials.

ARTICLE II. BOARD OF DIRECTORS

Section 1. _General Powers_. The business and affairs of the Corporation shall be managed under the direction of its Board of Directors.

Section 2. _Number, Tenure and Qualifications_. The number of Directors of the Corporation shall be not less than nine and not more than twenty as determined from time to time by the Board of Directors. Directors need not be residents of the State of South Carolina. Directors shall be required to own a number of shares of the Corporation's common stock equal to the number of shares granted in the five most recent annual retainers for Directors. Persons serving as independent directors as of February 1, 2009 shall be required to meet the minimum share ownership requirement by the last day of February 2014. Persons who are subsequently elected as directors shall be required to meet such requirement within six years following the date of their election to the Board of Directors. The Nominating and Governance Committee of the Board of Directors, or such other committee of the Board of Directors as the Board of Directors shall designate, shall have the discretion to grant a temporary waiver of these minimum share ownership requirements upon demonstration by a director that, due to a financial hardship or other good reason, he or she cannot meet the minimum share ownership requirements.

Section 3. _Regular Meetings_. The Board of Directors may provide, by resolution, the time and place, either within or without the State of South Carolina, for the holding of additional regular meetings.

Section 4. _Special Meetings_. Special meetings of the Board of Directors may be held at any time and place upon the call of the Chairman of the Board or of the Chief Executive Officer or by action of the Executive Committee or Audit Committee.

Section 5. *Quorum*. A majority of the number of Directors fixed as provided in Section 2 of this Article II shall constitute a quorum for the transaction of business at any meeting of the Board of Directors, but if less than a quorum is present at a meeting, a majority of the Directors present may adjourn the meeting from time to time without further notice.

Section 6. *Committees*. The Board of Directors may create one or more committees of the Board of Directors including an Audit Committee and an Executive Committee, and appoint members of the Board of Directors to serve on them. To the extent specified by the Board of Directors and subject to such limitations as may be specified by law, the Corporation's Articles of Incorporation or these Bylaws, such committees may exercise all of the authority of the Board of Directors in the management of the Corporation.

Meetings of a committee may be held at any time on call of the Chief Executive Officer or of any member of the committee. A majority of the members shall constitute a quorum for all meetings.

Section 7. *Compensation*. The Board of Directors may authorize payment to Directors of compensation for serving as Director, except that Directors who are also salaried officers of the Corporation or of any affiliated company shall not receive additional compensation for service as Directors. The Board of Directors may also authorize the payment of, or reimbursement for, all expenses of each Director related to such Director's attendance at meetings.

ARTICLE III. OFFICERS

Section 1. *Titles*. The officers of the Corporation shall be a Chairman of the Board, a Chief Executive Officer, a Chief Operating Officer, a Chief Financial Officer, a Treasurer, a General Counsel, a Secretary, a Corporate Compliance Officer, an Internal Auditor and such other officers and assistant officers as the Board of Directors or the Chief Executive Officer shall deem necessary or desirable. Any two or more offices may be held by the same person, and an officer may act in more than one capacity where action of two or more officers is required.

Section 2. _Appointment of Officers_. The Board of Directors shall appoint the Chairman of the Board, the Chief Executive Officer, the Chief Operating Officer, the Chief Financial Officer, the Treasurer, the General Counsel, the Secretary, the Corporate Compliance Officer, the Internal Auditor and such other officers and assistant officers as the Board of Directors shall deem necessary or desirable at such time or times as the Board of Directors shall determine. In the absence of any action by the Board of Directors, the Chief Executive Officer may appoint all other officers.

Section 3. _Removal_. Any officer appointed by the Board of Directors or the Chief Executive Officer may be removed by the Board of Directors or the Executive Committee, but no other committee, with or without cause. The Chief Executive Officer may remove any officer other than the Corporate Compliance Officer and the Internal Auditor.

Section 4. _Chairman of the Board_. The Chairman of the Board shall be chosen by and from among the Directors, shall preside at all meetings of the Board of Directors if present, and shall, in general, perform all duties incident to the office of Chairman of the Board and such other duties as, from time to time, may be assigned to him by the Board of Directors.

Section 5. _Chief Executive Officer_. The Chief Executive Officer, subject to the control of the Board of Directors, shall in general supervise and control all of the business and affairs of the Corporation. He shall, in the absence of the Chairman of the Board and the Chairman of the Executive Committee, preside at meetings of the Board of Directors. He may vote on behalf of the Corporation the stock of any other corporation owned by the Corporation and sign, with the Secretary or any other proper officer of the Corporation thereunto authorized by the Board of Directors, certificates for shares of the Corporation and any deeds, mortgages, bonds, contracts or other instruments which the Board of Directors has authorized to be executed, except in cases where the signing and execution thereof shall be expressly delegated by the Board of Directors or by these Bylaws to some other officer or agent of the Corporation, or shall be required by law to be otherwise signed or executed; and in general shall perform all duties incident to the office of Chief Executive Officer and such other duties as may be prescribed by the Board of Directors from time to time. The Chief Executive Officer may delegate his authority to vote stock on behalf of the Corporation and such delegation of authority may be either general or specific.

Section 6. *Chief Operating Officer*. The Chief Operating Officer shall in general perform all of the duties incident to the office of Chief Operating Officer and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 7. *Chief Financial Officer*. The Chief Financial Officer shall in general perform all of the duties incident to the office of Chief Financial Officer and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 8. *Treasurer*. The Treasurer shall in general perform all of the duties incident to the office of Treasurer and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 9. *General Counsel*. The General Counsel shall in general perform all of the duties incident to the office of the General Counsel and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 10. *Secretary*. The Secretary shall: (a) keep the minutes of the meetings of the shareholders and of the Board of Directors in one or more books provided for that purpose; (b) authenticate records of the Corporation when such authentication is required; and (c) in general perform all duties incident to the office of the Secretary and such other duties as from time to time may be assigned to him by the Chief Executive Officer, the Chairman of the Board or the Board of Directors.

Section 11. *Corporate Compliance Officer*. The Corporate Compliance Officer shall report to the Chairman of the Audit Committee and shall in general perform all of the duties incident to the office of Corporate Compliance Officer and such other duties as from time to time may be assigned to him by the Board of Directors or the Audit Committee, but no other committee.

Section 12. *Internal Auditor*. The Internal Auditor shall report to the Chairman of the Audit Committee and shall in general perform all of the duties incident to the office of Internal Auditor and such other duties as from time to time may be assigned to him by the Board of Directors or the Audit Committee, but no other committee.

Section 13. *Compensation*. The compensation of the officers appointed by the Board of Directors shall be fixed from time to time by the Board of Directors and the compensation of those appointed by the Chief Executive Officer shall, in the absence of any action by the Board of Directors, be set by the Chief Executive Officer. No officer shall be prevented from receiving compensation by reason of the fact that he is also a Director of the Corporation.

ARTICLE IV. AMENDMENTS

Except as otherwise provided by law, these Bylaws may be amended or repealed and new Bylaws may be adopted by the Board of Directors or the shareholders.

Exhibit 12.01

COMPUTATION OF RATIOS
December 31, 2016

BOND RATIO

SCANA and SCE&G:

Dollars in Millions Year Ended December 31, 2016		
Net earnings as defined in SCE&G's bond indenture dated April 1, 1993 (Mortgage)		$ 1,311.3
Divide by annualized interest charges on:		
Bonds outstanding under the Mortgage	$ 256.0	
Total annualized interest charges	256.0	
Bond Ratio		5.12

RATIO OF EARNINGS TO FIXED CHARGES

Dollars in Millions	SCANA					SCE&G				
Years Ended December 31,	2016	2015	2014	2013	2012	2016	2015	2014	2013	2012
Fixed Charges as defined:										
Interest on debt	$356.8	$327.8	$318.2	$305.9	$301.3	$284.6	$258.4	$237.6	$226.4	$217.4
Amortization of debt premium, discount and expense (net)	4.5	4.7	9.7	5.3	4.9	3.5	3.7	4.4	4.2	3.9
Interest component on rentals	3.5	3.7	4.1	4.9	4.9	4.0	4.1	4.0	4.5	3.2
Total Fixed Charges (A)	$364.8	$336.2	$332.0	$316.1	$311.1	$292.1	$266.2	$246.0	$235.1	$224.5
Earnings as defined:										
Pretax income from continuing operations	$865.6	$1138.4	$786.0	$693.8	$601.6	$774.1	$711.0	$676.0	$579.7	$509.5
Total fixed charges above	364.8	336.2	332.0	316.1	311.1	292.1	266.2	246.0	235.1	224.5
Pretax equity in (earnings) losses of investees	(0.7)	0.8	(1.4)	(3.2)	(3.3)	3.1	5.0	5.3	3.5	3.8
Cash distributions from equity investees	3.7	4.0	7.4	9.6	3.3	-	-	-	-	-
Total Earnings (B)	$1,233.4	$1,479.4	$1,124.0	$1016.3	$912.7	$1069.3	$982.2	$927.3	$818.3	$737.8
Ratio of Earnings to Fixed Charges (B/A)	3.38	4.40	3.39	3.22	2.93	3.66	3.69	3.77	3.48	3.29

Exhibit 21.01

Each of the following subsidiaries of SCANA is incorporated in the state of South Carolina, except as otherwise indicated.

South Carolina Electric & Gas Company
South Carolina Generating Company, Inc.
South Carolina Fuel Company, Inc.
Public Service Company of North Carolina, Incorporated
SCANA Energy Marketing, Inc.
SCANA Services, Inc.
SCANA Communications Holdings, Inc., incorporated in the State of Delaware
SCANA Corporate Security Services, Inc.

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-191691, 333-204218 and 333-213797 on Form S-8 and Registration Statement Nos. 333-206629 and 333-213798 on Form S-3 of our reports dated February 24, 2017, relating to the consolidated financial statements and financial statement schedule of SCANA Corporation and subsidiaries (the “Company”), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of SCANA Corporation for the year ended December 31, 2016.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-206629-01 on Form S-3 of our report dated February 24, 2017, relating to the consolidated financial statements and financial statement schedule of South Carolina Electric & Gas Company and affiliates appearing in this Annual Report on Form 10-K of South Carolina Electric & Gas Company for the year ended December 31, 2016.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 24, 2017

Exhibit 24.01

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of SCANA Corporation (“SCANA”), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCANA’s fiscal year ended December 31, 2016, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the “Annual Report”), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 16th day of February 2017.

/s/G. E. Aliff	/s/J. A. Bennett
G. E. Aliff Director	J. A. Bennett Director
/s/J. F. A. V. Cecil	/s/S. A. Decker
J. F. A. V. Cecil Director	S. A. Decker Director
/s/D. M. Hagood	/s/K. B. Marsh
D. M. Hagood Director	K. B. Marsh Director
/s/J. M. Micali	/s/L. M. Miller
J. M. Micali Director	L. M. Miller Director
/s/J. W. Roquemore	/s/M. K. Sloan
J. W. Roquemore Director	M. K. Sloan Director
/s/A. Trujillo	
A. Trujillo Director	

Exhibit 24.02

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of the undersigned, being a director or officer of South Carolina Electric & Gas Company ("SCE&G"), hereby constitutes and appoints Kevin B. Marsh, Jimmy E. Addison and Ronald T. Lindsay, and each of them, his or her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead in any and all capacities, to sign an Annual Report for SCE&G's fiscal year ended December 31, 2016, on Form 10-K under the Securities Exchange Act of 1934, as amended, or such other form as any such attorney-in-fact may deem necessary or desirable, and any amendments to the foregoing (collectively, the "Annual Report"), each in such form as they or any one of them may approve, and to file the same with all exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done so that such Annual Report shall comply with the Securities Exchange Act of 1934, as amended, and the applicable rules and regulations adopted or issued pursuant thereto, as fully and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them or their substitute or resubstitute, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, each of the undersigned has hereunto set his or her hand this 16th day of February 2017.

/s/G. E. Aliff
G. E. Aliff
Director

/s/J. A. Bennett
J. A. Bennett
Director

/s/J. F. A. V. Cecil
J. F. A. V. Cecil
Director

/s/S. A. Decker
S. A. Decker
Director

/s/D. M. Hagood
D. M. Hagood
Director

/s/K. B. Marsh
K. B. Marsh
Director

/s/J. M. Micali
J. M. Micali
Director

/s/L. M. Miller
L. M. Miller
Director

/s/J. W. Roquemore
J. W. Roquemore
Director

/s/M. K. Sloan
M. K. Sloan
Director

/s/A. Trujillo
A. Trujillo
Director

Exhibit 31.01

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

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.

February 24, 2017	/s/Kevin B. Marsh
	Kevin B. Marsh, Chairman of the Board, President, Chief Executive Officer and Chief Operating Officer

Exhibit 31.02

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of SCANA Corporation;

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.

February 24, 2017

/s/Jimmy E. Addison
Jimmy E. Addison
Executive Vice President and Chief Financial Officer

Exhibit 31.03

CERTIFICATION

I, Kevin B. Marsh, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas 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.

February 24, 2017

/s/Kevin B. Marsh

Kevin B. Marsh, Chairman of the Board and Chief Executive Officer

Exhibit 31.04

CERTIFICATION

I, Jimmy E. Addison, certify that:

1. I have reviewed this annual report on Form 10-K of South Carolina Electric & Gas 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.

February 24, 2017	/s/Jimmy E. Addison
	Jimmy E. Addison
	Executive Vice President and Chief Financial Officer

Exhibit 32.01

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of SCANA Corporation (the “Company”) on Form 10-K for the year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2017

/s/Kevin B. Marsh	/s/Jimmy E. Addison
Kevin B. Marsh	Jimmy E. Addison
Chairman of the Board, President, Chief Executive Officer and Chief Operating Officer	Executive Vice President and Chief Financial Officer

Exhibit 32.02

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of South Carolina Electric & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), we certify pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2017

/s/Kevin B. Marsh	/s/Jimmy E. Addison
Kevin B. Marsh	Jimmy E. Addison
Chairman of the Board and Chief Executive Officer	Executive Vice President and Chief Financial Officer

Exhibit 3

Byron W. Hinson
Director
Rates and Regulatory Services

SCE&G®
A SCANA COMPANY

December 7, 2017

Ms. Jocelyn Boyd
Chief Clerk & Administrator
The Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, South Carolina 29210

Dear Ms. Boyd:

Attached are copies of the Quarterly Report for South Carolina Electric & Gas Company, Electric Retail Operations and Gas Distribution Operations, for the twelve months ended September 30, 2017.

Sincerely,

Byron W. Hinson

cw

Attachments

c: Dawn Hipp (ORS)
Jay Jashinsky (ORS)

100 SCANA Parkway • Cayce, SC • P (803) 217-5352 • M (803) 331-0774 • bhinson@scana.com
Mailing Address 220 Operation Way • MC C111 • Cayce, SC • 29033-3701

CERTIFICATION

I, Kevin B. Marsh, state and attest, under penalty of perjury, that the attached Quarterly Reports of Retail Electric Operations and Gas Distribution Operations are filed on behalf of South Carolina Electric & Gas Company as required by the Public Service Commission of South Carolina; That I have reviewed said reports and, in the exercise of due diligence, have made reasonable inquiry into the accuracy of the information and representations provided therein; and that, to the best of my knowledge, information, and belief, all information contained therein is accurate and true and contains no false, fictitious, fraudulent or misleading statements; that no material information or fact has been knowingly omitted or misstated therein, and that all information contained therein has been prepared and presented in accordance with all applicable South Carolina general statutes, Commission rules and regulations, and applicable Commission Orders. Any violation of this Certification may result in the Commission initiating a formal earnings review proceeding.

KBMarsh
Signature of Chief Executive Officer

Kevin B. Marsh
Typed or Printed Name of Person Signing

Chairman of the Board, Chief Executive Officer
Title

12/7/17
Date Signed

Subscribed and Sworn to me on this 7th of December, 20 17.

Carol G. O'Shields
Notary Public

My Commission Expires: July 2, 2020

Carol G O'Shields
Notary Public
Gaston County, NC

CERTIFICATION

I, Jimmy E. Addison, state and attest, under penalty of perjury, that the attached Quarterly Reports of Retail Electric Operations and Gas Distribution Operations are filed on behalf of South Carolina Electric & Gas Company as required by the Public Service Commission of South Carolina; That I have reviewed said reports and, in the exercise of due diligence, have made reasonable inquiry into the accuracy of the information and representations provided therein; and that, to the best of my knowledge, information, and belief, all information contained therein is accurate and true and contains no false, fictitious, fraudulent or misleading statements; that no material information or fact has been knowingly omitted or misstated therein, and that all information contained therein has been prepared and presented in accordance with all applicable South Carolina general statutes, Commission rules and regulations, and applicable Commission Orders. Any violation of this Certification may result in the Commission initiating a formal earnings review proceeding.

Signature of Chief Financial Officer

Jimmy E. Addison
Typed or Printed Name of Person Signing

Chief Financial Officer
Title

12/7/17
Date Signed

Subscribed and Sworn to me on this Seventh of December, 2017.

Notary Public

My Commission Expires: 07-25-2021

EXHIBIT A

SOUTH CAROLINA ELECTRIC & GAS COMPANY
RETAIL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

DESCRIPTION	PER BOOKS ADJ. FOR REGULATORY ORDERS ($) COL. A	ACCOUNTING & PRO FORMA ADJUSTMENTS ($) COL. B	TOTAL AS ADJUSTED ($) COL. C
OPERATING REVENUES	2,573,825,310	(452,787,901)	2,121,037,409
OPERATING EXPENSES			
Fuel Costs	623,287,164	-	623,287,164
Other O&M Expenses	583,711,611	4,392,040	588,103,651
Deprec. & Amort. Expenses	267,744,349	2,490,706	270,235,055
Taxes Other Than Income	206,069,444	3,912,165	209,981,609
Income Taxes	189,028,533	(124,043,294)	64,985,239
Total Operating Expenses	1,869,841,101	(113,248,383)	1,756,592,718
Operating Return	703,984,209	(339,539,518)	364,444,691
Customer Growth	3,407,903	(1,643,670)	1,764,233
Int. on Customer Deposits	(1,114,066)	-	(1,114,066)
Total Income for Return	706,278,046	(341,183,188)	365,094,858
ORIGINAL COST RATE BASE			
Gross Plant in Service	9,642,974,430	(5,438,464)	9,637,535,966
Reserve for Deprec.	3,777,308,466	664,854	3,777,973,320
Net Plant	5,865,665,964	(6,103,318)	5,859,562,646
CWIP	4,885,050,807	(4,682,396,997)	202,653,810
Net Deferred/Credits	9,547,089	18,928	9,566,017
Accum. Def. Income Taxes	(1,144,013,449)	(296,866,643)	(1,440,880,092)
Materials & Supplies	422,196,596	14,274,571	436,471,167
Working Capital	17,474,474	549,005	18,023,479
Total Original Cost Rate Base	10,055,921,481	(4,970,524,454)	5,085,397,027
RATE OF RETURN	7.02%		7.18%
RETURN ON EQUITY	8.09%		8.39%

Note: For information purposes only, including DSM revenues and expenses, the Total as Adjusted ROE is 8.97%

**Supplemental
Schedule To
Exhibit A**

**SOUTH CAROLINA ELECTRIC & GAS COMPANY
ANNUALIZED INTEREST EXPENSE**

TWELVE MONTHS ENDED SEPTEMBER 30, 2017

RATE BASE	$	10,325,934,700
LONG-TERM DEBT RATIO		47.82%
	$	4,937,861,974
AVERAGE COST OF DEBT		5.86%
ANNUALIZED INTEREST	$	289,358,712
TAX BOOK INTEREST	$	246,416,868
INTEREST ADJUSTMENT	$	42,941,844
ADJUSTMENT TO INCOME TAXES:		
STATE INCOME TAX @ 5%	$	(2,147,092)
FEDERAL INCOME TAX @ 35%	$	(14,278,163)
TOTAL INCOME TAX EFFECT	$	(16,425,255)
RETAIL ELECTRIC RATE BASE PERCENTAGE		98.05%
	$	(16,105,546)

EXHIBIT A-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
PLANT IN SERVICE, CONSTRUCTION WORK IN PROGRESS, AND RESERVE FOR DEPRECIATION

AT SEPTEMBER 30, 2017

	TOTAL PER BOOKS ADJ. FOR REGULATORY ORDERS $	RATIOS %	ALLOCATED TO RETAIL $
ELECTRIC PLANT IN SERVICE			
Production	$ 4,658,637,485	96.83%	$ 4,510,958,676
Transmission	$ 1,323,838,257	96.67%	$ 1,279,688,251
Distribution	$ 3,259,344,267	99.99%	$ 3,258,985,738
General	$ 202,819,781	97.92%	$ 198,602,063
Intangible	$ 74,699,960	97.92%	$ 73,146,545
Common	$ 328,422,841	97.92%	$ 321,593,157
TOTAL	$ 9,847,762,591		$ 9,642,974,430
CONSTRUCTION WORK IN PROGRESS			
Production	$ 4,588,062,052	96.83%	$ 4,442,620,484
Transmission	$ 363,391,847	96.67%	$ 351,272,729
Distribution	$ 16,649,128	99.99%	$ 16,647,297
General	$ 36,279,624	97.92%	$ 35,525,175
Intangible	$ 38,314,863	97.92%	$ 37,518,090
Common	$ 1,498,187	97.92%	$ 1,467,032
TOTAL	$ 5,044,195,701		$ 4,885,050,807
RESERVE FOR DEPRECIATION			
Production	$ 2,187,904,354	96.83%	$ 2,118,547,786
Transmission	$ 363,297,903	96.67%	$ 351,200,083
Distribution	$ 1,017,664,277	99.99%	$ 1,017,552,334
General	$ 151,843,680	97.71%	$ 148,373,297
Common	$ 144,947,742	97.71%	$ 141,634,966
TOTAL	$ 3,865,657,956		$ 3,777,308,466

EXHIBIT A-2

SOUTH CAROLINA ELECTRIC & GAS COMPANY
RETAIL ELECTRIC OPERATIONS

AT SEPTEMBER 30, 2017

NET DEFERRED DEBITS/CREDITS	PER BOOKS ADJ. FOR REGULATORY ORDERS	ACCOUNTING & PRO FORMA ADJUSTMENTS	TOTAL AS ADJUSTED
Environmental	(360,119)		(360,119)
Wateree Scrubber Deferral - Ratebase Adj	14,565,160	-	14,565,160
FASB 106 Rate Base Reduction	(101,417,573)	18,928	(101,398,645)
Pension Deferral - Rate Base Adj	31,970,463	-	31,970,463
Canadys Retirement - Rate Base Adj	64,789,157	-	64,789,157
Storm Reserve	-	-	-
TOTAL	9,547,089	18,928	9,566,017
MATERIALS & SUPPLIES			
Nuclear Fuel	247,875,031	-	247,875,031
Fossil Fuel	41,977,365	14,274,571	56,251,936
Other Materials & Supplies	132,344,200	-	132,344,200
TOTAL	422,196,596	14,274,571	436,471,167
WORKING CAPITAL, OTHER THAN MATERIALS & SUPPLIES			
Working Cash	114,617,930	549,005	115,166,935
Prepayments	84,561,428	-	84,561,428
Total Investor Advanced Funds	199,179,358	549,005	199,728,363
Less: Customer Deposits	(54,354,631)	-	(54,354,631)
Average Tax Accruals	(117,253,805)	-	(117,253,805)
Nuclear Refueling	(1,688,716)	-	(1,688,716)
Injuries & Damages	(8,407,732)	-	(8,407,732)
TOTAL WORKING CAPITAL	17,474,474	549,005	18,023,479

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
TOTAL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CASH
1	WAGES, BENEFITS & PAYROLL TAXES		24,175,897		1,708,189	(1,294,204)	(8,606,459)							3,021,987
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,520,312)		(497,347)	350,883	2,333,372							(815,039)
3	ANNUALIZE HEALTH CARE		(619,011)			30,951	205,821							(77,376)
4	REMOVE EMPLOYEE CLUBS			(135,839)		6,792	45,166	(5,558,780)	(2,153,741)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	REMOVE NEW NUCLEAR AMOUNTS	(416,480,084)			(1,852,503)	(20,731,379)	(137,863,671)			(4,835,683,443)		(306,585,400)		
7	CWIP							4,834		(4,834)				
8	ANNUALIZE DEPRECIATION BASED ON CURRENT RATES			2,670,761		(133,538)	(888,028)		2,820,105					
9	ADJUST PROPERTY TAXES				4,848,850	(242,443)	(1,612,242)							
10	ANNUALIZE INSURANCE EXPENSE		(508,340)			25,417	169,023							(63,543)
11	OPEB		(31,504)			1,575	10,475						19,454	(3,938)
12	TAX EFFECT OF ANNUALIZED INTEREST					7,191,965	47,826,565							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	FUEL INVENTORY										14,880,195			
	TOTAL	(452,787,901)	4,840,606	2,534,922	4,045,692	(16,018,491)	(106,522,968)	(5,553,946)	666,364	(4,835,688,277)	14,880,195	(306,585,400)	19,454	605,075

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
RETAIL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CASH
1	WAGES, BENEFITS & PAYROLL TAXES		23,523,148		1,662,068	(1,259,261)	(8,374,084)							2,940,394
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,344,264)		(483,919)	341,409	2,270,371							(793,033)
3	ANNUALIZE HEALTH CARE		(602,298)			30,115	200,264							(75,287)
4	REMOVE EMPLOYEE CLUBS			(132,734)		6,637	44,134	(5,443,183)	(2,104,517)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	REMOVE NEW NUCLEAR AMOUNTS	(416,480,084)			(1,852,503)	(20,731,379)	(137,863,671)			(4,682,392,278)		(296,866,643)		
7	CWIP							4,719		(4,719)				
8	ANNUALIZE DEPRECIATION BASED ON CURRENT RATES			2,623,440		(131,172)	(872,294)		2,769,371					
9	ADJUST PROPERTY TAXES				4,748,016	(237,401)	(1,578,715)							
10	ANNUALIZE INSURANCE EXPENSE		(497,769)			24,888	165,508							(62,221)
11	OPEB		(30,653)			1,533	10,192						18,928	(3,832)
12	TAX EFFECT OF ANNUALIZED INTEREST					6,964,331	46,312,801							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	FUEL INVENTORY										14,274,571			
	TOTAL	(452,787,901)	4,392,040	2,490,706	3,912,165	(16,214,810)	(107,828,484)	(5,438,464)	664,854	(4,682,396,997)	14,274,571	(296,866,643)	18,928	549,005

EXHIBIT B

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPITAL STRUCTURE
AT SEPTEMBER 30, 2017

RETAIL ELECTRIC	CAPITALIZATION $	RATIO %	EMBEDDED COST/RATE %	OVERALL COST/RATE %
LONG-TERM DEBT	4,928,770,000	47.82	5.86	2.80
PREFERRED STOCK	100,000	0.00	0.00	0.00
COMMON EQUITY	5,377,832,362	52.18	**8.39**	4.38
TOTAL	10,306,702,362	100.00		7.18

EXHIBIT C

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
EARNINGS PER SHARE

Earnings per share are calculated based on average shares outstanding of Parent Company, SCANA Corporation and Companies, and represent South Carolina Electric & Gas Company's contribution to the Parent's overall earnings.

TWELVE MONTHS ENDED SEPTEMBER 30, 2017

NET INCOME AFTER DIV. OF PREF. STOCK	$359,499,330
EARNINGS PER SHARE	$2.52
AVG. NUMBER OF SHARES OUTSTANDING	142,916,917

EXHIBIT D

SOUTH CAROLINA ELECTRIC & GAS COMPANY
RATIO OF EARNINGS TO FIXED CHARGES [1]
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

LINE NO.		$000's
1	EARNINGS	
2	Net Income	526,574
3	Losses from Equity Investees	4,277
4	Total Fixed Charges, As Below	291,811
5	TOTAL EARNINGS	822,662
6	FIXED CHARGES	
7	Interest on Long-Term Debt	270,444
8	Other Interest	14,552
9	Amort. Of Debt Prem. - Discount & Exp. (Net)	2,920
10	Rental Int. Portion	3,895
11	Distribution on Trust Preferred	-
12	TOTAL FIXED CHARGES	291,811
13	Pre-tax earnings required to pay Preference Security Dividend	-
14	**Total Fixed Charges and Preference Security Dividend**	291,811
15	RATIO OF EARNINGS TO FIXED CHARGES	2.82
16	[1] - SEC COVERAGE	

EXHIBIT A

SOUTH CAROLINA ELECTRIC & GAS COMPANY
TOTAL GAS DISTRIBUTION - OPERATING EXPERIENCE
12 MONTHS ENDED
September, 2017

DESCRIPTION	PER BOOKS ADJ. FOR REGULATORY ORDERS	ACCOUNTING & PRO FORMA ADJUSTMENTS	TOTAL AS ADJUSTED
	COL. A $	COL. B $	COL. C $
OPERATING REVENUES	400,027,912	8,776,083	408,803,995
OPERATING EXPENSES			
Cost of Gas	204,725,614		204,725,614
Other O&M Expenses	71,135,035	3,045,440	74,180,476
Deprec. & Amort. Expenses	29,630,524	1,440,011	31,070,535
Taxes Other Than Income	28,272,711	2,662,559	30,935,271
Income Taxes	17,803,124	630,280	18,433,403
State	365,937	82,389	448,327
Federal	3,165,886	547,890	3,713,776
Def. Inc. Taxes (Net)	14,384,000	-	14,384,000
Invest. Tax Cr. (Net)	(112,700)	-	(112,700)
Total Operating Expenses	351,567,008	7,778,290	359,345,298
Operating Return	48,460,904	997,793	49,458,697
Customer Growth	891,555	18,357	909,911
Int. on Cust. Deposits Net	(174,146)		(174,146)
Total Income For Return	49,178,313	1,016,150	50,194,462
ORIGINAL COST RATE BASE			
Gross Plant in Service	1,181,807,777	(710,790)	1,181,096,987
Reserve for Depre.	445,404,862	291,274	445,696,136
Net Plant	736,402,915	(1,002,064)	735,400,851
CWIP	8,553,879	(85,658)	8,468,220
Accum. Def. Income Taxes	(166,573,800)	-	(166,573,800)
Net Deferred Debits / Credits	(427,391)	3,410	(423,980)
Materials & Supplies	21,165,230	-	21,165,230
Working Capital	(1,693,452)	380,680	(1,312,772)
Total Original Cost Rate Base	597,427,380	(703,632)	596,723,748
RATE OF RETURN	8.23%		8.41%
RETURN ON EQUITY	10.41%		10.75%

SUPPLEMENTAL SCHEDULE
TO EXHIBIT A

ADJ #	DESCRIPTION	REVENUE	O&M EXPENSE	DEPREC & AMORT EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5.0%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM DEPRE	CWIP	OPEB'S	WORKING CAPITAL
1	ANNUALIZE WAGES, BENEFITS AND PAYROLL TAXES		4,398,369		310,774	(235,457)	(1,565,790)					549,796
2	INCENTIVE COMPENSATION ADJUSTMENT		(1,012,049)		(73,130)	54,259	360,822					(126,506)
3	REMOVE EMPLOYEE CLUBS			(14,692)		735	4,885	(601,215)	(232,940)	-		-
4	RECOGNIZE PROPERTY RETIREMENTS, DEPRECIATION RESERVES					-	-	(195,233)	(195,233)			-
5	RECOGNIZE PROPERTY ADDITIONS/ADJUSTMENTS, PLANT IN SERVICE					-	-	85,658		(85,658)		-
6	ANNUALIZE DEPRECIATION-RESERVE ADJUSTMENT			1,127,517		(56,376)	(374,899)		719,447			-
7	ANNUALIZE PROPERTY TAXES				2,379,077	(118,954)	(791,043)					-
8	ANNUALIZE CUSTOMER AWARENESS CAMPAIGN EXPENSES		(180,932)			9,047	60,160					(22,616)
9	ANNUALIZE HEALTH CARE EXPENSES		(108,582)			5,429	36,104					(13,573)
10	OTHER POST-EMPLOYEE BENEFITS (OPEB)		(5,523)			276	1,836				3,410	(690)
11	ANNUALIZE INSURANCE EXPENSE		(34,630)			1,732	11,514					(4,329)
12	TAX EFFECT OF ANNUALIZED INTEREST					986	6,556					-
13	PENSION - CURRENT EXPENSE		(11,213)			561	3,728					(1,402)
14	WNA AMORTIZATION			327,186	-	(16,359)	(108,789)					-
15	ANNUALIZED REVENUE INCREASE (Order No. 2016-704) & (Order No. 2017-623)	8,776,083			45,837	436,512	2,902,807					-
	TOTAL ADJUSTMENTS	**8,776,083**	**3,045,440**	**1,440,011**	**2,662,559**	**82,389**	**547,890**	**(710,790)**	**291,274**	**(85,658)**	**3,410**	**380,680**

SUPPLEMENTAL SCHEDULE TO EXHIBIT A

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
GAS ANNUALIZED INTEREST EXPENSE
12 MONTHS ENDED
September, 2017

RATE BASE		$597,427,380
LONG-TERM DEBT RATIO		0.4782
		$285,689,773
AVERAGE COST OF DEBT		0.0586
ANNUALIZED INTEREST		$16,741,421
TAX BOOK INTEREST		$21,703,902
INTEREST ADJUSTMENT		($4,962,481)
ADJUSTMENT TO INCOME TAXES:		
STATE INCOME TAX	$248,124	
FEDERAL INCOME TAX	$1,650,025	
TOTAL INCOME TAX EFFECT		$1,898,149

**SUPPLEMENTAL
SCHEDULE
TO EXHIBIT A**

SOUTH CAROLINA ELECTRIC & GAS COMPANY
RATE BASE DETAIL TOTAL GAS OPERATIONS
12 MONTHS ENDED
September, 2017

NET DEFERRED DEBITS/CREDITS	PER BOOKS ADJ. FOR RGULATORY ORDERS	ACCOUNTING & PRO FORMA ADJUSTMENTS	TOTAL AS ADJUSTED
	$	$	$
ENVIRONMENTAL	9,174,769	0	9,174,769
PENSION DEFERRAL	5,924,590	0	5,924,590
FSB 106 RATE BASE REDUCTION	(15,526,750)	3,410	(15,523,340)
TOTAL	(427,391)	3,410	(423,980)
MATERIALS & SUPPLIES			
NATURAL GAS STORAGE	18,723,584	0	18,723,584
OTHER M&S	2,441,645	0	2,441,645
TOTAL	21,165,230	0	21,165,230
WORKING CAPITAL			
WORKING CASH	8,891,879	380,680	9,272,559
PREPAYMENTS	11,959,669	0	11,959,669
CUSTOMER DEPOSITS	(8,228,578)	0	(8,228,578)
AVERAGE TAX ACCRUALS	(13,150,350)	0	(13,150,350)
INJURIES & DAMAGES	(1,166,073)	0	(1,166,073)
TOTAL WORKING CAPITAL	(1,693,452)	380,680	(1,312,772)

EXHIBIT B

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WEIGHTED COST OF CAPITAL

	AMOUNT PER BOOKS Sep-17 (COL. 1)	CAPITALIZATION RATIO (COL. 2) %	COST OF DEBT RETURN ON EQUITY (COL. 3) %	WEIGHTED COST OF CAPITAL (COL. 4) %
LONG-TERM DEBT	4,928,770,000	47.82%	5.86%	2.80%
PREFERRED STOCK	100,000	0.00%	0.00%	0.00%
COMMON EQUITY	5,377,832,362	52.18%	10.75%	5.61%
TOTAL	10,306,702,362	100.00%		8.41%

EXHIBIT C

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
EARNINGS PER SHARE

Earnings per share are calculated based on average shares outstanding of Parent Company, SCANA Corporation and Companies, and represent South Carolina Electric & Gas Company's contribution to the Parent's overall earnings.

TWELVE MONTHS ENDED SEPTEMBER 30, 2017

NET INCOME AFTER DIV. OF PREF. STOCK	$359,499,330
EARNINGS PER SHARE	$2.52
AVG. NUMBER OF SHARES OUTSTANDING	142,916,917

EXHIBIT D

SOUTH CAROLINA ELECTRIC & GAS COMPANY
RATIO OF EARNINGS TO FIXED CHARGES [1]
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

LINE NO.		$000's
1	EARNINGS	
2	Net Income	526,574
3	Losses from Equity Investees	4,277
4	Total Fixed Charges, As Below	291,811
5	TOTAL EARNINGS	822,662
6	FIXED CHARGES	
7	Interest on Long-Term Debt	270,444
8	Other Interest	14,552
9	Amort. Of Debt Prem. - Discount & Exp. (Net)	2,920
10	Rental Int. Portion	3,895
11	Distribution on Trust Preferred	-
12	TOTAL FIXED CHARGES	291,811
13	Pre-tax earnings required to pay Preference Security Dividend	-
14	**Total Fixed Charges and Preference Security Dividend**	291,811
15	RATIO OF EARNINGS TO FIXED CHARGES	2.82
16	[1] - SEC COVERAGE	

SCANA Corporation and Subsidiaries
Security Credit Ratings
As of January 3, 2018

	Moody's	Standard & Poor's	Fitch
SCANA Corporation			
Issuer Rating/Corporate Credit Rating/Issuer Default Rating	Baa3	BBB	BB+
Senior Unsecured Debt (Medium-Term Notes)	Baa3	BBB-	BB+
Short-Term Debt (Commercial Paper)	P-3	A-2	B
Rating Outlook	negative	negative	evolving
South Carolina Electric & Gas Company			
Issuer Rating/Corporate Credit Rating/Issuer Default Rating	Baa2	BBB	BBB-
Senior Secured Debt (First Mortgage Bonds)	A3	A-	BBB+
Senior Unsecured Debt	---	---	BBB
Short-Term Debt (Commercial Paper)	P-2	A-2	F-3
Rating Outlook	negative	negative	evolving
South Carolina Fuel Company			
Short-Term Debt (Commercial Paper)	P-2	A-2	F-3
PSNC Energy			
Issuer Rating/Corporate Credit Rating/Issuer Default Rating	---	BBB	BBB-
Senior Unsecured Debt	A3	BBB	BBB
Short-Term Debt (Commercial Paper)	P-2	A-2	F-3
Rating Outlook	stable	negative	evolving

Recent Actions:

(1) On September 28, 2017, Moody's affirmed both the negative rating outlook for SCANA and SCE&G and the companies' ratings and they will continue to monitor developments.
(2) On September 29, 2017, S&P lowered its credit ratings for SCANA and its rated subsidiaries to BBB from BBB+ and revised the companies' rating outlook to negative from developing.
(3) On January 3, 2018, Fitch affirmed its credit ratings for SCANA of BB+ and SCEG and PSNC of BBB- and revised its rating outlook for SCANA, SCE&G and PSNC from negative to evolving.

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, 2016

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 RESOURCES, INC.**	**54-1229715**
000-55337	**VIRGINIA ELECTRIC AND POWER COMPANY**	**54-0418825**
001-37591	**DOMINION 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 RESOURCES, INC.	Common Stock, no par value	New York Stock Exchange
	2014 Series A 6.375% Corporate Units	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 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 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 Resources, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion 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 Resources, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion 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 Resources, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion 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 Resources, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion 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 Resources, Inc. ☐ Virginia Electric and Power Company ☒ Dominion Gas Holdings, LLC ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Dominion Resources, Inc.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Virginia Electric and Power Company

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

Dominion Gas Holdings, LLC

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act).

Dominion Resources, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Gas Holdings, LLC Yes ☐ No ☒

The aggregate market value of Dominion Resources, Inc. common stock held by non-affiliates of Dominion was approximately $47.9 billion based on the closing price of Dominion's common stock as reported on the New York Stock Exchange as of the last day of Dominion's most recently completed second fiscal quarter. Dominion is the sole holder of Virginia Electric and Power Company common stock. At February 15, 2017, Dominion had 628,115,398 shares of common stock outstanding and Virginia Power had 274,723 shares of common stock outstanding. Dominion Resources, Inc. holds all of the membership interests of Dominion Gas Holdings, LLC.

DOCUMENT INCORPORATED BY REFERENCE.

Portions of Dominion's 2017 Proxy Statement are incorporated by reference in Part III.

This combined Form 10-K represents separate filings by Dominion Resources, Inc., Virginia Electric and Power Company and Dominion 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 Gas Holdings, LLC make no representations as to the information relating to Dominion Resources, Inc.'s other operations.

VIRGINIA ELECTRIC AND POWER COMPANY AND DOMINION 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.

Exhibit 6

Table of Contents

Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC

Table of Contents

Glossary of Terms

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
2013 Biennial Review Order	Order issued by the Virginia Commission in November 2013 concluding the 2011—2012 biennial review of Virginia Power's base rates, terms and conditions
2013 Equity Units	Dominion's 2013 Series A Equity Units and 2013 Series B Equity Units issued in June 2013
2014 Equity Units	Dominion'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's 2016 Series A Equity Units issued in August 2016
2017 Proxy Statement	Dominion 2017 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
ARP	Acid Rain Program, a market-based initiative for emissions allowance trading, established pursuant to Title IV of the CAA
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC, a limited liability company owned by Dominion, Duke and Southern Company Gas (formerly known as AGL Resources Inc.)
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, Duke and Southern Company Gas (formerly known as AGL Resources Inc.) and constructed and operated by DTI
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
Blue Racer	Blue Racer Midstream, LLC, a joint venture between Dominion 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
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAO	Chief Accounting Officer
CAP	IRS Compliance Assurance Process
CCR	Coal combustion residual
CEA	Commodity Exchange Act
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CGN Committee	Compensation, Governance and Nominating Committee of Dominion'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
CNO	Chief Nuclear Officer
CO_2	Carbon dioxide
COL	Combined Construction Permit and Operating License
Companies	Dominion, Virginia Power and Dominion 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
Cove Point	Dominion Cove Point LNG, LP
Cove Point Holdings	Cove Point GP Holding Company, LLC
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
CWA	Clean Water Act

Table of Contents

Abbreviation or Acronym	Definition
DCG	Dominion Carolina Gas Transmission, LLC (successor by statutory conversion to and formerly known as Carolina Gas Transmission Corporation)
DEI	Dominion Energy, Inc.
DGP	Dominion Gathering and Processing, Inc.
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
DOE	Department of Energy
Dominion	The legal entity, Dominion Resources, Inc., one or more of its consolidated subsidiaries (other than Virginia Power and Dominion Gas) or operating segments, or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries
Dominion Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
Dominion Gas	The legal entity, Dominion Gas Holdings, LLC, one or more of its consolidated subsidiaries or operating segment, or the entirety of Dominion Gas Holdings, LLC and its consolidated subsidiaries
Dominion Iroquois	Dominion Iroquois, Inc., which, effective May 2016, holds a 24.07% noncontrolling partnership interest in Iroquois
Dominion Midstream	The legal entity, Dominion Midstream Partners, LP, one or more of its consolidated subsidiaries, Cove Point Holdings, Iroquois GP Holding Company, LLC, DCG (beginning April 1, 2015) and Questar Pipeline (beginning December 1, 2016) or operating segment, or the entirety of Dominion Midstream Partners, LP and its consolidated subsidiaries
Dominion Questar	The legal entity, Dominion Questar Corporation (formerly known as Questar Corporation), one or more of its consolidated subsidiaries or operating segment, or the entirety of Dominion Questar Corporation and its consolidated subsidiaries
Dominion Questar Combination	Dominion's acquisition of Dominion Questar completed on September 16, 2016 pursuant to the terms of the agreement and plan of merger entered on January 31, 2016
DRS	Dominion Resources Services, Inc.
DSM	Demand-side management
Dth	Dekatherm
DTI	Dominion Transmission, Inc.
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
DVP	Dominion Virginia Power operating segment
EA	Environmental assessment
East Ohio	The East Ohio Gas Company, doing business as Dominion East 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	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPS	Earnings per share
ERISA	The Employee Retirement Income Security Act of 1974
ERM	Enterprise Risk Management
ERO	Electric Reliability Organization
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 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
Gal	Gallon
GHG	Greenhouse gas
Granite Mountain	Granite Mountain Holdings, LLC, a limited liability company owned by Dominion 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

Table of Contents

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 Hope
Idaho Commission	Idaho Public Utilities Commission
IRCA	Intercompany revolving credit agreement
Iron Springs	Iron Springs Holdings, LLC, a limited liability company owned by Dominion 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’s 2016 Series A Enhanced Junior Subordinated Notes due 2076
June 2006 hybrids	Dominion’s 2006 Series A Enhanced Junior Subordinated Notes due 2066
June 2009 hybrids	Dominion’s 2009 Series A Enhanced Junior Subordinated Notes due 2064, subject to extensions no later than 2079
Kewaunee	Kewaunee nuclear power station
Keys Energy Project	Project to provide 107,000 Dths/day of firm transportation service from Cove Point’s interconnect with Transco in Fairfax County, Virginia to Keys Energy Center, LLC’s power generating facility in Prince George’s County, Maryland
Kincaid	Kincaid power station
kV	Kilovolt
Leidy South Project	Project to provide 155,000 Dths/day of firm transportation service from Clinton County, Pennsylvania to Loudoun County, Virginia
Liability Management Exercise	Dominion 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’s Gilmore Station in Tuscarawas County, Ohio
Liquefaction Project	A natural gas export/liquefaction facility currently under construction by 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
Lordstown Project	Project to provide 129,000 Dths/day of firm transportation service to the Lordstown power station in northeast Ohio
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
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
NAAQS	National Ambient Air Quality Standards
NAV	Net asset value
NedPower	NedPower Mount Storm LLC, a wind-turbine facility joint venture between Dominion and Shell in Grant County, West Virginia
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NG	Collectively, North East Transmission Co., Inc. and National Grid IGTS Corp.
NGL	Natural gas liquid
NJNR	NJNR Pipeline Company
NO_2	Nitrogen dioxide
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
NO_x	Nitrogen oxide
NRC	Nuclear Regulatory Commission

Table of Contents

Abbreviation or Acronym	Definition
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's 2014 Series A Enhanced Junior Subordinated Notes due 2054
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.
PREP	Pipeline Replacement and Expansion Program, a program of replacing, upgrading and expanding natural gas utility infrastructure deployed by Hope
PSMP	Pipeline Safety and 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
ppb	Parts-per-billion
PSD	Prevention of significant deterioration
Questar Gas	Questar Gas Company
Questar Pipeline	Questar Pipeline, LLC (successor by statutory conversion to and formerly known as Questar Pipeline Company), one or more of its consolidated subsidiaries, or the entirety of Questar Pipeline, LLC and its consolidated subsidiaries
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
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 DEI
Scott Solar	A 17 MW utility-scale solar power station in Powhatan County, VA
SEC	Securities and Exchange Commission
September 2006 hybrids	Dominion's 2006 Series B Enhanced Junior Subordinated Notes due 2066
Shell	Shell WindEnergy, Inc.
SO_2	Sulfur dioxide
Standard & Poor's	Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc.
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

Table of Contents

Abbreviation or Acronym	Definition
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
UAO	Unilateral Administrative Order
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 1,342 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
Woodland	A 19 MW utility-scale solar power station in Isle of Wight County, VA
Wyoming Commission	Wyoming Public Service Commission

Table of Contents

Part I

Item 1. Business

GENERAL

Dominion, headquartered in Richmond, Virginia and incorporated in Virginia in 1983, is one of the nation's largest producers and transporters of energy. Dominion'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, 2016, Dominion's portfolio of assets includes approximately 26,400 MW of generating capacity, 6,600 miles of electric transmission lines, 57,600 miles of electric distribution lines, 14,900 miles of natural gas transmission, gathering and storage pipeline and 51,300 miles of gas distribution pipeline, exclusive of service lines. As of December 31, 2016, Dominion serves over 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 completed the Dominion Questar Combination for total consideration of $4.4 billion and Dominion Questar became a wholly-owned subsidiary of Dominion. Dominion Questar is a Rockies-based integrated natural gas company. Questar Gas, a wholly-owned subsidiary of Dominion Questar, is consolidated by Dominion, and is a voluntary SEC filer. However, its Form 10-K is filed separately and is not combined herein.

In March 2014, Dominion formed Dominion Midstream, an MLP designed to grow a portfolio of natural gas terminaling, processing, storage, transportation and related assets. In October 2014, Dominion Midstream launched its initial public offering and issued 20,125,000 common units representing limited partner interests. Dominion has recently and may continue to investigate opportunities to acquire assets that meet its strategic objective for Dominion Midstream. At December 31, 2016, Dominion owns the general partner, 50.9% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DCG, Questar Pipeline and a 25.93% noncontrolling partnership interest in Iroquois. Dominion Midstream is consolidated by Dominion, and is an SEC registrant. However, its Form 10-K is filed separately and is not combined herein.

Dominion is focused on expanding its investment in regulated electric generation, transmission and distribution and regulated natural gas transmission and distribution infrastructure. Dominion expects 80% to 90% of earnings from its primary operating segments to come from regulated and long-term contracted businesses.

Dominion 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'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 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 has transitioned to a more regulated, less volatile earnings mix as evidenced by its capital investments in regulated infrastructure, including the Dominion 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's nonregulated operations include merchant generation, energy marketing and price risk management activities and natural gas retail energy marketing operations. Dominion's operations are conducted through various subsidiaries, including Virginia Power and Dominion 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 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 Virginia Power" and primarily serves retail customers. In North Carolina, it conducts business under the name "Dominion North Carolina Power" 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.

Dominion Gas, a limited liability company formed in September 2013, is a wholly-owned subsidiary of Dominion and a holding company. It serves as the intermediate parent company for certain of Dominion'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 Gas' principal wholly-owned subsidiaries are DTI, East Ohio, DGP and Dominion Iroquois. DTI 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 DTI system links to other major pipelines and markets in the mid-Atlantic, Northeast, and Midwest including Dominion's Cove Point pipeline. DTI also operates one of the largest underground natural gas storage systems in the U.S. In August 2016, DTI 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 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, 2016, Dominion Gas holds a

Table of Contents

24.07% noncontrolling partnership interest in Iroquois. All of Dominion Gas' membership interests are owned by Dominion.

Amounts and information disclosed for Dominion are inclusive of Virginia Power and/or Dominion Gas, where applicable.

EMPLOYEES

At December 31, 2016, Dominion had approximately 16,200 full-time employees, of which approximately 5,200 employees are subject to collective bargaining agreements. At December 31, 2016, Virginia Power had approximately 6,800 full-time employees, of which approximately 3,100 employees are subject to collective bargaining agreements. At December 31, 2016, Dominion Gas had approximately 2,800 full-time employees, of which approximately 2,000 employees 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's internet website, http://www.dom.com, as soon as reasonably practicable after filing or furnishing the material to the SEC. Information contained on Dominion's website is not incorporated by reference in this report.

ACQUISITIONS AND DISPOSITIONS

Following are significant acquisitions and divestitures by the Companies during the last five years.

ACQUISITION OF DOMINION QUESTAR

In September 2016, Dominion completed the Dominion Questar Combination for total consideration of $4.4 billion and Dominion Questar became a wholly-owned subsidiary of Dominion. In December 2016, Dominion contributed Questar Pipeline to Dominion Midstream. See Note 3 to the Consolidated Financial Statements and *Liquidity and Capital Resources* in Item 7. MD&A for additional information.

ACQUISITION OF WHOLLY- OWNED MERCHANT SOLAR PROJECTS

Throughout 2016, Dominion completed the acquisition of various wholly-owned merchant solar projects in Virginia, North Carolina and South Carolina for $32 million. The projects are expected to cost approximately $425 million to construct, including the initial acquisition cost, and are expected to generate approximately 221 MW.

Throughout 2015, Dominion 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 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 NON-WHOLLY-OWNED MERCHANT SOLAR PROJECTS

In 2015, Dominion 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 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 MIDSTREAM ACQUISITION OF INTEREST IN IROQUOIS

In September 2015, Dominion 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 Midstream's common units at closing. The common units issued to NG and NJNR are reflected as noncontrolling interest in Dominion's Consolidated Financial Statements. See Note 3 to the Consolidated Financial Statements for additional information.

ACQUISITION OF DCG

In January 2015, Dominion completed the acquisition of 100% of the equity interests of DCG from SCANA Corporation for $497 million in cash, as adjusted for working capital. In April 2015, Dominion contributed DCG to Dominion Midstream. See Note 3 to the Consolidated Financial Statements for additional information.

Table of Contents

SALE OF ELECTRIC RETAIL ENERGY MARKETING BUSINESS

In March 2014, Dominion 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. See Note 3 to the Consolidated Financial Statements for additional information.

SALE OF PIPELINES AND PIPELINE SYSTEMS

In March 2014, Dominion Gas sold the Northern System to an affiliate that subsequently sold the Northern System to Blue Racer for consideration of $84 million. Dominion Gas' consideration consisted of $17 million in cash proceeds and the extinguishment of affiliated current borrowings of $67 million and Dominion's consideration consisted of cash proceeds of $84 million.

In September 2013, DTI sold Line TL-388 to Blue Racer for $75 million in cash proceeds.

In December 2012, East Ohio sold two pipeline systems to an affiliate for consideration of $248 million. East Ohio's consideration consisted of $61 million in cash proceeds and the extinguishment of affiliated long-term debt of $187 million and Dominion's consideration consisted of a 50% interest in Blue Racer and cash proceeds of $115 million.

See Note 9 to the Consolidated Financial Statements for additional information on sales of pipelines and pipeline systems.

ASSIGNMENTS OF SHALE DEVELOPMENT RIGHTS

In March 2015, Dominion 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 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.

Also in March 2015, Dominion 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 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 Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage.

In November 2014, Dominion 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 provides for payments to Dominion 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 December 2013, Dominion 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 provide for payments to Dominion 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.

See Note 10 to the Consolidated Financial Statements for additional information on these sales of Marcellus acreage.

SALE OF BRAYTON POINT, KINCAID AND EQUITY METHOD INVESTMENT IN ELWOOD

In August 2013, Dominion 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 manages its daily operations through three primary operating segments: DVP, Dominion Generation and Dominion Energy. Dominion 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'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: DVP and Dominion 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 Gas manages its daily operations through its primary operating segment: Dominion Energy. 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 Gas as a result of Dominion'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.

Table of Contents

A description of the operations included in the Companies' primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion	Virginia Power	Dominion Gas
DVP	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Dominion Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Dominion Energy	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG import 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.

DVP

The DVP Operating Segment of Dominion 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.

DVP's existing five-year investment plan includes spending approximately $8.4 billion from 2017 through 2021 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 by the typical consumer. 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 137 minutes at the end of 2016, which is higher compared to the three-year average of 123 minutes, due to storm-related outages across all seasons. Virginia Power's overall customer satisfaction, however, improved year over year when compared to 2015 J.D. Power and Associates' scoring. In the future, safety, electric service reliability and customer service will remain key focus areas for electric distribution.

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

DVP Operating Segment—Dominion 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 FERC 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 to seek opportunities to build and own facilities in other service territories.

REGULATION

DVP Operating Segment—Dominion 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

DVP Operating Segment—Dominion 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 ($280 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 ($60 million); and
- Mt. Storm-Valley rebuild ($225 million).

Virginia Power plans to increase transmission substation physical security and expects to invest $300 million-$400 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 57,600 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 its most outage-prone overhead distribution lines underground, has an annual investment cap of approximately $175 million and is expected to be implemented 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 December 2016, Virginia Power filed its application with the Virginia Commission to recover costs associated with the first and second phases of this program. The second phase will convert an estimated 244 miles at a cost of $110 million.

SOURCES OF ENERGY SUPPLY

DVP Operating Segment—Dominion and Virginia Power

DVP's supply of electricity to serve Virginia Power customers is produced or procured by Dominion Generation. See *Dominion Generation* for additional information.

SEASONALITY

DVP Operating Segment—Dominion and Virginia Power

DVP'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 DVP'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.

Dominion Generation

The Dominion 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 the DVP segment's utility customers. *The Dominion Generation Operating Segment of Dominion* includes Virginia Power's generation facilities and its related energy supply operations as well as the generation operations of Dominion's merchant fleet and energy marketing and price risk management activities for these assets.

Dominion Generation's existing five-year investment plan includes spending approximately $8.0 billion from 2017 through 2021 to construct new generation capacity 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'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 sold under long-term power purchase agreements with terms generally ranging from 15 to 25 years. See Note 3 to the Consolidated Financial Statements for additional information regarding certain solar projects.

Earnings for the *Dominion 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 Dominion Generation Operating Segment of Dominion derives its earnings primarily from the sale of electricity generated by Virginia Power's utility and Dominion's merchant generation assets, as well as from associated capacity and ancillary services. Variability in earnings provided by Dominion'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 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's renewable merchant fleet is primarily driven by weather.

COMPETITION

Dominion Generation Operating Segment—Dominion 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.

Dominion Generation Operating Segment—Dominion

Dominion 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 lasting between 15 and 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 Dominion 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. Dominion 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. Dominion 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 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.

REGULATION

Dominion Generation Operating Segment—Dominion and Virginia Power

Virginia Power's utility generation fleet and Dominion'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.

The Clean Power Plan and related proposed rules discussed represent a significant regulatory development affecting this segment. See *Future Issues and Other Matters* in Item 7. MD&A.

PROPERTIES

For a listing of Dominion's and Virginia Power's existing generation facilities, see Item 2. Properties.

Dominion Generation Operating Segment—Dominion and Virginia Power

The generation capacity of Virginia Power's electric utility fleet totals approximately 21,700 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 construct certain solar facilities in Virginia. See Note 13 to the Consolidated Financial Statements for more information.
- Virginia Power is considering 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.
- In March 2016, the Virginia Commission authorized the construction of Greensville County and related transmission

Table of Contents

interconnection facilities. Commercial operations are expected to commence in late 2018, at an estimated cost of approximately $1.3 billion, excluding financing costs.

Dominion Generation Operating Segment—Dominion

The generation capacity of Dominion's merchant fleet totals approximately 4,700 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's merchant renewable generation facilities include a fuel cell generation facility in Connecticut, solar generation facilities in California, Connecticut, Georgia, Indiana, North Carolina, Tennessee, Utah and Virginia, and wind generation facilities in Indiana and West Virginia. Additional solar projects under construction are as set forth below:

- In August 2016, Dominion entered into an agreement to acquire 100% of the equity interests of two solar projects in California from Solar Frontier Americas Holding LLC for $128 million. The acquisition is expected to close prior to both projects commencing operations, which is expected by the end of 2017. The projects are expected to cost approximately $130 million once constructed, including the initial acquisition cost, and generate approximately 50 MW combined.
- In September 2016, Dominion entered into an agreement to acquire 100% of the equity interests of a solar project in Virginia from Community Energy Solar, LLC. The acquisition is expected to close during the first quarter of 2017, prior to the project commencing operations by the end of 2017, for an amount to be determined based on the costs incurred through closing. The project is expected to cost approximately $210 million once constructed, including the initial acquisition cost, and to generate approximately 100 MW.
- In November 2016, Dominion acquired 100% of the equity interest of four solar projects in Virginia and two solar projects in South Carolina for $21 million. The projects are expected to cost approximately $287 million once constructed, including the initial acquisition cost. The facilities are expected to begin commercial operations by the end of 2017 and generate approximately 161 MW.
- In January 2017, Dominion entered into an agreement to acquire 100% of the equity interests of a solar project in North Carolina from Cypress Creek Renewables, LLC for $154 million in cash. The acquisition is expected to close during the second quarter of 2017, prior to the project commencing commercial operations, which is expected by the end of the third quarter of 2017. The project is expected to cost $160 million once constructed, including the initial acquisition cost, and to generate approximately 79 MW.

SOURCES OF ENERGY SUPPLY

Dominion Generation Operating Segment—Dominion and Virginia Power

Dominion 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—Dominion 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—Dominion Generation primarily utilizes natural gas and coal in its fossil fuel plants. All recent fossil fuel plant construction for Dominion Generation, with the exception of the Virginia City Hybrid Energy Center, involves natural gas generation.

Dominion 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 or third parties. Dominion 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.

Dominion Generation's coal supply is obtained through long-term contracts and short-term spot agreements from domestic suppliers.

Biomass—Dominion Generation's biomass supply is obtained through long-term contracts and short-term spot agreements from local suppliers.

Purchased Power—Dominion Generation purchases electricity from the PJM spot market and through power purchase agreements with other suppliers to provide for utility system load requirements.

Dominion 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.

Dominion Generation Operating Segment—Virginia Power

Presented below is a summary of Virginia Power's actual system output by energy source:

Source	**2016**	2015	2014
Nuclear(1)	**31%**	30%	33%
Natural gas	**31**	23	15
Coal(2)	**24**	26	30
Purchased power, net	**8**	15	19
Other(3)	**6**	6	3
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.

Table of Contents

SEASONALITY

Dominion Generation Operating Segment—Dominion and Virginia Power

Sales of electricity for Dominion 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 *DVP-Seasonality* above for additional considerations that also apply to Dominion Generation.

NUCLEAR DECOMMISSIONING

Dominion Generation Operating Segment—Dominion 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 an operating life extension for Surry, and may for North Anna as well.

Dominion Generation Operating Segment—Dominion

In addition to the four nuclear units discussed above, Dominion has two licensed, operating nuclear reactors at Millstone in Connecticut. A third Millstone unit ceased operations before Dominion acquired the power station. In May 2013, Dominion 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'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 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 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'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 and Virginia Power are shown in the following table:

(dollars in millions)	NRC license expiration year	Most recent cost estimate (2016 dollars)(1)	Funds in trusts at December 31, 2016	2016 contributions to trusts
Surry				
Unit 1	**2032**	**$ 600**	**$ 597**	**$ 0.6**
Unit 2	**2033**	**620**	**588**	**0.6**
North Anna				
Unit 1(2)	**2038**	**513**	**475**	**0.4**
Unit 2(2)	**2040**	**525**	**446**	**0.3**
Total (Virginia Power)		**2,258**	**2,106**	**1.9**
Millstone				
Unit 1(3)	**N/A**	**373**	**474**	**—**
Unit 2	**2035**	**563**	**614**	**—**
Unit 3(4)	**2045**	**684**	**604**	**—**
Kewaunee				
Unit 1(5)	**N/A**	**467**	**686**	**—**
Total (Dominion)		**$ 4,345**	**$ 4,484**	**$ 1.9**

(1) The cost estimates shown above reflect reductions for the expected future recovery of certain spent fuel costs based on Dominion's and Virginia Power's contracts with the DOE for disposal of spent nuclear fuel consistent with the reductions reflected in Dominion'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's acquisition of Millstone.

(4) Millstone Unit 3 is jointly owned by Dominion 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's ownership percentage. At December 31, 2016, the minority owners held $37 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 for information about nuclear decommissioning trust investments.

Table of Contents

Dominion Energy

The Dominion Energy Operating Segment of Dominion Gas includes certain of Dominion's regulated natural gas operations. DTI, the gas transmission pipeline and storage business, serves gas distribution businesses and other customers in the Northeast, mid-Atlantic and Midwest. DGP conducts gas gathering and processing activities, which include the sale of extracted products at market rates, primarily in West Virginia, Ohio and Pennsylvania. East Ohio, the primary gas distribution business of Dominion, serves residential, commercial and industrial gas sales, transportation and gathering service customers primarily in Ohio. 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.

Earnings for the *Dominion Energy Operating Segment of Dominion Gas* primarily result from rates established by FERC and the Ohio Commission. The profitability of this business is dependent on Dominion 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 96% of the transmission capacity under contract on DTI's pipeline is subscribed with long-term contracts (two years or greater). The remaining 4% is contracted on a year-to-year basis. Less than 1% of firm transportation capacity is currently unsubscribed. Less than 1% of storage services are unsubscribed. All contracted storage is 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 Gas receives the wet gas product from producers and may retain the extracted NGLs as compensation for its services. This exposes Dominion Gas to commodity price risk for the value of the spread between the NGL products and natural gas. In addition, Dominion 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.

In addition to the operations of Dominion Gas, the *Dominion Energy Operating Segment of Dominion* also includes LNG operations, Dominion Questar operations, Hope's gas distribution operations in West Virginia, and nonregulated retail natural gas marketing, as well as Dominion's investments in the Blue Racer joint venture, Atlantic Coast Pipeline and Dominion Midstream. See *Properties and Investments* below for additional information regarding the Blue Racer and Atlantic Coast Pipeline investments. Dominion'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 has received DOE and FERC approval to export LNG from Cove Point and has begun construction on a bi-directional facility, which 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 completed the Dominion Questar Combination and Dominion Questar became a wholly-owned subsidiary of Dominion. Dominion Questar, a Rockies-based integrated natural gas company, included Questar Gas, Wexpro and Questar Pipeline at closing. Questar Gas' regulated gas distribution operations in Utah, southwestern Wyoming and southeastern Idaho includes 29,200 miles of gas distribution pipeline. Wexpro develops and produces natural gas from reserves supplied to Questar Gas under a cost-of-service framework. 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 Questar Combination.

In 2014, Dominion formed Dominion 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's contribution of Questar Pipeline to Dominion Midstream in December 2016 as well as Dominion's acquisition of DCG, which Dominion contributed to Dominion Midstream in April 2015, and Dominion Midstream's acquisition of a 25.93% noncontrolling partnership interest in Iroquois in September 2015. DCG provides FERC-regulated interstate natural gas transportation services in South Carolina and southeastern Georgia through 1,500 miles of gas transmission pipeline.

Dominion Energy's existing five-year investment plan includes spending approximately $8.0 billion from 2017 through 2021 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's portion of spending for the Atlantic Coast Pipeline Project.

In addition to the earnings drivers noted above for Dominion Gas, earnings for the *Dominion Energy Operating Segment of Dominion* 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 regasification services. Questar Pipeline's and DCG'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.

Dominion's retail energy marketing operations compete in nonregulated energy markets. In March 2014, Dominion completed the sale of its electric retail energy marketing business; however, it still participates in the retail natural gas and energy-related products and services businesses. The remaining customer base includes approximately 1.4 million customer accounts in 17 states. Dominion has a heavy concentration of natural gas customers in markets where utilities have a long-standing commitment to customer choice, primarily in the states of Ohio and Pennsylvania.

COMPETITION

Dominion Energy Operating Segment—Dominion and Dominion Gas

Dominion Gas' natural gas transmission operations compete with domestic and Canadian pipeline companies. Dominion Gas also competes with gas marketers seeking to provide or arrange transportation, storage and other services. Alternative energy 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 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, 2016, approximately 1 million of East Ohio's 1.2 million Ohio customers were participating in the Energy Choice program.

Dominion Energy Operating Segment—Dominion

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.

Questar Pipeline's and DCG'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, Questar Pipeline's pipeline system faces competitive pressures from similar facilities that serve the Rocky Mountain region and DCG'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's retail energy marketing operations compete against incumbent utilities and other energy marketers in nonregulated energy markets for natural gas. Customers in these markets have the right to select a retail marketer and typically do so based upon price savings or price stability; however, incumbent utilities have the advantage of long-standing relationships with their customers and greater name recognition in their markets.

REGULATION

Dominion Energy Operating Segment—Dominion and Dominion Gas

Dominion 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.

Dominion Energy Operating Segment—Dominion

Cove Point's, Questar Pipeline's, and DCG'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's and Dominion Gas' existing facilities see Item 2. Properties.

Dominion Energy Operating Segment—Dominion and Dominion Gas

Dominion Gas has the following significant projects under construction or development to better serve customers or expand its service offerings within its service territory.

Table of Contents

In September 2014, DTI announced its intent to construct and operate the Supply Header project which is expected to cost approximately $500 million and provide 1,500,000 Dths per day of firm transportation service to various customers. In October 2014, DTI requested authorization to use FERC's pre-filing process. The application to request FERC authorization to construct and operate the project facilities was filed in September 2015, with the facilities expected to be in service in late 2019. In December 2014, DTI entered into a precedent agreement with Atlantic Coast Pipeline for the Supply Header project.

In June 2014, DTI executed binding precedent agreements with two power generators for the Leidy South Project. In November 2014, one of the power generators assigned a portion of its capacity to an affiliate, bringing the total number of project customers to three. The project is expected to cost approximately $210 million. In August 2016, DTI received FERC authorization to construct and operate the Leidy South Project facilities. Service under the 20-year contracts is expected to commence in late 2017.

In September 2013, DTI executed binding precedent agreements with several local distribution company customers for the New Market project. The project is expected to cost approximately $180 million and provide 112,000 Dths per day of firm transportation service from Leidy, Pennsylvania to interconnects with Iroquois and Niagara Mohawk Power Corporation's distribution system in the Albany, New York market. In April 2016, DTI received FERC authorization to construct, operate and maintain the project facilities, which are expected to be in service in late 2017.

In March 2016, East Ohio executed a binding precedent agreement with a power generator for the Lordstown Project. In January 2017, East Ohio commenced construction of the project, with an in-service date expected in the third quarter of 2017 at a total estimated cost of approximately $35 million.

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.

Dominion Energy Operating Segment—Dominion

Dominion has the following significant projects under construction or development.

Cove Point—Dominion is pursuing the Liquefaction Project, which would enable Cove Point to liquefy domestically-produced natural gas for export as LNG. The DOE previously authorized Dominion to export LNG to countries with free trade agreements. In September 2013, the DOE authorized Dominion to export LNG from Cove Point to non-free trade agreement countries.

In May 2014, the FERC staff issued its EA for the Liquefaction Project. In the EA, the FERC staff addressed a variety of topics related to the proposed construction and development of the Liquefaction Project and its potential impact to the environment, and determined that with the implementation of appropriate mitigation measures, the Liquefaction Project can be built and operated safely with no significant impact to the environment. 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 EA. In October 2014, Cove Point commenced construction of the Liquefaction Project, with an in-service date anticipated in late 2017 at a total estimated cost of approximately $4.0 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 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 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 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 to explore the Liquefaction Project, which, assuming it becomes operational, will extend the economic life of Cove Point and contribute to Dominion'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 October 2015, Cove Point received FERC authorization to construct the approximately $40 million Keys Energy Project. Construction on the project commenced in December 2015, and the project facilities are expected to be placed into service in March 2017.

In November 2016, Cove Point filed an application to request FERC authorization to construct the approximately $150 million Eastern Market Access Project. Construction on the project is expected to begin in the fourth quarter of 2017, and the project facilities are expected to be placed into service in late 2018.

Table of Contents

DCG—In 2014, DCG executed binding precedent agreements with three customers for the Charleston project. The project is expected to cost approximately $120 million, and provide 80,000 Dths per day of firm transportation service from an existing interconnect with Transcontinental Gas Pipe Line, LLC in Spartanburg County, South Carolina to customers in Dillon, Marlboro, Sumter, Charleston, Lexington and Richland counties, South Carolina. In February 2017, DCG received FERC approval to construct and operate the project facilities, which are expected to be placed into service in the fourth quarter of 2017.

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 2016 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.

Dominion Energy Equity Method Investments—In September 2015, Dominion, through Dominion Midstream, acquired an additional 25.93% interest in Iroquois. Dominion 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's equity method investment in Iroquois.

In September 2014, Dominion, along with Duke and Southern Company Gas (formerly known as AGL Resources Inc.), announced the formation of Atlantic Coast Pipeline. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. In October 2016, Dominion purchased an additional 3% membership interest in Atlantic Coast Pipeline from Duke for $14 million. The members, which are subsidiaries of the above-referenced parent companies, hold the following membership interests: Dominion, 48%; Duke, 47%; and Southern Company Gas (formerly known as AGL Resources Inc.), 5%. Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina, which has a total expected cost of $5.0 billion to $5.5 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. The project is subject to FERC, state and other federal approvals. See Note 9 to the Consolidated Financial Statements for further information about Dominion's equity method investment in Atlantic Coast Pipeline.

In December 2012, Dominion 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 and Caiman, with Dominion 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's equity method investment in Blue Racer.

SOURCES OF ENERGY SUPPLY

Dominion's and Dominion 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's and Dominion 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's and Dominion 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's and Dominion 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's retail energy marketing customers is procured through Dominion's energy marketing group and market wholesalers.

SEASONALITY

Dominion Energy'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

Table of Contents

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'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'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 Gas

Virginia Power's and Dominion 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

Dominion'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'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.

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 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 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.

Table of Contents

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.

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.

Status of Competitive Retail Gas Services

The states of Ohio and West Virginia, in which Dominion and Dominion 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, 2016, approximately 1.0 million of Dominion 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

Table of Contents

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'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 and Utah, under Dominion'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 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 and Virginia Power are also subject to FERC's affiliate restrictions that (1) prohibit power sales between Virginia Power and Dominion'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 million per day, per violation and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation.

Dominion and Virginia Power plan and operate their facilities in compliance with approved NERC reliability requirements. Dominion 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 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 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 Questar Pipeline, DTI, DCG, Iroquois and certain services performed by Cove Point. Pursuant to FERC's February 2014 approval of DTI's uncontested settlement offer, DTI's base rates for storage and transportation services are subject to a moratorium through the end of 2016. 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's and Dominion 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 and Dominion 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 and Dominion Gas also make certain informational postings available on Dominion's website.

See Note 13 to the Consolidated Financial Statements for additional information.

Safety Regulations

Dominion and Dominion 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 and Dominion 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 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 GHG, mercury, other toxic metals, hydrogen chloride, NO_x, SO_2, 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 in recent years on 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 address climate change while meeting the growing needs of their service territory. Dominion's CEO and operating segment CEOs are responsible for compliance with the laws and regulations governing environmental matters, including climate change, and Dominion'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 the discharge of effluent into surface waters and require permits to be obtained from the EPA or the analogous state agency to discharge into state waters or waters of the U.S. Containment berms and similar structures may be required to help prevent accidental releases. Dominion must comply with applicable aspects of the CWA programs at its current and former operating facilities. From time to time, Dominion's projects and operations may impact tidal and non-tidal wetlands. In these instances, Dominion must obtain authorization from the appropriate federal, state and local agencies prior to impacting a subject wetland. The authorizing agency may impose significant direct or indirect mitigation costs to compensate for such impacts to wetlands.

GAS AND OIL WELLS

All 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. New environmental initiatives, proposed federal and state legislation, and rule-making pertaining to hydraulic fracture stimulation could increase Wexpro's costs, restrict its access to natural gas reserves and impose additional permitting and reporting requirements. These potential restrictions on the use of hydraulic-fracture stimulation could materially affect Dominion's ability to develop gas and oil reserves.

OTHER REGULATIONS

Other significant environmental regulations to which the Companies are subject include the CERCLA (providing for immediate response and removal actions, and contamination clean up, in the event of releases of hazardous substances into the environment), the Endangered Species Act (prohibiting activities that can result in harm to specific species of plants and animals), and federal and state laws protecting graves, sacred sites and cultural resources, including those of Native American populations. These regulations can result in compliance 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'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's and Virginia Power's nuclear generating units. See Note 22 to the Consolidated Financial Statements for further information.

The NRC also requires Dominion and Virginia Power to decontaminate their nuclear facilities once operations cease. This process is referred to as decommissioning, and Dominion and Virginia Power are required by the NRC to be financially prepared. For information on decommissioning trusts, see *Dominion 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

Environmental stewardship is embedded in the Companies' culture and core values and is the responsibility of all employees. They are committed to working with their stakeholders and the communities in which the Companies operate to find sustainable solutions to the energy and environmental challenges that confront the Companies and the U.S. The Companies are committed to delivering reliable, clean and affordable energy while protecting the environment and strengthening the communities they serve. The Companies are dedicated to meeting their customers' growing energy needs with innovative, sustainable solutions. It is the Companies' belief that sustainable solutions must balance the interdependent goals of environmental stewardship and economic prosperity. Their integrated strategy to meet this objective consists of four major elements:

- Compliance with applicable environmental laws, regulations and rules;
- Conservation and load management;
- Renewable generation development; and
- Improvements in other energy infrastructure, including natural gas operations.

This strategy incorporates the Companies' efforts to voluntarily reduce GHG emissions, which are described below. See *Dominion Generation-Properties* and *Dominion Energy-Properties* for more information on certain of the projects described below.

Conservation and Load Management

Conservation and load management play a significant role in meeting the growing demand for electricity. 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.

In Ohio, East Ohio offers three DSM programs, approved by the Ohio Commission, designed to help customers reduce their energy consumption.

Questar Gas offers an energy-efficiency program, approved by the Utah and Wyoming Commissions, designed to help customers reduce their energy consumption.

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 in monitoring 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.

Renewable Generation

Renewable energy is also an important component of a diverse and reliable energy mix. Both Virginia and North Carolina have passed legislation setting targets for renewable power. Dominion 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 in Virginia.

See *Operating Segments* and Item 2. Properties for additional information, including Dominion's merchant solar properties.

Improvements in Other Energy Infrastructure

Dominion'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 and address environmental requirements. These enhancements are primarily aimed at meeting Dominion's continued goal of providing reliable service, and are intended to address both continued population growth and increases in electricity consumption by the typical consumer. 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. See *Properties* in Item 1. Business, *Operating Segments, DVP* for additional information.

Dominion and Dominion Gas, in connection with their existing five-year investment plans, are also pursuing the construction

Table of Contents

or upgrade of regulated infrastructure in their natural gas businesses. See *Properties and Investments* in Item 1. Business, *Operating Segments, Dominion Energy* for additional information, including natural gas infrastructure projects.

The Companies' GHG Management Strategy

The Companies have not established a standalone GHG emissions reduction target or timetable, but they are actively engaged in GHG emission reduction efforts. The Companies have an integrated strategy for reducing GHG emission intensity with diversification and lower carbon intensity as its cornerstone. The principal components of the strategy include initiatives that address electric energy management, electric energy production, electric energy delivery and natural gas storage, transmission and delivery, as follows:

- Enhance conservation and energy efficiency programs to help customers use energy wisely and reduce environmental impacts;
- Expand the Companies' renewable energy portfolio, principally solar, wind power, fuel cells and biomass, to help diversify the Companies' fleet, meet state renewable energy targets and lower the carbon footprint;
- Evaluate other new generating capacity, including low emissions natural-gas fired and emissions-free nuclear units to meet customers' future electricity needs;
- Construct new electric transmission infrastructure to modernize the grid, promote economic security and help deliver more green energy to population centers where it is needed most;
- Construct new natural gas infrastructure to expand availability of this cleaner fuel, to reduce emissions, and to promote energy and economic security both in the U.S. and abroad;
- Implement and enhance voluntary methane mitigation measures through the EPA's Natural Gas Star and Methane Challenge programs; and
- As part of their commitment to compliance with such environmental laws, Dominion and Virginia Power have sold or closed a number of coal-fired generation units over the past several years, and may close additional units in the future.

Since 2000, Dominion 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 2015 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 2015 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 23%. Dominion and Virginia Power do not yet have final 2016 emissions data.

Dominion also develops a comprehensive GHG inventory annually. For Dominion Generation, Dominion's and Virginia Power's direct CO_2 equivalent emissions, based on ownership percentage, were 34.3 million metric tons and 30.9 million metric tons, respectively, in 2015, compared to 33.6 million metric tons and 30.1 million metric tons, respectively, in 2014. For the DVP operating segment's electric transmission and distribution operations, direct CO_2 equivalent emissions for 2015 were 53,819 metric tons, compared to 75,671 metric tons in 2014. For 2015, DTI's and Cove Point's direct CO_2 equivalent emissions together were 1.0 million metric tons, decreasing from 1.3 million metric tons in 2014, and Hope's and East Ohio's direct CO_2 equivalent emissions together remained unchanged since 2014 at 0.9 million metric tons. 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.

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's and Dominion 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's and Dominion Gas' gas transmission and distribution operations is based primarily on rates approved by state and federal regulatory agencies. 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's and Dominion Gas' gas transmission businesses are subject to review by FERC. In addition, the rates of Dominion's and Dominion Gas' gas distribution businesses are subject to state regulatory review in the jurisdictions in which they operate. A failure by us to support these rates could result in rate decreases from current rate levels, which could adversely affect our 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 the Clean Power Plan 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.

Dominion's 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's 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'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's 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's 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.

Table of Contents

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 fuel type conversions to natural gas and biomass. 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 and construction of several large-scale infrastructure projects simultaneously involves significant execution risk. The Companies are currently simultaneously developing or constructing several major projects, including the Liquefaction Project, the Atlantic Coast Pipeline Project, the Supply Header project, Greensville County and multiple DTI projects, which together help contribute to the over $24 billion in capital expenditures planned by the Companies through 2021. Several of the Companies' key projects are increasingly large-scale, complex and being constructed in constrained geographic areas (for example, the Liquefaction Project) 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 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 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.

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 is targeted at reducing CO_2 emissions from existing fossil fuel-fired power generation facilities.

Compliance with the Clean Power Plan may 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. The Clean Power Plan 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. Compliance with the Clean Power Plan's anticipated implementing regulations may require Virginia Power to prematurely retire certain generating facilities, with the potential lack or delay of cost recovery and higher electric rates, which could affect consumer demand. The cost of compliance with the Clean Power Plan is subject to significant uncertainties due to the outcome of several interrelated assumptions and variables, including timing of the implementation of rules, required levels of reductions, allocation requirements of the new rules, the maturation and commercialization of carbon controls and/or reduction programs, and the selected compliance alternatives. Dominion 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's and Virginia Power's generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect Dominion's or Virginia Power's results of operations, financial performance or liquidity.

There are also potential impacts on Dominion's and Dominion 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.

The Companies' operations are subject to a number of environmental laws and regulations which impose significant compliance costs to the Companies. The Companies' operations 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 or become applicable, 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 above. In addition, further regulation of air quality and GHG emissions under the CAA will be imposed on the natural gas sector, including rules to limit methane leakage. The Companies are also subject to recently finalized 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 liability 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.

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 may face litigation regarding alleged CWA violations at Possum Point power station, and is facing litigation regarding alleged CWA violations at Chesapeake power station and could incur settlement expenses and other costs, depending on the outcome of any such litigation, including costs associated with closing, corrective action and ongoing monitoring of certain ash ponds. In addition, the EPA and Virginia recently issued regulations concerning the management and storage of CCRs and West Virginia may impose additional regulations that would apply to the facilities noted above. These regulations would 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 and Virginia Power have substantial ownership interests in and operate nuclear generating units; as a result, each may incur substantial costs and liabilities. Dominion'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 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'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'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 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 and Dominion Gas gather, process, and transport and reducing the value of NGLs retained by Dominion Gas, which may adversely affect Dominion and Dominion Gas' revenues and earnings. Dominion and Dominion 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's and Dominion Gas' facilities. A number of other factors could reduce the volumes of natural gas and NGLs available to Dominion's and Dominion 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 and Dominion Gas. Producers with direct commodity price exposure face liquidity constraints, which could present a credit risk to Dominion and Dominion Gas. Producers could shift their production activities to regions outside Dominion's and Dominion 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's and Dominion Gas' systems and facilities for any reason, Dominion and Dominion Gas could experience lower revenues to the extent they are unable to replace the lost volumes on similar terms. In addition, Dominion Gas' revenue from processing and fractionation operations largely results from the sale of commodities at market prices. Dominion Gas receives the wet gas product from producers and may retain the extracted NGLs as compensation for its services. This exposes Dominion 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 Gas' results.

Dominion's merchant power business operates in a challenging market, which could adversely affect its results of operations and future growth. The success of Dominion's merchant power business depends upon favorable market conditions including the ability to sell power at prices sufficient to cover its operating costs. Dominion operates in active wholesale markets that expose it to price volatility for electricity and fuel as well as the credit risk of counterparties. Dominion 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 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.

Table of Contents

Dominion purchases fuel under a variety of terms, including long-term and short-term contracts and spot market purchases. Dominion 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's financial results.

In addition, in the event that any of the merchant generation facilities experience a forced outage, Dominion may not receive the level of revenue it anticipated.

The Companies' financial results can be adversely affected by various factors driving 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.

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 Gas has experienced a decline in demand for certain of its processing services due to competing facilities operating in nearby areas.

Dominion and Dominion 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 and Dominion 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's and Dominion Gas' services, the extent to which Dominion and Dominion 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 and Dominion Gas and related decreases in their earnings and cash flows.

Certain of Dominion and Dominion 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 result of these "negotiated rate" contracts could decrease Dominion and Dominion 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's operations are conducted through less than wholly-owned subsidiaries. In such arrangements, Dominion 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, joint venture partners, financial institutions or other third parties may adversely affect the Companies' financial results.

Dominion 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's favor, Dominion 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's decommissioning trust funds and Dominion's and Dominion Gas' benefit plan assets or increase Dominion's and Dominion 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's nuclear plants and under Dominion's and Dominion Gas' pension and other postretirement benefit plans. Dominion and Dominion Gas have significant obligations in these areas and holds 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'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's and Dominion 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's and Dominion 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,

Table of Contents

Dominion's and Dominion Gas' 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 and Dominion 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 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, the implementation of, and compliance with, 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,

Table of Contents

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 Questar Combination may not achieve its intended results. The Questar Combination is expected to result in various benefits, including, among other things, being accretive to earnings. Achieving the anticipated benefits of the transaction is subject to a number of uncertainties, including whether the business of Dominion Questar is integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management's time and energy, all of which could have an adverse effect on the combined company's financial position, results of operations or cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2016, Dominion owned its principal executive office and three other corporate offices, all located in Richmond, Virginia. Dominion also leases corporate offices in other cities in which its subsidiaries operate. Virginia Power and Dominion Gas share Dominion's principal office in Richmond, Virginia, which is owned by Dominion. In addition, Virginia Power's DVP and 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'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, 2016; however, by leaving the indenture open, Virginia Power expects to retain the flexibility to issue mortgage bonds in the future. Certain of Dominion's merchant generation facilities are also subject to liens.

DOMINION ENERGY

Dominion and Dominion 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 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 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 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 Gas is approximately 929 bcf. Certain storage fields are jointly-owned and operated by Dominion Gas. The capacity of those fields owned by Dominion Gas' partners totals approximately 220 bcf.

Dominion

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

Table of Contents

Columbia Gas Transmission, LLC and DTI 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 29,200 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.

Questar Pipeline operates 2,200 miles of natural gas transportation pipelines that interconnect with other pipelines in Utah, Wyoming and western Colorado. Questar Pipeline's system ranges in diameter from lines that are less than four inches to 36-inches. 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.

DCG's interstate natural gas pipeline system in South Carolina and southeastern Georgia is comprised of nearly 1,500 miles of transmission pipeline.

In total, Dominion has 170 compressor stations with approximately 1,175,000 installed compressor horsepower.

DVP

See Item 1. Business, *General* for details regarding DVP's principal properties, which primarily include transmission and distribution lines.

DOMINION GENERATION

Dominion and Virginia Power generate electricity for sale on a wholesale and a retail level. Dominion and Virginia Power supply electricity demand either from their generation facilities or through purchased power contracts. As of December 31, 2016, Dominion Generation's total utility and merchant generating capacity was approximately 26,400 MW.

Table of Contents

The following tables list Dominion Generation's utility and merchant generating units and capability, as of December 31, 2016:

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	1,342	
Ladysmith (CT)	Ladysmith, VA	783	
Remington (CT)	Remington, VA	608	
Bear Garden (CC)	Buckingham County, VA	590	
Possum Point (CC)	Dumfries, VA	573	
Chesterfield (CC)	Chester, VA	397	
Elizabeth River (CT)	Chesapeake, VA	348	
Possum Point	Dumfries, VA	316	
Bellemeade (CC)	Richmond, VA	267	
Bremo	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		7,548	35%
Coal			
Mt. Storm	Mt. Storm, WV	1,629	
Chesterfield	Chester, VA	1,267	
Virginia City Hybrid Energy Center	Wise County, VA	610	
Clover	Clover, VA	439(2)	
Yorktown(3)	Yorktown, VA	323	
Mecklenburg	Clarksville, VA	138	
Total Coal		4,406	21
Nuclear			
Surry	Surry, VA	1,676	
North Anna	Mineral, VA	1,672(4)	
Total Nuclear		3,348	15
Oil			
Yorktown	Yorktown, VA	790	
Possum Point	Dumfries, VA	786	
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		2,160	10
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	—
		19,891	
Power Purchase Agreements		1,764	8
Total Utility Generation		21,655	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 which has a net summer capacity of 20 MW, as the facility is dedicated to serving a non-jurisdictional customer.

(2) Excludes 50% undivided interest owned by ODEC.

(3) Coal-fired units are expected to be retired at Yorktown power station as early as 2017 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 Allegheny Energy, Inc.

Table of Contents

DOMINION MERCHANT GENERATION

Plant	Location	Net Summer Capability (MW)	Percentage Net Summer Capability
Nuclear			
Millstone	Waterford, CT	2,001(1)	
Total Nuclear		2,001	43%
Gas			
Fairless (CC)	Fairless Hills, PA	1,240	
Manchester (CC)	Providence, RI	468	
Total Gas		1,708	36
Solar(2)			
Escalante I, II and III	Beaver County, UT	120(3)	
Amazon Solar Farm U.S. East	Oak Hall, VA	80	
Granite Mountain East and West	Iron County, UT	65(3)	
Summit Farms Solar	Moyock, NC	60	
Enterprise	Beaver County, UT	40(3)	
Iron Springs	Iron County, UT	40(3)	
Pavant Solar	Holden, UT	34(4)	
Camelot Solar	Mojave, CA	30(4)	
Indy I, II and III	Indianapolis, IN	20(4)	
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 2 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)	
Azalea Solar	Davisboro, GA	5(4)	
Somers Solar	Somers, CT	3(4)	
Total Solar		687	15
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		4,693	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.
(4) Excludes 33% noncontrolling interest owned by Terra Nova Renewable Partners. Dominion'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.

Table of Contents

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. In February 2016, Virginia Power received a notice of violation from the VDEQ relating to this matter. Virginia Power has assumed the role of responsible party and is continuing to cooperate with ongoing requirements for investigative and corrective action. In September 2016, Virginia Power received a proposed consent order from the VDEQ related to this matter. The order was signed by Virginia Power in October 2016 and approved by the Virginia State Water Control Board in December 2016. The order included a penalty of $260,000, which is inclusive of both the Crystal City substation oil release and an oil release from another Virginia Power facility in 2016. The portion of the penalty attributable to the other facility represents less than $100,000 of the total proposed penalty.

In December 2016, Wexpro received a notice of violation from the Wyoming Division of Air Quality in connection with an alleged non-compliance with an air quality permit and certain air quality regulations relating to Wexpro's Church Buttes #63 well. The notice did not include a proposed penalty. Dominion is unable to evaluate the final outcome of this matter but it could result in a penalty in excess of $100,000.

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.

Table of Contents

Executive Officers of Dominion

Information concerning the executive officers of Dominion, each of whom is elected annually, is as follows:

Name and Age	Business Experience Past Five Years(1)
Thomas F. Farrell II (62)	Chairman of the Board of Directors, President and CEO of Dominion from April 2007 to date; Chairman and CEO of Dominion Midstream GP, LLC (the general partner of Dominion Midstream) from March 2014 to date and President from February 2015 to date; CEO of Dominion 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 (59)	Executive Vice President and CFO of Dominion from June 2009 to date, Dominion Midstream GP, LLC from March 2014 to date, Virginia Power from June 2009 to date, Dominion Gas from September 2013 to date, and Questar Gas from September 2016 to date.
Paul D. Koonce (57)	Executive Vice President and President & CEO—Dominion Generation Group of Dominion from January 2017 to date; Executive Vice President and CEO—Dominion Generation Group of Dominion from January 2016 to December 2016; Executive Vice President and CEO—Energy Infrastructure Group of Dominion from February 2013 to December 2015; Executive Vice President of Dominion from April 2006 to February 2013; Executive Vice President of Dominion Midstream GP, LLC from March 2014 to December 2015; President and COO of Virginia Power from June 2009 to date; President of Dominion Gas from September 2013 to December 2015.
Robert M. Blue (49)	Senior Vice President and President & CEO—Dominion Virginia Power of Dominion from January 2017 to date; President and COO of Virginia Power from January 2017 to date; Senior Vice President—Law, Regulation & Policy of Dominion, Dominion Gas and Dominion 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 and Dominion Gas from May 2015 to January 2016 and Dominion 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 from January 2011 to December 2013.
Diane Leopold (50)	Senior Vice President and President & CEO—Dominion Energy of Dominion and Dominion Midstream GP, LLC from January 2017 to date; President of Dominion Gas from January 2017 to date; President of DTI, East Ohio and Dominion Cove Point, Inc. from January 2014 to date; Senior Vice President of DTI from April 2012 to December 2013; Senior Vice President—Business Development & Generation Construction of Virginia Power from April 2009 to March 2012.
Mark O. Webb (52)	Senior Vice President—Corporate Affairs and Chief Legal Officer of Dominion, Virginia Power, Dominion Gas, Dominion Midstream GP, LLC, and Questar Gas from January 2017 to date; Senior Vice President, General Counsel and Chief Risk Officer of Dominion, Virginia Power and Dominion Gas from May 2016 to December 2016; Senior Vice President and General Counsel of Dominion 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, Virginia Power and Dominion Gas from January 2014 to May 2016; Vice President and General Counsel of Dominion Midstream GP, LLC from March 2014 to May 2016; Vice President and General Counsel of Dominion and Virginia Power from January 2013 to December 2013, and Dominion Gas from September 2013 to December 2013; Deputy General Counsel of DRS from July 2011 to December 2012.
Michele L. Cardiff (49)	Vice President, Controller and CAO of Dominion and Virginia Power from April 2014 to date, Dominion Gas and Dominion Midstream GP, LLC from March 2014 to date and Questar Gas from September 2016 to date; Vice President—Accounting of DRS from January 2014 to March 2014; Vice President and General Auditor of DRS from September 2012 to December 2013; Controller of Virginia Power from June 2009 to August 2012.
David A. Heacock (59)	President of Virginia Power from June 2009 to date and CNO from June 2009 to September 2016. Mr. Heacock will retire effective March 1, 2017.

(1) Any service listed for Virginia Power, Dominion Midstream GP, LLC, Dominion Gas, DTI, East Ohio, Dominion Cove Point, Inc., Questar Gas and DRS reflects service at a subsidiary of Dominion.

Table of Contents

Part II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Dominion

Dominion's common stock is listed on the NYSE. At January 31, 2017, there were approximately 126,500 record holders of Dominion's common stock. The number of record holders is comprised of individual shareholder accounts maintained on Dominion'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 Direct®. Discussions of expected dividend payments and restrictions on Dominion'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 2016 and 2015. 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's common stock repurchases during the fourth quarter of 2016:

DOMINION 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)
10/1/2016-10/31/16	233	$74.27	N/A	19,629,059 shares/$1.18 billion
11/1/2016-11/30/16	—	—	N/A	19,629,059 shares/$1.18 billion
12/1/2016-12/31/16	2,728	73.31	N/A	19,629,059 shares/$1.18 billion
Total	2,961	$73.38	N/A	19,629,059 shares/$1.18 billion

(1) 233 and 2,728 shares were tendered by employees to satisfy tax withholding obligations on vested restricted stock in October and December 2016, respectively.
(2) Represents the weighted-average price paid per share.
(3) The remaining repurchase authorization is pursuant to repurchase authority granted by the Dominion Board of Directors in February 2005, as modified in June 2007. The aggregate authorization granted by the Dominion 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. Potential restrictions on Virginia Power's payment of dividends are discussed in Note 20 to the Consolidated Financial Statements. In the first through fourth quarters of 2015, Virginia Power declared and paid quarterly cash dividends of $149 million, $121 million, $146 million and $75 million. In 2016, no dividends were declared or paid given the sufficiency of operating and other cash flows at Dominion. Virginia Power intends to pay quarterly cash dividends in 2017 but is neither required to nor restricted from making such payments.

Dominion Gas

All of Dominion Gas' membership interests are owned by Dominion. Potential restrictions on Dominion Gas' payment of distributions are discussed in Note 20 to the Consolidated Financial Statements. In the first through fourth quarters of 2015, Dominion Gas declared and paid quarterly cash distributions of $96 million, $68 million, $80 million and $448 million. Dominion Gas declared and paid cash distributions of $150 million in the second quarter of 2016.

Table of Contents

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

Year Ended December 31,	2016(1)	2015	2014(2)	2013(3)	2012(4)
(millions, except per share amounts)					
Operating revenue	**$11,737**	$11,683	$12,436	$13,120	$12,835
Income from continuing operations, net of tax(5)	**2,123**	1,899	1,310	1,789	1,427
Loss from discontinued operations, net of tax(5)	**—**	—	—	(92)	(1,125)
Net income attributable to Dominion	**2,123**	1,899	1,310	1,697	302
Income from continuing operations before loss from discontinued operations per common share-basic	**3.44**	3.21	2.25	3.09	2.49
Net income attributable to Dominion per common share-basic	**3.44**	3.21	2.25	2.93	0.53
Income from continuing operations before loss from discontinued operations per common share-diluted	**3.44**	3.20	2.24	3.09	2.49
Net income attributable to Dominion per common share-diluted	**3.44**	3.20	2.24	2.93	0.53
Dividends declared per common share	**2.80**	2.59	2.40	2.25	2.11
Total assets(6)	**71,610**	58,648	54,186	49,963	46,711
Long-term debt(6)	**30,231**	23,468	21,665	19,199	16,736

(1) Includes a $122 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

(2) 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's restructuring of its producer services business and a $174 million after-tax charge associated with the Liability Management Exercise.

(3) Includes a $109 million after-tax charge related to Dominion's restructuring of its producer services business ($76 million) and an impairment of certain natural gas infrastructure assets ($33 million). Also in 2013, Dominion recorded a $92 million after-tax net loss from the discontinued operations of Brayton Point and Kincaid.

(4) Includes a $1.1 billion after-tax loss from discontinued operations, including impairment charges, of Brayton Point and Kincaid and a $303 million after-tax charge primarily resulting from management's decision to cease operations and begin decommissioning Kewaunee in 2013.

(5) Amounts attributable to Dominion's common shareholders.

(6) As discussed in Note 2 to the Consolidated Financial Statements, prior period amounts have been reclassified to conform to the 2016 presentation.

Table of Contents

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

MD&A discusses Dominion's results of operations and general financial condition and Virginia Power's and Dominion 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 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 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;
- 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 emissions, 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;
- 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's and Dominion 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 and Virginia Power and in benefit plan trusts by Dominion and Dominion 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, including the recently completed Dominion Questar Combination, divestitures, transfers of assets to joint ventures or Dominion Midstream, including the recently completed contribution of Questar Pipeline to Dominion Midstream, and retirements of assets based on asset portfolio reviews;
- Receipt of approvals for, and timing of, closing dates for acquisitions and divestitures;
- The timing and execution of Dominion Midstream's growth strategy;
- Changes in rules for RTOs and ISOs in which Dominion 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 and Dominion Gas' pipeline and processing systems, failure to maintain or replace customer

Table of Contents

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'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 and Dominion Gas;
- Changes in operating, maintenance and construction costs;
- Timing and receipt of regulatory approvals necessary for planned construction or expansion projects and compliance with conditions associated with such regulatory approvals;
- The inability to complete planned construction, conversion or expansion projects at all, or with the outcomes or within the terms and time frames initially anticipated;
- 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 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 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's regulated electric and gas operations differs from the accounting for nonregulated operations in that Dominion 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 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 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 and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Dominion 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 rates in the future, may be significant. When Dominion 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 adjusts the carrying amount of the ARO liability with such changes recognized in income. Dominion accretes the ARO liability to reflect the passage of time. In 2016, Dominion recorded an increase in AROs of $449 million primarily related to future ash pond and landfill closure costs at certain utility generation facilities and the Dominion Questar Combination. See Note 22 to the Consolidated Financial Statements for additional information.

In 2016, 2015 and 2014, Dominion recognized $104 million, $93 million and $81 million, respectively, of accretion, and expects to recognize $117 million in 2017. Dominion 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's AROs relates to the future decommissioning of its merchant and utility nuclear facilities. These nuclear decommissioning AROs are reported in the Dominion Generation segment. At December 31, 2016, Dominion's nuclear decommissioning AROs totaled $1.5 billion, representing approximately 60% 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's nuclear decommissioning obligations.

Dominion 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's cost estimates include cost escalation rates that are applied to the base year costs. Dominion 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 involves uncertainty, since tax authorities may interpret the laws differently. 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.

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, 2016, Dominion had $64 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 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 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, 2016, Dominion had established $135 million of valuation allowances.

ACCOUNTING FOR DERIVATIVE CONTRACTS AND OTHER INSTRUMENTS AT FAIR VALUE

Dominion 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. Accounting requirements for derivatives and related hedging activities are complex and may be subject to further clarification by standard-setting bodies. The majority of investments held in Dominion'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 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 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 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 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, 2016, Dominion 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 Questar Combination in 2016.

In April of each year, Dominion 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 2016, 2015 and 2014 annual tests and any interim tests did not result in the recognition of any goodwill impairment.

In general, Dominion 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'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

Table of Contents

discount rates or growth rates inherent in Dominion's estimates of future cash flows, could result in a future impairment of goodwill. Although Dominion 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 IMPAIRMENT TESTING

Impairment testing for an individual or group of long-lived assets or for intangible assets with definite lives is required when circumstances indicate those assets may be impaired. When an 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. Performing an impairment test on long-lived assets involves judgment in areas such as identifying if circumstances indicate an impairment may exist, identifying and grouping affected assets, and developing the undiscounted and discounted estimated future cash flows (used to estimate fair value in the absence of 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 operating the long-lived assets and the selection of an appropriate discount rate. When determining whether an 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, including future production and sales levels, expected fluctuations of prices of commodities sold and consumed and expected proceeds from dispositions. See Note 6 to the Consolidated Financial Statements for a discussion of impairments related to certain long-lived assets.

EMPLOYEE BENEFIT PLANS

Dominion 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'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 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;
- Forecasts of an independent investment advisor;
- 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'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'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'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 develops assumptions, which are then compared to the forecasts of an independent investment advisor to ensure reasonableness. An internal committee selects the final assumptions. Dominion calculated its pension cost using an expected long-term rate of return on plan assets assumption of 8.75% for 2016, 2015 and 2014. For 2017, the expected long-term rate of return for pension cost assumption is 8.75%. Dominion calculated its other postretirement benefit cost using an expected long-term rate of return on plan assets assumption of 8.50% for 2016, 2015 and 2014. For 2017, 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 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 2.87% to 4.99% for pension plans and 3.56% to 4.94% for other postretirement benefit plans in 2016, were 4.40% in 2015,

Table of Contents

ranged from 5.20% to 5.30% for pension plans and 4.20% to 5.10% for other postretirement benefit plans in 2014. Dominion selected a discount rate ranging from 3.31% to 4.50% for pension plans and ranging from 3.92% to 4.47% for other postretirement benefit plans for determining its December 31, 2016 projected benefit obligations.

Dominion 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's healthcare cost trend rate assumption as of December 31, 2016 was 7.00% and is expected to gradually decrease to 5.00% by 2021 and continue at that rate for years thereafter.

Mortality rates are developed from actual and projected plan experience for postretirement benefit plans. Dominion's actuary conducts an experience study periodically as part of the process to select its best estimate of mortality. Dominion considers both standard mortality tables and improvement factors as well as the plans' actual experience when selecting a best estimate. During 2016, Dominion 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	
	Change in Actuarial Assumption	Pension Benefits	Other Postretirement Benefits
(millions, except percentages)			
Discount rate	**(0.25)%**	**$ 18**	**$ 2**
Long-term rate of return on plan assets	**(0.25)%**	**18**	**4**
Healthcare cost trend rate	**1 %**	**N/A**	**23**

In addition to the effects on cost, at December 31, 2016, a 0.25% decrease in the discount rate would increase Dominion's projected pension benefit obligation by $287 million and its accumulated postretirement benefit obligation by $43 million, while a 1.00% increase in the healthcare cost trend rate would increase its accumulated postretirement benefit obligation by $152 million.

See Note 21 to the Consolidated Financial Statements for additional information on Dominion's employee benefit plans.

New Accounting Standards

See Note 2 to the Consolidated Financial Statements for a discussion of new accounting standards.

Dominion

RESULTS OF OPERATIONS

Presented below is a summary of Dominion's consolidated results:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions, except EPS)					
Net Income attributable to Dominion	**$2,123**	**$ 224**	$1,899	$ 589	$1,310
Diluted EPS	**3.44**	**0.24**	3.20	0.96	2.24

Overview

2016 VS. 2015

Net income attributable to Dominion 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.

2015 VS. 2014

Net income attributable to Dominion increased 45%, primarily due to the absence of 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, the absence of losses related to the repositioning of Dominion's producer services business in the first quarter of 2014, and the absence of charges related to Dominion's Liability Management Exercise. See Note 13 to the Consolidated Financial Statements for more information on legislation related to North Anna and offshore wind facilities. See *Liquidity and Capital Resources* for more information on the Liability Management Exercise.

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion's results of operations:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions)					
Operating Revenue	**$11,737**	**$ 54**	$11,683	$ (753)	$12,436
Electric fuel and other energy-related purchases	**2,333**	**(392)**	2,725	(675)	3,400
Purchased electric capacity	**99**	**(231)**	330	(31)	361
Purchased gas	**459**	**(92)**	551	(804)	1,355
Net Revenue	**8,846**	**769**	8,077	757	7,320
Other operations and maintenance	**3,064**	**469**	2,595	(170)	2,765
Depreciation, depletion and amortization	**1,559**	**164**	1,395	103	1,292
Other taxes	**596**	**45**	551	9	542
Other income	**250**	**54**	196	(54)	250
Interest and related charges	**1,010**	**106**	904	(289)	1,193
Income tax expense	**655**	**(250)**	905	453	452

Table of Contents

An analysis of Dominion's results of operations follows:

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 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 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).

2015 VS. 2014

Net revenue increased 10%, primarily reflecting:

- The absence of losses related to the repositioning of Dominion's producer services business in the first quarter of 2014, reflecting the termination of natural gas trading and certain energy marketing activities ($313 million);
- A $159 million increase from electric utility operations, primarily reflecting:
  - An increase from rate adjustment clauses ($225 million);
  - An increase in sales to retail customers, primarily due to a net increase in cooling degree days ($38 million); and
  - A decrease in capacity related expenses ($33 million); partially offset by
  - An $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015;
  - A decrease in sales to customers due to the effect of changes in customer usage and other factors ($24 million); and
  - A decrease due to a charge based on the 2015 Biennial Review Order to refund revenues to customers ($20 million).
- The absence of losses related to the retail electric energy marketing business which was sold in the first quarter of 2014 ($129 million);
- A $77 million increase from merchant generation operations, primarily due to increased generation output reflecting the absence of planned outages at certain merchant generation facilities ($83 million) and additional solar generating facili-

Table of Contents

ties placed into service ($53 million), partially offset by lower realized prices ($58 million);
- A $38 million increase from regulated natural gas distribution operations, primarily due to an increase in rate adjustment clause revenue related to low income assistance programs ($12 million), an increase in AMR and PIR program revenues ($24 million) and various expansion projects placed into service ($22 million); partially offset by a decrease in gathering revenues ($9 million); and
- A $30 million increase from regulated natural gas transmission operations, primarily reflecting:
  - A $61 million increase in gas transportation and storage activities, primarily due to the addition of DCG ($62 million), decreased fuel costs ($24 million) and various expansion projects placed into service ($24 million), partially offset by decreased regulated gas sales ($46 million); and
  - A $46 million net increase primarily due to services performed for Atlantic Coast Pipeline and Blue Racer; partially offset by
  - A $61 million decrease from NGL activities, primarily due to decreased prices.

Other operations and maintenance decreased 6%, primarily reflecting:
- The absence of 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 ($370 million);
- An increase in gains from agreements to convey shale development rights underneath several natural gas storage fields ($63 million);
- A $97 million decrease in planned outage costs primarily due to a decrease in scheduled outage days at certain merchant generation facilities ($59 million) and non-nuclear utility generation facilities ($38 million); and
- A $22 million decrease in charges related to future ash pond and landfill closure costs at certain utility generation facilities.

These decreases were partially offset by:
- The absence of a gain on the sale of Dominion's electric retail energy marketing business in March 2014 ($100 million), net of a $31 million write-off of goodwill;
- An $80 million increase in certain electric transmission-related expenditures. These expenses are primarily recovered through state and FERC rates and do not impact net income;
- The absence of gains on the sale of assets to Blue Racer ($59 million);
- A $53 million increase in utility nuclear refueling outage costs primarily due to the amortization of outage costs that were previously deferred pursuant to Virginia legislation enacted in April 2014;
- A $46 million net increase due to services performed for Atlantic Coast Pipeline and Blue Racer. These expenses are billed to these entities and do not significantly impact net income; and
- A $22 million increase due to the acquisition of DCG.

Other income decreased 22%, primarily reflecting lower tax recoveries associated with contributions in aid of construction ($17 million), a decrease in interest income related to income taxes ($12 million), and lower net realized gains on nuclear decommissioning trust funds ($11 million).

Interest and related charges decreased 24%, primarily as a result of the absence of charges associated with Dominion's Liability Management Exercise in 2014.

Income tax expense increased 100%, primarily reflecting higher pre-tax income.

Outlook

Dominion's strategy is to continue focusing on its regulated 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 expects 80% to 90% of earnings from its primary operating segments to come from regulated and long-term contracted businesses.

Dominion's 2017 net income is expected to remain substantially consistent on a per share basis as compared to 2016.

Dominion's 2017 results are expected to be positively impacted by the following:
- Decreased charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- The inclusion of operations acquired from Dominion Questar for the entire year;
- Decreased transaction and transition costs associated with the Dominion Questar Combination;
- Growth in weather-normalized electric utility sales of approximately 1%;
- Construction and operation of growth projects in electric utility operations and associated rate adjustment clause revenue; and
- Construction and operation of growth projects in gas transmission and distribution.

Dominion's 2017 results are expected to be negatively impacted by the following:
- Lower power prices and an additional planned refueling outage at Millstone;
- Decreased Cove Point import contract revenues;
- An increase in depreciation, depletion, and amortization;
- A higher effective tax rate, driven primarily by a decrease in investment tax credits; and
- Share dilution.

Additionally, in 2017, Dominion expects to focus on meeting new and developing environmental requirements, including making investments in utility-scale solar generation, particularly in Virginia. In 2018, Dominion is expected to experience an increase in net income on a per share basis as compared to 2017 primarily due to the Liquefaction Project being in service for the full year.

Table of Contents

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's operating segments to net income attributable to Dominion:

Year Ended December 31,	2016 Net Income attributable to Dominion	2016 Diluted EPS	2015 Net Income attributable to Dominion	2015 Diluted EPS	2014 Net Income attributable to Dominion	2014 Diluted EPS
(millions, except EPS)						
DVP	$ 484	$ 0.78	$ 490	$ 0.82	$ 502	$ 0.86
Dominion Generation	1,397	2.26	1,120	1.89	1,061	1.81
Dominion Energy	726	1.18	680	1.15	717	1.23
Primary operating segments	2,607	4.22	2,290	3.86	2,280	3.90
Corporate and Other	(484)	(0.78)	(391)	(0.66)	(970)	(1.66)
Consolidated	$ 2,123	$ 3.44	$ 1,899	$ 3.20	$ 1,310	$ 2.24

DVP

Presented below are operating statistics related to DVP's operations:

Year Ended December 31,	2016	% Change	2015	% Change	2014
Electricity delivered (million MWh)	83.7	—%	83.9	—%	83.5
Degree days:					
Cooling	1,830	(1)	1,849	13	1,638
Heating	3,446	1	3,416	(10)	3,793
Average electric distribution customer accounts (thousands)(1)	2,549	1	2,525	1	2,500

(1) Period average.

Presented below, on an after-tax basis, are the key factors impacting DVP's net income contribution:

2016 VS. 2015

	Increase (Decrease) Amount	Increase (Decrease) 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)

2015 VS. 2014

	Increase (Decrease) Amount	Increase (Decrease) EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$ 5	$ 0.01
Other	(4)	—
FERC transmission equity return	36	0.06
Tax recoveries on contribution in aid of construction	(10)	(0.02)
Depreciation and amortization	(9)	(0.02)
Other operations and maintenance	(12)	(0.02)
AFUDC return	(6)	(0.01)
Interest expense	(5)	(0.01)
Other	(7)	(0.01)
Share dilution	—	(0.02)
Change in net income contribution	$ (12)	$ (0.04)

Dominion Generation

Presented below are operating statistics related to Dominion Generation's operations:

Year Ended December 31,	2016	% Change	2015	% Change	2014
Electricity supplied (million MWh):					
Utility	87.9	3%	85.2	2%	83.9
Merchant	28.9	7	26.9	8	25.0
Degree days (electric utility service area):					
Cooling	1,830	(1)	1,849	13	1,638
Heating	3,446	1	3,416	(10)	3,793

Presented below, on an after-tax basis, are the key factors impacting Dominion Generation's net income contribution:

2016 VS. 2015

	Increase (Decrease) Amount	Increase (Decrease) 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.

2015 VS. 2014

	Increase (Decrease) Amount	Increase (Decrease) EPS
(millions, except EPS)		
Merchant generation margin	$ 53	$ 0.09
Regulated electric sales:		
Weather	19	0.03
Other	(13)	(0.02)
Rate adjustment clause equity return	20	0.03
PJM ancillary services	(15)	(0.02)
Outage costs	26	0.05
Depreciation and amortization	(32)	(0.05)
Electric capacity	20	0.03
Other	(19)	(0.03)
Share dilution	—	(0.03)
Change in net income contribution	$ 59	$ 0.08

Table of Contents

Dominion Energy

Presented below are selected operating statistics related to Dominion Energy's operations.

Year Ended December 31,	2016	% Change	2015	% Change	2014
Gas distribution throughput (bcf)(1):					
Sales	**61**	**126%**	27	(16)%	32
Transportation	**537**	**14**	470	33	353
Heating degree days (gas distribution service area):					
Eastern region	**5,235**	**(8)**	5,666	(10)	6,330
Western region(1)	**1,876**	**100**	—	—	—
Average gas distribution customer accounts (thousands)(1)(2):					
Sales	**1,234(3)**	**414**	240	(2)	244
Transportation	**1,071**	**1**	1,057	—	1,052
Average retail energy marketing customer accounts (thousands)(2)	**1,376**	**6**	1,296	1	1,283(4)

(1) Includes Dominion Questar effective September 2016.
(2) Period average.
(3) Includes Dominion Questar customer accounts for the entire year.
(4) Excludes 511 thousand average retail electric energy marketing customer accounts due to the sale of this business in March 2014.

Presented below, on an after-tax basis, are the key factors impacting Dominion Energy's net income contribution:

2016 VS. 2015

	Increase (Decrease) Amount	Increase (Decrease) 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 Questar Combination	**78**	**0.13**
Other	**3**	**0.01**
Share dilution	**—**	**(0.05)**
Change in net income contribution	**$ 46**	**$ 0.03**

2015 VS. 2014

	Increase (Decrease) Amount	Increase (Decrease) EPS
(millions, except EPS)		
Gas distribution margin:		
Weather	$ (5)	$(0.01)
Rate adjustment clauses	16	0.03
Other	9	0.02
Assignment of shale development rights	33	0.06
Depreciation and amortization	(12)	(0.02)
Blue Racer	(39)(1)	(0.07)
Noncontrolling interest(2)	(13)	(0.02)
Retail energy marketing operations	(11)	(0.02)
Other	(15)	(0.04)
Share dilution	—	(0.01)
Change in net income contribution	$ (37)	$(0.08)

(1) Primarily represents absence of a gain from the sale of the Northern System.

(2) Represents the portion of earnings attributable to Dominion Midstream's public unitholders.

Corporate and Other

Presented below are the Corporate and Other segment's after-tax results:

Year Ended December 31,	2016	2015	2014
(millions, except EPS amounts)			
Specific items attributable to operating segments	**$ (180)**	$ (136)	$ (544)
Specific items attributable to Corporate and Other segment	**(44)**	(5)	(149)
Total specific items	**(224)**	(141)	(693)
Other corporate operations	**(260)**	(250)	(277)
Total net expense	**$ (484)**	$ (391)	$ (970)
EPS impact	**$(0.78)**	$(0.66)	$(1.66)

TOTAL SPECIFIC ITEMS

Corporate and Other includes specific items attributable to Dominion'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 2016, this primarily included $53 million of after-tax transaction and transition costs associated with the Dominion Questar Combination. In 2014, this primarily included $174 million of after-tax charges associated with Dominion's Liability Management Exercise.

VIRGINIA POWER

RESULTS OF OPERATIONS

Presented below is a summary of Virginia Power's consolidated results:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions)					
Net Income	**$1,218**	**$ 131**	$1,087	$ 229	$858

Overview

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.

2015 VS. 2014

Net income increased 27%, primarily due to the absence of 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.

Table of Contents

Analysis of Consolidated Operations

Presented below are selected amounts related to Virginia Power's results of operations:

Year Ended December 31, (millions)	2016	$ Change	2015	$ Change	2014
Operating Revenue	**$7,588**	**$ (34)**	$7,622	$ 43	$7,579
Electric fuel and other energy-related purchases	**1,973**	**(347)**	2,320	(86)	2,406
Purchased electric capacity	**99**	**(231)**	330	(30)	360
Net Revenue	**5,516**	**544**	4,972	159	4,813
Other operations and maintenance	**1,857**	**223**	1,634	(282)	1,916
Depreciation and amortization	**1,025**	**72**	953	38	915
Other taxes	**284**	**20**	264	6	258
Other income	**56**	**(12)**	68	(25)	93
Interest and related charges	**461**	**18**	443	32	411
Income tax expense	**727**	**68**	659	111	548

An analysis of Virginia Power's results of operations follows:

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.

2015 VS. 2014

Net revenue increased 3%, primarily reflecting:
- An increase from rate adjustment clauses ($225 million);
- An increase in sales to retail customers, primarily due to a net increase in cooling degree days ($38 million); and
- A decrease in capacity related expenses ($33 million); partially offset by
- An $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015;
- A decrease in sales to customers due to the effect of changes in customer usage and other factors ($24 million); and
- A decrease due to a charge based on the 2015 Biennial Review Order to refund revenues to customers ($20 million).

Other operations and maintenance decreased 15%, primarily reflecting:
- The absence of $370 million in 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; and
- A $38 million decrease in planned outage costs primarily due to a decrease in scheduled outage days at certain non-nuclear utility generation facilities.

These decreases were partially offset by:
- An $80 million increase in certain electric transmission-related expenditures. These expenses are primarily recovered through state and FERC rates and do not impact net income; and
- A $53 million increase in utility nuclear refueling outage costs primarily due to the amortization of outage costs that were previously deferred pursuant to Virginia legislation enacted in April 2014.

Other income decreased 27%, primarily reflecting lower tax recoveries associated with contributions in aid of construction.

Income tax expense increased 20%, primarily reflecting higher pre-tax income.

DOMINION GAS

RESULTS OF OPERATIONS

Presented below is a summary of Dominion Gas' consolidated results:

Year Ended December 31, (millions)	2016	$ Change	2015	$ Change	2014
Net Income	**$392**	**$ (65)**	$457	$ (55)	$512

Overview

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.

2015 VS. 2014

Net income decreased 11%, primarily due to the absence of gains on the indirect sale of assets to Blue Racer, a decrease in income from NGL activities and higher interest expense, partially offset by increased gains from agreements to convey shale development rights underneath several natural gas storage fields.

Table of Contents

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion Gas' results of operations:

Year Ended December 31, (millions)	2016	$ Change	2015	$ Change	2014
Operating Revenue	**$1,638**	**$ (78)**	$1,716	$ (182)	$1,898
Purchased gas	**109**	**(24)**	133	(182)	315
Other energy-related purchases	**12**	**(9)**	21	(19)	40
Net Revenue	**1,517**	**(45)**	1,562	19	1,543
Other operations and maintenance	**474**	**84**	390	52	338
Depreciation and amortization	**204**	**(13)**	217	20	197
Other taxes	**170**	**4**	166	9	157
Earnings from equity method investee	**21**	**(2)**	23	2	21
Other income	**11**	**10**	1	—	1
Interest and related charges	**94**	**21**	73	46	27
Income tax expense	**215**	**(68)**	283	(51)	334

An analysis of Dominion Gas' results of operations follows:

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.

2015 VS. 2014

Net revenue increased 1%, primarily reflecting:

- A $43 million increase from regulated natural gas distribution operations, primarily due to an increase in AMR and PIR program revenues ($24 million) and various expansion projects placed into service ($22 million); partially offset by
- A $27 million decrease from regulated natural gas transmission operations, primarily reflecting:
  - A $62 million decrease from NGL activities, primarily due to decreased prices; partially offset by
  - A $2 million increase in gas transportation and storage activities, primarily due to decreased fuel costs ($24 million) and various expansion projects placed into service ($24 million), partially offset by decreased regulated gas sales ($46 million); and
  - A $33 million net increase in other revenue primarily due to services performed for Atlantic Coast Pipeline and Blue Racer ($47 million), partially offset by a decrease in non-regulated gas sales ($8 million) and decreased farm-out revenues ($6 million).

Other operations and maintenance increased 15%, primarily reflecting:

- A $47 million net increase due to services performed for Atlantic Coast Pipeline and Blue Racer. These expenses are billed to these entities and do not significantly impact net income; and
- The absence of gains on the sale of assets to Blue Racer ($59 million); partially offset by
- An increase in gains from agreements to convey shale development rights underneath several natural gas storage fields ($63 million).

Depreciation and amortization increased 10% primarily due to various expansion projects placed into service.

Interest and related charges increased $46 million, primarily due to higher long-term debt interest expense resulting from debt issuances in December 2014.

Income tax expense decreased 15% primarily reflecting lower pre-tax income.

Table of Contents

Liquidity and Capital Resources

Dominion 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, 2016, Dominion had $2.3 billion of unused capacity under its credit facilities. See additional discussion below under *Credit Facilities and Short-Term Debt.*

A summary of Dominion's cash flows is presented below:

Year Ended December 31,	2016	2015	2014
(millions)			
Cash and cash equivalents at beginning of year	**$ 607**	$ 318	$ 316
Cash flows provided by (used in):			
Operating activities	**4,127**	4,475	3,439
Investing activities	**(10,703)**	(6,503)	(5,181)
Financing activities	**6,230**	2,317	1,744
Net increase (decrease) in cash and cash equivalents	**(346)**	289	2
Cash and cash equivalents at end of year	**$ 261**	$ 607	$ 318

Operating Cash Flows

Net cash provided by Dominion's operating activities decreased $348 million, primarily due to higher operations and maintenance expenses, derivative activities, and increased payments for income taxes and interest. The decrease was partially offset with the benefit from the new PJM capacity performance market and higher deferred fuel cost recoveries and revenues from rate adjustment clauses in its Virginia jurisdiction.

Dominion 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 2016, Dominion's Board of Directors established an annual dividend rate for 2017 of $3.02 per share of common stock, a 7.9% increase over the 2016 rate. Dividends are subject to declaration by the Board of Directors. In January 2017, Dominion's Board of Directors declared dividends payable in March 2017 of 75.5 cents per share of common stock.

Dominion'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'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's credit exposure as of December 31, 2016 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)	**$ 36**	**$ —**	**$ 36**
Non-investment grade(2)	**9**	**—**	**9**
No external ratings:			
Internally rated-investment grade(3)	**16**	**—**	**16**
Internally rated-non-investment grade(4)	**37**	**—**	**37**
Total	**$ 98**	**$ —**	**$ 98**

(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 27% of the total net credit exposure.

(2) The five largest counterparty exposures, combined, for this category represented approximately 10% of the total net credit exposure.

(3) The five largest counterparty exposures, combined, for this category represented approximately 15% of the total net credit exposure.

(4) The five largest counterparty exposures, combined, for this category represented approximately 16% of the total net credit exposure.

Investing Cash Flows

Net cash used in Dominion's investing activities increased $4.2 billion, primarily due to the Dominion Questar Combination and higher capital expenditures, partially offset by the absence of Dominion's acquisition of DCG in 2015 and the acquisition of fewer solar development projects in 2016.

Financing Cash Flows and Liquidity

Dominion 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'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 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 to use automatic shelf registration statements to register any offering of securities, other than those for exchange offers or business combination transactions.

Net cash provided by Dominion's financing activities increased $3.9 billion, primarily reflecting higher net debt issuances and higher issuances of common stock and Dominion Midstream common and convertible preferred units in connection with the Dominion Questar Combination.

LIABILITY MANAGEMENT

During 2014, Dominion elected to redeem certain debt and preferred securities prior to their stated maturities. Proceeds from the issuance of lower-cost senior and enhanced junior subordinated notes were used to fund the redemption payments. See Note 17 to the Consolidated Financial Statements for descriptions of these redemptions.

From time to time, Dominion 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.

CREDIT FACILITIES AND SHORT-TERM DEBT

Dominion 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 January 2016, Dominion expanded its short-term funding resources through a $1.0 billion increase to one of its joint revolving credit facility limits. In addition, Dominion utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion's credit ratings and the credit quality of its counterparties.

In connection with commodity hedging activities, Dominion is required to provide collateral to counterparties under some circumstances. Under certain collateral arrangements, Dominion 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 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 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's commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

December 31, 2016	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
Joint revolving credit facility(1)(2)	$5,000	$ 3,155	$ —	$1,845
Joint revolving credit facility(1)	500	—	85	415
Total	$5,500	$ 3,155(3)	$ 85	$2,260

(1) In May 2016, the maturity dates for these facilities were extended from April 2019 to April 2020. These credit facilities 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) In January 2016, this facility limit was increased from $4.0 billion to $5.0 billion.

(3) The weighted-average interest rate of the outstanding commercial paper supported by Dominion's credit facilities was 1.05% at December 31, 2016.

Dominion Questar's revolving multi-year and 364-day credit facilities with limits of $500 million and $250 million, respectively, were terminated in October 2016.

SHORT-TERM NOTES

In November 2015, Dominion issued $400 million of private placement short-term notes that matured in May 2016 and bore interest at a variable rate. In December 2015, Dominion issued an additional $200 million of the variable rate short-term notes that matured in May 2016. The proceeds were used for general corporate purposes.

In February 2016, Dominion purchased and cancelled $100 million of the variable rate short-term notes that would have otherwise matured in May 2016 using the proceeds from the February 2016 issuance of senior notes that mature in 2018.

In September 2016, Dominion borrowed $1.2 billion under a term loan agreement that bore interest at a variable rate. The net proceeds were used to finance the Dominion Questar Combination. In December 2016, the loan was repaid with cash received from Dominion Midstream in connection with the contribution of Questar Pipeline. The loan would have otherwise matured in September 2017. See Note 3 to the Consolidated Financial Statements for more information.

LONG-TERM DEBT

During 2016, Dominion issued the following long-term public debt:

Type	Principal	Rate	Maturity
	(millions)		
Senior notes	$ 500	1.60%	2019
Senior notes	400	2.00%	2021
Remarketable subordinated notes	700	2.00%	2021
Remarketable subordinated notes	700	2.00%	2024
Senior notes	400	2.85%	2026
Senior notes	400	2.95%	2026
Senior notes	750	3.15%	2026
Senior notes	500	4.00%	2046
Enhanced junior subordinated notes	800	5.25%	2076
Total notes issued	$5,150		

During 2016, Dominion also issued the following long-term private debt:

- In February 2016, Dominion issued $500 million of 2.125% senior notes in a private placement. The notes mature in 2018. The proceeds were used to repay or repurchase short-term debt, including commercial paper and short-term notes, and for general corporate purposes.
- In May 2016, Dominion Gas issued $150 million of private placement 3.8% senior notes that mature in 2031. The proceeds were used for general corporate purposes. In June 2016, Dominion Gas issued $250 million of private placement 2.875% senior notes that mature in 2023. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper. Also in June 2016, Dominion Gas issued € 250 million of private placement 1.45% senior notes that mature in 2026. The notes were recorded at $280 million at issuance and included in long-term debt in the Consolidated Balance Sheets at $263 million at December 31,

2016. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.
- In September 2016, Dominion issued $300 million of private placement 1.50% senior notes that mature in 2018. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.
- In December 2016, Questar Gas issued $50 million of 3.62% private placement senior notes, and $50 million of 3.67% private placement senior notes, that mature in 2046 and 2051, respectively. The proceeds were used for general corporate purposes.
- In December 2016, Dominion issued $250 million of private placement 1.875% senior notes that mature in 2018. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.

During 2016, Dominion also remarketed the following long-term debt:
- In March 2016 and May 2016, Dominion 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 rates on the Series A and Series B junior subordinated notes were reset to 4.104% and 2.962%, respectively. Dominion did not receive any proceeds from the remarketings. See Note 17 to the Consolidated Financial Statements for more information.
- In December 2016, Virginia Power remarketed the $37 million Industrial Development Authority of the Town of Louisa, Virginia Pollution Control Refunding Revenue Bonds, Series 2008 C, which mature in 2035 and bear interest at a coupon rate of 1.85% until May 2019 after which they will bear interest at a market rate to be determined at that time. Previously, the bonds bore interest at a coupon rate of .70%. This remarketing was accounted for as a debt extinguishment with the previous investors.

During 2016, Dominion also borrowed the following under term loan agreements:
- In December 2016, Dominion Midstream borrowed $300 million under a term loan agreement that matures in December 2019 and bears interest at a variable rate. The net proceeds were used to finance a portion of the acquisition of Questar Pipeline from Dominion. See Note 3 to the Consolidated Financial Statements for more information.
- In December 2016, SBL Holdco borrowed $405 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 December 2023. The debt is nonrecourse to Dominion and is secured by SBL Holdco's interest in certain merchant solar facilities. See Note 15 to the Consolidated Financial Statements for more information. The proceeds were used for general corporate purposes.

During 2016, Dominion repaid $1.8 billion of short-term notes and repaid and repurchased $1.6 billion of long-term debt.

In January 2017, Dominion issued $400 million of 1.875% senior notes and $400 million of 2.75% senior notes that mature in 2019 and 2022, respectively.

ISSUANCE OF COMMON STOCK AND OTHER EQUITY SECURITIES

Dominion maintains Dominion Direct® and a number of employee savings plans through which contributions may be invested in Dominion'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 began purchasing its common stock on the open market for these plans. In April 2014, Dominion began issuing new common shares for these direct stock purchase plans.

During 2016, Dominion issued 4.2 million shares of common stock totaling $314 million through employee savings plans, direct stock purchase and dividend reinvestment plans and other employee and director benefit plans. Dominion received cash proceeds of $295 million from the issuance of 4.0 million of such shares through Dominion Direct® and employee savings plans.

In both April 2016 and July 2016, Dominion issued 8.5 million shares under the related stock purchase contract entered into as part of Dominion's 2013 Equity Units and received $1.1 billion of total proceeds. Additionally, Dominion 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 Questar Combination. See Note 3 to the Consolidated Financial Statements for more information.

During 2017, Dominion plans to issue shares for employee savings plans, direct stock purchase and dividend reinvestment plans and stock purchase contracts. See Note 17 to the Consolidated Financial Statements for a description of common stock to be issued by Dominion for stock purchase contracts.

During the fourth quarter of 2016, Dominion 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 Questar Pipeline from Dominion. See Note 3 to the Consolidated Financial Statements for more information.

REPURCHASE OF COMMON STOCK

Dominion did not repurchase any shares in 2016 and does not plan to repurchase shares during 2017, except for shares tendered by employees to satisfy tax withholding obligations on vested restricted stock, which does not count against its stock repurchase authorization.

PURCHASE OF DOMINION MIDSTREAM UNITS

In September 2015, Dominion initiated a program to purchase from the market up to $50 million of common units representing limited partner interests in Dominion Midstream, which expired in September 2016. Dominion 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.

ACQUISITION OF DOMINION QUESTAR

In accordance with the terms of the Dominion Questar Combination, at closing, each share of issued and outstanding Dominion 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 Questar outstanding at closing. Dominion also acquired Dominion Questar's outstanding debt of approximately $1.5 billion. Dominion financed the Dominion 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, which was repaid with cash received from Dominion Midstream in connection with the contribution of Questar Pipeline and (4) $500 million of the proceeds from the April 2016 issuance of common stock.

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 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 may affect its ability to access these funding sources or cause an increase in the return required by investors. Dominion'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 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 February 2016, Standard & Poor's lowered the following ratings for Dominion: issuer to BBB+ from A-, senior unsecured debt securities to BBB from BBB+ and junior/remarketable subordinated debt securities to BBB- from BBB. In addition, Standard & Poor's affirmed Dominion's commercial paper rating of A-2 and revised its outlook to stable from negative.

In March 2016, Fitch and Standard & Poor's changed the rating for Dominion's junior subordinated debt securities to account for its inability to defer interest payments on the remarketed 2013 Series A RSNs. Subsequently, junior subordinated debt securities without an interest deferral feature are rated one notch higher by Fitch and Standard & Poor's (BBB) than junior subordinated debt securities with an interest deferral feature (BBB-). See Note 17 to the Consolidated Financial Statements for a description of the remarketed notes.

Credit ratings as of February 23, 2017 follow:

	Fitch	Moody's	Standard & Poor's
Dominion			
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, 2017, Fitch, Moody's, and Standard & Poor's maintained a stable outlook for their respective ratings of Dominion.

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 works closely with Fitch, Moody's and Standard & Poor's with the objective of achieving its targeted credit ratings. Dominion 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 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.

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'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 is required to pay annual commitment fees to maintain its credit facilities. In addition, Dominion'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, 2016, 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	**70%**	**61%**

(1) Pursuant to a waiver received in April 2016 and in connection with the closing of the Dominion Questar Combination, the 65% maximum debt to total capital ratio in Dominion's credit agreements has, with respect to Dominion only, been temporarily increased to 70% until the end of the fiscal quarter ending June 30, 2017.
(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.

Table of Contents

If Dominion 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'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's obligations to repay any outstanding borrowing under the credit facilities could also be accelerated and the lenders' commitments to Dominion could terminate.

Dominion executed RCCs in connection with its issuance of the following hybrid securities:

- June 2006 hybrids;
- September 2006 hybrids; and
- June 2009 hybrids.

In October 2014, Dominion redeemed all of the June 2009 hybrids. The redemption was conducted in compliance with the RCC. See Note 17 to the Consolidated Financial Statements for additional information, including terms of the RCCs.

At December 31, 2016, the termination dates and covered debt under the RCCs associated with Dominion'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 monitors these debt covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2016, there have been no events of default under Dominion's debt covenants.

Dividend Restrictions

Certain agreements associated with Dominion's credit facilities contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict Dominion's ability to pay dividends or receive dividends from its subsidiaries at December 31, 2016.

See Note 17 to the Consolidated Financial Statements for a description of potential restrictions on dividend payments by Dominion 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 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 is a party as of December 31, 2016. 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's current liabilities will be paid in cash in 2017.

	2017	2018-2019	2020-2021	2022 and thereafter	Total
(millions)					
Long-term debt(1)	**$1,711**	**$ 6,666**	**$3,888**	**$19,927**	**$32,192**
Interest payments(2)	**1,339**	**2,349**	**1,902**	**14,596**	**20,186**
Leases(3)	**72**	**127**	**71**	**238**	**508**
Purchase obligations(4):					
Purchased electric capacity for utility operations	**149**	**153**	**98**	**—**	**400**
Fuel commitments for utility operations	**1,300**	**1,163**	**386**	**1,487**	**4,336**
Fuel commitments for nonregulated operations	**122**	**114**	**124**	**131**	**491**
Pipeline transportation and storage	**305**	**495**	**380**	**1,253**	**2,433**
Other(5)	**648**	**179**	**43**	**14**	**884**
Other long-term liabilities(6):					
Other contractual obligations(7)	**77**	**188**	**28**	**24**	**317**
Total cash payments	**$5,723**	**$11,434**	**$6,920**	**$37,670**	**$61,747**

(1) Based on stated maturity dates rather than the earlier redemption dates that could be elected by instrument holders.

(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, 2016 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'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, $48 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's planned capital expenditures are expected to total approximately $5.8 billion, $5.0 billion and $5.2 billion in 2017, 2018 and 2019, respectively. Dominion'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 the construction of the Liquefaction Project and Dominion's portion of the Atlantic Coast Pipeline.

Dominion 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 *DVP, Dominion Generation* and *Dominion Energy-Properties* in Item 1. Business for a discussion of Dominion's expansion plans.

These estimates are based on a capital expenditures plan reviewed and endorsed by Dominion's Board of Directors in late 2016 and are subject to continuing review and adjustment and actual capital expenditures may vary from these estimates. Dominion 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 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 has been appointed to act as the construction agent for the lessor, during which time Dominion will request cash draws from the lessor and debt investors to fund all project costs, which totaled $46 million as of December 31, 2016. If the project is terminated under certain events of default, Dominion could be required to pay up to 89.9% of the then funded amount. For specific full recourse events, Dominion 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 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 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 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 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 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 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. 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 is 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.

ENVIRONMENTAL PROTECTION AND MONITORING EXPENDITURES

Dominion incurred $394 million, $298 million and $313 million of expenses (including accretion and depreciation) during 2016, 2015, and 2014 respectively, in connection with environmental protection and monitoring activities, including charges related to future ash pond and landfill closure costs, and expects these expenses to be approximately $190 million and $185 million in 2017 and 2018, respectively. In addition, capital expenditures related to environmental controls were $191 million, $94 million, and $101 million for 2016, 2015 and 2014, respectively. These expenditures are expected to be approximately $185 million and $115 million for 2017 and 2018, 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 new rule requires states to impose standards of performance limits for existing fossil fuel-fired electric generating units or equivalent statewide intensity-based or mass-based CO_2 binding goals or limits. States are required to submit final plans identifying how they will comply with the rule by September 2018. The EPA also issued a proposed federal plan and model trading rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by the EPA. Virginia Power's most recent integrated resources plan filed in April 2016 includes four

Table of Contents

alternative plans that represent plausible compliance strategies with the rule as proposed, and which include additional coal unit retirements and additional low or zero-carbon 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. Dominion does not know whether these legal challenges will impact the submittal deadlines for the state implementation plans. In June 2016, the Governor of Virginia signed an executive order directing the Virginia Natural Resources Secretary to convene a workgroup charged with recommending concrete steps to reduce carbon pollution which include the Clean Power Plan as an option. Unless the rule survives the court challenges and until the state plans are developed and the EPA approves the plans, Dominion cannot predict the potential financial statement impacts but believes the potential expenditures to comply could be material.

In December 2012, the EPA issued a final rule that set a more stringent annual air quality standard for fine particulate matter. The EPA issued final attainment/nonattainment designations in January 2015. Until states develop their implementation plans, Dominion cannot determine whether or how facilities located in areas designated nonattainment for the standard will be impacted, but does not expect such impacts to be material.

The EPA has finalized rules establishing a new 1-hour NAAQS for NO_2 and a new 1-hour NAAQS for SO_2, which could require additional NO_X and SO_2 controls in certain areas where Dominion operates. Until the states have developed implementation plans for these standards, the impact on Dominion's facilities that emit NO_X and SO_2 is uncertain. Additionally, the impact of permit limits for implementing NAAQS on Dominion's facilities is uncertain at this time.

Climate Change

In December 2015, the Paris Agreement was formally adopted under the United Nations Framework Convention on Climate Change. The accord establishes a universal framework for addressing GHG emissions involving actions by all nations through the concept of nationally determined contributions in which each nation defines the GHG commitment it can make and sets in place a process for increasing those commitments every five years. It also contains a global goal of holding the increase in the global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius above pre-industrial levels and to aim to reach global peaking of GHG emissions as soon as possible.

A key element of the initial U.S. nationally determined contributions of achieving a 26% to 28% reduction below 2005 levels by 2025 is the implementation of the Clean Power Plan, which establishes interim emission reduction targets for fossil fuel-fired electric generating units over the period 2022 through 2029 with final targets to be achieved by 2030. The EPA estimates that the Clean Power Plan will result in a nationwide reduction in CO_2 emissions from fossil fuel-fired electric generating units of 32% from 2005 levels by 2030.

In March 2016, as part of its Climate Action Plan, 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. Depending on the results of this Information Collection Request, the EPA may propose new regulations on existing sources. Dominion cannot currently estimate the potential impacts on results of operations, financial condition and/or cash flows related to this matter.

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.

Legal Matters

Collective Bargaining Agreement

In April 2016, the labor contract between Dominion and Local 69 expired. In August 2016, the parties reached a tentative agreement for a new labor contract, however, the agreement was not submitted to members of Local 69 for approval. In September 2016, following a temporary lock out of union members, Local 69 agreed to not strike at DTI and Hope at least through April 1, 2017. In exchange, DTI and Hope agreed to recall the union members to work and not lock them out during that period. Contract negotiations resumed in October 2016 and are continuing. Local 69 represents approximately 760 DTI employees in West Virginia, New York, Pennsylvania, Ohio and Virginia and approximately 150 Hope employees in West Virginia.

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 has elected to exempt its swaps from the CEA's clearing requirements. The CFTC may continue to adopt final rules and implement provisions of the Dodd-Frank Act through its ongoing rulemaking process, including rules regarding margin requirements for non-cleared swaps. If, as a result of the rulemaking process, Dominion'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's swap dealer counterparties may attempt to pass-through additional trading costs in connection with the implementation of, and compliance with, Title VII of the Dodd-Frank Act. Due to the evolving rulemaking process, Dominion 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.

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’s and Virginia Power’s electric operations and Dominion’s and Dominion 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 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 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 $27 million and $24 million of Dominion’s commodity-based derivative instruments as of December 31, 2016 and December 31, 2015, respectively.

A hypothetical 10% decrease in commodity prices would have resulted in a decrease in the fair value of $62 million and $42 million of Virginia Power’s commodity-based derivative instruments as of December 31, 2016 and December 31, 2015, respectively. The increase in sensitivity is largely due to an increase in commodity derivative activity and higher commodity prices.

A hypothetical 10% increase in commodity prices of Dominion Gas’ commodity-based financial derivative instruments would have resulted in a decrease in fair value of $4 million and $5 million as of December 31, 2016 and 2015, respectively.

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, 2016 or 2015.

The Companies may also use forward-starting interest rate swaps and interest rate lock agreements as anticipatory hedges. As of December 31, 2016, Dominion 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’s and Virginia Power’s interest rate derivatives at December 31, 2016. As of December 31, 2015, Dominion, Virginia Power and Dominion Gas had $4.6 billion, $2.0 billion and $250 million, 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 $71 million, $52 million and $2 million, respectively, in the fair value of Dominion’s, Virginia Power’s and Dominion Gas’ interest rate derivatives at December 31, 2015.

In June 2016, Dominion 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, 2016, Dominion and Dominion 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’s and Dominion Gas’ 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 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

Table of Contents

managers. These trust funds primarily hold marketable securities that are reported in the Consolidated Balance Sheets at fair value.

Dominion recognized net realized gains (including investment income) on nuclear decommissioning and rabbi trust investments of $144 million and $184 million in 2016 and 2015, 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 recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains of $183 million in 2016, and a net decrease in unrealized gains of $157 million in 2015.

Virginia Power recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $67 million and $88 million in 2016 and 2015, 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 $93 million in 2016, and a net decrease in unrealized gains of $76 million in 2015.

Dominion sponsors pension and other postretirement employee benefit plans that hold investments in trusts to fund employee benefit payments. Virginia Power and Dominion Gas employees participate in these plans. Dominion's pension and other postretirement plan assets experienced aggregate actual returns of $534 million in 2016 and aggregate actual losses of $72 million in 2015, versus expected returns of $691 million and $648 million, respectively. Dominion Gas' pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual returns of $130 million in 2016 and aggregate actual losses of $13 million in 2015, versus expected returns of $157 million and $150 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's plan assets would result in an increase in net periodic cost of $18 million and $16 million as of December 31, 2016 and 2015, respectively, for pension benefits and $4 million and $3 million as of December 31, 2016 and 2015, respectively, for other postretirement benefits. A hypothetical 0.25% decrease in the assumed long-term rates of return on Dominion 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, 2016 and 2015, for pension benefits and $1 million as of both December 31, 2016 and 2015, 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 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 Gas. Dominion 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 also monitors the financial condition of existing counterparties on an ongoing basis. Based on these credit policies and the Companies' December 31, 2016 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.

Table of Contents

Item 8. Financial Statements and Supplementary Data

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Dominion Resources, Inc.
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Dominion Resources, Inc. and subsidiaries ("Dominion") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of Dominion's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Dominion Resources, Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, 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), Dominion's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2017 expressed an unqualified opinion on Dominion's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 28, 2017

Table of Contents

Dominion Resources, Inc.
Consolidated Statements of Income

Year Ended December 31, (millions, except per share amounts)	**2016**	2015	2014
Operating Revenue	**$11,737**	$11,683	$12,436
Operating Expenses			
Electric fuel and other energy-related purchases	**2,333**	2,725	3,400
Purchased electric capacity	**99**	330	361
Purchased gas	**459**	551	1,355
Other operations and maintenance	**3,064**	2,595	2,765
Depreciation, depletion and amortization	**1,559**	1,395	1,292
Other taxes	**596**	551	542
Total operating expenses	**8,110**	8,147	9,715
Income from operations	**3,627**	3,536	2,721
Other income	**250**	196	250
Interest and related charges	**1,010**	904	1,193
Income from operations including noncontrolling interests before income taxes	**2,867**	2,828	1,778
Income tax expense	**655**	905	452
Net income including noncontrolling interests	**2,212**	1,923	1,326
Noncontrolling interests	**89**	24	16
Net income attributable to Dominion	**2,123**	1,899	1,310
Earnings Per Common Share			
Net income attributable to Dominion—Basic	**$ 3.44**	$ 3.21	$ 2.25
Net income attributable to Dominion—Diluted	**$ 3.44**	$ 3.20	$ 2.24
Dividends declared per common share	**$ 2.80**	$ 2.59	$ 2.40

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Table of Contents

Dominion Resources, Inc.
Consolidated Statements of Comprehensive Income

Year Ended December 31,	2016	2015	2014
(millions)			
Net income including noncontrolling interests	**$2,212**	$1,923	$1,326
Other comprehensive income (loss), net of taxes:			
Net deferred gains on derivatives-hedging activities, net of $(37), $(74) and $(20) tax	**55**	110	17
Changes in unrealized net gains on investment securities, net of $(53), $23 and $(59) tax	**93**	6	128
Changes in net unrecognized pension and other postretirement benefit costs, net of $189, $29 and $189 tax	**(319)**	(66)	(305)
Amounts reclassified to net income:			
Net derivative (gains) losses-hedging activities, net of $100, $68 and $(59) tax	**(159)**	(108)	93
Net realized gains on investment securities, net of $15, $29 and $33 tax	**(28)**	(50)	(54)
Net pension and other postretirement benefit costs, net of $(22), $(35) and $(24) tax	**34**	51	33
Changes in other comprehensive loss from equity method investees, net of $—, $1 and $3 tax	**(1)**	(1)	(4)
Total other comprehensive loss	**(325)**	(58)	(92)
Comprehensive income including noncontrolling interests	**1,887**	1,865	1,234
Comprehensive income attributable to noncontrolling interests	**89**	24	16
Comprehensive income attributable to Dominion	**$1,798**	$1,841	$1,218

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Table of Contents

Dominion Resources, Inc.
Consolidated Balance Sheets

At December 31, (millions)	2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 261**	$ 607
Customer receivables (less allowance for doubtful accounts of $18 and $32)	**1,523**	1,200
Other receivables (less allowance for doubtful accounts of $2 at both dates)	**183**	169
Inventories:		
Materials and supplies	**1,087**	902
Fossil fuel	**341**	381
Gas stored	**96**	65
Derivative assets	**140**	255
Prepayments	**194**	198
Regulatory assets	**244**	351
Other	**179**	61
Total current assets	**4,248**	4,189
Investments		
Nuclear decommissioning trust funds	**4,484**	4,183
Investment in equity method affiliates	**1,561**	1,320
Other	**298**	271
Total investments	**6,343**	5,774
Property, Plant and Equipment		
Property, plant and equipment	**69,556**	57,776
Accumulated depreciation, depletion and amortization	**(19,592)**	(16,222)
Total property, plant and equipment, net	**49,964**	41,554
Deferred Charges and Other Assets		
Goodwill	**6,399**	3,294
Pension and other postretirement benefit assets	**1,078**	943
Intangible assets, net	**618**	570
Regulatory assets	**2,473**	1,865
Other	**487**	459
Total deferred charges and other assets	**11,055**	7,131
Total assets	**$ 71,610**	$ 58,648

Table of Contents

At December 31,	2016	2015
(millions)		
LIABILITIES AND EQUITY		
Current Liabilities		
Securities due within one year	**$ 1,709**	$ 1,825
Short-term debt	**3,155**	3,509
Accounts payable	**1,000**	726
Accrued interest, payroll and taxes	**798**	515
Regulatory liabilities	**163**	100
Other(1)	**1,290**	1,444
Total current liabilities	**8,115**	8,119
Long-Term Debt		
Long-term debt	**24,878**	20,048
Junior subordinated notes	**2,980**	1,340
Remarketable subordinated notes	**2,373**	2,080
Total long-term debt	**30,231**	23,468
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**8,602**	7,414
Asset retirement obligations	**2,236**	1,887
Pension and other postretirement benefit liabilities	**2,112**	1,199
Regulatory liabilities	**2,622**	2,285
Other	**852**	674
Total deferred credits and other liabilities	**16,424**	13,459
Total liabilities	**54,770**	45,046
Commitments and Contingencies (see Note 22)		
Equity		
Common stock-no par(2)	**8,550**	6,680
Retained earnings	**6,854**	6,458
Accumulated other comprehensive loss	**(799)**	(474)
Total common shareholders' equity	**14,605**	12,664
Noncontrolling interests	**2,235**	938
Total equity	**16,840**	13,602
Total liabilities and equity	**$71,610**	$58,648

(1) See Note 3 for amounts attributable to related parties.
(2) 1 billion shares authorized; 628 million shares and 596 million shares outstanding at December 31, 2016 and 2015, respectively.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Table of Contents

Dominion Resources, Inc.
Consolidated Statements of Equity

	Common Stock		Dominion Shareholders				
(millions)	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Noncontrolling Interests	Total Equity
December 31, 2013	581	$5,783	$ 6,183	$ (324)	$ 11,642	$ —	$11,642
Net income including noncontrolling interests			1,323		1,323	3	1,326
Issuance of Dominion Midstream common units, net of offering costs					—	392	392
Issuance of stock-employee and direct stock purchase plans	3	205			205		205
Stock awards (net of change in unearned compensation)		14			14		14
Other stock issuances(1)	1	14			14		14
Present value of stock purchase contract payments related to RSNs(2)		(143)			(143)		(143)
Dividends			(1,411)(3)		(1,411)		(1,411)
Other comprehensive loss, net of tax				(92)	(92)		(92)
Other		3			3	7	10
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 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 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 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 Midstream common units—net of offering costs					**—**	**482**	**482**
Sale of Dominion Midstream convertible preferred units—net of offering costs					**—**	**490**	**490**
Purchase of Dominion 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(2)		**(191)**			**(191)**		**(191)**
Tax effect of Questar Pipeline contribution to Dominion 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**

(1) Contains shares issued in excess of principal amounts related to converted securities. See Note 17 for further information on convertible securities.
(2) See Note 17 for further information.
(3) Includes subsidiary preferred dividends related to noncontrolling interests of $13 million.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements

Table of Contents

Dominion Resources, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31,	2016	2015	2014
(millions)			
Operating Activities			
Net income including noncontrolling interests	**$ 2,212**	$ 1,923	$ 1,326
Adjustments to reconcile net income including noncontrolling interests to net cash provided by operating activities:			
Depreciation, depletion and amortization (including nuclear fuel)	**1,849**	1,669	1,560
Deferred income taxes and investment tax credits	**725**	854	449
Current income tax for Questar Pipeline contribution to Dominion Midstream	**(212)**	—	—
Gains on the sale of assets and businesses and equity method investment in Iroquois	**(50)**	(123)	(220)
Charges associated with North Anna and offshore wind legislation	**—**	—	374
Charges associated with Liability Management Exercise	**—**	—	284
Charges associated with future ash pond and landfill closure costs	**197**	99	121
Other adjustments	**(108)**	(42)	(113)
Changes in:			
Accounts receivable	**(286)**	294	131
Inventories	**1**	(26)	(43)
Deferred fuel and purchased gas costs, net	**54**	94	(180)
Prepayments	**21**	(25)	24
Accounts payable	**97**	(199)	(202)
Accrued interest, payroll and taxes	**203**	(52)	(41)
Margin deposit assets and liabilities	**(66)**	237	361
Net realized and unrealized changes related to derivative activities	**(335)**	(176)	(38)
Other operating assets and liabilities	**(175)**	(52)	(354)
Net cash provided by operating activities	**4,127**	4,475	3,439
Investing Activities			
Plant construction and other property additions (including nuclear fuel)	**(6,085)**	(5,575)	(5,345)
Acquisition of Dominion Questar, net of cash acquired	**(4,381)**	—	—
Acquisition of solar development projects	**(40)**	(418)	(206)
Acquisition of DCG	**—**	(497)	—
Proceeds from sales of securities	**1,422**	1,340	1,235
Purchases of securities	**(1,504)**	(1,326)	(1,241)
Proceeds from the sale of electric retail energy marketing business	**—**	—	187
Proceeds from Blue Racer	**—**	—	85
Proceeds from assignments of shale development rights	**10**	79	60
Other	**(125)**	(106)	44
Net cash used in investing activities	**(10,703)**	(6,503)	(5,181)
Financing Activities			
Issuance (repayment) of short-term debt, net	**(654)**	734	848
Issuance of short-term notes	**1,200**	600	400
Repayment and repurchase of short-term notes	**(1,800)**	(400)	(400)
Issuance and remarketing of long-term debt	**7,722**	2,962	6,085
Repayment and repurchase of long-term debt, including redemption premiums	**(1,610)**	(892)	(3,993)
Net proceeds from issuance of Dominion Midstream common units	**482**	—	392
Net proceeds from issuance of Dominion Midstream convertible preferred units	**490**	—	—
Proceeds from sale of interest in merchant solar projects	**117**	184	—
Contributions from SunEdison to Four Brothers and Three Cedars	**189**	103	—
Subsidiary preferred stock redemption	**—**	—	(259)
Issuance of common stock	**2,152**	786	205
Common dividend payments	**(1,727)**	(1,536)	(1,398)
Subsidiary preferred dividend payments	**—**	—	(11)
Other	**(331)**	(224)	(125)
Net cash provided by financing activities	**6,230**	2,317	1,744
Increase (decrease) in cash and cash equivalents	**(346)**	289	2
Cash and cash equivalents at beginning of year	**607**	318	316
Cash and cash equivalents at end of year	**$ 261**	$ 607	$ 318
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 905**	$ 843	$ 889
Income taxes	**145**	75	72
Significant noncash investing and financing activities:(1)(2)			
Accrued capital expenditures	**427**	478	315
Dominion Midstream's acquisition of a noncontrolling partnership interest in Iroquois in exchange for issuance of Dominion 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 2016.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Table of Contents

[THIS PAGE INTENTIONALLY LEFT BLANK]

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Virginia Electric and Power Company
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries ("Virginia Power") as of December 31, 2016 and 2015, and 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, 2016. These financial statements are the responsibility of Virginia Power's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Virginia Power is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Virginia Electric and Power Company and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 28, 2017

Table of Contents

Virginia Electric and Power Company
Consolidated Statements of Income

Year Ended December 31,	2016	2015	2014
(millions)			
Operating Revenue(1)	**$7,588**	$7,622	$7,579
Operating Expenses			
Electric fuel and other energy-related purchases(1)	**1,973**	2,320	2,406
Purchased electric capacity	**99**	330	360
Other operations and maintenance:			
Affiliated suppliers	**310**	279	286
Other	**1,547**	1,355	1,630
Depreciation and amortization	**1,025**	953	915
Other taxes	**284**	264	258
Total operating expenses	**5,238**	5,501	5,855
Income from operations	**2,350**	2,121	1,724
Other income	**56**	68	93
Interest and related charges	**461**	443	411
Income from operations before income tax expense	**1,945**	1,746	1,406
Income tax expense	**727**	659	548
Net Income	**1,218**	1,087	858
Preferred dividends(2)	**—**	—	13
Balance available for common stock	**$1,218**	$1,087	$ 845

(1) See Note 24 for amounts attributable to affiliates.
(2) Includes $2 million associated with the write-off of issuance expenses related to the redemption of Virginia Power's preferred stock in 2014. See Note 18 for additional information.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Table of Contents

Virginia Electric and Power Company
Consolidated Statements of Comprehensive Income

Year Ended December 31,	2016	2015	2014
(millions)			
Net income	**$1,218**	$1,087	$858
Other comprehensive income (loss), net of taxes:			
Net deferred losses on derivatives-hedging activities, net of $1, $2 and $2 tax	**(2)**	(1)	(4)
Changes in unrealized net gains (losses) on nuclear decommissioning trust funds, net of $(7), $1 and $(9) tax	**11**	(4)	15
Amounts reclassified to net income:			
Net derivative (gains) losses-hedging activities, net of $—, $— and $2 tax	**1**	1	(3)
Net realized gains on nuclear decommissioning trust funds, net of $2, $4 and $4 tax	**(4)**	(6)	(6)
Other comprehensive income (loss)	**6**	(10)	2
Comprehensive income	**$1,224**	$1,077	$860

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Table of Contents

Virginia Electric and Power Company
Consolidated Balance Sheets

At December 31, (millions)	2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 11**	$ 18
Customer receivables (less allowance for doubtful accounts of $10 and $27)	**892**	822
Other receivables (less allowance for doubtful accounts of $1 at both dates)	**99**	109
Affiliated receivables	**112**	296
Inventories (average cost method):		
Materials and supplies	**525**	502
Fossil fuel	**328**	371
Prepayments(1)	**30**	38
Regulatory assets	**179**	326
Other(1)	**72**	22
Total current assets	**2,248**	2,504
Investments		
Nuclear decommissioning trust funds	**2,106**	1,945
Other	**3**	3
Total investments	**2,109**	1,948
Property, Plant and Equipment		
Property, plant and equipment	**40,030**	37,639
Accumulated depreciation and amortization	**(12,436)**	(11,708)
Total property, plant and equipment, net	**27,594**	25,931
Deferred Charges and Other Assets		
Pension and other postretirement benefit assets(1)	**130**	77
Intangible assets, net	**225**	213
Regulatory assets	**770**	667
Derivative assets(1)	**128**	109
Other	**104**	116
Total deferred charges and other assets	**1,357**	1,182
Total assets	**$ 33,308**	$ 31,565

(1) See Note 24 for amounts attributable to affiliates.

Table of Contents

At December 31, (millions)	2016	2015
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	**$ 678**	$ 476
Short-term debt	**65**	1,656
Accounts payable	**444**	366
Payables to affiliates	**109**	73
Affiliated current borrowings	**262**	376
Accrued interest, payroll and taxes(1)	**239**	190
Asset retirement obligations	**181**	143
Regulatory liabilities	**115**	35
Other(1)	**429**	415
Total current liabilities	**2,522**	3,730
Long-Term Debt	**9,852**	8,892
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**5,103**	4,654
Asset retirement obligations	**1,262**	1,104
Regulatory liabilities	**1,962**	1,929
Pension and other postretirement benefit liabilities(1)	**396**	316
Other	**346**	299
Total deferred credits and other liabilities	**9,069**	8,302
Total liabilities	**21,443**	20,924
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	**4,968**	3,750
Accumulated other comprehensive income	**46**	40
Total common shareholder's equity	**11,865**	10,641
Total liabilities and shareholder's equity	**$33,308**	$31,565

(1) See Note 24 for amounts attributable to affiliates.
(2) 500,000 shares authorized; 274,723 shares outstanding at December 31, 2016 and 2015.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Table of Contents

Virginia Electric and Power Company
Consolidated Statements of Common Shareholder's Equity

	Common Stock					
(millions, except for shares)	Shares (thousands)	Amount	Other Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2013	275	$5,738	$1,113	$2,899	$ 48	$ 9,798
Net income				858		858
Dividends				(603)		(603)
Other comprehensive income, net of tax					2	2
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**

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Table of Contents

Virginia Electric and Power Company
Consolidated Statements of Cash Flows

Year Ended December 31,	2016	2015	2014
(millions)			
Operating Activities			
Net income	**$ 1,218**	$ 1,087	$ 858
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (including nuclear fuel)	**1,210**	1,121	1,090
Deferred income taxes and investment tax credits	**469**	251	396
Charges associated with North Anna and offshore wind legislation	**—**	—	374
Charges associated with future ash pond and landfill closure costs	**197**	99	121
Other adjustments	**(16)**	(27)	(35)
Changes in:			
Accounts receivable	**(65)**	128	(27)
Affiliated accounts receivable and payable	**220**	(314)	23
Inventories	**20**	(20)	(45)
Prepayments	**8**	214	(220)
Deferred fuel expenses, net	**69**	64	(191)
Accounts payable	**25**	(75)	5
Accrued interest, payroll and taxes	**49**	(9)	(19)
Net realized and unrealized changes related to derivative activities	**(153)**	(67)	(37)
Other operating assets and liabilities	**18**	103	(45)
Net cash provided by operating activities	**3,269**	2,555	2,248
Investing Activities			
Plant construction and other property additions	**(2,489)**	(2,474)	(2,911)
Purchases of nuclear fuel	**(153)**	(172)	(196)
Acquisition of solar development projects	**(7)**	(43)	—
Purchases of securities	**(775)**	(651)	(574)
Proceeds from sales of securities	**733**	639	549
Other	**(33)**	(87)	(2)
Net cash used in investing activities	**(2,724)**	(2,788)	(3,134)
Financing Activities			
Issuance (repayment) of short-term debt, net	**(1,591)**	295	519
Issuance (repayment) of affiliated current borrowings, net	**(114)**	(51)	330
Issuance and remarketing of long-term debt	**1,688**	1,112	950
Repayment and repurchase of long-term debt	**(517)**	(625)	(61)
Preferred stock redemption	**—**	—	(259)
Common dividend payments to parent	—	(491)	(590)
Preferred dividend payments	**—**	—	(11)
Other	**(18)**	(4)	7
Net cash provided by (used in) financing activities	**(552)**	236	885
Increase (decrease) in cash and cash equivalents	**(7)**	3	(1)
Cash and cash equivalents at beginning of year	**18**	15	16
Cash and cash equivalents at end of year	**$ 11**	$ 18	$ 15
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 435**	$ 422	$ 383
Income taxes	**79**	517	386
Significant noncash investing activities:			
Accrued capital expenditures	**256**	169	181

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Table of Contents

[THIS PAGE INTENTIONALLY LEFT BLANK]

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Dominion Gas Holdings, LLC
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Dominion Gas Holdings, LLC (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries ("Dominion Gas") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of Dominion Gas' management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Dominion Gas is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Dominion Gas' internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Dominion Gas Holdings, LLC and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 28, 2017

Table of Contents

Dominion Gas Holdings, LLC
Consolidated Statements of Income

Year Ended December 31, (millions)	2016	2015	2014
Operating Revenue(1)	**$1,638**	$1,716	$1,898
Operating Expenses			
Purchased gas(1)	**109**	133	315
Other energy-related purchases(1)	**12**	21	40
Other operations and maintenance:			
Affiliated suppliers	**81**	64	64
Other(1)(2)	**393**	326	274
Depreciation and amortization	**204**	217	197
Other taxes	**170**	166	157
Total operating expenses	**969**	927	1,047
Income from operations	**669**	789	851
Earnings from equity method investee	**21**	23	21
Other income	**11**	1	1
Interest and related charges(1)	**94**	73	27
Income from operations before income tax expense	**607**	740	846
Income tax expense	**215**	283	334
Net Income	**$ 392**	$ 457	$ 512

(1) See Note 24 for amounts attributable to related parties.
(2) Includes a gain on the sale of assets to a related party of $59 million in 2014. See Note 9 for more information.

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

Table of Contents

Dominion Gas Holdings, LLC
Consolidated Statements of Comprehensive Income

Year Ended December 31,	**2016**	2015	2014
(millions)			
Net income	**$392**	$457	$512
Other comprehensive income (loss), net of taxes:			
Net deferred gains (losses) on derivatives-hedging activities, net of $10, $(4) and $19 tax	**(16)**	6	(31)
Changes in unrecognized pension costs, net of $14, $13 and $6 tax	**(20)**	(20)	(10)
Amounts reclassified to net income:			
Net derivative (gains) losses-hedging activities, net of $(6), $3 and $(5) tax	**9**	(3)	8
Net pension and other postretirement benefit costs, net of $(2), $(3) and $(3) tax	**3**	4	5
Other comprehensive loss	**(24)**	(13)	(28)
Comprehensive income	**$368**	$444	$484

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

Table of Contents

Dominion Gas Holdings, LLC
Consolidated Balance Sheets

At December 31, (millions)	2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 23**	$ 13
Customer receivables (less allowance for doubtful accounts of $1 at both dates)(1)	**281**	219
Other receivables (less allowance for doubtful accounts of $1 and $2)(1)	**13**	7
Affiliated receivables	**17**	98
Inventories:		
Materials and supplies	**57**	54
Gas stored	**13**	24
Prepayments(1)	**94**	88
Regulatory assets	**26**	23
Gas imbalances(1)	**37**	17
Other	**21**	23
Total current assets	**582**	566
Investments	**99**	104
Property, Plant and Equipment		
Property, plant and equipment	**10,475**	9,693
Accumulated depreciation and amortization	**(2,851)**	(2,690)
Total property, plant and equipment, net	**7,624**	7,003
Deferred Charges and Other Assets		
Goodwill	**542**	542
Intangible assets, net	**98**	83
Regulatory assets	**577**	449
Pension and other postretirement benefit assets(1)	**1,557**	1,510
Other(1)	**63**	51
Total deferred charges and other assets	**2,837**	2,635
Total assets	**$11,142**	$10,308

(1) See Note 24 for amounts attributable to related parties.

Table of Contents

At December 31,	2016	2015
(millions)		
LIABILITIES AND EQUITY		
Current Liabilities		
Securities due within one year	**$ —**	$ 400
Short-term debt	**460**	391
Accounts payable	**221**	201
Payables to affiliates	**29**	22
Affiliated current borrowings	**118**	95
Accrued interest, payroll and taxes(1)	**225**	183
Regulatory liabilities	**35**	55
Other(1)	**127**	128
Total current liabilities	**1,215**	1,475
Long-Term Debt	**3,528**	2,869
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,438**	2,214
Regulatory liabilities	**219**	201
Other(1)	**206**	231
Total deferred credits and other liabilities	**2,863**	2,646
Total liabilities	**7,606**	6,990
Commitments and Contingencies (see Note 22)		
Equity		
Membership interests	**3,659**	3,417
Accumulated other comprehensive loss	**(123)**	(99)
Total equity	**3,536**	3,318
Total liabilities and equity	**$11,142**	$10,308

(1) See Note 24 for amounts attributable to related parties.

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

Exhibit 6

[Table of Contents](#)

Dominion Gas Holdings, LLC
Consolidated Statements of Equity

(millions)	Membership Interests	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2013	$ 3,485	$ (58)	$3,427
Net income	512		512
Equity contribution from parent	1		1
Distributions	(346)		(346)
Other comprehensive loss, net of tax		(28)	(28)
Balance at December 31, 2014	3,652	(86)	3,566
Net income	457		457
Distributions	(692)		(692)
Other comprehensive loss, net of tax		(13)	(13)
Balance at December 31, 2015	3,417	(99)	3,318
Net income	**392**		**392**
Distributions	**(150)**		**(150)**
Other comprehensive loss, net of tax		**(24)**	**(24)**
Balance at December 31, 2016	**$ 3,659**	**$ (123)**	**$3,536**

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

Table of Contents

Dominion Gas Holdings, LLC
Consolidated Statements of Cash Flows

Year Ended December 31,	2016	2015	2014
(millions)			
Operating Activities			
Net income	**$ 392**	$ 457	$ 512
Adjustments to reconcile net income to net cash provided by operating activities:			
Gains on sales of assets	**(50)**	(123)	(124)
Depreciation and amortization	**204**	217	197
Deferred income taxes and investment tax credits	**238**	163	216
Other adjustments	**(6)**	16	2
Changes in:			
Accounts receivable	**(68)**	115	(42)
Affiliated receivables and payables	**88**	(105)	(5)
Inventories	**8**	(13)	(2)
Prepayments	**(6)**	99	(99)
Accounts payable	**15**	(51)	(35)
Accrued interest, payroll and taxes	**42**	(11)	(15)
Pension and other postretirement benefits	**(141)**	(119)	(112)
Other operating assets and liabilities	**(68)**	(17)	(22)
Net cash provided by operating activities	**648**	628	471
Investing Activities			
Plant construction and other property additions	**(854)**	(795)	(719)
Proceeds from sale of equity method investment in Iroquois	**7**	—	—
Proceeds from sale of assets to affiliate	**—**	—	47
Proceeds from assignments of shale development rights	**10**	79	60
Other	**(18)**	(11)	(4)
Net cash used in investing activities	**(855)**	(727)	(616)
Financing Activities			
Issuance of short-term debt, net	**69**	391	—
Issuance (repayment) of affiliated current borrowings, net	**23**	(289)	(892)
Repayment of long-term debt	**(400)**	—	—
Issuance of long-term debt	**680**	700	1,400
Distribution payments to parent	**(150)**	(692)	(346)
Other	**(5)**	(7)	(16)
Net cash provided by financing activities	**217**	103	146
Increase in cash and cash equivalents	**10**	4	1
Cash and cash equivalents at beginning of year	**13**	9	8
Cash and cash equivalents at end of year	**$ 23**	$ 13	$ 9
Supplemental Cash Flow Information			
Cash paid (received) during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 81**	$ 70	$ 23
Income taxes	**(92)**	98	266
Significant noncash investing and financing activities:			
Accrued capital expenditures	**59**	57	35
Extinguishment of affiliated long-term debt in exchange for assets sold to affiliate	**—**	—	67

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Table of Contents

Combined Notes to Consolidated Financial Statements

NOTE 1. NATURE OF OPERATIONS

Dominion, headquartered in Richmond, Virginia, is one of the nation's largest producers and transporters of energy. Dominion's operations are conducted through various subsidiaries, including Virginia Power and Dominion 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. Dominion 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 Gas' membership interests are held by Dominion. The Dominion Questar Combination was completed in September 2016. See Note 3 for a description of operations acquired in the Dominion Questar Combination.

Dominion'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'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 Midstream launched its initial public offering of 20,125,000 common units representing limited partner interests at a price of $21 per unit. Dominion received $392 million in net proceeds from the sale of the units, after deducting underwriting discounts, structuring fees and estimated offering expenses. At December 31, 2016, Dominion owns the general partner, 50.9% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DCG, Questar Pipeline and a 25.93% noncontrolling partnership interest in Iroquois. The public's ownership interest in Dominion Midstream is reflected as noncontrolling interest in Dominion's Consolidated Financial Statements.

Dominion manages its daily operations through three primary operating segments: DVP, Dominion Generation and Dominion Energy. Dominion 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'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: DVP and Dominion 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 Gas manages its daily operations through one primary operating segment: Dominion Energy. 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 Gas as a result of Dominion'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's merchant solar projects, is reflected as noncontrolling interest in Dominion'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 maintains pension and other postretirement benefit plans. Virginia Power and Dominion Gas participate in certain of these plans. See Note 21 for further information on these plans.

Certain amounts in the 2015 and 2014 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2016 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 are inclusive of Virginia Power and/or Dominion 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 and Virginia Power collect sales, consumption and consumer utility taxes and Dominion Gas collects sales taxes; however, these amounts are excluded from revenue. Dominion's customer receivables at December 31, 2016 and 2015 included $631 million and $462 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, 2016 and 2015 included $349 million and $333 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity delivered but not yet billed to its customers. Dominion Gas' customer receivables at December 31, 2016 and 2015 included $134 million and $98 million, respectively, of accrued unbilled revenue based on estimated amounts of natural gas delivered but not yet billed to its customers.

The primary types of sales and service activities reported as operating revenue for Dominion 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'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 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's and Virginia Power's actual electric fuel and purchased energy expenses and Dominion's and Dominion 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 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 and its subsidiaries, including Virginia Power and Dominion Gas' subsidiaries. In addition, where applicable, combined income tax returns for Dominion and its subsidiaries are filed in various states; otherwise, separate state income tax returns are filed.

Although Dominion 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. Virginia Power and Dominion Gas participate in intercompany tax sharing agreements with Dominion 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 consolidated group members. Otherwise, the net operating loss or credit is carried forward and is recognized as a deferred tax asset until realized.

Effective January 2016, deferred tax liabilities and assets are classified as noncurrent in the Consolidated Balance Sheets. For prior years, the Companies presented deferred taxes in either the current or noncurrent sections of the Consolidated Balance Sheets based on the classification of the related financial accounting assets or liabilities, or, for items such as operating loss carryforwards, the period in which the deferred taxes were expected to reverse.

Accounting for income taxes involves an asset and liability approach. Deferred income tax assets and liabilities are provided,

Table of Contents

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's, Virginia Power's and Dominion Gas' interest and penalties were immaterial in 2016, 2015 and 2014.

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 net of $10 million for state income taxes due to Dominion. Dominion Gas also had an affiliated receivable of $11 million due from Dominion, representing $10 million of federal income taxes and $1 million of state income taxes. The net affiliated receivables are expected to be refunded by Dominion.

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 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.

At December 31, 2015, Virginia Power's Consolidated Balance Sheet included a $296 million affiliated receivable, representing excess federal income tax payments expected to be refunded, $9 million of federal income taxes payable for prior years, less than $1 million of state income taxes payable, $10 million of state income taxes receivable, $14 million of noncurrent state income taxes receivable and $2 million of non-current state income taxes payable. In March 2016, Virginia Power received a $300 million refund of its 2015 income tax payments.

At December 31, 2015, Dominion Gas' Consolidated Balance Sheet included $91 million of affiliated receivables, representing excess federal income tax payments expected to be refunded and the benefit of utilizing a subsidiary's tax loss to offset taxable income in Dominion's consolidated tax return, less than $1 million of state income taxes payable, $4 million of state income taxes receivable and $22 million of noncurrent state income taxes payable. In March 2016, Dominion Gas received a $92 million refund for its 2015 income tax payments and benefit of a subsidiary's tax loss.

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,	2016	2015
(millions)		
Dominion	**$24**	$27
Virginia Power	**11**	11
Dominion Gas	**9**	7

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 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 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.

Table of Contents

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 had margin assets of $82 million and $16 million associated with cash collateral at December 31, 2016 and 2015, respectively. Dominion's margin liabilities associated with cash collateral at December 31, 2016 or 2015 were immaterial. Virginia Power's and Dominion Gas' margin assets and liabilities associated with cash collateral were immaterial at December 31, 2016 and 2015. 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. As part of Dominion's strategy to market energy and manage related risks, it formerly managed a portfolio of commodity-based financial derivative instruments held for trading purposes. Dominion used established policies and procedures to manage the risks associated with price fluctuations in these energy commodities and used various derivative instruments to reduce risk by creating offsetting market positions. In the second quarter of 2013, Dominion commenced a repositioning of its producer services business. The repositioning was completed in the first quarter of 2014 and resulted in the termination of natural gas trading and certain energy marketing activities.

Statement of Income Presentation:

- **Derivatives Held for Trading Purposes:** All income statement activity, including amounts realized upon settlement, is presented in operating revenue on a net basis.
- **Derivatives Not Held for Trading Purposes:** 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, NGLs and other energy-related products. 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 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 as cash flow hedges prior to the formation of Dominion Gas. For the purposes of the Dominion Gas financial statements, the derivative balances, AOCI balance, and any income statement impact related to these interest rate derivative instruments entered into by Dominion have been, and will continue to be, included in the Dominion Gas' Consolidated Financial Statements as the forecasted interest payments related to the debt issuances now occur at Dominion Gas.

Fair Value Hedges-Dominion also uses fair value hedges to mitigate the fixed price exposure inherent in certain firm commodity commitments and commodity inventory. In addition, Dominion 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 2016, 2015 and 2014, Dominion capitalized interest costs and AFUDC to property, plant and equipment of $159 million, $100 million and $80 million, respectively. In 2016, 2015 and

Table of Contents

2014, Virginia Power capitalized AFUDC to property, plant and equipment of $21 million, $30 million and $39 million, respectively. In 2016, 2015 and 2014, Dominion Gas capitalized AFUDC to property, plant and equipment of $8 million, $1 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 2016, 2015 and 2014, Virginia Power recorded $31 million, $19 million and $8 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 Gas natural gas distribution and transmission property, and for certain Dominion 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,	2016	2015	2014
(percent)			
Dominion			
Generation	**2.83**	2.78	2.66
Transmission	**2.47**	2.42	2.38
Distribution	**3.02**	3.11	3.12
Storage	**2.29**	2.42	2.39
Gas gathering and processing	**2.66**	3.19	2.81
General and other	**4.12**	3.67	3.62
Virginia Power			
Generation	**2.83**	2.78	2.66
Transmission	**2.36**	2.33	2.34
Distribution	**3.32**	3.33	3.34
General and other	**3.49**	3.40	3.29
Dominion Gas			
Transmission	**2.43**	2.46	2.40
Distribution	**2.55**	2.45	2.47
Storage	**2.19**	2.44	2.40
Gas gathering and processing	**2.58**	3.20	2.82
General and other	**4.54**	4.72	5.77

In 2014, Virginia Power made a one-time adjustment to depreciation expense as ordered by the Virginia Commission. This adjustment resulted in an increase of $38 million ($23 million after-tax) in depreciation and amortization expense in Virginia Power's Consolidated Statements of Income.

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 $2.08 per mcfe in 2016.

Dominion'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	**15-36 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 Gas' nonutility property, plant and equipment and exploration and production properties was immaterial for the years ended December 31, 2016, 2015 and 2014, except for Dominion 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 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. See Note 6 for a discussion of impairments related to certain long-lived assets.

Regulatory Assets and Liabilities

The accounting for Dominion's and Dominion 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. Periodically, the Companies evaluate the key assumptions underlying their AROs including estimates of the amounts and timing of future cash flows associated with retirement activities. AROs are adjusted when significant changes in these assumptions are identified. Dominion and Dominion 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 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. Effective January 2016, deferred debt issuance costs were recorded as a reduction in long-term debt in the Consolidated Balance Sheets. Such costs had previously been recorded as an asset in other current assets and other deferred charges and other assets 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 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 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'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'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 and Virginia Power do not have the ability to exercise significant influence over the investee. Dominion's and Virginia Power's investments are included in other investments and nuclear decommissioning trust funds.

OTHER-THAN-TEMPORARY IMPAIRMENT

Dominion and Virginia Power 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.

Table of Contents

- *Debt Securities*—Using information obtained from their nuclear decommissioning trust fixed-income investment managers, Dominion 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 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'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 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 $13 million and $24 million at December 31, 2016 and December 31, 2015, respectively. Based on the average price of gas purchased during 2016 and 2015, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by $55 million and $109 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 and Dominion 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 from other parties are reported in other current assets and imbalances that Dominion and Dominion Gas owe to other parties are reported in other current liabilities in the Consolidated Balance Sheets.

Goodwill

Dominion and Dominion 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 preliminary evaluations of the impact of this guidance and, pending evaluation of the items discussed below, expect no significant impact on their results of operations. Now that their preliminary evaluations are complete, the Companies will expand the scope of their assessment to include all contracts with customers. In addition, the Companies are considering certain issues that could potentially change the accounting for certain transactions. Among the issues being considered are accounting for contributions in aid of construction, recognition of revenue when collectability is in question, recognition of revenue in contracts with variable consideration, accounting for alternative revenue programs, and the capitalization of costs to acquire new contracts. The Companies plan on applying 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. Most notably the update revises the accounting for equity securities, except for those accounted for under the equity method of accounting or resulting in consolidation, by requiring equity securities to be measured at fair value with the changes in fair value recognized in net income. However, an entity may measure equity investments that do not have a readily determinable fair value at cost minus impairment, if any, plus changes from observable price changes in orderly transactions for the identical or a similar investment of the same issuer. The guidance also simplifies the impairment assessment of equity investments without readily determinable fair values, revises the presentation of financial assets and liabilities and amends certain disclosure requirements associated with the fair value of financial instruments. The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2018, with a cumulative-effect adjustment to the balance sheet. Amendments related to equity securities without readily determinable fair values are to be applied prospectively to such investments that exist as of the date of adoption.

Net realized and unrealized gains and losses (including any other-than-temporary impairments) on equity securities subject to cost-based regulation will not be impacted by the adoption of this standard. For all other available for sale equity securities, unrealized gains and losses currently recorded through other comprehensive income will be recognized in net income upon the adoption of this standard.

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 are currently in the preliminary stages of evaluating the impact of this guidance on their financial position and plan to complete their initial assessment in 2017. The Companies expect to elect the practical expedients, which would require no reassessment of whether existing contracts are or contain leases as well as no reassessment of lease classification for existing leases. While the Companies cannot quantify the impact until their assessment is complete, the Companies believe the adoption could have a material impact to the Companies' financial position.

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 Dominion's interim and annual reporting periods beginning January 1, 2018, and Dominion may elect to apply the update under the full retrospective method or the modified retrospective method. Dominion is currently evaluating the impacts of the revised accounting guidance on its consolidated financial statements and disclosures.

NOTE 3. ACQUISITIONS AND DISPOSITIONS

DOMINION

ACQUISITION OF DOMINION QUESTAR

In September 2016, Dominion completed the Dominion Questar Combination and Dominion Questar became a wholly-owned subsidiary of Dominion. Dominion Questar, a Rockies-based integrated natural gas company, included Questar Gas, Wexpro and 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. Questar Pipeline provides FERC-regulated interstate natural gas transportation and storage services in Utah, Wyoming and western Colorado. The Dominion Questar Combination provides Dominion with pipeline infrastructure that provides a principal source of gas supply to Western states. Dominion Questar's regulated businesses also provide further balance between Dominion's electric and gas operations.

In accordance with the terms of the Dominion Questar Combination, at closing, each share of issued and outstanding Dominion 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 Questar outstanding at closing.

Dominion financed the Dominion 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 Questar's assets acquired and liabilities assumed were measured at estimated fair value at the closing date and are included in the Dominion Energy 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 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 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 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'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.

Table of Contents

The table below shows the preliminary allocation of the purchase price to the assets acquired and liabilities assumed at closing. The allocation is subject to change during the remainder of the measurement period, which ends one year from the closing date, as additional information is obtained about the facts and circumstances that existed at the closing date. Any material adjustments to provisional amounts identified during the measurement period will be recognized and disclosed in the reporting period in which the adjustment amounts are determined. During the fourth quarter, 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 relate primarily to the sale of Questar Fueling Company in December 2016 as further described in the *Sale of Questar Fueling Company.*

(millions)	Amount
Total current assets	**$ 224**
Investments(1)	**58**
Property, plant and equipment(2)	**4,131**
Goodwill	**3,105**
Total deferred charges and other assets, excluding goodwill	**75**
Total Assets	**7,593**
Total current liabilities(3)	**793**
Long-term debt(4)	**963**
Deferred income taxes	**801**
Regulatory liabilities	**259**
Asset retirement obligations	**160**
Other deferred credits and other liabilities	**220**
Total Liabilities	**3,196**
Total estimated 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, 2016, as well as a $250 million term loan which matures in August 2017 and bears interest at a variable rate.
(4) Unsecured senior and medium-term notes have 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 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 Questar Combination under the Hart-Scott-Rodino Act. In May 2016, Dominion Questar's shareholders voted to approve the Dominion 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 Public Utilities Commission, who acknowledged the Dominion Questar Combination in October 2016, and directed Dominion Questar to notify the Idaho Public Utilities Commission when it makes filings with the Utah Commission.

With the approval of the Dominion Questar Combination in Utah and Wyoming, Dominion agreed to the following:

- Contribution of $75 million to Dominion 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 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 Questar Combination on Dominion's operating revenue and net income attributable to Dominion 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 incurred transaction and transition costs, of which $58 million was recorded in other operations and maintenance expense for the twelve months ended December 31, 2016, and $16 million was recorded in interest and related charges for the twelve months ended December 31, 2016, in Dominion'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 assuming the Dominion 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,	
(millions, except EPS)	**2016(1)**	2015
Operating Revenue	**$ 12,497**	$ 12,818
Net Income	**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 Questar Combination.

Contribution of Questar Pipeline to Dominion Midstream

In October 2016, Dominion entered into the Contribution Agreement under which Dominion contributed Questar Pipeline to Dominion Midstream. Upon closing of the agreement on December 1, 2016, Dominion Midstream became the owner of all of the issued and outstanding membership interests of Questar Pipeline in exchange for consideration consisting of Dominion 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 Midstream repurchased 6,656,839 common units from Dominion, and repaid its $301 million promissory note to Dominion 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 consolidates Dominion 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 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's Consolidated Statements of Income, as the sale resulted in measurement period adjustments to the net assets acquired of Dominion Questar. See the *Purchase Price Allocation* section above for additional details on the measurement period adjustments recorded.

WHOLLY-OWNED MERCHANT SOLAR PROJECTS

Acquisitions
The following table presents significant completed acquisitions of wholly-owned merchant solar projects by Dominion. Long-term power purchase, interconnection and operation and maintenance agreements have been executed for all of the projects. Dominion has claimed federal investment tax credits on the projects. These projects are included in the Dominion Generation operating segment.

Completed Acquisition Date	Seller	Number of Projects	Project Location	Project Name(s)	Initial Acquisition Cost (millions)(1)	Project Cost (millions)(2)	Date of Commercial Operations	MW Capacity
March 2014	Recurrent Energy Development Holdings, LLC	6	California	Camelot, Kansas, Kent South, Old River One, Adams East, Columbia 2	$ 50	$ 428	Fourth quarter 2014	139
November 2014	CSI Project Holdco, LLC	1	California	West Antelope	79	79	November 2014	20
December 2014	EDF Renewable Development, Inc.	1	California	CID	71	71	January 2015	20
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, Inc.	1	Virginia	Amazon Solar Farm U.S. East	34	212	October 2016	80

(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.

In addition during 2016, Dominion 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 are expected to cost approximately $425 million in total once constructed, including initial acquisition costs, and to generate approximately 221 MW combined. One of the projects commenced commercial operations in 2016 and the remaining projects are expected to begin commercial operations in 2017.

In August 2016, Dominion entered into an agreement to acquire 100% of the equity interests of two solar projects in California from Solar Frontier Americas Holding LLC for approximately $128 million in cash. The acquisition is expected to close prior to both projects commencing operations, which is expected by the end of 2017. The projects are expected to cost approximately $130 million once constructed, including the initial acquisition cost, and to generate approximately 50 MW combined.

In September 2016, Dominion entered into an agreement to acquire 100% of the equity interests of a solar project in Virginia from Community Energy Solar, LLC. The acquisition is expected to close during the first quarter of 2017, prior to the project commencing operations by the end of 2017, for an amount to be determined based on the costs incurred through closing. The project is expected to cost approximately $210 million once constructed, including the initial acquisition cost, and to generate approximately 100 MW.

In January 2017, Dominion entered into an agreement to acquire 100% of the equity interests of a solar project in North Carolina from Cypress Creek Renewables, LLC for $154 million in cash. The acquisition is expected to close during the second quarter of 2017, prior to the project commencing commercial operations, which is expected by the end of the third quarter of 2017. The project is expected to cost $160 million once constructed, including the initial acquisition cost, and to generate approximately 79 MW.

Table of Contents

Sale of Interest in Merchant Solar Projects
In September 2015, Dominion 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 projects discussed 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's remaining 67% ownership in the projects upon the occurrence of certain events, none of which are expected to occur in 2017.

NON-WHOLLY-OWNED MERCHANT SOLAR PROJECTS

Acquisitions of Four Brothers and Three Cedars
In June 2015, Dominion 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 has no remaining obligation related to this payable as of 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 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. As of

December 31, 2016, a $2 million payable is included in other current liabilities in Dominion's Consolidated Balance Sheets. 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 will claim 99% of the federal investment tax credits on the projects.

Dominion 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 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 Dominion Generation operating segment.

Dominion 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, 2016 and 2015. Subsequent to Dominion's acquisition of Four Brothers and Three Cedars, SunEdison made contributions to Four Brothers and Three Cedars of $292 million in aggregate through December 31, 2016, which are reflected as noncontrolling interests in the Consolidated Balance Sheets.

In November 2016, NRG acquired the 50% of units in Four Brothers and Three Cedars previously held by SunEdison.

DOMINION MIDSTREAM ACQUISITION OF INTEREST IN IROQUOIS
In September 2015, Dominion 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 Midstream issued 8.6 million common units representing limited partnership interests in Dominion 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 Midstream's common units at closing. These common units are reflected as noncontrolling interest in Dominion's Consolidated Financial Statements. Dominion Midstream's noncontrolling partnership interest is reflected in the Dominion Energy operating segment. In addition to this acquisition, Dominion Gas currently holds a 24.07% noncontrolling partnership interest in Iroquois. Dominion Midstream and Dominion 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 DCG
In January 2015, Dominion completed the acquisition of 100% of the equity interests of DCG from SCANA Corporation for $497 million in cash, as adjusted for working capital. DCG owns and operates nearly 1,500 miles of FERC-regulated interstate natural gas pipeline in South Carolina and southeastern Georgia. This acquisition supports Dominion'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's regulated gas position, economic value attributable to future expansion projects as well as increased opportunities for synergies. The acquired assets of DCG are included in the Dominion Energy operating segment.

On March 24, 2015, DCG converted to a limited liability company under the laws of South Carolina and changed its name from Carolina Gas Transmission Corporation to DCG. On April 1, 2015, Dominion contributed 100% of the issued and outstanding membership interests of DCG to Dominion Midstream in exchange for total consideration of $501 million, as adjusted for working capital. Total consideration to Dominion consisted of the issuance of a two-year, $301 million senior unsecured promissory note payable by Dominion 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 Midstream. The number of units was based on the volume weighted average trading price of Dominion Midstream's common units for the ten trading days prior to April 1, 2015, or $39.12 per unit. Since Dominion consolidates Dominion Midstream for financial reporting purposes, this transaction was eliminated upon consolidation and did not impact Dominion's financial position or cash flows.

SALE OF ELECTRIC RETAIL ENERGY MARKETING BUSINESS

In March 2014, Dominion completed the sale of its electric retail energy marketing business. The proceeds were $187 million, net of transaction costs. The sale resulted in a gain, subject to post-closing adjustments, of $100 million ($57 million after-tax) net of a $31 million write-off of goodwill, and is included in other operations and maintenance expense in Dominion's Consolidated Statements of Income. The sale of the electric retail energy marketing business did not qualify for discontinued operations classification.

Virginia Power

ACQUISITION OF SOLAR PROJECT

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 Virginia Power Generation operating segment.

Dominion and Dominion Gas

BLUE RACER

See Note 9 for a discussion of transactions related to Blue Racer.

ASSIGNMENTS OF SHALE DEVELOPMENT RIGHTS

See Note 10 for a discussion of assignments of shale development rights.

NOTE 4. OPERATING REVENUE

The Companies' operating revenue consists of the following:

Year Ended December 31,	2016	2015	2014
(millions)			
Dominion			
Electric sales:			
Regulated	**$ 7,348**	$ 7,482	$ 7,460
Nonregulated	**1,519**	1,488	1,839
Gas sales:			
Regulated	**500**	218	334
Nonregulated	**354**	471	751
Gas transportation and storage	**1,636**	1,616	1,543
Other	**380**	408	509
Total operating revenue	**$11,737**	$11,683	$12,436
Virginia Power			
Regulated electric sales	**$ 7,348**	$ 7,482	$ 7,460
Other	**240**	140	119
Total operating revenue	**$ 7,588**	$ 7,622	$ 7,579
Dominion Gas			
Gas sales:			
Regulated	**$ 119**	$ 122	$ 209
Nonregulated	**13**	10	26
Gas transportation and storage	**1,307**	1,366	1,353
NGL revenue	**62**	93	212
Other	**137**	125	98
Total operating revenue	**$ 1,638**	$ 1,716	$ 1,898

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.

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, and a phasing down of the allowance to 40% in 2018 and 30% in 2019 and expiration thereafter. In addition, the legislation extends 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.

Table of Contents

Continuing Operations

Details of income tax expense for continuing operations including noncontrolling interests were as follows:

	Dominion			Virginia Power			Dominion Gas		
Year Ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
(millions)									
Current:									
Federal	**$ (155)**	$ (24)	$ (11)	**$168**	$316	$ 85	**$(27)**	$ 90	$ 86
State	**85**	75	14	**90**	92	67	**4**	30	32
Total current expense (benefit)	**(70)**	51	3	**258**	408	152	**(23)**	120	118
Deferred:									
Federal									
Taxes before operating loss carryforwards and investment tax credits	**1,050**	384	956	**435**	154	381	**239**	156	192
Tax utilization (benefit) of operating loss carryforwards	**(161)**	539	(352)	**(2)**	96	—	**(2)**	6	—
Investment tax credits	**(248)**	(134)	(152)	**(25)**	(11)	—	**—**	—	—
State	**50**	66	(2)	**27**	13	16	**1**	1	24
Total deferred expense	**691**	855	450	**435**	252	397	**238**	163	216
Investment tax credit—gross deferral	**35**	—	—	**35**	—	—	**—**	—	—
Investment tax credit—amortization	**(1)**	(1)	(1)	**(1)**	(1)	(1)	**—**	—	—
Total income tax expense	**$ 655**	$ 905	$ 452	**$727**	$659	$548	**$215**	$283	$334

In 2016, Dominion realized a taxable gain resulting from the contribution of Questar Pipeline to Dominion Midstream. The contribution and related transactions resulted in increases in the tax basis of Questar Pipeline's assets and the number of Dominion 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, are reflected in Dominion's current federal income tax expense.

In 2015, Dominion'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			Virginia Power			Dominion Gas		
Year Ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
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	**2.4**	3.7	—	**3.8**	3.9	3.8	**0.5**	2.7	4.4
Investment tax credits	**(11.7)**	(4.7)	(8.6)	**—**	(0.6)	—	**—**	—	—
Production tax credits	**(0.8)**	(0.8)	(1.2)	**(0.5)**	(0.6)	(0.6)	**—**	—	—
Valuation allowances	**1.2**	(0.3)	0.7	**0.1**	—	—	**—**	—	—
AFUDC—equity	**(0.6)**	(0.3)	—	**(0.6)**	(0.6)	—	**(0.2)**	0.2	—
Legislative change	**(0.6)**	(0.1)	—	**—**	—	—	**—**	—	—
Employee stock ownership plan deduction	**(0.6)**	(0.6)	(0.9)	**—**	—	—	**—**	—	—
Other, net	**(1.4)**	0.1	0.4	**(0.4)**	0.6	0.8	**0.1**	0.3	0.1
Effective tax rate	**22.9%**	32.0%	25.4%	**37.4%**	37.7%	39.0%	**35.4%**	38.2%	39.5%

In 2016, Dominion's effective tax rate reflects a valuation allowance on a state credit not expected to be utilized by a Dominion subsidiary which files a separate state return.

Table of Contents

The Companies' deferred income taxes consist of the following:

	Dominion		Virginia Power		Dominion Gas	
At December 31,	**2016**	2015	**2016**	2015	**2016**	2015
(millions)						
Deferred income taxes:						
Total deferred income tax assets	**$ 1,827**	$ 1,152	**$ 268**	$ 164	**$ 126**	$ 129
Total deferred income tax liabilities	**10,381**	8,552	**5,323**	4,805	**2,564**	2,343
Total net deferred income tax liabilities	**$ 8,554**	$ 7,400	**$5,055**	$4,641	**$2,438**	$2,214
Total deferred income taxes:						
Plant and equipment, primarily depreciation method and basis differences	**$ 7,782**	$ 6,299	**$4,604**	$4,133	**$1,726**	$1,541
Nuclear decommissioning	**1,240**	1,158	**406**	378	**—**	—
Deferred state income taxes	**747**	646	**321**	302	**204**	205
Federal benefit of deferred state income taxes	**(261)**	(226)	**(112)**	(106)	**(71)**	(72)
Deferred fuel, purchased energy and gas costs	**(25)**	(1)	**(29)**	(3)	**4**	1
Pension benefits	**155**	291	**(138)**	(99)	**646**	613
Other postretirement benefits	**(68)**	(15)	**49**	30	**(6)**	(7)
Loss and credit carryforwards	**(1,547)**	(1,004)	**(88)**	(53)	**(5)**	(4)
Valuation allowances	**135**	73	**3**	—	**—**	—
Partnership basis differences	**688**	367	**—**	—	**43**	41
Other	**(292)**	(188)	**39**	59	**(103)**	(104)
Total net deferred income tax liabilities	**$ 8,554**	$ 7,400	**$5,055**	$4,641	**$2,438**	$2,214
Deferred Investment Tax Credits – Regulated Operations	**48**	14	**48**	13	**—**	—
Total Deferred Taxes and Deferred Investment Tax Credits	**$ 8,602**	$ 7,414	**$5,103**	$4,654	**$2,438**	$2,214

At December 31, 2016, Dominion had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	**$ 1,060**	**$ 358**	**$ —**	**2031-2036**
Federal investment credits	**—**	**708**	**—**	**2033-2036**
Federal production credits	**—**	**102**	**—**	**2031-2036**
Other federal credits	**—**	**48**	**—**	**2031-2036**
State losses	**1,383**	**102**	**(59)**	**2018-2034**
State minimum tax credits	**—**	**135**	**—**	**No expiration**
State investment and other credits	**—**	**94**	**(76)**	**2017-2027**
Total		**$1,547**	**$ (135)**	

At December 31, 2016, Virginia Power had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	**$ 12**	**$ 3**	**$ —**	**2031-2034**
Federal investment credits	**—**	**40**	**—**	**2034-2036**
Federal production and other credits	**—**	**35**	**—**	**2031-2036**
State investment credits	**—**	**10**	**(3)**	**2018-2024**
Total		**$ 88**	**$ (3)**	

At December 31, 2016, Dominion Gas had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	**$ 14**	**$ 4**	**$ —**	**2031-2036**
Other federal credits	**—**	**1**	**—**	**2032-2035**
Total		**$ 5**	**$ —**	

A reconciliation of changes in the Companies' unrecognized tax benefits follows:

	Dominion			Virginia Power			Dominion Gas		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
(millions)									
Balance at January 1	**$103**	$145	$222	**$12**	$ 36	$ 39	**$ 29**	$29	$29
Increases-prior period positions	**9**	2	24	**4**	—	2	**1**	—	—
Decreases-prior period positions	**(44)**	(40)	(26)	**(3)**	(25)	(16)	**(19)**	—	—
Increases-current period positions	**6**	8	16	**—**	1	11	**—**	—	—
Settlements with tax authorities	**(8)**	(5)	—	**—**	—	—	**(4)**	—	—
Expiration of statutes of limitations	**(2)**	(7)	(91)	**—**	—	—	**—**	—	—
Balance at December 31	**$ 64**	$103	$145	**$13**	$ 12	$ 36	**$ 7**	$29	$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 and its subsidiaries, these unrecognized tax benefits were $45 million, $69 million and $77 million at December 31, 2016, 2015 and 2014, respectively. For Dominion, the change in these unrecognized tax benefits decreased income tax expense by $18 million, $6 million and $47 million in 2016, 2015 and 2014, respectively. For Virginia Power, these unrecognized tax benefits were $9 million at December 31, 2016 and $8 million at December 31, 2015 and 2014. For Virginia Power, the change in these unrecognized tax benefits increased income tax expense by $1 million in 2016 and affected income tax expense by less than $1 million in 2015 and 2014. For Dominion Gas, these unrecognized tax benefits were $5 million at December 31, 2016 and $19 million at December 31, 2015 and 2014. For Dominion Gas, the change in these unrecognized tax benefits decreased income tax expense by $11 million in 2016 and affected income tax expense by less than $1 million in 2015 and 2014.

Table of Contents

Effective for its 2014 tax year, Dominion was accepted into the CAP. Through the CAP, Dominion has 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. The IRS has completed its audit of tax years 2013, 2014 and 2015, for which the statute of limitations has not yet expired. Although Dominion has not received a final letter indicating no changes to its taxable income for tax year 2015, no adjustments are expected. The IRS examination of tax year 2016 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 2017 by up to $25 million for Dominion, $3 million for Virginia Power and $7 million for Dominion 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 $20 million for Dominion, $3 million for Virginia Power and $5 million for Dominion Gas.

Otherwise, with regard to 2016 and prior years, Dominion, Virginia Power and Dominion Gas cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2017.

For each of the major states in which Dominion operates, the earliest tax year remaining open for examination is as follows:

State	Earliest Open Tax Year
Pennsylvania(1)	2012
Connecticut	2013
Virginia(2)	2013
West Virginia(1)	2013
New York(1)	2007

(1) Considered a major state for Dominion 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 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 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's rabbi, 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 Gas applies fair value measurements to certain assets and liabilities including commodity, interest rate, and foreign currency derivative instruments and investments 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'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.

Table of Contents

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, Dominion 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 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 and Virginia Power, benefit plan trust funds for Dominion and Dominion Gas, and rabbi trust funds for Dominion.
- 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 and Virginia Power, benefit plan trust funds for Dominion and Dominion Gas and rabbi trust funds for Dominion.
- 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.

Table of Contents

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, forward market prices, credit spreads 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's quantitative information about Level 3 fair value measurements at December 31, 2016. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility and credit spreads.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets:					
Physical and Financial Forwards and Futures:					
Natural Gas(2)	$ 70	Discounted Cash Flow	Market Price (per Dth)(4)	(2) - 12	—
			Credit Spreads(5)	1% - 4%	2%
FTRs	7	Discounted Cash Flow	Market Price (per MWh)(4)	(9) - 7	1
Physical and Financial Options:					
Natural Gas	3	Option Model	Market Price (per Dth)(4)	2 - 7	3
			Price Volatility(6)	18% - 50%	24%
Electricity	67	Option Model	Market Price (per MWh)(4)	21 - 55	34
			Price Volatility(6)	14% - 104%	31%
Total assets	$ 147				
Liabilities:					
Physical and Financial Forwards and Futures:					
Natural Gas(2)	$ 2	Discounted Cash Flow	Market Price (per Dth)(4)	(2) - 4	4
Liquids(3)	3	Discounted Cash Flow	Market Price (per Gal)(4)	0 - 2	1
FTRs	3	Discounted Cash Flow	Market Price (per MWh)(4)	(9) - 3	—
Total liabilities	$ 8				

(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 credit spreads unrepresented in published markets.
(6) 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)
Credit Spread	Asset	Increase (decrease)	Loss (gain)

Nonrecurring Fair Value Measurements

DOMINION GAS

Natural Gas Assets

In the fourth quarter of 2014, Dominion Gas recorded an impairment charge of $9 million ($6 million after-tax) in other operations and maintenance expense in its Consolidated Statements of Income, to write off previously capitalized costs following the cancellation of a development project.

Table of Contents

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's and Dominion Gas' pension and other postretirement benefit plans are presented in Note 21.

DOMINION

The following table presents Dominion'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
At 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**
At December 31, 2015				
Assets:				
Derivatives:				
Commodity	$ 1	$ 249	$114	$ 364
Interest rate	—	24	—	24
Investments(1):				
Equity securities:				
U.S.	2,625	—	—	2,625
Fixed Income:				
Corporate debt instruments	—	439	—	439
Government securities	458	574	—	1,032
Cash equivalents and other	2	2	—	4
Total assets	$3,086	$1,288	$114	$4,488
Liabilities:				
Derivatives:				
Commodity	$ —	$ 141	$ 19	$ 160
Interest rate	—	183	—	183
Total liabilities	$ —	$ 324	$ 19	$ 343

(1) Includes investments held in the nuclear decommissioning and rabbi trusts. Excludes $89 million and $101 million of assets at December 31, 2016 and 2015, 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's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	2016	2015	2014
Balance at January 1,	**$ 95**	$107	$ (16)
Total realized and unrealized gains (losses):			
Included in earnings	**(35)**	(5)	97
Included in other comprehensive income (loss)	**—**	(9)	7
Included in regulatory assets/liabilities	**(39)**	(4)	109
Settlements	**38**	9	(88)
Purchases	**87**	—	—
Transfers out of Level 3	**(7)**	(3)	(2)
Balance at December 31,	**$139**	$ 95	$107
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	**$ (1)**	$ 2	$ 6

The following table presents Dominion'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, 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
Year Ended December 31, 2014				
Total gains (losses) included in earnings	$ 4	$ 97	$ (4)	$ 97
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	4	1	1	6

Table of Contents

VIRGINIA POWER

The following table presents Virginia Power's quantitative information about Level 3 fair value measurements at December 31, 2016. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility and credit spreads.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets:					
Physical and Financial Forwards and Futures:					
Natural gas(2)	**$ 68**	Discounted Cash Flow	Market Price (per Dth)(3)	(2) - 7	—
			Credit Spreads(4)	1% - 4%	2%
FTRs	**7**	Discounted Cash Flow	Market Price (per MWh)(3)	(9) - 7	1
Physical and Financial Options:					
Natural Gas	**3**	Option Model	Market Price (per Dth)(3)	2 - 7	3
			Price Volatility(5)	18% - 34%	24%
Electricity	**67**	Option Model	Market Price (per MWh)(3)	21 - 55	34
			Price Volatility(5)	14% - 104%	31%
Total assets	**$ 145**				
Liabilities:					
Physical and Financial Forwards and Futures:					
FTRs	**$ 2**	Discounted Cash Flow	Market Price (per MWh)(3)	(9) - 3	—
Total liabilities	**$ 2**				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Represents market prices beyond defined terms for Levels 1 and 2.
(4) Represents credit spreads unrepresented in published markets.
(5) Represents volatilities unrepresented in published markets.

Table of Contents

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)
Credit Spread	Asset	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
At 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**
At December 31, 2015				
Assets:				
Derivatives:				
Commodity	$ —	$ 13	$101	$ 114
Interest rate	—	13	—	13
Investments(1):				
Equity securities:				
U.S.	1,163	—	—	1,163
Fixed Income:				
Corporate debt instruments	—	238	—	238
Government Securities	180	254	—	434
Total assets	$1,343	$518	$101	$1,962
Liabilities:				
Derivatives:				
Commodity	$ —	$ 19	$ 8	$ 27
Interest rate	—	59	—	59
Total liabilities	$ —	$ 78	$ 8	$ 86

(1) Includes investments held in the nuclear decommissioning trust. Excludes $26 million and $34 million of assets at December 31, 2016 and 2015, 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)	2016	2015	2014
Balance at January 1,	**$ 93**	$102	$ (7)
Total realized and unrealized gains (losses):			
Included in earnings	**(35)**	(13)	96
Included in regulatory assets/liabilities	**(37)**	(5)	109
Settlements	**35**	13	(96)
Purchases	**87**	—	—
Transfers out of Level 3	**—**	(4)	—
Balance at December 31,	**$143**	$ 93	$102

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, 2016, 2015 and 2014. 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, 2016, 2015 and 2014.

DOMINION GAS

The following table presents Dominion Gas' quantitative information about Level 3 fair value measurements at December 31, 2016. 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:					
Physical and Financial Forwards and Futures:					
NGLs	**$ 2**	Discounted Cash Flow	Market Price (per Gal)(2)	0 - 2	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)

Table of Contents

The following table presents Dominion Gas' assets and liabilities for commodity, interest rate, 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)				
At December 31, 2016				
Liabilities:				
Commodity	**$ —**	**$ 3**	**$ 2**	**5**
Foreign currency	**—**	**6**	**—**	**6**
Total liabilities	**$ —**	**$ 9**	**$ 2**	**$11**
At December 31, 2015				
Assets:				
Commodity	$ —	$ 5	$ 6	$11
Total assets	$ —	$ 5	$ 6	$11
Liabilities:				
Interest rate	$ —	$ 14	$ —	14
Total liabilities	$ —	$ 14	$ —	$14

The following table presents the net change in Dominion Gas' derivative assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

	2016	2015	2014
(millions)			
Balance at January 1,	**$ 6**	$ 2	$ (6)
Total realized and unrealized gains (losses):			
Included in earnings	**—**	1	2
Included in other comprehensive income (loss)	**—**	(5)	10
Settlements	**—**	(1)	(4)
Transfers out of Level 3	**(8)**	9	—
Balance at December 31,	**$ (2)**	$ 6	$ 2

The gains and losses included in earnings in the Level 3 fair value category were classified in operating revenue in Dominion Gas' Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014. 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, 2016, 2015 and 2014.

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:

At December 31,	2016		2015	
	Carrying Amount	**Estimated Fair Value(1)**	Carrying Amount	Estimated Fair Value(1)
(millions)				
Dominion				
Long-term debt, including securities due within one year(2)	**$26,587**	**$ 28,273**	$21,873	$ 23,210
Junior subordinated notes(3)	**2,980**	**2,893**	1,340	1,192
Remarketable subordinated notes(3)	**2,373**	**2,418**	2,080	2,129
Virginia Power				
Long-term debt, including securities due within one year(3)	**$10,530**	**$ 11,584**	$ 9,368	$ 10,400
Dominion Gas				
Long-term debt, including securities due within one year(4)	**$ 3,528**	**$ 3,603**	$ 3,269	$ 3,299

(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, 2016, and 2015, includes the valuation of certain fair value hedges associated with Dominion's fixed rate debt of $(1) million and $7 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.

Table of Contents

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'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 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.

Table of Contents

DOMINION

Balance Sheet Presentation

The tables below present Dominion's derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2016			December 31, 2015		
(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	$ 211	$ —	$ 211	$ 217	$ —	$ 217
Exchange	44	—	44	138	—	138
Interest rate contracts:						
Over-the-counter	17	—	17	24	—	24
Total derivatives, subject to a master netting or similar arrangement	272	—	272	379	—	379
Total derivatives, not subject to a master netting or similar arrangement	7	—	7	9	—	9
Total	$ 279	$ —	$ 279	$ 388	$ —	$ 388

	December 31, 2016				December 31, 2015			
		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	$ 211	$ 14	$ —	$ 197	$ 217	$ 37	$ —	$ 180
Exchange	44	44	—	—	138	82	—	56
Interest rate contracts:								
Over-the-counter	17	9	—	8	24	22	—	2
Total	$ 272	$ 67	$ —	$ 205	$ 379	$ 141	$ —	$ 238

	December 31, 2016			December 31, 2015		
(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	$ 23	$ —	$ 23	$ 70	$ —	$ 70
Exchange	71	—	71	82	—	82
Interest rate contracts:						
Over-the-counter	53	—	53	183	—	183
Foreign currency contracts:						
Over-the-counter	6	—	6	—	—	—
Total derivatives, subject to a master netting or similar arrangement	153	—	153	335	—	335
Total derivatives, not subject to a master netting or similar arrangement	2	—	2	8	—	8
Total	$ 155	$ —	$ 155	$ 343	$ —	$ 343

Table of Contents

(millions)	December 31, 2016 Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Gross Amounts Not Offset in the Consolidated Balance Sheet: Financial Instruments	Cash Collateral Paid	Net Amounts	December 31, 2015 Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Gross Amounts Not Offset in the Consolidated Balance Sheet: Financial Instruments	Cash Collateral Paid	Net Amounts
Commodity contracts:								
Over-the-counter	$ 23	$ 14	$ —	$ 9	$ 70	$ 37	$ —	$ 33
Exchange	71	44	27	—	82	82	—	—
Interest rate contracts:								
Over-the-counter	53	9	—	44	183	22	—	161
Foreign currency contracts:								
Over-the-counter	6	—	—	6	—	—	—	—
Total	$ 153	$ 67	$ 27	$ 59	$ 335	$ 141	$ —	$ 194

Volumes

The following table presents the volume of Dominion's derivative activity as of December 31, 2016. 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)	91	18
Basis	223	593
Electricity (MWh):		
Fixed price(1)	11,880,630	1,963,426
FTRs	46,269,912	—
Liquids (Gal)(2)	46,311,225	12,741,120
Interest rate(3)	$1,800,000,000	$2,903,640,679
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, 2016, 2015 and 2014, 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's Consolidated Balance Sheet at December 31, 2016:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
Commodities:			
Gas	$ 10	$ 10	36 months
Electricity	(20)	(20)	12 months
Other	(3)	(3)	15 months
Interest rate	(274)	(5)	375 months
Foreign currency	7	(1)	114 months
Total	$ (280)	$ (19)	

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.

Table of Contents

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion'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, 2016			
ASSETS			
Current Assets			
Commodity	**$ 29**	**$ 101**	**$130**
Interest rate	**10**	**—**	**10**
Total current derivative assets	**39**	**101**	**140**
Noncurrent Assets			
Commodity	**—**	**132**	**132**
Interest rate	**7**	**—**	**7**
Total noncurrent derivative assets(1)	**7**	**132**	**139**
Total derivative assets	**$ 46**	**$ 233**	**$279**
LIABILITIES			
Current Liabilities			
Commodity	**$ 51**	**$ 41**	**$ 92**
Interest rate	**33**	**—**	**33**
Foreign currency	**3**	**—**	**3**
Total current derivative liabilities(2)	**87**	**41**	**128**
Noncurrent Liabilities			
Commodity	**1**	**3**	**4**
Interest rate	**20**	**—**	**20**
Foreign currency	**3**	**—**	**3**
Total noncurrent derivative liabilities(3)	**24**	**3**	**27**
Total derivative liabilities	**$ 111**	**$ 44**	**$155**
At December 31, 2015			
ASSETS			
Current Assets			
Commodity	$ 101	$ 151	$252
Interest rate	3	—	3
Total current derivative assets	104	151	255
Noncurrent Assets			
Commodity	3	109	112
Interest rate	21	—	21
Total noncurrent derivative assets(1)	24	109	133
Total derivative assets	$ 128	$ 260	$388
LIABILITIES			
Current Liabilities			
Commodity	$ 32	$ 116	$148
Interest rate	164	—	164
Total current derivative liabilities(2)	196	116	312
Noncurrent Liabilities			
Commodity	—	12	12
Interest rate	19	—	19
Total noncurrent derivative liabilities(3)	19	12	31
Total derivative liabilities	$ 215	$ 128	$343

(1) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion's Consolidated Balance Sheets.

(2) Current derivative liabilities are presented in other current liabilities in Dominion's Consolidated Balance Sheets.

(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion's Consolidated Balance Sheets.

The following tables present the gains and losses on Dominion'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, 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)
Year Ended December 31, 2014			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		$ (130)	
Purchased gas		(13)	
Electric fuel and other energy-related purchases		7	
Total commodity	$ 245	$ (136)	$ (4)
Interest rate(3)	(208)	(16)	(81)
Total	$ 37	$ (152)	$ (85)

(1) Amounts deferred into AOCI have no associated effect in Dominion'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's Consolidated Statements of Income.

(3) Amounts recorded in Dominion's Consolidated Statements of Income are classified in interest and related charges.

(4) Amounts recorded in Dominion's Consolidated Statements of Income are classified in other income.

Table of Contents

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives(1)		
Year Ended December 31,	**2016**	2015	2014
(millions)			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue	**$ 2**	$ 24	$ (310)
Purchased gas	**4**	(14)	(51)
Electric fuel and other energy-related purchases	**(70)**	(14)	113
Other operations & maintenance	**1**	—	—
Interest rate(2)	**—**	(1)	—
Total	**$ (63)**	$ (5)	$ (248)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion's Consolidated Statements of Income.
(2) Amounts recorded in Dominion'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, 2016			December 31, 2015		
	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	**$ 147**	**$ —**	**$ 147**	$ 101	$ —	$ 101
Interest rate contracts:						
Over-the-counter	**6**	**—**	**6**	13	—	13
Total derivatives, subject to a master netting or similar arrangement	**153**	**—**	**153**	114	—	114
Total derivatives, not subject to a master netting or similar arrangement	**41**	**—**	**41**	13	—	13
Total	**$ 194**	**$ —**	**$ 194**	$ 127	$ —	$ 127

	December 31, 2016				December 31, 2015			
		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	**$ 147**	**$ 2**	**$ —**	**$ 145**	$ 101	$ 3	$ —	$ 98
Interest rate contracts:								
Over-the-counter	**6**	**—**	**—**	**6**	13	10	—	3
Total	**$ 153**	**$ 2**	**$ —**	**$ 151**	$ 114	$ 13	$ —	$ 101

Table of Contents

(millions)	December 31, 2016 Gross Amounts of Recognized Liabilities	December 31, 2016 Gross Amounts Offset in the Consolidated Balance Sheet	December 31, 2016 Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	December 31, 2015 Gross Amounts of Recognized Liabilities	December 31, 2015 Gross Amounts Offset in the Consolidated Balance Sheet	December 31, 2015 Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$ 2	$ —	$ 2	$ 5	$ —	$ 5
Interest rate contracts:						
Over-the-counter	21	—	21	59	—	59
Total derivatives, subject to a master netting or similar arrangement	23	—	23	64	—	64
Total derivatives, not subject to a master netting or similar arrangement	8	—	8	22	—	22
Total	$ 31	$ —	$ 31	$ 86	$ —	$ 86

	December 31, 2016	Gross Amounts Not Offset in the Consolidated Balance Sheet			December 31, 2015	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	$ 2	$ 2	$ —	$ —	$ 5	$ 3	$ —	$ 2
Interest rate contracts:								
Over-the-counter	21	—	—	21	59	10	—	49
Total	$ 23	$ 2	$ —	$ 21	$ 64	$ 13	$ —	$ 51

Volumes

The following table presents the volume of Virginia Power's derivative activity at December 31, 2016. 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)	27	14
Basis	101	539
Electricity (MWh):		
Fixed price(1)	1,343,310	1,963,426
FTRs	43,853,950	—
Interest rate	$800,000,000	$850,000,000

(1) Includes options.

Ineffectiveness and AOCI

For the years ended December 31, 2016, 2015 and 2014, 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 Virginia Power's Consolidated Balance Sheet at December 31, 2016:

(millions)	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
Interest rate	$ (8)	$ (1)	375 months
Total	$ (8)	$ (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.

Table of Contents

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, 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**
At December 31, 2015			
ASSETS			
Current Assets			
Commodity	$ —	$ 18	$ 18
Total current derivative assets(1)	—	18	18
Noncurrent Assets			
Commodity	—	96	96
Interest rate	13	—	13
Total noncurrent derivative assets	13	96	109
Total derivative assets	$ 13	$ 114	$127
LIABILITIES			
Current Liabilities			
Commodity	$ —	$ 23	$ 23
Interest rate	57	—	57
Total current derivative liabilities(2)	57	23	80
Noncurrent Liabilities			
Commodity	—	4	4
Interest rate	2	—	2
Total noncurrent derivative liabilities(3)	2	4	6
Total derivative liabilities	$ 59	$ 27	$ 86

(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, 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)
Year Ended December 31, 2014			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$ 5	
Total commodity	$ 4	$ 5	$ (4)
Interest rate(3)	(10)	—	(81)
Total	$ (6)	$ 5	$ (85)

(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,	**2016**	2015	2014
(millions)			
Derivative Type and Location of Gains (Losses)			
Commodity(2)	**$ (70)**	$ (13)	$ 105
Total	**$ (70)**	$ (13)	$ 105

(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.

Table of Contents

DOMINION GAS

Balance Sheet Presentation

The tables below present Dominion Gas' derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2016			December 31, 2015		
	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	$ —	$ —	$ —	$ 11	$ —	$ 11
Total derivatives, subject to a master netting or similar arrangement	$ —	$ —	$ —	$ 11	$ —	$ 11

	December 31, 2016				December 31, 2015			
		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	$ —	$ —	$ —	$ —	$ 11	$ —	$ —	$ 11
Total	$ —	$ —	$ —	$ —	$ 11	$ —	$ —	$ 11

	December 31, 2016			December 31, 2015		
	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	$ 5	$ —	$ 5	$ —	$ —	$ —
Interest rate contracts:						
Over-the-counter	—	—	—	14	—	14
Foreign currency contracts:						
Over-the-counter	6	—	6	—	—	—
Total derivatives, subject to a master netting or similar arrangement	$ 11	$ —	$ 11	$ 14	$ —	$ 14

	December 31, 2016				December 31, 2015			
		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	$ 5	$ —	$ —	$ 5	$ —	$ —	$ —	$ —
Interest rate contracts:								
Over-the-counter	—	—	—	—	14	—	—	14
Foreign currency contracts:								
Over-the-counter	6	—	—	6	—	—	—	—
Total	$ 11	$ —	$ —	$ 11	$ 14	$ —	$ —	$ 14

Table of Contents

Volumes

The following table presents the volume of Dominion Gas' derivative activity at December 31, 2016. 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
NGLs (Gal)	**39,549,225**	**7,953,120**
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, 2016, 2015 and 2014, 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 Gas' Consolidated Balance Sheet at December 31, 2016:

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
(millions)			
Commodities:			
NGLs	**$ (3)**	**$ (3)**	**15 months**
Interest rate	**(28)**	**(3)**	**336 months**
Foreign currency	**7**	**(1)**	**114 months**
Total	**$ (24)**	**$ (7)**	

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 Gas' derivatives and where they are presented in its Consolidated Balance Sheets:

	Fair Value - Derivatives under Hedge Accounting	Fair Value - Derivatives not under Hedge Accounting	Total Fair Value
(millions)			
At December 31, 2016			
LIABILITIES			
Current Liabilities			
Commodity	**$ 4**	**—**	**$ 4**
Foreign currency	**3**	**—**	**3**
Total current derivative liabilities(3)	**7**	**—**	**7**
Noncurrent Liabilities			
Commodity	**1**	**—**	**1**
Foreign currency	**3**	**—**	**3**
Total noncurrent derivative liabilities(4)	**4**	**—**	**4**
Total derivative liabilities	**$ 11**	**$ —**	**$ 11**
At December 31, 2015			
ASSETS			
Current Assets			
Commodity	$ 10	$ —	$ 10
Total current derivative assets(1)	10	—	10
Noncurrent Assets			
Commodity	1	—	1
Total noncurrent derivative assets(2)	1	—	1
Total derivative assets	$ 11	$ —	$ 11
LIABILITIES			
Current Liabilities			
Interest rate	$ 14	$ —	$ 14
Total current derivative liabilities(3)	14	—	14
Total derivative liabilities	$ 14	$ —	$ 14

(1) Current derivative assets are presented in other current assets in Dominion Gas' Consolidated Balance Sheets.

(2) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion Gas' Consolidated Balance Sheets.

(3) Current derivative liabilities are presented in other current liabilities in Dominion Gas' Consolidated Balance Sheets.

(4) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion Gas' Consolidated Balance Sheets.

Table of Contents

The following tables present the gains and losses on Dominion 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, 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
Year Ended December 31, 2014		
Derivative Type and Location of Gains (Losses)		
Commodity:		
Operating revenue		$ 2
Purchased gas		(14)
Total commodity	$ 12	$ (12)
Interest rate(2)	(62)	(1)
Total	$ (50)	$ (13)

(1) Amounts deferred into AOCI have no associated effect in Dominion Gas' Consolidated Statements of Income.

(2) Amounts recorded in Dominion Gas' Consolidated Statements of Income are classified in interest and related charges.

(3) Amounts recorded in Dominion 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,	**2016**	2015	2014
(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's basic and diluted EPS:

	2016	2015	2014
(millions, except EPS)			
Net income attributable to Dominion	**$2,123**	$1,899	$1,310
Average shares of common stock outstanding-Basic	**616.4**	592.4	582.7
Net effect of dilutive securities(1)	**0.7**	1.3	1.8
Average shares of common stock outstanding-Diluted	**617.1**	593.7	584.5
Earnings Per Common Share-Basic	**$ 3.44**	$ 3.21	$ 2.25
Earnings Per Common Share-Diluted	**$ 3.44**	$ 3.20	$ 2.24

(1) Dilutive securities consist primarily of the 2013 Equity Units for 2016 and 2015 and the 2013 Equity Units and contingently convertible senior notes for 2014. Dominion redeemed all of its contingently convertible senior notes in 2014. 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, 2015 and 2014, 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, 2016, as the dilutive stock price threshold was not met. See Note 17 for more information. The Dominion Midstream convertible preferred units are potentially dilutive securities but had no effect on the calculation of diluted EPS for the year ended December 31, 2016. See Note 19 for more information.

Table of Contents

NOTE 9. INVESTMENTS

DOMINION

Equity and Debt Securities

RABBI TRUST SECURITIES

Marketable equity and debt securities and cash equivalents held in Dominion's rabbi trusts and classified as trading totaled $104 million and $100 million at December 31, 2016 and 2015, respectively.

DECOMMISSIONING TRUST SECURITIES

Dominion 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's decommissioning trust funds are summarized below:

(millions)	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
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**
At December 31, 2015				
Marketable equity securities:				
U.S.	$ 1,354	$ 1,217	$ —	$2,571
Fixed income:				
Corporate debt instruments	436	11	(7)	440
Government securities	962	30	(4)	988
Common/collective trust funds	100	—	—	100
Cost method investments	70	—	—	70
Cash equivalents and other(2)	14	—	—	14
Total	$ 2,936	$ 1,258	$ (11)(3)	$4,183

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $9 million and $12 million at December 31, 2016 and 2015, respectively.
(3) The fair value of securities in an unrealized loss position was $576 million and $592 million at December 31, 2016 and 2015, respectively.

The fair value of Dominion's marketable debt securities held in nuclear decommissioning trust funds at December 31, 2016 by contractual maturity is as follows:

(millions)	Amount
Due in one year or less	**$ 192**
Due after one year through five years	**418**
Due after five years through ten years	**368**
Due after ten years	**568**
Total	**$1,546**

Presented below is selected information regarding Dominion's marketable equity and debt securities held in nuclear decommissioning trust funds:

Year Ended December 31, (millions)	2016	2015	2014
Proceeds from sales	**$1,422**	$1,340	$1,235
Realized gains(1)	**128**	219	171
Realized losses(1)	**55**	84	30

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

Table of Contents

Dominion recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31,	2016	2015	2014
(millions)			
Total other-than-temporary impairment losses(1)	**$ 51**	$ 66	$21
Losses recorded to nuclear decommissioning trust regulatory liability	**(16)**	(26)	(5)
Losses recognized in other comprehensive income (before taxes)	**(12)**	(9)	(3)
Net impairment losses recognized in earnings	**$ 23**	$ 31	$13

(1) Amounts include other-than-temporary impairment losses for debt securities of $13 million, $9 million and $3 million at December 31, 2016, 2015 and 2014, 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:

	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
(millions)				
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**
At December 31, 2015				
Marketable equity securities:				
U.S.	$ 633	$ 528	$ —	$1,161
Fixed income:				
Corporate debt instruments	238	5	(5)	238
Government securities	421	15	(2)	434
Common/collective trust funds	34	—	—	34
Cost method investments	70	—	—	70
Cash equivalents and other(2)	8	—	—	8
Total	$ 1,404	$ 548	$ (7)(3)	$1,945

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $7 million and $8 million at December 31, 2016 and 2015, respectively.
(3) The fair value of securities in an unrealized loss position was $287 million and $281 million at December 31, 2016 and 2015, respectively.

The fair value of Virginia Power's marketable debt securities at December 31, 2016, by contractual maturity is as follows:

	Amount
(millions)	
Due in one year or less	**$ 55**
Due after one year through five years	**181**
Due after five years through ten years	**208**
Due after ten years	**285**
Total	**$ 729**

Presented below is selected information regarding Virginia Power's marketable equity and debt securities held in nuclear decommissioning trust funds.

Year Ended December 31,	2016	2015	2014
(millions)			
Proceeds from sales	**$733**	$639	$549
Realized gains(1)	**63**	110	73
Realized losses(1)	**27**	43	12

(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,	2016	2015	2014
(millions)			
Total other-than-temporary impairment losses(1)	**$ 26**	$ 36	$ 8
Losses recorded to nuclear decommissioning trust regulatory liability	**(16)**	(26)	(4)
Losses recorded in other comprehensive income (before taxes)	**(7)**	(6)	(2)
Net impairment losses recognized in earnings	**$ 3**	$ 4	$ 2

(1) Amounts include other-than-temporary impairment losses for debt securities of $8 million, $6 million and $2 million at December 31, 2016, 2015 and 2014, respectively.

EQUITY METHOD INVESTMENTS

Dominion and Dominion Gas

Investments that Dominion and Dominion Gas account for under the equity method of accounting are as follows:

Company	Ownership%	Investment Balance		Description
As of December 31,		2016	2015	
(millions)				
Dominion				
Blue Racer	50%	**$ 677**	$ 661	Midstream gas and related services
Iroquois	50%(1)	**316**	324	Gas transmission system
Atlantic Coast Pipeline	48%	**256**	59	Gas transmission system
Fowler Ridge	50%	**116**	125	Wind-powered merchant generation facility
NedPower	50%	**112**	119	Wind-powered merchant generation facility
Other	various	**84**	32	
Total		**$1,561**	$1,320	
Dominion Gas				
Iroquois	24.07%	**$ 98**	$ 102	Gas transmission system
Total		**$ 98**	$ 102	

(1) Comprised of Dominion Midstream's interest of 25.93% and Dominion Gas' interest of 24.07%. See Note 15 for more information.

Dominion's equity earnings on its investments totaled $111 million, $56 million and $46 million in 2016, 2015 and 2014, respectively. Dominion received distributions from these investments of $104 million, $83 million and $60 million in 2016, 2015, and 2014, respectively. As of December 31, 2016 and 2015, the carrying amount of Dominion's investments exceeded its share of underlying equity in net assets by $260 million and $234 million, respectively. These differences are comprised at December 31, 2016 and 2015, of $84 million and $72 million, respectively, related to basis differences from Dominion's investments in Blue Racer and wind projects, which are being amortized over the useful lives of the underlying assets, and $176 million and $162 million, respectively, reflecting equity method goodwill that is not being amortized.

Dominion Gas' equity earnings on its investment totaled $21 million, $23 million and $21 million in 2016, 2015 and 2014, respectively. Dominion Gas received distributions from its investment of $22 million, $28 million and $20 million in 2016, 2015, and 2014, respectively. As of December 31, 2016 and 2015, the carrying amount of Dominion 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 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 Gas' Consolidated Statements of Income.

Equity earnings are recorded in other income in Dominion's and Dominion Gas' Consolidated Statements of Income.

BLUE RACER

In December 2012, Dominion 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 and Caiman, with Dominion contributing midstream assets and Caiman contributing private equity capital.

In March 2014, Dominion Gas sold the Northern System to an affiliate, that subsequently sold the Northern System to Blue Racer for consideration of $84 million. Dominion Gas' consideration consisted of $17 million in cash proceeds and the extinguishment of affiliated current borrowings of $67 million and Dominion's consideration consisted of cash proceeds of $84 million. The sale resulted in a gain of $59 million ($35 million after-tax for Dominion Gas and $34 million after-tax for Dominion) net of a $3 million write-off of goodwill, and is included in other operations and maintenance expense in both Dominion Gas' and Dominion's Consolidated Statements of Income.

In December 2016, Dominion Gas repurchased a portion of the Western System from Blue Racer for $10 million, which is included in property, plant and equipment in Dominion Gas' Consolidated Balance Sheets.

Dominion

ATLANTIC COAST PIPELINE

In September 2014, Dominion, along with Duke and Southern Company Gas (formerly known as AGL Resources Inc.), announced the formation of Atlantic Coast Pipeline. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. In October 2016, Dominion purchased an additional 3% membership interest in Atlantic Coast Pipeline from Duke for $14 million. The members, which are subsidiaries of the above-referenced parent companies, hold the following membership interests: Dominion, 48%; Duke, 47%; and Southern Company Gas (formerly known as AGL Resources Inc.), 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 has the ability to exercise significant influence, but not control, over the investee. See Note 15 for more information.

Table of Contents

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,	2016	2015
(millions)		
Dominion		
Utility:		
Generation	**$17,147**	$15,656
Transmission	**14,315**	11,461
Distribution	**16,381**	13,128
Storage	**2,814**	2,460
Nuclear fuel	**1,537**	1,464
Gas gathering and processing	**216**	799
Oil and gas	**1,652**	—
General and other	**1,450**	927
Plant under construction	**6,254**	5,550
Total utility	**61,766**	51,445
Nonutility:		
Merchant generation-nuclear	**1,419**	1,339
Merchant generation-other	**4,149**	2,683
Nuclear fuel	**897**	938
Gas gathering and processing	**619**	—
Other-including plant under construction	**706**	1,371
Total nonutility	**7,790**	6,331
Total property, plant and equipment	**$69,556**	$57,776
Virginia Power		
Utility:		
Generation	**$17,147**	$15,656
Transmission	**7,871**	6,963
Distribution	**10,573**	10,048
Nuclear fuel	**1,537**	1,464
General and other	**745**	709
Plant under construction	**2,146**	2,793
Total utility	**40,019**	37,633
Nonutility-other	**11**	6
Total property, plant and equipment	**$40,030**	$37,639
Dominion Gas		
Utility:		
Transmission	**$ 4,231**	$ 3,804
Distribution	**3,019**	2,765
Storage	**1,627**	1,583
Gas gathering and processing	**198**	797
General and other	**184**	165
Plant under construction	**448**	443
Total utility	**9,707**	9,557
Nonutility:		
Gas gathering and processing	**$ 619**	$ —
Other-including plant under construction	**149**	136
Total nonutility	**768**	136
Total property, plant and equipment	**$10,475**	$ 9,693

Jointly-Owned Power Stations

Dominion's and Virginia Power's proportionate share of jointly-owned power stations at December 31, 2016 is as follows:

	Bath County Pumped Storage Station(1)	North Anna Units 1 and 2(1)	Clover Power Station(1)	Millstone Unit 3(2)
(millions, except percentages)				
Ownership interest	**60%**	**88.4%**	**50%**	**93.5%**
Plant in service	**$1,052**	**$ 2,520**	**$ 586**	**$1,190**
Accumulated depreciation	**(585)**	**(1,210)**	**(219)**	**(349)**
Nuclear fuel	**—**	**718**	**—**	**469**
Accumulated amortization of nuclear fuel	**—**	**(549)**	**—**	**(366)**
Plant under construction	**8**	**69**	**4**	**51**

(1) Units jointly owned by Virginia Power.
(2) Unit jointly owned by Dominion.

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 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.

Assignments of Shale Development Rights

In December 2013, Dominion 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 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 Gas received approximately $100 million in cash proceeds, resulting in a $20 million ($12 million after-tax) gain, recorded to operations and maintenance expense in Dominion Gas' Consolidated Statements of Income. In 2014, Dominion Gas received $16 million in additional cash proceeds resulting from post-closing adjustments. In March 2015, Dominion 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 Gas' Consolidated Statements of Income. In April 2016, Dominion 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 Gas' Consolidated Statements of Income.

In November 2014, Dominion 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 provides for payments to

Table of Contents

Dominion 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 Gas closed on the agreement and received proceeds of $60 million associated with an initial conveyance of approximately 12,000 acres, resulting in a $60 million ($36 million after-tax) gain, recorded to operations and maintenance expense in Dominion Gas' Consolidated Statements of Income. In connection with that agreement, in 2016, Dominion Gas conveyed 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. The gains are included in other operations and maintenance expense in Dominion Gas' Consolidated Statements of Income.

In March 2015, Dominion 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 Gas' Consolidated Statements of Income.

In September 2015, Dominion 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 Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage. In September 2015, Dominion 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 Gas' Consolidated Statements of Income.

NOTE 11. GOODWILL AND INTANGIBLE ASSETS

Goodwill

The changes in Dominion's and Dominion Gas' carrying amount and segment allocation of goodwill are presented below:

(millions)	Dominion Generation	Dominion Energy	DVP	Corporate and Other(1)	Total
Dominion					
Balance at December 31, 2014(2)	$ 1,422(3)	$ 696(3)	$926	$ —	$3,044
DCG acquisition	—	250(4)	—	—	250
Balance at December 31, 2015(2)	$ 1,422	$ 946	$926	$ —	$3,294
Dominion Questar Combination	**—**	**3,105(4)**	**—**	**—**	**3,105**
Balance at December 31, 2016(2)	**$ 1,422**	**$4,051**	**$926**	**$ —**	**$6,399**
Dominion Gas					
Balance at December 31, 2014(2)	$ —	$ 542	$ —	$ —	$ 542
No events affecting goodwill	—	—	—	—	—
Balance at December 31, 2015(2)	**$ —**	**$ 542**	**$ —**	**$ —**	**$ 542**
No events affecting goodwill	—	—	—	—	—
Balance at December 31, 2016(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) Recast to reflect nonregulated retail energy marketing operations in the Dominion Energy segment.
(4) See Note 3 for discussion of Dominion's acquisitions.

Table of Contents

Other Intangible Assets

The Companies' other intangible assets are subject to amortization over their estimated useful lives. Dominion's amortization expense for intangible assets was $73 million, $78 million and $71 million for 2016, 2015 and 2014, respectively. In 2016, Dominion acquired $124 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of approximately 15 years. Amortization expense for Virginia Power's intangible assets was $29 million, $25 million and $24 million for 2016, 2015 and 2014, respectively. In 2016, Virginia Power acquired $40 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of 12 years. Dominion Gas' amortization expense for intangible assets was $6 million, $18 million and $17 million for 2016, 2015 and 2014, respectively. In 2016, Dominion Gas acquired $20 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of approximately 12 years. The components of intangible assets are as follows:

At December 31,	2016		2015	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
(millions)				
Dominion				
Software, licenses and other	$ 955	$ 337	$ 942	$ 372
Total	$ 955	$ 337	$ 942	$ 372
Virginia Power				
Software, licenses and other	$ 326	$ 101	$ 301	$ 88
Total	$ 326	$ 101	$ 301	$ 88
Dominion Gas				
Software, licenses and other	$ 147	$ 49	$ 211	$ 128
Total	$ 147	$ 49	$ 211	$ 128

Annual amortization expense for these intangible assets is estimated to be as follows:

	2017	2018	2019	2020	2021
(millions)					
Dominion	$78	$67	$57	$45	$32
Virginia Power	$29	$25	$22	$16	$ 9
Dominion Gas	$13	$11	$10	$10	$ 9

NOTE 12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities include the following:

At December 31,	2016	2015
(millions)		
Dominion		
Regulatory assets:		
Deferred nuclear refueling outage costs(1)	$ 71	$ 75
Deferred rate adjustment clause costs(2)	63	90
Unrecovered gas costs(3)	19	12
Deferred cost of fuel used in electric generation(4)	—	111
Other	91	63
Regulatory assets-current	244	351
Unrecognized pension and other postretirement benefit costs(5)	1,401	1,015
Deferred rate adjustment clause costs(2)	329	295
PJM transmission rates(6)	192	192
Derivatives(7)	174	110
Income taxes recoverable through future rates(8)	123	126
Utility reform legislation(9)	99	65
Other	155	62
Regulatory assets-non-current	2,473	1,865
Total regulatory assets	$2,717	$2,216
Regulatory liabilities:		
Deferred cost of fuel used in electric generation(4)	$ 61	$ —
PIPP(10)	28	46
Other	74	54
Regulatory liabilities-current	163	100
Provision for future cost of removal and AROs(11)	1,427	1,120
Nuclear decommissioning trust(12)	902	804
Derivatives(7)	69	79
Deferred cost of fuel used in electric generation(4)	14	97
Other	210	185
Regulatory liabilities-non-current	2,622	2,285
Total regulatory liabilities	$2,785	$2,385
Virginia Power		
Regulatory assets:		
Deferred nuclear refueling outage costs(1)	$ 71	$ 75
Deferred rate adjustment clause costs(2)	51	80
Deferred cost of fuel used in electric generation(4)	—	111
Other	57	60
Regulatory assets-current	179	326
Deferred rate adjustment clause costs(2)	246	213
PJM transmission rates(6)	192	192
Derivatives(7)	133	110
Income taxes recoverable through future rates(8)	76	97
Other	123	55
Regulatory assets-non-current	770	667
Total regulatory assets	$ 949	$ 993
Regulatory liabilities:		
Deferred cost of fuel used in electric generation(4)	$ 61	$ —
Other	54	35
Regulatory liabilities-current	115	35
Provision for future cost of removal(11)	946	890
Nuclear decommissioning trust(12)	902	804
Derivatives(7)	69	79
Deferred cost of fuel used in electric generation(4)	14	97
Other	31	59
Regulatory liabilities-non-current	1,962	1,929
Total regulatory liabilities	$2,077	$1,964

Table of Contents

At December 31, (millions)	2016	2015
Dominion Gas		
Regulatory assets:		
Unrecovered gas costs(3)	**$ 12**	$ 11
Deferred rate adjustment clause costs(2)	**12**	10
Other	**2**	2
Regulatory assets-current	**26**	23
Unrecognized pension and other postretirement benefit costs(5)	**358**	282
Utility reform legislation(9)	**99**	65
Deferred rate adjustment clause costs(2)	**79**	82
Income taxes recoverable through future rates(8)	**23**	20
Other	**18**	—
Regulatory assets-non-current	**577**	449
Total regulatory assets	**$603**	$472
Regulatory liabilities:		
PIPP(10)	**$ 28**	$ 46
Other	**7**	9
Regulatory liabilities-current	**35**	55
Provision for future cost of removal and AROs(11)	**174**	170
Other	**45**	31
Regulatory liabilities-non-current	**219**	201
Total regulatory liabilities	**$254**	$256

(1) 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.

(2) 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 Gas. See Note 13 for more information.

(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'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's and Dominion Gas' rate-regulated subsidiaries.

(6) Reflects amount related to the PJM transmission cost allocation matter. See Note 13 for more information.

(7) 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.

(8) 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.

(9) 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.

(10) 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.

(11) 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.

(12) 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.

At December 31, 2016, $303 million of Dominion's, $230 million of Virginia Power's and $31 million of Dominion Gas' regulatory assets represented past expenditures on which they do not currently earn a return. With the exception of the $192 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'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 and Utah, under Dominion'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.

Table of Contents

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 that $223 million in transmission costs related to specific projects were unjust, unreasonable and unduly discriminatory or preferential and should be excluded from Virginia Power's transmission formula rate. In October 2010, FERC issued an order dismissing the complaint in part and established hearings and settlement procedures on the remaining part of the complaint. In February 2012, Virginia Power submitted to FERC a settlement agreement to resolve all issues set for hearing. The settlement was accepted by FERC in May 2012 and provides for payment by Virginia Power to the transmission customer parties collectively of $250,000 per year for ten years and resolves all matters other than allocation of the incremental cost of certain underground transmission facilities.

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. While Virginia Power cannot predict the outcome of the hearing, 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, 2016, Virginia Power has a contingent liability of $200 million in other deferred credits and other liabilities, which is offset by a $192 million regulatory asset for the amount that will be recovered through retail rates in Virginia. The remaining $8 million was recorded in other operations and maintenance expense, during 2015, in the Consolidated Statements of Income.

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 and setting a base ROE of 9.6% for the projects. After separate, additional bifurcated hearings, the Virginia Commission issued final orders setting base ROEs of 9.6% in March 2016 for Rider GV, in April 2016 for Riders C1A and C2A, in June 2016 for Riders BW and US-2, and in August 2016 for Rider U. In February 2017, the Virginia Commission issued final orders setting base ROEs of 9.4% for Riders B, R, S, W, and GV effective April 1, 2017.

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. These appeals are pending.

2015 Biennial Review

Pursuant to the Regulation Act, in March 2015, Virginia Power filed its base rate case and schedules for the Virginia Commission's 2015 biennial review of Virginia Power's rates, terms and conditions. Per legislation enacted in February 2015, this biennial review was limited to reviewing Virginia Power's earnings on rates for generation and distribution services for the combined 2013 and 2014 test period, and determining whether credits are due to customers in the event Virginia Power's earnings exceeded the earnings band determined in the 2013 Biennial Review Order. 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. Based upon 2015 legislation keeping Virginia Power's base rates unchanged until at least December 1, 2022, the Virginia Commission did not order certain existing rate adjustment clauses to be combined with Virginia Power's base rates. The Virginia Commission did not determine whether Virginia Power had a revenue deficiency or sufficiency when projecting the annual revenues generated by base rates to the revenues required to recover costs of service and earn a fair return. In December 2015, a group of large industrial customers filed notices of appeal with the Supreme Court of Virginia from both the 2015 Biennial Review Order and the Virginia Commission's order denying their petition for rehearing or reconsideration. In April 2016, the Supreme Court of Virginia granted these appeals as a matter of right. Also in April 2016, the Attorney General filed an unopposed motion to suspend appellate briefing pending the outcome of a separate case at the Virginia Commission raising the same issues. In May 2016, the Supreme Court of Virginia denied the Attorney General's unopposed motion to suspend briefing in the previously granted appeals from the Virginia Commission's orders. The Supreme Court of Virginia later granted leave for the industrial customer appellants to withdraw their appeals, thus concluding this matter.

Virginia Fuel Expenses

In May 2016, Virginia Power submitted its annual fuel factor to the Virginia Commission to recover an estimated $1.4 billion in Virginia jurisdictional projected fuel expenses for the rate year beginning July 1, 2016. Virginia Power's proposed fuel rate represented a fuel revenue decrease of $286 million when applied to projected kilowatt-hour sales for the period July 1, 2016 to June 30, 2017. In October 2016, 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 total estimated cost of the Remington solar facility is approximately $47 million, excluding financing costs. The facility is now the subject of a public-private partnership whereby the Commonwealth of Virginia, a non-jurisdictional customer, will compensate Virginia Power for the facility's net electrical energy output, and Microsoft Corporation will purchase 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 October 2015, Virginia Power filed an application with the Virginia Commission for CPCNs to construct and operate the Scott Solar, Whitehouse, and Woodland solar facilities and related distribution-level interconnection facilities. Virginia Power also applied for approval of Rider US-2 to recover the costs of these projects. In June 2016, the Virginia Commission granted the requested CPCNs and approved a $4 million revenue requirement, subject to true-up on a cost-of-service basis using a 9.6% ROE for Rider US-2 for the rate year beginning September 1, 2016. These projects were placed into service in

Table of Contents

December 2016, and increased Dominion's renewable generation by a combined 56 MW at a total cost of approximately $130 million, excluding financing costs. See below for further information on Rider US-2.

In August 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate the Oceana solar facility and related distribution interconnection facilities on land owned by the U.S. Navy. The facility would begin commercial operations in late 2017 and increase Dominion's renewable generation by approximately 18 MW at an estimated cost of approximately $40 million, excluding financing costs. The facility is the subject of a public-private partnership whereby the Commonwealth of Virginia, a non-jurisdictional customer, will compensate Virginia Power for the facility's net electrical energy output. Virginia Power will retire renewable energy certificates on the Commonwealth's behalf in an amount equal to those generated by the facility. There is no rate adjustment clause associated with this CPCN filing, nor will any costs of the project be recovered from jurisdictional customers. This case is pending.

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 2016, Virginia Power proposed a $639 million total revenue requirement for the rate year beginning September 1, 2016, which represents a $1 million increase over the revenues projected to be produced during the rate year under current rates. In July 2016, the Virginia Commission approved Virginia Power's proposed total revenue requirement.
- The Virginia Commission previously approved Rider S in conjunction with the Virginia City Hybrid Energy Center. In February 2016, the Virginia Commission approved a $251 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2016. It also established a 10.6% ROE for Rider S effective April 1, 2016. In June 2016, Virginia Power proposed a $254 million revenue requirement for the rate year beginning April 1, 2017, which represents a $3 million increase over the previous year. In February 2017, the Virginia Commission established a 10.4% ROE for Rider S effective April 1, 2017. This case is pending.
- The Virginia Commission previously approved Rider W in conjunction with Warren County. In February 2016, the Virginia Commission approved a $118 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2016. It also established a 10.6% ROE for Rider W effective April 1, 2016. In June 2016, Virginia Power proposed a $126 million revenue requirement for the rate year beginning April 1, 2017, which represents an $8 million increase over the previous year. In February 2017, the Virginia Commission established a 10.4% ROE for Rider W effective April 1, 2017. This case is pending.
- The Virginia Commission previously approved Rider R in conjunction with Bear Garden. In February 2016, the Virginia Commission approved a $74 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2016. It also established a 10.6% ROE for Rider R effective April 1, 2016. In June 2016, Virginia Power proposed a $75 million revenue requirement for the rate year beginning April 1, 2017, which represents a $1 million increase over the previous year. In February 2017, the Virginia Commission established a 10.4% ROE for Rider R effective April 1, 2017. This case is pending.
- The Virginia Commission previously approved Rider B in conjunction with the conversion of three power stations to biomass. In February 2016, the Virginia Commission approved a $30 million revenue requirement for the rate year beginning April 1, 2016. It also established an 11.6% ROE for Rider B effective April 1, 2016. In June 2016, Virginia Power proposed a $28 million revenue requirement for the rate year beginning April 1, 2017, which represents a $2 million decrease versus the previous year. In February 2017, the Virginia Commission established an 11.4% ROE for Rider B effective April 1, 2017. 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 August 2016, the Virginia Commission approved a net $20 million revenue requirement and a 9.6% ROE for the rate year beginning September 1, 2016, and an additional $2 million in credits to offset approved revenue requirements for Phase One for each of the 2017-2018 and 2018-2019 rate years. The order limited the total investment in Phase One of Virginia Power's proposed program to $140 million, with $123 million recoverable through Rider U. In December 2016, Virginia Power proposed a total $31 million revenue requirement for Phase One and Phase Two costs for the rate year beginning September 1, 2017. Virginia Power's estimated total investment in Phase Two is $110 million. This case is pending.
- The Virginia Commission previously approved Riders C1A and C2A in connection with cost recovery for DSM programs. In April 2016, the Virginia Commission approved a $46 million revenue requirement, subject to true-up, for the rate year beginning May 1, 2016. It also established a 9.6% ROE for Riders C1A and C2A effective May 1, 2016. The Virginia Commission approved one new energy efficiency program at a reduced cost cap, denied a second energy efficiency program, and approved the extension of an existing peak shaving program recovered in base rates at no additional incremental cost. In October 2016, Virginia Power proposed a total revenue requirement of $45 million for the rate year beginning July 1, 2017. Virginia Power also proposed two new energy efficiency programs for Virginia Commission approval with a requested five-year cost cap of $178 million. Virginia Power further proposed to extend an existing energy efficiency program for an additional two years under current funding, and an existing peak shaving program for an additional five years with an additional $5 million cost cap. This case is pending.
- The Virginia Commission previously approved Rider BW in conjunction with Brunswick County. In June 2016, the Virginia Commission approved a $119 million revenue requirement for the rate year beginning September 1, 2016. It also established a 10.6% ROE for Rider BW effective September 1, 2016. In October 2016, Virginia Power proposed a

$134 million revenue requirement for the rate year beginning September 1, 2017, which represents a $15 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 June 2016, the Virginia Commission approved a $4 million revenue requirement for the rate year beginning September 1, 2016. It also established a 9.6% ROE for Rider US-2 effective September 1, 2016. In October 2016, Virginia Power proposed a $10 million revenue requirement for the rate year beginning September 1, 2017, which represents a $6 million increase over the previous year. This case is pending.
- In July 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate Greensville County and related transmission interconnection facilities. Virginia Power also applied for approval of Rider GV to recover the costs of Greensville County. In March 2016, the Virginia Commission granted the requested CPCN and approved a $40 million revenue requirement for the rate year beginning April 1, 2016. It also established a 9.6% ROE for Rider GV effective April 1, 2016. In June 2016, Virginia Power proposed an $89 million revenue requirement for the rate year beginning April 1, 2017, which represents a $49 million increase over the previous year. In February 2017, the Virginia Commission established a 9.4% ROE for Rider GV effective April 1, 2017. This matter is pending.

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. In February 2014, the Virginia Commission granted reconsideration requested by Virginia Power and issued an Order Amending Certificate. Several appeals were filed with the Supreme Court of Virginia. In April 2015, the Supreme Court of Virginia issued its opinion in the consolidated appeals of the Virginia Commission's order granting a CPCN for the Skiffes Creek transmission line and related facilities. The Supreme Court of Virginia unanimously affirmed all but one of the alleged grounds for appeal. The court approved the proposed project including the proposed route for a 500 kV overhead transmission line from Surry to the Skiffes Creek switching station site. The court reversed and remanded the Virginia Commission's determination in one set of appeals that the Skiffes Creek switching station was a transmission line for purposes of statutory exemption from local zoning ordinances. In May 2015, the Supreme Court of Virginia denied separate petitions filed by Virginia Power and the Virginia Commission to rehear its ruling regarding the Skiffes Creek switching station. Pending receipt of remaining required permits and approvals, Virginia Power expects to construct the project.

Virginia Power previously filed an application with the Virginia Commission for a CPCN to construct and operate in Loudoun County, Virginia, a new approximately 230 kV Poland Road substation, and a new approximately four mile overhead 230 kV double circuit transmission line between the existing 230 kV Loudoun-Brambleton line and the Poland Road substation. In August 2016, the Virginia Commission granted a CPCN to construct and operate the project along a revised route. The total estimated cost of the project is approximately $55 million.

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. This case 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. The total estimated cost of the project is approximately $105 million. This case is pending.

In February 2016, the Virginia Commission issued an order granting Virginia Power a CPCN to construct and operate the Remington CT-Warrenton 230 kV double circuit transmission line, the Vint Hill-Wheeler and Wheeler-Gainesville 230 kV lines and the 230 kV Vint Hill and Wheeler switching stations along Virginia Power's proposed route. The total estimated cost of the project is approximately $110 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. The total estimated cost of the project is approximately $60 million. This case is pending.

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. The total estimated cost of the project is approximately $55 million. This case is pending.

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. The total estimated cost of the project is approximately $110 million. This case is pending.

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 must first receive a COL from the NRC, approval of the Virginia Commission and certain environmental permits and other approvals. The COL is expected in 2017. 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 have been 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 is closed. The NRC is required to conduct a hearing in all COL proceedings. This mandatory NRC hearing is anticipated to occur in the first half of 2017 and will be uncontested.

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 has been filed and in November 2016, the Army Corps of Engineers suspended the section 404 permit while it gathers additional information. This permitting issue is not expected to affect the NRC's issuance of the COL. Virginia Power is currently unable to make an estimate of the potential impacts to its consolidated financial statements related to this matter.

NORTH CAROLINA REGULATION

In March 2016, Virginia Power filed its base rate case and schedules with the North Carolina Commission. Virginia Power proposed a non-fuel, base rate increase of $51 million effective November 1, 2016 with an ROE of 10.5%. In October 2016, Virginia Power entered into a stipulation and settlement agreement for a non-fuel, base rate increase of $35 million with an ROE of 9.9% effective November 1, 2016, on a temporary basis subject to refund, with any permanent rates ordered by the North Carolina Commission effective January 1, 2017. In December 2016, the North Carolina Commission approved the stipulation and settlement agreement.

In August 2016, 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 $36 million decrease to the fuel component of its electric rates for the rate year beginning January 1, 2017. In December 2016, the North Carolina Commission approved the requested decrease and an additional $1 million reduction to Virginia Power's fuel rates.

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. Costs associated with calendar year 2016 investment will be recovered under the existing terms.

In February 2016, East Ohio filed an application to adjust the PIR cost recovery for 2015 costs. The filing reflects gross plant investment for 2015 of $171 million, cumulative gross plant investment of $1 billion and a revenue requirement of $131 million. This application was approved by the Ohio Commission in April 2016.

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 February 2016, East Ohio filed an application to adjust the AMR cost recovery for costs incurred during the calendar year 2015. The filing reflects a revenue requirement of approximately $7 million. This application was approved by the Ohio Commission in April 2016.

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 2016, 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 2016 through June 2017 of projected deferred program costs of approximately $32 million from April 2016 through June 2017, net of a refund for over-recovery of accumulated arrearages of approximately $28 million as of March 31, 2016.

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 August 2016, the Ohio Commission approved an increase to East Ohio's UEX Rider, which reflects a refund of over-recovered accumulated bad debt expense of approximately $8 million as of March 31, 2016, and recovery of prospective net bad debt expense projected to total approximately $19 million for the twelve-month period from April 2016 to March 2017.

PSMP

In November 2016, the Ohio Commission approved East Ohio's request to defer the operation and maintenance costs associated with implementing PSMP of up to $15 million per year.

Table of Contents

WEST VIRGINIA REGULATION

In May 2016, Hope filed a PREP application with the West Virginia Commission requesting approval of a projected capital investment for 2017 of $27 million as part of a total five-year projected capital investment of $152 million. In September 2016, Hope reached a settlement with all parties to the case agreeing to new PREP customer rates, for the year beginning November 1, 2016, that provide for annual projected revenue of $2 million related to capital investments of $20 million and $27 million for 2016 and 2017, respectively. In October 2016, the West Virginia Commission approved the settlement.

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.

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's and Virginia Power's AROs are primarily associated with the decommissioning of their nuclear generation facilities and ash pond and landfill closures. Dominion 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's LNG facility, Dominion's and Dominion 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'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 2015 and 2016 were as follows:

	Amount
(millions)	
Dominion	
AROs at December 31, 2014	$1,714
Obligations incurred during the period(1)	315
Obligations settled during the period	(106)
Revisions in estimated cash flows(1)	88
Accretion	93
Other	(1)
AROs at December 31, 2015(2)	$2,103
Obligations incurred during the period(3)	**204**
Obligations settled during the period	**(171)**
Revisions in estimated cash flows(1)	**245**
Accretion	**104**
AROs at December 31, 2016(2)	**$2,485**
Virginia Power	
AROs at December 31, 2014	$ 855
Obligations incurred during the period(1)	289
Obligations settled during the period	(39)
Revisions in estimated cash flows(1)	92
Accretion	50
AROs at December 31, 2015	$1,247
Obligations incurred during the period	**9**
Obligations settled during the period	**(115)**
Revisions in estimated cash flows(1)	**245**
Accretion	**57**
AROs at December 31, 2016	**$1,443**

Table of Contents

	Amount
(millions)	
Dominion Gas	
AROs at December 31, 2014	$ 147
Obligations incurred during the period	5
Obligations settled during the period	(6)
Revisions in estimated cash flows	(5)
Accretion	9
Other	(1)
AROs at December 31, 2015(4)	$ 149
Obligations incurred during the period	**6**
Obligations settled during the period	**(8)**
Revisions in estimated cash flows	**—**
Accretion	**9**
AROs at December 31, 2016(4)	**$ 156**

(1) Primarily reflects future ash pond and landfill closure costs at certain utility generation facilities. See Note 22 for further information.
(2) Includes $216 million and $249 million reported in other current liabilities at December 31, 2015, and 2016, respectively.
(3) Primarily reflects AROs assumed in the Dominion Questar Combination. See Note 3 for further information.
(4) Includes $137 million and $147 million reported in other deferred credits and other liabilities, with the remainder recorded in other current liabilities, at December 31, 2015 and 2016, respectively.

Dominion and Virginia Power have established trusts dedicated to funding the future decommissioning of their nuclear plants. At December 31, 2016 and 2015, the aggregate fair value of Dominion's trusts, consisting primarily of equity and debt securities, totaled $4.5 billion and $4.2 billion, respectively. At December 31, 2016 and 2015, the aggregate fair value of Virginia Power's trusts, consisting primarily of debt and equity securities, totaled $2.1 billion and 1.9 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

At December 31, 2016, Dominion owns the general partner, 50.9% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Midstream, which owns a preferred equity interest and the general partner interest in Cove Point. Additionally, Dominion owns the manager and 67% of the membership interest in certain merchant solar facilities, as discussed in Note 2. Dominion 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 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 is the primary beneficiary of Dominion Midstream, SBL Holdco and the merchant solar facilities, and Dominion 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's securities due within one year and long-term debt include $17 million and $377 million, respectively, of debt issued in 2016 by SBL Holdco net of issuance costs that is nonrecourse to Dominion and is secured by SBL Holdco's interest in the merchant solar facilities.

Dominion owns a 48% membership interest in Atlantic Coast Pipeline. See Note 9 for more details regarding the nature of this entity. Dominion concluded that Atlantic Coast Pipeline is a VIE because it has insufficient equity to finance its activities without additional subordinated financial support. Dominion 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 is obligated to provide capital contributions based on its ownership percentage. Dominion's maximum exposure to loss is limited to its current and future investment.

Dominion and Virginia Power

Dominion's and Virginia Power's nuclear decommissioning trust funds and Dominion's rabbi trusts hold investments in limited partnerships or similar type entities (see Note 9 for further details). Dominion and Virginia Power concluded that these partnership investments are VIEs due to the limited partners lacking the characteristics of a controlling financial interest. Dominion 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 and Virginia Power are obligated to provide capital contributions to the partnerships as required by each partnership agreement based on their ownership percentages. Dominion and Virginia Power's maximum exposure to loss is limited to their current and future investments.

Dominion and Dominion Gas

Dominion 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 of 2016, such right no longer existed and, as a result, Dominion 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 leaving a remaining aggregate summer generation capacity of approximately 418 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 entities during the remaining terms of Virginia Power's contracts and for the years the entities are expected to operate after its contractual relationships expire. The remaining contracts expire at various

Table of Contents

dates ranging from 2017 to 2021. Virginia Power is not subject to any risk of loss from these potential VIEs other than its remaining purchase commitments which totaled $287 million as of December 31, 2016. Virginia Power paid $144 million, $200 million, and $223 million for electric capacity and $31 million, $83 million, and $138 million for electric energy to these entities for the years ended December 31, 2016, 2015 and 2014, respectively.

Dominion Gas

DTI 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 DTI holds a membership interest in Atlantic Coast Pipeline, therefore DTI 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. DTI 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. DTI 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 Gas

Virginia Power and Dominion Gas purchased shared services from DRS, an affiliated VIE, of $346 million and $123 million, $318 million and $115 million, and $335 million and $106 million for the years ended December 31, 2016, 2015 and 2014, respectively. Virginia Power and Dominion Gas determined that neither is the primary beneficiary of DRS 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. DRS provides accounting, legal, finance and certain administrative and technical services to all Dominion subsidiaries, including Virginia Power and Dominion Gas. Virginia Power and Dominion Gas have no obligation to absorb more than their allocated shares of DRS 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 January 2016, Dominion expanded its short-term funding resources through a $1.0 billion increase to one of its joint revolving credit facility limits. In addition, Dominion utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion's credit ratings and the credit quality of its counterparties.

Dominion

Commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
At December 31, 2016				
Joint revolving credit facility(1)(2)	**$5,000**	**$ 3,155**	**$ —**	**$1,845**
Joint revolving credit facility(1)	**500**	**—**	**85**	**415**
Total	**$5,500**	**$ 3,155(3)**	**$ 85**	**$2,260**
At December 31, 2015				
Joint revolving credit facility(1)	$4,000	$ 3,353	$ —	$ 647
Joint revolving credit facility(1)	500	156	59	285
Total	$4,500	$ 3,509(3)	$ 59	$ 932

(1) In May 2016, the maturity dates for these facilities were extended from April 2019 to April 2020. These credit facilities 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) In January 2016, this facility limit was increased from $4.0 billion to $5.0 billion.
(3) The weighted-average interest rates of the outstanding commercial paper supported by Dominion's credit facilities were 1.05% and 0.62% at December 31, 2016 and 2015, respectively.

Dominion Questar's revolving multi-year and 364-day credit facilities with limits of $500 million and $250 million, respectively, were terminated in October 2016. Questar Gas' short-term financing is supported by the two joint revolving credit facilities discussed above with Dominion, Virginia Power and Dominion Gas, to which Questar Gas was added as a borrower in November 2016, with an initial aggregate sub-limit of $250 million. In December 2016, Questar Gas entered into a commercial paper program pursuant to which it began accessing the commercial paper markets.

In addition to the credit facilities mentioned above, SBL Holdco has $30 million of credit facilities which have a stated maturity date of December 2017 with automatic one-year renewals through the maturity of the SBL Holdco term loan agreement in 2023. As of December 31, 2016, no amounts were outstanding under these facilities.

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.

Table of Contents

Virginia Power's share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion, Dominion Gas and Questar Gas were as follows:

	Facility Limit(1)	Outstanding Commercial Paper	Outstanding Letters of Credit
(millions)			
At December 31, 2016			
Joint revolving credit facility(1)(2)	**$5,000**	**$ 65**	**$ —**
Joint revolving credit facility(1)	**500**	**—**	**1**
Total	**$5,500**	**$ 65(3)**	**$ 1**
At December 31, 2015			
Joint revolving credit facility(1)	$4,000	$ 1,500	$ —
Joint revolving credit facility(1)	500	156	—
Total	$4,500	$ 1,656(3)	$ —

(1) The full amount of the facilities is available to Virginia Power, less any amounts outstanding to co-borrowers Dominion, Dominion Gas and Questar Gas. Sub-limits for Virginia Power are set within the facility limit but can be changed at the option of Dominion, Dominion Gas and Questar Gas multiple times per year. At December 31, 2016, the sub-limit for Virginia Power was an aggregate $2.0 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. In May 2016, the maturity dates for these facilities were extended from April 2019 to April 2020. These credit facilities 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) In January 2016, this facility limit was increased from $4.0 billion to $5.0 billion.

(3) The weighted-average interest rates of the outstanding commercial paper supported by these credit facilities were 0.97% and 0.60% at December 31, 2016 and 2015, respectively.

In addition to the credit facility commitments mentioned above, Virginia Power also has a $100 million credit facility. In May 2016, the maturity date for this credit facility was extended from April 2019 to April 2020. In October 2016, this facility was reduced from $120 million to $100 million. As of December 31, 2016, this facility supports $100 million of certain variable rate tax-exempt financings of Virginia Power.

Dominion Gas

Dominion 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 Gas' share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion, Virginia Power and Questar Gas were as follows:

	Facility Limit(1)	Outstanding Commercial Paper	Outstanding Letters of Credit
(millions)			
At December 31, 2016			
Joint revolving credit facility(1)	**$1,000**	**$ 460**	**$ —**
Joint revolving credit facility(1)	**500**	**—**	**—**
Total	**$1,500**	**$ 460(2)**	**$ —**
At December 31, 2015			
Joint revolving credit facility(1)	$1,000	$ 391	$ —
Joint revolving credit facility(1)	500	—	—
Total	$1,500	$ 391(2)	$ —

(1) A maximum of a combined $1.5 billion of the facilities is available to Dominion Gas, assuming adequate capacity is available after giving effect to uses by co-borrowers Dominion, Virginia Power and Questar Gas. Sub-limits for Dominion Gas are set within the facility limit but can be changed at the option of the Companies multiple times per year. In November 2016, the aggregate sub-limit for Dominion Gas was decreased from $750 million to $500 million. If Dominion 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. In May 2016, the maturity dates for these facilities were extended from April 2019 to April 2020. These credit facilities 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 1.00% and 0.63% at December 31, 2016 and 2015, respectively.

Table of Contents

NOTE 17. LONG-TERM DEBT

At December 31,	2016 Weighted-average Coupon(1)	2016	2015
(millions, except percentages)			
Dominion Gas Holdings, LLC:			
Unsecured Senior Notes:			
1.05% to 2.8%, due 2016 to 2020	**2.68%**	**$ 1,150**	$ 1,550
2.875% to 4.8%, due 2023 to 2044(2)	**3.90%**	**2,413**	1,750
Dominion Gas Holdings, LLC total principal		**$ 3,563**	$ 3,300
Securities due within one year		**—**	(400)
Unamortized discount and debt issuance costs		**(35)**	(31)
Dominion Gas Holdings, LLC total long-term debt		**$ 3,528**	$ 2,869
Virginia Electric and Power Company:			
Unsecured Senior Notes:			
1.2% to 8.625%, due 2016 to 2019	**4.93%**	**$ 1,804**	$ 2,261
2.75% to 8.875%, due 2022 to 2046	**4.59%**	**7,940**	6,292
Tax-Exempt Financings(3):			
Variable rates, due 2016 to 2027	**1.22%**	**175**	194
1.75% to 5.6%, due 2023 to 2041	**2.25%**	**678**	678
Virginia Electric and Power Company total principal		**$10,597**	$ 9,425
Securities due within one year	**5.47%**	**(678)**	(476)
Unamortized discount, premium and debt issuances costs, net		**(67)**	(57)
Virginia Electric and Power Company total long-term debt		**$ 9,852**	$ 8,892
Dominion Resources, Inc.:			
Unsecured Senior Notes:			
Variable rate, due 2016		**$ —**	$ 600
1.25% to 6.4%, due 2016 to 2021	**2.83%**	**5,400**	3,900
2.75% to 7.0%, due 2022 to 2044	**4.68%**	**4,999**	4,599
Tax-Exempt Financing, variable rate, due 2041	**1.41%**	**75**	75
Unsecured Junior Subordinated Notes:			
2.962% and 4.104%, due 2019 and 2021	**3.53%**	**1,100**	—
Payable to Affiliated Trust, 8.4% due 2031	**8.40%**	**10**	10
Enhanced Junior Subordinated Notes:			
5.25% to 7.5%, due 2054 to 2076	**5.48%**	**1,485**	971
Variable rates, due 2066	**3.45%**	**422**	377
Remarketable Subordinated Notes, 1.07% to 2.0%, due 2019 to 2024	**1.79%**	**2,400**	2,100
Unsecured Debentures and Senior Notes:			
6.8% and 6.875%, due 2026 and 2027(4)	**6.81%**	**89**	89
Term Loan, variable rate, due 2017(5)	**1.85%**	**250**	—
Unsecured Senior and Medium-Term Notes(5):			
5.31% to 6.85%, due 2017 and 2018	**5.84%**	**135**	—
2.98% to 7.20%, due 2024 to 2051	**4.57%**	**500**	—
Term Loan, variable rate, due 2023(6)	**4.75%**	**405**	—
Tax-Exempt Financing, 1.55%, due 2033(7)	**1.55%**	**27**	27
Dominion Midstream Partners, LP:			
Term Loan, variable rate, due 2019	**2.19%**	**300**	—
Unsecured Senior and Medium-Term Notes, 5.83% and 6.48%, due 2018(8)	**5.84%**	**255**	—
Unsecured Senior Notes, 4.875%, due 2041(8)	**4.88%**	**180**	—
Dominion Gas Holdings, LLC total principal (from above)		**3,563**	3,300
Virginia Electric and Power Company total principal (from above)		**10,597**	9,425
Dominion Resources, Inc. total principal		**$32,192**	$25,473
Fair value hedge valuation(9)		**(1)**	7
Securities due within one year(10)	**3.13%**	**(1,709)**	(1,825)
Unamortized discount, premium and debt issuance costs, net		**(251)**	(187)
Dominion Resources, Inc. total long-term debt		**$30,231**	$23,468

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2016.
(2) Beginning June 30, 2016, amount includes foreign currency remeasurement adjustments.
(3) These financings relate to certain pollution control equipment at Virginia Power's generating facilities. Certain variable rate tax-exempt financings are supported by a $100 million credit facility that terminates in April 2020.
(4) Represents debt assumed by Dominion from the merger of its former CNG subsidiary.

Table of Contents

(5) Represents debt obligations of Dominion Questar or Questar Gas. See Note 3 for more information.
(6) Represents debt associated with SBL Holdco. The debt is nonrecourse to Dominion and is secured by SBL Holdco's interest in certain merchant solar facilities.
(7) Represents debt obligations of a DEI subsidiary.
(8) Represents debt obligations of Questar Pipeline. See Note 3 for more information.
(9) Represents the valuation of certain fair value hedges associated with Dominion's fixed rate debt.
(10) 2015 excludes $100 million of variable rate short-term notes that were purchased and cancelled in February 2016 using proceeds from the issuance of long-term debt. The notes would have otherwise matured in May 2016.

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, 2016, were as follows:

(millions, except percentages)	2017	2018	2019	2020	2021	Thereafter	Total
Dominion Gas	$ —	$ —	$ 450	$ 700	$ —	$ 2,413	$ 3,563
Weighted-average Coupon			2.50%	2.80%		3.90%	
Virginia Power							
Unsecured Senior Notes	$ 604	$ 850	$ 350	$ —	$ —	$ 7,940	$ 9,744
Tax-Exempt Financings	75	—	—	—	—	778	853
Total	$ 679	$ 850	$ 350	$ —	$ —	$ 8,718	$10,597
Weighted-average Coupon	5.47%	4.17%	5.00%			4.37%	
Dominion							
Term Loans	$ 268	$ 20	$ 321	$ 19	$ 19	$ 308	$ 955
Unsecured Senior Notes	1,368	3,275	2,500	700	900	16,122	24,865
Tax-Exempt Financings	75	—	—	—	—	880	955
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts	—	—	—	—	—	10	10
Unsecured Junior Subordinated Notes	—	—	550	—	550	—	1,100
Enhanced Junior Subordinated Notes	—	—	—	—	—	1,907	1,907
Remarketable Subordinated Notes	—	—	—	1,000	700	700	2,400
Total	$1,711	$3,295	$3,371	$1,719	$2,169	$19,927	$32,192
Weighted-average Coupon	3.13%	3.62%	3.09%	2.07%	3.12%	4.38%	

The Companies short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2016, there were no events of default under these covenants.

In January 2017, Dominion issued $400 million of 1.875% senior notes and $400 million of 2.75% senior notes that mature in 2019 and 2022, respectively.

Senior Note Redemptions

As part of Dominion's Liability Management Exercise, in December 2014, Dominion redeemed five outstanding series of senior notes with an aggregate outstanding principal of $1.9 billion. The aggregate redemption price paid in December 2014 was $2.2 billion and represents the principal amount outstanding, accrued and unpaid interest and the applicable make-whole premium of $263 million. Total charges for the Liability Management Exercise of $284 million, including the make-whole premium, were recognized and recorded in interest expense in Dominion's Consolidated Statements of Income. Proceeds from Dominion's issuance of senior notes in November 2014 were used to offset the payment of the redemption price. Also see Convertible Securities called for redemption below.

Convertible Securities

As part of Dominion's Liability Management Exercise, in November 2014, Dominion provided notice to redeem all $22 million of outstanding contingent convertible senior notes. The senior notes were eligible for conversion during 2014. However, in lieu of redemption, holders elected to convert the remaining $22 million of notes in December 2014 into $26 million of common stock. Proceeds from Dominion's issuance of senior notes in November 2014 were used to offset the portion of the conversions paid in cash.

Enhanced Junior Subordinated Notes

In June 2006 and September 2006, Dominion 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 June 2009, Dominion issued $685 million of 8.375% June 2009 hybrids. The June 2009 hybrids were listed on the NYSE under the symbol DRU.

In October 2014, Dominion 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 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 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 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 executed RCCs in connection with its issuance of the June 2006 hybrids, the September 2006 hybrids, and the June

2009 hybrids. Under the terms of the RCCs, Dominion covenants to and for the benefit of designated covered debtholders, as may be designated from time to time, that Dominion 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 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 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. In July 2014, Dominion amended the RCC of the June 2009 hybrids to expand the measurement period for consideration of proceeds from the sale of common stock or other equity-like issuances from 180 days to 365 days. The proceeds Dominion receives from the replacement offering, adjusted by a predetermined factor, must equal or exceed the redemption or repurchase price.

As part of Dominion's Liability Management Exercise, in October 2014, Dominion redeemed all $685 million of the June 2009 hybrids plus accrued interest with the net proceeds from the issuance of the October 2014 hybrids. In 2015, Dominion 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 purchased and cancelled $38 million and $4 million of the June 2006 hybrids and the September 2006 hybrids, respectively. In July 2016, Dominion 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 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 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.

From time to time, Dominion 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 additional tender offers or otherwise.

Remarketable Subordinated Notes

In June 2013, Dominion 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. The Corporate Units were listed on the NYSE under the symbols DCUA and DCUB, respectively.

Each Corporate Unit consisted of a stock purchase contract and 1/20 interest in a RSN issued by Dominion. The stock purchase contracts obligated the holders to purchase shares of Dominion 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 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 March 2016 and May 2016, Dominion 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 ceased to have the ability to redeem the notes at its option or defer interest payments. At December 31, 2016, the securities are included in junior subordinated notes in Dominion's Consolidated Balance Sheets. Dominion did not receive any proceeds from the remarketings. Remarketing proceeds belonged to the investors holding the related 2013 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 for issuance of 8.5 million shares of its common stock on both April 1, 2016 and July 1, 2016. See Issuance of Common Stock below for a description of common stock issued by Dominion in April 2016 and July 2016 under the stock purchase contracts.

In July 2014, Dominion issued $1.0 billion of 2014 Series A 6.375% Equity Units, initially in the form of Corporate Units. In August 2016, Dominion 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 symbols DCUC and DCUD, respectively. The net proceeds from the 2016 Equity Units were used to finance the Dominion Questar Combination. See Note 3 for more information.

Each 2014 Series A Corporate Unit consists of a stock purchase contract and 1/20 interest in a 2014 Series A RSN issued by Dominion. 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 and a 1/40 interest in a 2016 Series A-2 RSN issued by Dominion. The stock purchase contracts obligate the holders to purchase shares of Dominion 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 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 makes quarterly interest payments on the RSNs and quarterly contract adjustment payments on the stock purchase contracts, at the rates described below. Dominion 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 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 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.

Table of Contents

Dominion 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 applies the treasury stock method to the Equity Units.

Pursuant to the terms of the 2014 Equity Units and 2016 Equity Units, Dominion expects to remarket the 2014 Series A RSNs during the second quarter of 2017 and 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 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 for issuance of its common stock.

Under the terms of the stock purchase contracts, assuming no anti-dilution or other adjustments, Dominion will issue between 11.6 million and 14.5 million shares of its common stock in July 2017 and between 15.0 million and 18.7 million shares in August 2019. A total of 40.9 million shares of Dominion's common stock has been reserved for issuance in connection with the stock purchase contracts.

Selected information about Dominion'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	RSN Maturity Date
(millions, except interest rates)								
7/1/2014	20	$ 982.0	$ 1,000.0	1.500%	4.875%	$ 142.8	7/1/2017	7/1/2020
8/15/2016(2)	28	$1,374.8	$ 1,400.0	2.000%(3)	4.750%	$ 190.6	8/15/2019	

(1) Payments of $94 million and $101 million were made in 2016 and 2015, respectively, including payments for the remarketed 2013 Series A and B notes. The stock purchase contract liability was $212 million and $115 million at December 31, 2016 and 2015, 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 is authorized to issue up to 20 million shares of preferred stock; however, none were issued and outstanding at December 31, 2016 or 2015.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference. During 2014, Virginia Power redeemed 2.59 million shares, which represented all outstanding series of its preferred stock, some of which were redeemed as a part of Dominion's Liability Management Exercise in September 2014. Upon redemption, each series was no longer outstanding for any purpose and dividends ceased to accumulate. Virginia Power had no preferred stock issued and outstanding at December 31, 2016 or 2015.

NOTE 19. EQUITY

Issuance of Common Stock

DOMINION

Dominion maintains Dominion Direct® and a number of employee savings plans through which contributions may be invested in Dominion'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 began purchasing its common stock on the open market for these plans. In April 2014, Dominion began issuing new common shares for these direct stock purchase plans.

During 2016, Dominion received cash proceeds, net of fees and commissions, of $2.2 billion from the issuance of approximately 32 million shares of common stock through various programs resulting in approximately 628 million of shares of common stock outstanding at December 31, 2016. These proceeds include cash of $295 million received from the issuance of 4.0 million of such shares through Dominion Direct® and employee savings plans.

In December 2014, Dominion 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 December 2014, Dominion entered into four 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 and the sales agents and in conformance with applicable securities laws. Following issuances during the first and second quarters of 2015, Dominion has the ability to issue up to approximately $200 million of stock under the 2014 sales agency agreements; however, no additional issuances occurred under these agreements in 2016.

In both April 2016 and July 2016, Dominion issued 8.5 million shares under the related stock purchase contracts entered into as part of Dominion's 2013 Equity Units and received $1.1 billion of total proceeds. Additionally, Dominion 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 Questar Combination. See Note 3 for more information.

VIRGINIA POWER

In 2016, 2015 and 2014, Virginia Power did not issue any shares of its common stock to Dominion.

Shares Reserved for Issuance

At December 31, 2016, Dominion had approximately 63 million shares reserved and available for issuance for Dominion 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 did not repurchase any shares in 2016 or 2015 and does not plan to repurchase shares during 2017, 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 Midstream Units

In September 2015, Dominion initiated a program to purchase from the market up to $50 million of common units representing limited partner interests in Dominion Midstream, which expired in September 2016. Dominion 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 Midstream Units

During the fourth quarter of 2016, Dominion 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 Questar Pipeline from Dominion. 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 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 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's net income attributable to noncontrolling interests.

Table of Contents

Accumulated Other Comprehensive Income (Loss)

Presented in the table below is a summary of AOCI by component:

At December 31,	2016	2015
(millions)		
Dominion		
Net deferred losses on derivatives-hedging activities, net of tax of $173 and $110	**$ (280)**	$(176)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(318) and $(281)	**569**	504
Net unrecognized pension and other postretirement benefit costs, net of tax of $691 and $525	**(1,082)**	(797)
Other comprehensive loss from equity method investees, net of tax of $4 and $4	**(6)**	(5)
Total AOCI	**$ (799)**	$(474)
Virginia Power		
Net deferred losses on derivatives-hedging activities, net of tax of $5 and $4	**$ (8)**	$ (7)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(35) and $(30)	**54**	47
Total AOCI	**$ 46**	$ 40
Dominion Gas		
Net deferred losses on derivatives-hedging activities, net of tax of $15 and $10	**$ (24)**	$ (17)
Net unrecognized pension costs, net of tax of $68 and $56	**(99)**	(82)
Total AOCI	**$ (123)**	$ (99)

DOMINION

The following table presents Dominion'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, 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)**
Year Ended December 31, 2015					
Beginning balance	$ (178)	$ 548	$ (782)	$ (4)	$(416)
Other comprehensive income before reclassifications: gains (losses)	110	6	(66)	(1)	49
Amounts reclassified from AOCI: (gains) losses(1)	(108)	(50)	51	—	(107)
Net current period other comprehensive income (loss)	2	(44)	(15)	(1)	(58)
Ending balance	$ (176)	$ 504	$ (797)	$ (5)	$(474)

(1) See table below for details about these reclassifications.

Table of Contents

The following table presents Dominion'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, 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**	
Year Ended December 31, 2015		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$ (203)	Operating revenue
	15	Purchased gas
	1	Electric fuel and other energy-related purchases
Interest rate contracts	11	Interest and related charges
Total	(176)	
Tax	68	Income tax expense
Total, net of tax	$ (108)	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$ (110)	Other income
Impairment	31	Other income
Total	(79)	
Tax	29	Income tax expense
Total, net of tax	$ (50)	
Unrecognized pension and other postretirement benefit costs:		
Prior-service costs (credits)	$ (12)	Other operations and maintenance
Actuarial losses	98	Other operations and maintenance
Total	86	
Tax	(35)	Income tax expense
Total, net of tax	$ 51	

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, 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**
Year Ended December 31, 2015			
Beginning balance	$ (7)	$ 57	$ 50
Other comprehensive income before reclassifications: gains (losses)	(1)	(4)	(5)
Amounts reclassified from AOCI: (gains) losses(1)	1	(6)	(5)
Net current period other comprehensive income (loss)	—	(10)	(10)
Ending balance	$ (7)	$ 47	$ 40

(1) See table below for details about these reclassifications.

Table of Contents

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, 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)**	
Year Ended December 31, 2015		
(Gains) losses on cash flow hedges:		
Commodity contracts	$ 1	Electric fuel and other energy-related purchases
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	$ (14)	Other income
Impairment	4	Other income
Total	(10)	
Tax	4	Income tax expense
Total, net of tax	$ (6)	

DOMINION GAS

The following table presents Dominion 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, 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 loss	**(7)**	**(17)**	**(24)**
Ending balance	**$ (24)**	**$ (99)**	**$(123)**
Year Ended December 31, 2015			
Beginning balance	$ (20)	$ (66)	$ (86)
Other comprehensive income before reclassifications: gains (losses)	6	(20)	(14)
Amounts reclassified from AOCI(1): (gains) losses	(3)	4	1
Net current period other comprehensive income (loss)	3	(16)	(13)
Ending balance	$ (17)	$ (82)	$ (99)

(1) See table below for details about these reclassifications.

Table of Contents

The following table presents Dominion Gas' 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, 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**	
Year Ended December 31, 2015		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$ (6)	Operating revenue
Total	(6)	
Tax	3	Income tax expense
Total, net of tax	$ (3)	
Unrecognized pension costs:		
Actuarial losses	$ 7	Other operations and maintenance
Total	7	
Tax	(3)	Income tax expense
Total, net of tax	$ 4	

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, 2016, approximately 24 million shares were available for future grants under these plans.

Dominion 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's results for the years ended December 31, 2016, 2015 and 2014 include $33 million, $39 million, and $39 million, respectively, of compensation costs and $11 million, $14 million, and $14 million, respectively of income tax benefits related to Dominion's stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in Dominion's Consolidated Statements of Income. Excess Tax Benefits are classified as a financing cash flow. Dominion realized less than $1 million and $3 million of Excess Tax Benefits from the vesting of restricted stock awards during the year ended December 31, 2016 and 2015, respectively, and less than $1 million during the year ended December 31, 2014.

RESTRICTED STOCK

Restricted stock grants are made to officers under Dominion's LTIP and may also be granted to certain key non-officer employees from time to time. The fair value of Dominion's restricted stock awards is equal to the closing price of Dominion'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, 2016, 2015 and 2014:

	Shares	Weighted - average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2013	1,007	$ 49.35
Granted	354	67.98
Vested	(278)	44.50
Cancelled and forfeited	(18)	53.61
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**

As of December 31, 2016, unrecognized compensation cost related to nonvested restricted stock awards totaled $31 million and is expected to be recognized over a weighted-average period of 1.9 years. The fair value of restricted stock awards that vested was $21 million, $37 million, and $19 million in 2016, 2015 and 2014, 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 stock and the applicable federal, state and local tax withholding rates.

GOAL-BASED STOCK

Goal-based stock awards are granted under Dominion's LTIP to officers who have not achieved a certain targeted level of share ownership, in lieu of cash-based performance grants. Current outstanding goal-based shares include awards granted to officers in February 2015 and February 2016.

Table of Contents

The issuance of awards is based on the achievement of two performance metrics during a two-year period: 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 actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is determined on the date of grant. Awards to officers vest at the end of the two-year performance period. All goal-based stock awards are settled by issuing new shares.

The following table provides a summary of goal-based stock activity for the years ended December 31, 2016, 2015 and 2014:

	Targeted Number of Shares	Weighted - average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2013	5	$53.85
Granted	13	68.83
Vested	(1)	52.48
Nonvested at December 31, 2014	17	$65.15
Granted	14	72.72
Vested	(7)	56.22
Nonvested at December 31, 2015	24	$72.27
Granted	**12**	**69.93**
Vested	**(10)**	**68.83**
Cancelled and forfeited	**(3)**	**68.83**
Nonvested at December 31, 2016	**23**	**$72.99**

At December 31, 2016, the targeted number of shares expected to be issued under the February 2015 and February 2016 awards was approximately 23 thousand. In January 2017, the CGN Committee determined the actual performance against metrics established for the February 2015 awards with a performance period that ended December 31, 2016. Based on that determination, the total number of shares to be issued under the February 2015 goal-based stock awards was approximately 9 thousand.

As of December 31, 2016, unrecognized compensation cost related to nonvested goal-based stock awards was not material.

CASH-BASED PERFORMANCE GRANTS

Cash-based performance grants are made to Dominion's officers under Dominion'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 2014, a cash-based performance grant was made to officers. The performance grant was paid out in January 2016 based on the achievement of two performance metrics during 2014 and 2015: 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 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 is expected to occur by March 15, 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. At December 31, 2016, the targeted amount of the grant was $14 million and a liability of $6 million had been accrued for this 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, 2016, 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, 2016, 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, 2016, 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, 2016.

See Note 17 for a description of potential restrictions on dividend payments by Dominion 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 and Dominion Gas—Defined Benefit Plans

Dominion provides certain retirement benefits to eligible active employees, retirees and qualifying dependents. Dominion Gas participates in a number of the Dominion-sponsored retirement plans. Under the terms of its benefit plans, Dominion 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 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'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 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 Gas employees not represented by collective bargaining units are covered by the Dominion Pension Plan, a defined benefit pension plan sponsored by Dominion that provides benefits to multiple Dominion subsidiaries. Pension benefits for Dominion Gas employees represented by collective bargaining units are covered by separate pension plans for East Ohio and, for DTI, a plan that provides benefits to employees of both DTI and Hope. Employee compensation is the basis for allocating pension costs and obligations between DTI and Hope and determining East Ohio's share of total pension costs.

Retiree healthcare and life insurance benefits for Dominion Gas employees not represented by collective bargaining units are covered by the Dominion Retiree Health and Welfare Plan, a plan sponsored by Dominion that provides certain retiree healthcare and life insurance benefits to multiple Dominion subsidiaries. Retiree healthcare and life insurance benefits for Dominion Gas employees represented by collective bargaining units are covered by separate other postretirement benefit plans for East Ohio and, for DTI, a plan that provides benefits to both DTI and Hope. Employee headcount is the basis for allocating other postretirement benefit costs and obligations between DTI 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 uses December 31 as the measurement date for all of its employee benefit plans, including those in which Dominion Gas participates. Dominion 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 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's pension and other postretirement benefit plans hold investments in trusts to fund employee benefit payments. Dominion's pension and other postretirement plan assets experienced aggregate actual returns of $534 million in 2016 and aggregate actual losses of $72 million in 2015, versus expected returns of $691 million and $648 million, respectively. Dominion Gas' pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual returns of $130 million in 2016 and aggregate actual losses of $13 million in 2015, versus expected returns of $157 million and $150 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 changed its assumption for mortality rates to reflect a generational improvement scale. This change in assumption increased net periodic benefit cost for Dominion and Dominion Gas (for employees represented by collective bargaining units) by $25 million and $3 million, respectively, for 2015.

During 2016, Dominion and Dominion 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 and $24 million and $9 million in the pension and other postretirement benefits obligations, respectively, at December 31, 2016 for Dominion Gas. In addition, these changes will increase net periodic benefit costs for Dominion by $42 million for 2017. The increase in net periodic benefit costs for Dominion Gas for 2017 is immaterial.

Plan Amendments and Remeasurements

In the third quarter of 2016, Dominion 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'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.

In the third quarter of 2014, East Ohio remeasured its other postretirement benefit plan as a result of an amendment that changed medical coverage upon the attainment of age 65 for certain future retirees effective January 1, 2016. For employees represented by collective bargaining units, the remeasurement resulted in an increase in the accumulated postretirement benefit obligation of $22 million. The impact of the remeasurement on net periodic benefit credit was recognized prospectively from the remeasurement date and reduced net periodic benefit credit for 2014, for employees represented by collective bargaining units, by less than $1 million. The discount rate used for the remeasurement was 4.20% and the expected long-term rate of return used was 8.50%. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2013.

Table of Contents

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 and Dominion Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
Year Ended December 31,	**2016**	2015	**2016**	2015
(millions, except percentages)				
Dominion				
Changes in benefit obligation:				
Benefit obligation at beginning of year	**$ 6,391**	$ 6,667	**$ 1,430**	$ 1,571
Dominion Questar Combination	**817**	—	**85**	—
Service cost	**118**	126	**31**	40
Interest cost	**317**	287	**65**	67
Benefits paid	**(286)**	(246)	**(83)**	(79)
Actuarial (gains) losses during the year	**784**	(443)	**166**	(138)
Plan amendments(1)	**—**	—	**(216)**	(31)
Settlements and curtailments(2)	**(9)**	—	**—**	—
Benefit obligation at end of year	**$ 8,132**	$ 6,391	**$ 1,478**	$ 1,430
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 6,166**	$ 6,480	**$ 1,382**	$ 1,402
Dominion Questar Combination	**704**	—	**45**	—
Actual return (loss) on plan assets	**426**	(71)	**108**	(1)
Employer contributions	**15**	3	**12**	12
Benefits paid	**(286)**	(246)	**(35)**	(31)
Settlements(2)	**(9)**	—	**—**	—
Fair value of plan assets at end of year	**$ 7,016**	$ 6,166	**$ 1,512**	$ 1,382
Funded status at end of year	**$ (1,116)**	$ (225)	**$ 34**	$ (48)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	**$ 930**	$ 931	**$ 148**	$ 12
Other current liabilities	**(43)**	(14)	**(5)**	(3)
Noncurrent pension and other postretirement benefit liabilities	**(2,003)**	(1,142)	**(109)**	(57)
Net amount recognized	**$ (1,116)**	$ (225)	**$ 34**	$ (48)
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	**3.31%–4.50%**	4.96%–4.99%	**3.92%–4.47%**	4.93%–4.94%
Weighted average rate of increase for compensation	**4.09%**	4.22%	**3.29%**	4.22%
Dominion Gas				
Changes in benefit obligation:				
Benefit obligation at beginning of year	**$ 608**	$ 638	**$ 292**	$ 320
Service cost	**13**	15	**5**	7
Interest cost	**30**	27	**14**	14
Benefits paid	**(32)**	(29)	**(19)**	(18)
Actuarial (gains) losses during the year	**64**	(43)	**28**	(31)
Benefit obligation at end of year	**$ 683**	$ 608	**$ 320**	$ 292
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 1,467**	$ 1,510	**$ 283**	$ 288
Actual return (loss) on plan assets	**107**	(14)	**23**	1
Employer contributions	**—**	—	**12**	12
Benefits paid	**(32)**	(29)	**(19)**	(18)
Fair value of plan assets at end of year	**$ 1,542**	$ 1,467	**$ 299**	$ 283
Funded status at end of year	**$ 859**	$ 859	**$ (21)**	$ (9)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	**$ 859**	$ 859	**$ —**	$ —
Noncurrent pension and other postretirement benefit liabilities(3)	**—**	—	**(21)**	(9)
Net amount recognized	**$ 859**	$ 859	**$ (21)**	$ (9)
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	**4.50%**	4.99%	**4.47%**	4.93%
Weighted average rate of increase for compensation	**4.11%**	3.93%	**n/a**	3.93%

(1) 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. 2015 amount relates primarily to a plan amendment that changed retiree medical benefits for certain nonunion employees after Medicare eligibility.

(2) Relates primarily to a settlement for certain executives.

(3) Reflected in other deferred credits and other liabilities in Dominion Gas' Consolidated Balance Sheets.

The ABO for all of Dominion's defined benefit pension plans was $7.3 billion and $5.8 billion at December 31, 2016 and 2015, respectively. The ABO for the defined benefit pension plans covering Dominion Gas employees represented by collective bargaining units was $640 million and $578 million at December 31, 2016 and 2015, respectively.

Under its funding policies, Dominion 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 determines the amount of contributions for the current year, if any, at that time. During 2016, Dominion and Dominion Gas made no contributions to the qualified defined benefit pension plans and no contributions are currently expected in 2017. In January 2017, Dominion made a $75 million contribution to Dominion Questar's qualified pension plan to satisfy a regulatory condition to closing of the Dominion Questar Combination. 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 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's subsidiaries, including Dominion Gas, fund other postretirement benefit costs through VEBAs. Dominion's remaining subsidiaries do not prefund other postretirement benefit costs but instead pay claims as presented. Dominion's contributions to VEBAs, all of which pertained to Dominion Gas employees, totaled $12 million for both 2016 and 2015, and Dominion expects to contribute approximately $12 million to the Dominion VEBAs in 2017, all of which pertains to Dominion Gas employees.

Dominion and Dominion Gas do not expect any pension or other postretirement plan assets to be returned during 2017.

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 and Dominion Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
As of December 31,	**2016**	2015	**2016**	2015
(millions)				
Dominion				
Benefit obligation	**$7,386**	$5,728	**$ 470**	$ 359
Fair value of plan assets	**5,340**	4,571	**356**	299
Dominion Gas				
Benefit obligation	**$ —**	$ —	**$ 320**	$ 292
Fair value of plan assets	**—**	—	**299**	283

The following table provides information on the ABO and fair value of plan assets for Dominion's pension plans with an ABO in excess of plan assets:

As of December 31,	**2016**	2015
(millions)		
Accumulated benefit obligation	**$5,987**	$5,198
Fair value of plan assets	**4,653**	4,571

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid for Dominion's and Dominion Gas' (for employees represented by collective bargaining units) plans:

	Estimated Future Benefit Payments	
	Pension Benefits	Other Postretirement Benefits
(millions)		
Dominion		
2017	**$ 380**	**$ 92**
2018	**361**	**96**
2019	**373**	**97**
2020	**398**	**99**
2021	**415**	**100**
2022-2026	**2,345**	**490**
Dominion Gas		
2017	**$ 33**	**$ 17**
2018	**35**	**18**
2019	**37**	**19**
2020	**38**	**19**
2021	**40**	**20**
2022-2026	**211**	**101**

Plan Assets

Dominion'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, Dominion Gas is subject to Dominion'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'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 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

Table of Contents

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'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'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.

Table of Contents

The fair values of Dominion's and Dominion Gas' (for employees represented by collective bargaining units) pension plan assets by asset category are as follows:

At December 31,	2016				2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(millions)								
Dominion								
Cash and cash equivalents	**$ 12**	**$ 2**	**$ —**	**$ 14**	$ 16	$ —	$ —	$ 16
Common and preferred stocks:								
U.S.	**1,705**	**—**	**—**	**1,705**	1,736	—	—	1,736
International	**928**	**—**	**—**	**928**	786	—	—	786
Insurance contracts	**—**	**334**	**—**	**334**	—	330	—	330
Corporate debt instruments	**35**	**682**	**—**	**717**	44	695	—	739
Government securities	**13**	**522**	**—**	**535**	85	390	—	475
Total recorded at fair value	**$2,693**	**$1,540**	**$ —**	**$4,233**	$2,667	$1,415	$ —	$4,082
Assets recorded at NAV(1):								
Common/collective trust funds(2)				**1,960**				1,200
Alternative investments:								
Real estate funds				**121**				153
Private equity funds				**506**				465
Debt funds				**153**				170
Hedge funds				**25**				86
Total recorded at NAV				**$2,765**				$2,074
Total investments(3)				**$6,998**				$6,156
Dominion Gas								
Cash and cash equivalents	**$ 3**	**$ —**	**$ —**	**$ 3**	$ 4	$ —	$ —	$ 4
Common and preferred stocks:								
U.S.	**375**	**—**	**—**	**375**	413	—	—	413
International	**203**	**—**	**—**	**203**	187	—	—	187
Insurance contracts	**—**	**73**	**—**	**73**	—	78	—	78
Corporate debt instruments	**8**	**150**	**—**	**158**	10	165	—	175
Government securities	**3**	**115**	**—**	**118**	20	93	—	113
Total recorded at fair value	**$ 592**	**$ 338**	**$ —**	**$ 930**	$ 634	$ 336	$ —	$ 970
Assets recorded at NAV(1):								
Common/collective trust funds(4)				**430**				286
Alternative investments:								
Real estate funds				**27**				36
Private equity funds				**111**				111
Debt funds				**34**				40
Hedge funds				**6**				21
Total recorded at NAV				**$ 608**				$ 494
Total investments(5)				**$1,538**				$1,464

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient are not required to be categorized in the fair value hierarchy.

(2) Also included in the common collective trust funds is the Northern Trust Collective Short-Term Investment Fund, totaling $167 million and $125 million at December 31, 2016 and 2015, respectively, which is comprised of money market instruments with short-term maturities used for temporary investment. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

(3) Includes net assets related to pending sales of securities of $46 million, net accrued income of $19 million, and excludes net assets related to pending purchases of securities of $47 million at December 31, 2016. Includes net assets related to pending sales of securities of $112 million, net accrued income of $16 million, and excludes net assets related to pending purchases of securities of $118 million at December 31, 2015.

(4) Also included in the common collective trust funds is the Northern Trust Collective Short-Term Investment Fund, totaling $37 million and $30 million at December 31, 2016 and 2015, respectively, which is comprised of money market instruments with short-term maturities used for temporary investment. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

(5) Includes net assets related to pending sales of securities of $10 million, net accrued income of $4 million, and excludes net assets related to pending purchases of securities of $10 million at December 31, 2016. Includes net assets related to pending sales of securities of $27 million, net accrued income of $4 million, and excludes net assets related to pending purchases of securities of $28 million at December 31, 2015.

Table of Contents

The fair values of Dominion's and Dominion Gas' (for employees represented by collective bargaining units) other postretirement plan assets by asset category are as follows:

At December 31,	2016				2015			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
(millions)								
Dominion								
Cash and cash equivalents	**$ 1**	**$ 1**	**$ —**	**$ 2**	$ 1	$ 1	$ —	$ 2
Common and preferred stocks:								
U.S.	**571**	**—**	**—**	**571**	531	—	—	531
International	**143**	**—**	**—**	**143**	134	—	—	134
Insurance contracts	**—**	**19**	**—**	**19**	—	18	—	18
Corporate debt instruments	**2**	**40**	**—**	**42**	3	38	—	41
Government securities	**1**	**30**	**—**	**31**	4	22	—	26
Total recorded at fair value	**$718**	**$ 90**	**$ —**	**$ 808**	$673	$ 79	$ —	$ 752
Assets recorded at NAV(1):								
Common/collective trust funds(2)				**621**				543
Alternative investments:								
Real estate funds				**9**				14
Private equity funds				**59**				54
Debt funds				**12**				14
Hedge funds				**1**				5
Total recorded at NAV				**$ 702**				$ 630
Total investments(3)				**$1,510**				$1,382
Dominion Gas								
Common and preferred stocks:								
U.S.	**$121**	$ —	$ —	$ 121	$113	$ —	$ —	$ 113
International	**24**	—	—	24	24	—	—	24
Total recorded at fair value	**$145**	**$ —**	**$ —**	**$ 145**	$137	$ —	$ —	$ 137
Assets recorded at NAV(1):								
Common/collective trust funds(4)				**140**				132
Alternative investments:								
Real estate funds				**1**				2
Private equity funds				**12**				11
Debt funds				**1**				1
Total recorded at NAV				**$ 154**				$ 146
Total investments				**$ 299**				$ 283

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient are not required to be categorized in the fair value hierarchy.

(2) Also included in the common collective trust funds is the Northern Trust Collective Short-Term Investment Fund, totaling $16 million and $9 million at December 31, 2016 and 2015, respectively, which is comprised of money market instruments with short-term maturities used for temporary investment. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

(3) Includes net assets related to pending sales of securities of $5 million, net accrued income of $2 million, and excludes net assets related to pending purchases of securities of $5 million at December 31, 2016.

(4) Also included in the common collective trust funds is the Northern Trust Collective Short-Term Investment Fund, totaling $2 million and $3 million at December 31, 2016 and 2015, respectively, which is comprised of money market instruments with short-term maturities used for temporary investment. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

Table of Contents

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 is 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.

Table of Contents

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's and Dominion Gas' (for employees represented by collective bargaining units) plans are as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2016**	2015	2014	**2016**	2015	2014
(millions, except percentages)						
Dominion						
Service cost	**$ 118**	$ 126	$ 114	**$ 31**	$ 40	$ 32
Interest cost	**317**	287	290	**65**	67	67
Expected return on plan assets	**(573)**	(531)	(499)	**(118)**	(117)	(111)
Amortization of prior service (credit) cost	**1**	2	3	**(35)**	(27)	(28)
Amortization of net actuarial loss	**111**	160	111	**8**	6	2
Settlements and curtailments	**1**	—	1	**—**	—	—
Net periodic benefit (credit) cost	**$ (25)**	$ 44	$ 20	**$ (49)**	$ (31)	$ (38)
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ 931**	$ 159	$ 784	**$ 178**	$ (18)	$ 183
Prior service (credit) cost	**—**	—	—	**(216)**	(31)	9
Settlements and curtailments	**(1)**	—	(1)	**—**	—	—
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(111)**	(160)	(111)	**(8)**	(6)	(2)
Amortization of prior service credit (cost)	**(1)**	(2)	(3)	**35**	27	28
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ 818**	$ (3)	$ 669	**$ (11)**	$ (28)	$ 218
Significant assumptions used to determine periodic cost:						
Discount rate	**2.87%-4.99%**	4.40%	5.20%-5.30%	**3.56%-4.94%**	4.40%	4.20%-5.10%
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	**4.22%**	4.22%	4.21%	**4.22%**	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)				**2020**	2019	2018
Dominion Gas						
Service cost	**$ 13**	$ 15	$ 12	**$ 5**	$ 7	$ 6
Interest cost	**30**	27	28	**14**	14	13
Expected return on plan assets	**(134)**	(126)	(115)	**(23)**	(24)	(23)
Amortization of prior service (credit) cost	**—**	1	1	**1**	(1)	(1)
Amortization of net actuarial loss	**13**	20	19	**1**	2	—
Net periodic benefit (credit) cost	**$ (78)**	$ (63)	$ (55)	**$ (2)**	$ (2)	$ (5)
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ 91**	$ 97	$ 43	**$ 28**	$ (9)	$ 40
Prior service cost	**—**	—	—	**—**	—	10
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(13)**	(20)	(19)	**(1)**	(2)	—
Amortization of prior service credit (cost)	**—**	(1)	(1)	**(1)**	1	1
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ 78**	$ 76	$ 23	**$ 26**	$ (10)	$ 51
Significant assumptions used to determine periodic cost:						
Discount rate	**4.99%**	4.40%	5.20%	**4.93%**	4.40%	4.20%-5.00%
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	**3.93%**	3.93%	3.93%	**3.93%**	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)(2)				**2020**	2019	2018

(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.

Table of Contents

The components of AOCI and regulatory assets and liabilities for Dominion's and Dominion 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,	**2016**	2015	**2016**	2015
(millions)				
Dominion				
Net actuarial loss	**$3,200**	$2,381	**$ 283**	$ 114
Prior service (credit) cost	**4**	5	**(419)**	(237)
Total(1)	**$3,204**	$2,386	**$(136)**	$(123)
Dominion Gas				
Net actuarial loss	**$ 458**	$ 380	**$ 60**	$ 33
Prior service (credit) cost	**—**	1	**7**	7
Total(2)	**$ 458**	$ 381	**$ 67**	$ 40

(1) 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. As of December 31, 2015, of the $2.4 billion and $(123) million related to pension benefits and other postretirement benefits, $1.4 billion and $(90) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities.

(2) 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. As of December 31, 2015, of the $381 million related to pension benefits, $138 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $40 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's and Dominion Gas' (for employees represented by collective bargaining units) plans as of December 31, 2016 that are expected to be amortized as components of net periodic benefit (credit) cost in 2017:

	Pension Benefits	Other Postretirement Benefits
(millions)		
Dominion		
Net actuarial loss	**$ 161**	**$ 13**
Prior service (credit) cost	**1**	**(47)**
Dominion Gas		
Net actuarial loss	**$ 16**	**$ 2**
Prior service (credit) cost	**—**	**1**

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 develops assumptions, which are then compared to the forecasts of an independent investment advisor (except for the expected long-term rates of return) to ensure reasonableness. An internal committee selects the final assumptions used for Dominion's pension and other postretirement plans, including those in which Dominion Gas participates, including discount rates, expected long-term rates of return, healthcare cost trend rates and mortality rates.

Dominion 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 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;
- Forecasts of an independent investment advisor;
- 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 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 Gas participates.

Mortality rates are developed from actual and projected plan experience for postretirement benefit plans. Dominion's actuary conducts an experience study periodically as part of the process to select its best estimate of mortality. Dominion considers both standard mortality tables and improvement factors as well as the plans' actual experience when selecting a best estimate. During 2016, Dominion conducted a new experience study as scheduled and, as a result, updated its mortality assumptions for all its plans, including those in which Dominion Gas participates.

Assumed healthcare cost trend rates have a significant effect on the amounts reported for Dominion's retiree healthcare plans, including those in which Dominion Gas participates. A one percentage point change in assumed healthcare cost trend rates would have had the following effects for Dominion's and Dominion 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		
Effect on net periodic cost for 2017	**$ 23**	**$ (18)**
Effect on other postretirement benefit obligation at December 31, 2016	**152**	**(127)**
Dominion Gas		
Effect on net periodic cost for 2017	**$ 5**	**$ (4)**
Effect on other postretirement benefit obligation at December 31, 2016	**41**	**(34)**

Dominion Gas (Employees Not Represented by Collective Bargaining Units) and Virginia Power—Participation in Defined Benefit Plans

Virginia Power employees and Dominion Gas employees not represented by collective bargaining units are covered by the Dominion Pension Plan described above. As participating employers, Virginia Power and Dominion Gas are subject to Dominion's funding policy, which is to contribute annually an amount that is in accordance with ERISA. During 2016, Virginia Power and Dominion Gas made no contributions to the Dominion Pension Plan, and no contributions to this plan are currently expected in 2017. Virginia Power's net periodic pension cost related to this plan was $79 million, $97 million and $75 million in 2016, 2015 and 2014, respectively. Dominion Gas' net periodic pension credit related to this plan was $(45) million, $(38) million and $(37) million in 2016, 2015 and 2014, 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 subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating Dominion subsidiaries. See Note 24 for Virginia Power and Dominion Gas amounts due to/from Dominion related to this plan.

Retiree healthcare and life insurance benefits, for Virginia Power employees and for Dominion Gas employees not represented by collective bargaining units, are covered by the Dominion Retiree Health and Welfare Plan described above. Virginia Power's net periodic benefit (credit) cost related to this plan was $(29) million, $(16) million and $(18) million in 2016, 2015 and 2014, respectively. Dominion Gas' net periodic benefit (credit) cost related to this plan was $(4) million, $(5) million and $(5) million for 2016, 2015 and 2014, 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 subsidiaries. See Note 24 for Virginia Power and Dominion Gas amounts due to/from Dominion related to this plan.

Dominion holds investments in trusts to fund employee benefit payments for the pension and other postretirement benefit plans in which Virginia Power and Dominion 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 Gas will provide to Dominion 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 Gas fund other postretirement benefit costs through VEBAs. During 2016 and 2015, Virginia Power made no contributions to the VEBA and does not expect to contribute to the VEBA in 2017. Dominion Gas made no contributions to the VEBAs for employees not represented by collective bargaining units during 2016 and 2015 and does not expect to contribute in 2017.

Defined Contribution Plans

Dominion also sponsors defined contribution employee savings plans that cover substantially all employees. During 2016, 2015 and 2014, Dominion recognized $44 million, $43 million and $41 million, respectively, as employer matching contributions to these plans. Dominion Gas participates in these employee savings plans, both specific to Dominion Gas and that cover multiple Dominion subsidiaries. During 2016, 2015 and 2014, Dominion Gas recognized $7 million as employer matching contributions to these plans. Virginia Power also participates in these employee savings plans. During 2016, 2015 and 2014, Virginia Power recognized $19 million, $18 million and $17 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 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 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

In December 2011, the EPA issued MATS for coal and oil-fired electric utility steam generating units. The rule establishes strict emission limits for mercury, particulate matter as a surrogate for toxic metals and hydrogen chloride as a surrogate for acid gases. The rule includes a limited use provision for oil-fired units with annual capacity factors under 8% that provides an exemption from emission limits, and allows compliance with operational work practice standards. Compliance was required by April 16, 2015, with certain limited exceptions. However, in June 2014, the VDEQ granted a one-year MATS compliance extension for two coal-fired units at Yorktown power station to defer planned retirements and allow for continued operation of the units to address reliability concerns while necessary electric transmission upgrades are being completed. These coal units will need to continue operating until at least April 2017 due to delays in transmission upgrades needed to maintain electric reliability. Therefore, in October 2015 Virginia Power submitted a request to the EPA for an additional one year compliance extension under an EPA Administrative Order. The order was signed by the EPA in April 2016 allowing the Yorktown units to operate for up to one additional year, as required to maintain reliable power availability while transmission upgrades are being made.

In June 2015, the U.S. Supreme Court issued a decision holding that the EPA failed to take cost into account when the agency first decided to regulate the emissions from coal- and oil-fired plants, and remanded the MATS rule back to the U.S. Court of Appeals for the D.C. Circuit. However, the Supreme Court did not vacate or stay the effective date and implementation of the MATS rule. In November 2015, in response to the Supreme Court decision, the EPA proposed a supplemental finding that consideration of cost does not alter the agency's previous conclusion that it is appropriate and necessary to regulate coal- and oil-fired electric utility steam generating units under Section 112 of the CAA. In December 2015, the U.S. Court of Appeals for the D.C. Circuit issued an order remanding the MATS rulemaking proceeding back to the EPA without setting aside judgment, noting that EPA had represented it was on track to issue a final finding regarding its consideration of cost. In April 2016, the EPA issued a final supplemental finding that consideration of costs does not alter its conclusion regarding appropriateness and necessity for the regulation. These actions do not change Virginia Power's plans to close coal units at Yorktown power station by April 2017 or the need to complete necessary electricity transmission upgrades which are expected to be in service approximately 20 months following receipt of all required permits and approvals for construction. Since the MATS rule remains in effect and Dominion is complying with the requirements of the rule, Dominion does not expect any adverse impacts to its operations at this time.

CSAPR

In July 2011, the EPA issued a replacement rule for CAIR, called CSAPR, that required 28 states to reduce power plant emissions that cross state lines. CSAPR established new SO_2 and NO_X emissions cap and trade programs that were completely independent of the current ARP. Specifically, CSAPR required reductions in SO_2 and NO_X emissions from fossil fuel-fired electric generating units of 25 MW or more through annual NO_X emissions caps, NO_X emissions caps during the ozone season (May 1 through September 30) and annual SO_2 emission caps with differing requirements for two groups of affected states. Following numerous petitions by industry participants for review and a successful motion for stay, in October 2014, the U.S. Court of Appeals for the D.C. Circuit ordered that the EPA's motion to lift the stay of CSAPR be granted. Further, the Court granted the EPA's request to shift the CSAPR compliance deadlines by three years, so that Phase 1 emissions budgets (which would have gone into effect in 2012 and 2013) applied in 2015 and 2016, and Phase 2 emissions budgets will apply in 2017 and beyond. CSAPR replaced CAIR beginning in January 2015. In September 2016, the EPA issued a revision to CSAPR that reduces the ozone season NO_X emission budgets in 22 states beginning in 2017. The cost to comply with CSAPR, including the recent revision to the CSAPR ozone season NO_X program, is not expected to be material to Dominion's or Virginia Power's Consolidated Financial Statements.

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 NO_X Reasonable Available Control Technology analysis for Unit 5 at Possum Point power station. In December 2016, the VDEQ determined that NO_X controls are required on Unit 5. Installation and operation of these NO_X controls including an associated water treatment system will be required by mid-2019 with an expected cost in the range of $25 to $35 million.

The EPA is expected to complete attainment designations for a new standard by December 2017 and states will have until 2020 or 2021 to develop plans to address the new standard. Until the states have developed implementation plans, the Companies are unable to predict whether or to what extent the new rules will ultimately require additional controls. However, if significant expenditures are required to implement additional controls, it could materially affect the Companies' results of operations and cash flows.

NO_x and VOC Emissions

In April 2016, the Pennsylvania Department of Environmental Protection issued final regulations, with an effective date of January 2017, to reduce NO_X and VOC emissions from combustion sources. To comply with the regulations, Dominion 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 $25 million.

Table of Contents

NSPS

In August 2012, the EPA issued the first 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 final 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 will be required to comply with this regulation. Dominion and Dominion Gas are still evaluating whether potential impacts on results of operations, financial condition and/or cash flows related to this matter will be material.

CLIMATE CHANGE REGULATION

Carbon Regulations

In October 2013, the U.S. Supreme Court granted petitions filed by several industry groups, states, and the U.S. Chamber of Commerce seeking review of the U.S. Court of Appeals for the D.C. Circuit's June 2012 decision upholding the EPA's regulation of GHG emissions from stationary sources under the CAA's permitting programs. In June 2014, the U.S. Supreme Court ruled that the EPA lacked the authority under the CAA to require PSD or Title V permits for stationary sources based solely on GHG emissions. However, the Court upheld the EPA's ability to require BACT for GHG for sources that are otherwise subject to PSD or Title V permitting for conventional pollutants. 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 July 2011, the EPA signed a final rule deferring the need for PSD and Title V permitting for CO_2 emissions for biomass projects. This rule temporarily deferred for a period of up to three years 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. The deferral policy expired in July 2014. In July 2013, the U.S. Court of Appeals for the D.C. Circuit vacated this rule; however, a mandate making this decision effective has not been issued. Virginia Power converted three coal-fired generating stations, Altavista, Hopewell and Southampton, to biomass during the CO_2 deferral period. It is unclear how the court's decision or the EPA's final policy regarding the treatment of specific feedstock will affect biomass sources that were permitted during the deferral period; however, the expenditures to comply with any new requirements could be material to Dominion'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, DTI and Questar Gas (prior to the Dominion Questar Combination) joined the EPA as founding partners in the new Methane Challenge program and submitted implementation plans in September 2016. DCG joined the EPA's voluntary Natural Gas STAR Program in July 2016 and submitted an implementation plan in September 2016. Dominion and Dominion 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 and Virginia Power have 14 and 11 facilities, respectively, that may be subject to the final regulations. Dominion anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling systems. Dominion 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'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 that may be subject to additional wastewater treatment requirements associated with the final rule. While the impacts of this rule could be material to Dominion'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.

SOLID AND HAZARDOUS WASTE

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, Virginia Power, or Dominion 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. Each party can be held jointly, severally and strictly liable for the cleanup costs. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, Dominion, Virginia Power, or Dominion 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.

In September 2011, the EPA issued a UAO to Virginia Power and 22 other parties, pursuant to CERCLA, ordering specific remedial action of certain areas at the Ward Transformer Superfund site located in Raleigh, North Carolina. In September 2016, the U.S., on behalf of the EPA, lodged a proposed Remedial Design/Remedial Action Consent Decree with the U.S. District Court for the Eastern District of North Carolina, settling claims related to the site between the EPA and a number of parties, including Virginia Power. In November 2016, the court approved and entered the final Consent Decree and closed the case. The Consent Decree identifies Virginia Power as a non-performing cash-out party to the settlement and resolves Virginia Power's alleged liability under CERCLA with respect to the site, including liability pursuant to the UAO. Virginia Power's cash settlement for this case was less than $1 million.

Dominion 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 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 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, DTI received multiple change order requests and other claims for additional payments from a pipeline contractor for the project. In July 2013, DTI filed a complaint in U.S. District Court for the Eastern District of Virginia for breach of contract as well as accounting and declaratory relief. The contractor filed a motion to dismiss, or in the alternative, a motion to transfer venue to Pennsylvania and/or West Virginia, where the pipelines were constructed. DTI filed an opposition to the contractor's motion in August 2013. In November 2013, the court granted the contractor's motion on the basis that DTI must first comply with the dispute resolution process. In July 2015, the contractor filed a complaint against DTI in U.S. District Court for the Western District of Pennsylvania. In August 2015, DTI filed a motion to dismiss, or in the alternative, a motion to transfer venue to Virginia. In March 2016, the Pennsylvania court granted the motion to dismiss and transferred the case to the U.S. District Court for the Eastern District of Virginia. In April 2016, the Virginia court issued an order staying the proceedings and ordering mediation. A mediation occurred in May 2016 but was unsuccessful. In July 2016, DTI filed a motion to dismiss. This case is pending. DTI has accrued a liability of $6 million for this matter. Dominion 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 Field Services, Inc. entered into contracts for firm purchase rights with a group of small gas producers. In June 2016, the gas pro-

Table of Contents

ducers filed a complaint in the Circuit Court of Marshall County, West Virginia against Dominion, DTI and Dominion 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, DTI and Dominion Field Services, Inc. were served with the complaint. Also in the third quarter of 2016, Dominion and DTI, 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. This case is pending. Dominion and Dominion 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 September 2014, Virginia Power received a notice from the Southern Environmental Law Center on behalf of the Potomac Riverkeeper and Sierra Club alleging CWA violations at Possum Point power station. The notice alleges unpermitted discharges to surface water and groundwater from Possum Point power station's historical and active ash storage facilities. A similar notice from the Southern Environmental Law Center on behalf of the Sierra Club was subsequently received related to Chesapeake power station. In December 2014, Virginia Power offered to close all of its coal ash ponds and landfills at Possum Point power station, Chesapeake and Bremo power stations as settlement of the potential litigation. While the issue is open to potential further negotiations, the Southern Environmental Law Center declined the offer as presented in January 2015 and, in March 2015, filed a lawsuit related to its claims of the alleged CWA violations at Chesapeake power station. Virginia Power filed a motion to dismiss in April 2015, which was denied in November 2015. A trial was held in June 2016. This case is pending. As a result of the December 2014 settlement offer, Virginia Power recognized a charge of $121 million in other operations and maintenance expense in its Consolidated Statements of Income for the year ended December 31, 2014.

In April 2015, the EPA's final rule regulating the management of CCRs stored in impoundments (ash ponds) and landfills was published in the Federal Register. The final rule regulates 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. The enactment of the final rule in April 2015 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. The CCR rule requires that groundwater impacts associated with ash ponds be remediated. It is too early in the implementation phase of the rule to determine the scope of any potential groundwater remediation, but the costs, if required, could be material.

In April 2016, the EPA announced a partial settlement with certain environmental and industry organizations that had challenged the final CCR rule in the U.S. Court of Appeals for the D.C. Circuit. As part of the settlement, certain exemptions included in the final rule for inactive ponds that closed by April 2018 will be removed, resulting in inactive ponds ultimately being subject to the same requirements as existing ponds. In June 2016, the court issued an order approving the settlement, which requires the EPA to modify provisions in the final CCR rule concerning inactive ponds. In August 2016, the EPA issued a final rule, effective October 2016, extending certain compliance deadlines in the final CCR rule for inactive ponds.

In February and March 2016, respectively, two parties filed administrative appeals in the Circuit Court for the City of Richmond challenging certain provisions, relating to ash pond dewatering activities, of Possum Point power station's wastewater discharge permit issued by the VDEQ in January 2016. One of those parties withdrew its appeal in June 2016. In November 2016, the court dismissed the remaining appeal.

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 related to reversal of the contingent liability described above 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. The actual AROs related to the CCR rule may vary substantially from the estimates used to record the obligation at December 31, 2016.

In December 2016, the U.S. Congress passed and the President signed legislation that creates a framework for EPA- approved state CCR permit programs. Under this legislation, an approved state CCR permit program functions in lieu of the self-implementing Federal CCR rule. The legislation allows states more flexibility in developing permit programs to implement the environmental criteria in the CCR rule. It is unknown how long it will take for the EPA to develop the framework for state program approvals. The EPA has enforcement authority until these new CCR rules are in place and 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. Dominion cannot forecast potential incremental impacts or costs related to existing coal ash sites until rules implementing the 2016 CCR legislation are in place.

Cove Point

Dominion is constructing the Liquefaction Project at the Cove Point facility, which 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. In October 2014, several parties filed a motion with FERC to stay the order and requested rehearing. In May 2015, FERC denied the requests for stay and rehearing.

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. Cove Point believes that on remand FERC will be able to justify its decision.

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. This case is pending.

FERC

The 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. The 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 the 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 July 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. Virginia Power is currently unable to make an estimate of the potential impacts to its consolidated financial statements related to this matter.

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 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 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 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 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 2016 calculation for the NRC minimum financial assurance amount, aggregated for Dominion'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 \$2.9 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 2016 NRC minimum financial assurance amounts above were calculated using preliminary December 31, 2016 U.S. Bureau of Labor Statistics indices. Dominion 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

Table of Contents

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 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 $13.36 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 and Virginia Power have purchased $375 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's and Virginia Power's nuclear units is as follows:

	Coverage
(billions)	
Dominion	
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'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's and Virginia Power's maximum retrospective premium assessment for the current policy period is $87 million and $49 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 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 and Virginia Power are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. Dominion's and Virginia Power's maximum retrospective premium assessment for the current policy period is $23 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 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 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's and Virginia Power's contracts with the DOE. Dominion 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 additional extensions are contemplated by the settlement agreements. Possible settlement of the Kewaunee claims for damages incurred after December 31, 2013 is being evaluated.

In 2016, Virginia Power and Dominion 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 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.

In 2014, Virginia Power and Dominion received payments of $27 million for the resolution of claims incurred at North Anna and Surry for the period January 1, 2011 through December 31, 2012 and $17 million for the resolution of claims incurred at Millstone for the period of July 1, 2012 through June 30, 2013. In 2014, Dominion also received payments totaling $7 million for the resolution of claims incurred at Kewaunee for periods from January 1, 2011 through December 31, 2013.

Dominion 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's receivables for spent nuclear fuel-related costs totaled $56 million and $87 million at December 31, 2016 and 2015, respectively. Virginia Power's receivables for spent nuclear fuel-related costs totaled $37 million and $54 million at December 31, 2016 and 2015, respectively.

Pursuant to a November 2013 decision of the U.S Court of Appeals for the D.C. Circuit, in January 2014 the Secretary of the DOE sent a recommendation to the U.S. Congress to adjust to zero the current fee of $1 per MWh for electricity paid by civilian nuclear power generators for disposal of spent nuclear fuel. The processes specified in the Nuclear Waste Policy Act for adjustment of the fee have been completed, and as of May 2014, Dominion and Virginia Power are no longer required to pay the waste fee. In 2014, Dominion and Virginia Power recognized fees of $16 million and $10 million, respectively.

Dominion and Virginia Power will continue to manage their spent fuel until it is accepted by the DOE.

Long-Term Purchase Agreements

At December 31, 2016, Virginia Power had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services:

(millions)	2017	2018	2019	2020	2021	Thereafter	Total
Purchased electric capacity(1)	**$149**	**$93**	**$60**	**$52**	**$46**	**$ —**	**$400**

(1) Commitments represent estimated amounts payable for capacity under power purchase contracts with qualifying facilities and independent power producers, the last of which ends in 2021. Capacity payments under the contracts are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2016, the present value of Virginia Power's total commitment for capacity payments is $347 million. Capacity payments totaled $248 million, $305 million, and $330 million, and energy payments totaled $126 million, $198 million, and $304 million for the years ended 2016, 2015 and 2014, 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, 2016 are as follows:

(millions)	2017	2018	2019	2020	2021	Thereafter	Total
Dominion(1)	**$72**	**$69**	**$58**	**$39**	**$32**	**$ 238**	**$508**
Virginia Power	**$33**	**$30**	**$24**	**$20**	**$16**	**$ 32**	**$155**
Dominion Gas	**$27**	**$26**	**$21**	**$ 8**	**$ 5**	**$ 18**	**$105**

(1) Amounts include a lease agreement for the Dominion Questar corporate office, which is accounted for as a capital lease. At December 31, 2016, the Consolidated Balance Sheets include $30 million in property, plant and equipment and $35 million in other deferred credits and other liabilities. The Consolidated Statements of Income include less than $1 million recorded in depreciation, depletion and amortization for the year ended December 31, 2016.

Rental expense for Dominion totaled $104 million, $99 million, and $92 million for 2016, 2015 and 2014, respectively. Rental expense for Virginia Power totaled $52 million, $51 million, and $43 million for 2016, 2015, and 2014, respectively. Rental expense for Dominion Gas totaled $37 million, $37 million, and $35 million for 2016, 2015 and 2014, respectively. The majority of rental expense is reflected in other operations and maintenance expense in the Consolidated Statements of Income.

In July 2016, Dominion 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 has been appointed to act as the construction agent for the lessor, during which time Dominion will request cash draws from the lessor and debt investors to fund all project costs, which totaled $46 million as of December 31, 2016. If the project is terminated under certain events of default, Dominion could be required to pay up to 89.9% of the then funded amount. For specific full recourse events, Dominion 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 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 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 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

At December 31, 2016, Dominion had issued $48 million of guarantees, primarily to support equity method investees. No significant amounts related to these guarantees have been recorded.

Dominion 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 would be obligated to satisfy such obligation. To the extent that a liability subject to a guarantee has been incurred by one of Dominion's consolidated subsidiaries, that liability is included in the Consolidated Financial Statements. Dominion 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 currently believes it is unlikely that it would be required to perform or otherwise incur any losses associated with guarantees of its subsidiaries' obligations.

Table of Contents

At December 31, 2016, Dominion had issued the following subsidiary guarantees:

		Maximum Exposure
(millions)		
Commodity transactions(1)	$	2,074
Nuclear obligations(2)		169
Cove Point(3)		1,900
Solar(4)		1,130
Other(5)		545
Total(6)	$	5,818

(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 DEI 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 DEI 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 DEI subsidiaries' obligations for equity capital contributions and energy generation associated with Fowler Ridge and NedPower. As of December 31, 2016, Dominion's maximum remaining cumulative exposure under these equity funding agreements is $36 million through 2019 and its maximum annual future contributions could range from approximately $4 million to $19 million.
(6) Excludes Dominion's guarantee for the construction of the new corporate office property discussed further within Lease Commitments above.

Additionally, at December 31, 2016, Dominion had purchased $149 million of surety bonds, including $71 million at Virginia Power and $22 million at Dominion Gas, and authorized the issuance of letters of credit by financial institutions of $85 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, 2016, 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, 2016, 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, 2016 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

As a diversified energy company, Dominion 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 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 is not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations.

Dominion's exposure to credit risk is concentrated primarily within its energy marketing and price risk management activities, as Dominion 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, 2016, Dominion's credit exposure totaled $98 million. Of this amount, investment grade counterparties, including those internally rated, represented 53%, and no single counterparty, whether investment grade or non-investment grade, exceeded $9 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, 2016, Virginia Power's credit exposure totaled $42 million. Of this amount, investment grade counterparties, including those internally rated, represented 33%, and no single counterparty, whether investment grade or non-investment grade, exceeded $6 million of exposure.

DOMINION GAS

Dominion 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 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 Gas is not exposed to a significant concentration of credit risk for receivables arising from gas utility operations.

In 2016, DTI 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 40% of the total storage and transportation revenue and the thirty largest provided approximately 70% 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's derivative instruments contain credit-related contingent provisions. These provisions require Dominion 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, 2016 and 2015, Dominion would have been required to post an additional $3 million and $12 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 had posted no collateral at December 31, 2016 and 2015, 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, 2016 and 2015 was $9 million and $49 million, respectively, which does not include the impact of any offsetting asset positions. Credit-related contingent provisions for Virginia Power and Dominion Gas were not material as of December 31, 2016 and 2015. See Note 7 for further information about derivative instruments.

NOTE 24. RELATED-PARTY TRANSACTIONS

Virginia Power and Dominion Gas engage in related party transactions primarily with other Dominion subsidiaries (affiliates). Virginia Power's and Dominion 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 Gas are included in Dominion's consolidated federal income tax return and, where applicable, combined income tax returns for Dominion are filed in various states. See Note 2 for further information. Dominion'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, 2016, Virginia Power's derivative assets and liabilities with affiliates were $41 million and $8 million, respectively. As of December 31, 2015, Virginia Power's derivative assets and liabilities with affiliates were $13 million and $22 million, respectively.

Virginia Power participates in certain Dominion benefit plans as described in Note 21. At December 31, 2016 and 2015, Virginia Power's amounts due to Dominion associated with the Dominion Pension Plan and reflected in noncurrent pension and other postretirement benefit liabilities in the Consolidated Balance Sheets were $396 million and $316 million, respectively. At December 31, 2016 and 2015, Virginia Power's amounts due from Dominion associated with the Dominion Retiree Health and Welfare Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $130 million and $77 million, respectively.

DRS 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 DRS to Virginia Power on the basis of direct and allocated methods in accordance with Virginia Power's services agreements with DRS. Where costs incurred cannot be determined by specific identification, the costs are allocated based on the proportional level of effort devoted by DRS resources that is attributable

Table of Contents

to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DRS service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable.

Presented below are significant transactions with DRS and other affiliates:

Year Ended December 31, (millions)	2016	2015	2014
Commodity purchases from affiliates	**$571**	$555	$543
Services provided by affiliates(1)	**454**	422	432
Services provided to affiliates	**22**	22	22

(1) Includes capitalized expenditures of $144 million, $143 million and $146 million for the year ended December 31, 2016, 2015, and 2014, respectively.

Virginia Power has borrowed funds from Dominion under short-term borrowing arrangements. There were $262 million and $376 million in short-term demand note borrowings from Dominion as of December 31, 2016 and 2015, respectively. The weighted-average interest rate of these borrowings was 0.97% and 0.60% at December 31, 2016 and 2015, respectively. Virginia Power had no outstanding borrowings, net of repayments under the Dominion money pool for its nonregulated subsidiaries as of December 31, 2016 and 2015. Interest charges related to Virginia Power's borrowings from Dominion were immaterial for the years ended December 31, 2016, 2015 and 2014.

There were no issuances of Virginia Power's common stock to Dominion in 2016, 2015 or 2014.

DOMINION GAS

Transactions with Related Parties

Dominion Gas transacts with affiliates for certain quantities of natural gas and other commodities at market prices in the ordinary course of business. Additionally, Dominion Gas provides transportation and storage services to affiliates. Dominion Gas also enters into certain other contracts with affiliates, which are presented separately from contracts involving commodities or services. As of December 31, 2016 and 2015, all of Dominion 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 Gas participates in certain Dominion benefit plans as described in Note 21. At December 31, 2016 and 2015, Dominion Gas' amounts due from Dominion associated with the Dominion Pension Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $697 million and $652 million, respectively. At December 31, 2016 and 2015, Dominion Gas' amounts due from Dominion and liabilities due to Dominion associated with the Dominion Retiree Health and Welfare Plan were immaterial.

DRS and other affiliates provide accounting, legal, finance and certain administrative and technical services to Dominion Gas. Dominion 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 DRS to Dominion Gas on the basis of direct and allocated methods in accordance with Dominion Gas' services agreements with DRS. Where costs incurred cannot be determined by specific identification, the costs are allocated based on the proportional level of effort devoted by DRS resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DRS 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)	2016	2015	2014
Purchases of natural gas and transportation and storage services from affiliates	**$ 9**	$ 10	$ 34
Sales of natural gas and transportation and storage services to affiliates	**69**	69	84
Services provided by related parties(1)	**141**	133	106
Services provided to related parties(2)	**128**	101	17

(1) Includes capitalized expenditures of $49 million, $57 million and $49 million for the year ended December 31, 2016, 2015, and 2014, respectively.
(2) Amounts primarily attributable to Atlantic Coast Pipeline.

The following table presents affiliated and related party balances reflected in Dominion Gas' Consolidated Balance Sheets:

At December 31, (millions)	2016	2015
Other receivables(1)	**$10**	$ 7
Customer receivables from related parties	**1**	4
Imbalances receivable from affiliates	**2**	1
Imbalances payable to affiliates(2)	**4**	—
Affiliated notes receivable(3)	**18**	14

(1) Represents amounts due from Atlantic Coast Pipeline, a related party VIE.
(2) Amounts are presented in other current liabilities in Dominion Gas' Consolidated Balance Sheets.
(3) Amounts are presented in other deferred charges and other assets in Dominion Gas' Consolidated Balance Sheets.

Dominion Gas' borrowings under the IRCA with Dominion totaled $118 million and $95 million as of December 31, 2016 and 2015, respectively. The weighted-average interest rate of these borrowings was 1.08% and 0.65% at December 31, 2016 and 2015, respectively. Interest charges related to Dominion Gas' total borrowings from Dominion were immaterial for the years ended December 31, 2016 and 2015 and $4 million for the year ended December 31, 2014.

Table of Contents

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	Virginia Power	Dominion Gas
DVP	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Dominion Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Dominion Energy	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG import 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

The Corporate and Other Segment of Dominion includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

In March 2014, Dominion exited the electric retail energy marketing business. As a result, the earnings impact from the electric retail energy marketing business has been included in the Corporate and Other Segment of Dominion for 2014 first quarter results of operations.

In the second quarter of 2013, Dominion commenced a restructuring of its producer services business, which aggregates natural gas supply, engages in natural gas trading and marketing activities and natural gas supply management and provides price risk management services to Dominion affiliates. The restructuring, which was completed in the first quarter of 2014, resulted in the termination of natural gas trading and certain energy marketing activities. As a result, the earnings impact from natural gas trading and certain energy marketing activities has been included in the Corporate and Other Segment of Dominion for 2014.

In 2016, Dominion 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 Dominion Generation; and
- A $59 million ($36 million after-tax) charge related to an organizational design initiative, attributable to:
  - DVP ($5 million after-tax);
  - Dominion Energy ($12 million after-tax); and
  - Dominion Generation ($19 million after-tax).

In 2015, Dominion 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 Dominion 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 Dominion Generation.

In 2014, Dominion reported after-tax net expenses of $970 million in the Corporate and Other segment, with $544 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2014 primarily related to the impact of the following items:

- $374 million ($248 million after-tax) in 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, attributable to Dominion Generation;
- A $319 million ($193 million after-tax) net loss related to the producer services business discussed above, attributable to Dominion Energy; and
- A $121 million ($74 million after-tax) charge related to a settlement offer to incur future ash pond closure costs at certain utility generation facilities, attributable to Dominion Generation.

Table of Contents

The following table presents segment information pertaining to Dominion's operations:

Year Ended December 31, (millions)	DVP	Dominion Generation	Dominion Energy	Corporate and Other	Adjustments & Eliminations	Consolidated Total
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 taxes	**308**	**279**	**431**	**(363)**	**—**	**655**
Net income (loss) attributable to Dominion	**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 taxes	307	465	423	(290)	—	905
Net income (loss) attributable to Dominion	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
Total assets (billions)	14.7	25.6	15.2	8.9	(5.8)	58.6
2014						
Total revenue from external customers	$1,918	$ 7,135	$2,446	$ (12)	$ 949	$ 12,436
Intersegment revenue	18	34	880	572	(1,504)	—
Total operating revenue	1,936	7,169	3,326	560	(555)	12,436
Depreciation, depletion and amortization	462	514	243	73	—	1,292
Equity in earnings of equity method investees	—	(18)	54	10	—	46
Interest income	—	58	23	20	(33)	68
Interest and related charges	205	240	11	770	(33)	1,193
Income taxes	317	365	463	(693)	—	452
Net income (loss) attributable to Dominion	502	1,061	717	(970)	—	1,310
Capital expenditures	1,652	2,466	1,329	104	—	5,551

Intersegment sales and transfers for Dominion 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 DVP and Dominion 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 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 Dominion 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 Dominion 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 Dominion Generation.

In 2014, Virginia Power reported after-tax net expenses of $342 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2014 primarily related to the impact of the following items:

- $374 million ($248 million after-tax) in 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, attributable to Dominion Generation; and
- A $121 million ($74 million after-tax) charge related to a settlement offer to incur future ash pond closure costs at certain utility generation facilities, attributable to Dominion Generation.

Table of Contents

The following table presents segment information pertaining to Virginia Power's operations:

Year Ended December 31,	DVP	Dominion Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
(millions)					
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 taxes	**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 taxes	308	437	(86)		659
Net income (loss)	490	750	(153)	—	1,087
Capital expenditures	1,569	1,120	—	—	2,689
Total assets (billions)	14.7	17.0	—	(0.1)	31.6
2014					
Operating revenue	$1,928	$ 5,651	$ —	$ —	$ 7,579
Depreciation and amortization	462	416	37	—	915
Interest income	—	8	—	—	8
Interest and related charges	205	203	3	—	411
Income taxes	317	416	(185)	—	548
Net income (loss)	509	691	(342)	—	858
Capital expenditures	1,651	1,456	—	—	3,107

DOMINION GAS

The Corporate and Other Segment of Dominion Gas primarily includes specific items attributable to Dominion 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 Gas as a result of Dominion's basis in the net assets contributed.

In 2016, Dominion 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 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.

In 2014, Dominion Gas reported after-tax net expenses of $9 million in its Corporate and Other segment, with none of these net expenses attributable to specific items related to its operating segment.

Table of Contents

The following table presents segment information pertaining to Dominion Gas' operations:

Year Ended December 31,	Dominion Energy	Corporate and Other	Consolidated Total
(millions)			
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 taxes	**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 taxes	296	(13)	283
Net income (loss)	478	(21)	457
Investment in equity method investees	102	—	102
Capital expenditures	795	—	795
Total assets (billions)	9.7	0.6	10.3
2014			
Operating revenue	$1,898	$ —	$ 1,898
Depreciation and amortization	197	—	197
Equity in earnings of equity method investees	21	—	21
Interest income	1	—	1
Interest and related charges	27	—	27
Income taxes	340	(6)	334
Net income (loss)	521	(9)	512
Capital expenditures	719	—	719

NOTE 26. QUARTERLY FINANCIAL AND COMMON STOCK DATA (UNAUDITED)

A summary of the Companies' quarterly results of operations for the years ended December 31, 2016 and 2015 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

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2016					
Operating revenue	**$ 2,921**	**$ 2,598**	**$ 3,132**	**$ 3,086**	**$11,737**
Income from operations	**882**	**781**	**1,145**	**819**	**3,627**
Net income including noncontrolling interests	**531**	**462**	**728**	**491**	**2,212**
Net income attributable to Dominion	**524**	**452**	**690**	**457**	**2,123**
Basic EPS:					
Net income attributable to Dominion	**0.88**	**0.73**	**1.10**	**0.73**	**3.44**
Diluted EPS:					
Net income attributable to Dominion	**0.88**	**0.73**	**1.10**	**0.73**	**3.44**
Dividends declared per share	**0.7000**	**0.7000**	**0.7000**	**0.7000**	**2.8000**
Common stock prices (intraday high-low)	**$75.18 - 66.25**	**$77.93 - 68.71**	**$78.97 - 72.49**	**$77.32 - 69.51**	**$78.97 - 66.25**

(millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2015					
Operating revenue	$ 3,409	$ 2,747	$ 2,971	$ 2,556	$11,683
Income from operations	1,002	773	1,123	638	3,536
Net income including noncontrolling interests	540	418	599	366	1,923
Net income attributable to Dominion	536	413	593	357	1,899
Basic EPS:					
Net income attributable to Dominion	0.91	0.70	1.00	0.60	3.21
Diluted EPS:					
Net income attributable to Dominion	0.91	0.70	1.00	0.60	3.20
Dividends declared per share	0.6475	0.6475	0.6475	0.6475	2.5900
Common stock prices (intraday high-low)	$79.89 - 68.25	$74.34 - 66.52	$76.59 - 66.65	$74.88 - 64.54	$79.89 - 64.54

Dominion'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.

There were no significant items impacting Dominion's 2015 quarterly results.

Table of Contents

VIRGINIA POWER

Virginia Power's quarterly results of operations were as follows:

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2016					
Operating revenue	**$1,890**	**$1,776**	**$2,211**	**$1,711**	**$7,588**
Income from operations	**514**	**553**	**914**	**369**	**2,350**
Net income	**263**	**280**	**503**	**172**	**1,218**
2015					
Operating revenue	$2,137	$1,813	$2,058	$1,614	$7,622
Income from operations	525	481	741	374	2,121
Net income	269	246	385	187	1,087

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.

Virginia Power's 2015 results include the impact of the following significant items:

- Fourth quarter results include a $32 million after-tax charge related to incremental future ash pond and landfill closure costs at certain utility generation facilities.
- Second quarter results include a $28 million after-tax charge related to incremental future ash pond and landfill closure costs at certain utility generation facilities due to the enactment of the final CCR rule in April 2015.
- First quarter results include a $52 million after-tax write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015.

DOMINION GAS

Dominion Gas' quarterly results of operations were as follows:

(millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2016					
Operating revenue	**$ 431**	**$ 368**	**$ 382**	**$ 457**	**$1,638**
Income from operations	**175**	**186**	**133**	**175**	**669**
Net income	**98**	**105**	**83**	**106**	**392**
2015					
Operating revenue	$ 531	$ 395	$ 365	$ 425	$1,716
Income from operations	271	153	202	163	789
Net income	161	85	111	100	457

There were no significant items impacting Dominion Gas' 2016 quarterly results.

Dominion Gas' 2015 results include the impact of the following significant items:

- Third quarter results include a $29 million after-tax gain from an agreement to convey shale development rights underneath a natural gas storage field.
- First quarter results include a $43 million after-tax gain from agreements to convey shale development rights underneath several natural gas storage fields.

Table of Contents

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

DOMINION

Senior management, including Dominion's CEO and CFO, evaluated the effectiveness of Dominion's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Dominion's CEO and CFO have concluded that Dominion's disclosure controls and procedures are effective. There were no changes in Dominion'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's internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Dominion understands and accepts responsibility for Dominion's financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as Dominion does throughout all aspects of its business.

Dominion 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, 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 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 Committee at any time.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 require Dominion's 2016 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 tested and evaluated the design and operating effectiveness of internal controls. Based on its assessment as of December 31, 2016, Dominion makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Dominion.

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's internal control over financial reporting as of December 31, 2016. 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 maintained effective internal control over financial reporting as of December 31, 2016.

Dominion's independent registered public accounting firm is engaged to express an opinion on Dominion's internal control over financial reporting, as stated in their report which is included herein.

In September 2016, Dominion acquired Dominion Questar. Dominion excluded all of the acquired Dominion Questar's business from the scope of management's assessment of the effectiveness of Dominion's internal control over financial reporting as of December 31, 2016. Dominion Questar constituted 3% of Dominion's total revenues for 2016 and 6% of Dominion's total assets as of December 31, 2016.

February 28, 2017

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Dominion Resources, Inc.
Richmond, Virginia

We have audited the internal control over financial reporting of Dominion Resources, Inc. and subsidiaries ("Dominion") as of December 31, 2016, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Annual Report on Internal Control over Financial Reporting, management excluded from its assessment the internal control over financial reporting the acquired Dominion Questar businesses which were acquired on September 16, 2016 and who constitute 3% of total revenues and 6% of total assets of the consolidated financial statement amounts at and for the year ended December 31, 2016. Accordingly, our audit did not include the internal control over financial reporting of Questar businesses. Dominion'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's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Dominion maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of Dominion and our report dated February 28, 2017 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP
Richmond, Virginia
February 28, 2017

Table of Contents

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 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 2016 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, 2016, 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, 2016. 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, 2016.

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 28, 2017

DOMINION GAS

Senior management, including Dominion Gas' CEO and CFO, evaluated the effectiveness of Dominion Gas' disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Dominion Gas' CEO and CFO have concluded that Dominion Gas' disclosure controls and procedures are effective. There were no changes in Dominion 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 Gas' internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Dominion Gas understands and accepts responsibility for Dominion Gas' financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion 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 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 Gas' Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss Dominion 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 Gas' 2016 Annual Report to contain a management's report regarding the effectiveness of internal control. As a basis for the report, Dominion Gas tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2016, Dominion Gas makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Dominion 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 Gas' internal control over financial reporting as of December 31, 2016. 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 Gas maintained effective internal control over financial reporting as of December 31, 2016.

This annual report does not include an attestation report of Dominion Gas' independent registered public accounting firm regarding internal control over financial reporting. Management's report is not subject to attestation by Dominion Gas' independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 28, 2017

Item 9B. Other Information

None.

Table of Contents

Part III

Item 10. Directors, Executive Officers and Corporate Governance

DOMINION

The following information for Dominion is incorporated by reference from the Dominion 2017 Proxy Statement, which will be filed on or around March 20, 2017:

- 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 Audit Committee Financial expert(s) required by this item is found under the heading *Board of Directors Committees—Audit Committee*.
- Information regarding the Dominion Audit Committee required by this item is found under the headings *Board of Directors Committees—Audit Committee* and *Audit Committee Report*.
- Information regarding Dominion's Code of Ethics required by this item is found under the heading *Corporate Governance and Board Matters*.

The information concerning the executive officers of Dominion required by this item is included in Part I of this Form 10-K under the caption *Executive Officers of Dominion*. Each executive officer of Dominion is elected annually.

Item 11. Executive Compensation

DOMINION

The following information about Dominion is contained in the 2017 Proxy Statement and is incorporated by reference: the information regarding executive compensation contained under the headings *Compensation Discussion and Analysis* and *Executive Compensation*; the information regarding Compensation Committee interlocks contained under the heading *Compensation Committee Interlocks and Insider Participation*; *The 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

The information concerning stock ownership by directors, executive officers and five percent beneficial owners contained under the heading *Securities Ownership* in the 2017 Proxy Statement is incorporated by reference.

The information regarding equity securities of Dominion that are authorized for issuance under its equity compensation plans contained under the heading *Executive Compensation-Equity Compensation Plans* in the 2017 Proxy Statement is incorporated by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

DOMINION

The information regarding related party transactions required by this item found under the heading *Other Information-Related Party Transactions,* and information regarding director independence found under the heading *Corporate Governance and Board Matters-Independence of Directors,* in the 2017 Proxy Statement is incorporated by reference.

Table of Contents

Item 14. Principal Accountant Fees and Services

DOMINION

The information concerning principal accountant fees and services contained under the heading *Auditor Fees and Pre-Approval Policy* in the 2017 Proxy Statement is incorporated by reference.

VIRGINIA POWER AND DOMINION GAS

The following table presents fees paid to Deloitte & Touche LLP for services related to Virginia Power and Dominion Gas for the fiscal years ended December 31, 2016 and 2015.

Type of Fees	2016	2015
(millions)		
Virginia Power		
Audit fees	**$1.82**	$1.87
Audit-related fees	**—**	—
Tax fees	**—**	—
All other fees	**—**	—
Total Fees	**$1.82**	$1.87
Dominion Gas		
Audit fees	**$1.05**	$1.06
Audit-related fees	**0.16**	0.19
Tax fees	**—**	—
All other fees	**—**	—
Total Fees	**$1.21**	$1.25

Audit fees represent fees of Deloitte & Touche LLP for the audit of Virginia Power's and Dominion Gas' annual consolidated financial statements, the review of financial statements included in Virginia Power's and Dominion 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's and Dominion 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's and Dominion Gas' Boards of Directors have adopted the Dominion Audit Committee pre-approval policy for their independent auditor's services and fees and have delegated the execution of this policy to the Dominion Audit Committee. In accordance with this delegation, each year the Dominion 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 2017 meeting, the Dominion Audit Committee approved Virginia Power's and Dominion Gas' schedules of services and fees for 2017. In accordance with the pre-approval policy, any changes to the pre-approved schedule may be pre-approved by the Dominion Audit Committee or a delegated member of the Dominion Audit Committee.

Table of Contents

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 60.

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	Virginia Power	Dominion Gas
3.1.a	Dominion Resources, Inc. Articles of Incorporation as amended and restated, effective May 20, 2010 (Exhibit 3.1, Form 8-K filed May 20, 2010, 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 Gas Holdings, LLC (Exhibit 3.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
3.2.a	Dominion Resources, Inc. Amended and Restated Bylaws, effective December 17, 2015 (Exhibit 3.1, Form 8-K filed December 17, 2015, 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 Gas Holdings, LLC dated as of September 12, 2013 (Exhibit 3.2, Form S-4 filed April 4, 2014, File No. 333-195066).			X
4	Dominion Resources, Inc., Virginia Electric and Power Company and Dominion 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(iii), Form S-3 Registration Statement filed February 27, 1998, File No. 333-47119); Form of Twelfth Supplemental Indenture, dated January 1, 2006 (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255); 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); Twenty-Second Supplemental Indenture, dated as of January 1, 2012 (Exhibit 4.3, Form 8-K filed January 12, 2012, File	X	X	

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	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).			
4.4	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)) 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		
4.5	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		
4.6	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); Forms of Thirty-Fifth and Thirty-Sixth Supplemental Indentures, dated June 1, 2008 (Exhibits 4.2 and 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-Fourth Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 15, 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); 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).	X		

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
4.7	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 (filed herewith); 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).	X		
4.8	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); Fourth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.3, Form 8-K filed June 7, 2013, File No. 1-8489); Fifth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.4, Form 8-K filed June 7, 2013, 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).	X		
4.9	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		
4.10	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		
4.11	Series A Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.12	Series B Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.8, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.13	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		

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
4.14	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		
4.15	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); First Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.2, 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	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		
10.4	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	
10.5	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
10.6	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
10.7	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
10.8	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
10.9	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	

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.10	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	
10.11*	Dominion Resources, 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
10.12*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company, 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
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company 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 27, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.14*	Dominion Resources, 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
10.15*	Dominion Resources, 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
10.16*	Dominion Resources, 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
10.17*	Dominion Resources, 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
10.18*	Dominion Resources, 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		
10.19*	Dominion Resources, 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		
10.20*	Dominion Resources, 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		
10.21*	Dominion Resources, 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

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.22*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed December 23, 2004, File No. 1-8489).	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*	Supplemental Retirement Agreement dated December 12, 2000, between Dominion Resources, Inc. and David A. Christian (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2001 filed March 11, 2002, File No. 1-2255).	X	X	X
10.27*	Form of Advancement of Expenses for certain directors and officers of Dominion Resources, Inc., approved by the Dominion Resources, Inc. Board of Directors on 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
10.28*	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
10.29*	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
10.30*	Form of Restricted Stock Award Agreement for Mark F. McGettrick, Paul D. Koonce and David A. Christian approved December 17, 2012 (Exhibit 10.1, Form 8-K filed December 21, 2012, File No. 1-8489).	X	X	X
10.31*	Form of Restricted Stock Award Agreement under the 2012 Long-Term Incentive Program approved January 19, 2012 (Exhibit 10.2, Form 8-K filed January 20, 2012, File No. 1-8489).	X	X	X
10.32*	2013 Performance Grant Plan under the 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.1, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.33*	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
10.34*	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
10.35*	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
10.36*	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
10.37*	Form of Special Performance Grant for Thomas F. Farrell II and Mark F. McGettrick approved January 16, 2014 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.38*	Dominion Resources, 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

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.39	Registration Rights Agreement, dated as of October 22, 2013, by and among Dominion Gas Holdings, LLC and RBC Capital Markets, LLC, RBS Securities Inc. and Scotia Capital (USA) Inc., as the initial purchasers of the Notes (Exhibit 10.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.40	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
10.41*	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
10.42*	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
10.43*	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
10.44*	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
10.45*	2017 Performance Grant Plan under the 2017 Long-Term Incentive Program approved January 24, 2017 (filed herewith).	X	X	X
10.46*	Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Program approved January 24, 2017 (filed herewith).	X	X	X
10.47*	Base salaries for named executive officers of Dominion Resources, Inc. (filed herewith).	X		
10.48*	Non-employee directors' annual compensation for Dominion Resources, Inc. (filed herewith).	X		
12.a	Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith).	X		
12.b	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X	
12.c	Ratio of earnings to fixed charges for Dominion Gas Holdings, LLC (filed herewith).			X
21	Subsidiaries of Dominion Resources, Inc. (filed herewith).	X		
23	Consent of Deloitte & Touche LLP (filed herewith).	X	X	X
31.a	Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.b	Certification by Chief Financial Officer of Dominion Resources, 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 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 Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
32.a	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, 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 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 Resources, Inc. and Virginia Electric and Power Company Annual Report on Form 10-K for the year ended December 31, 2016, filed on February 28, 2017, 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.

Table of Contents

Signatures

DOMINION

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 RESOURCES, INC.

By: /s/ Thomas F. Farrell II
(Thomas F. Farrell II, Chairman, President and Chief Executive Officer)

Date: February 28, 2017

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 28th day of February, 2017.

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/ Ronald W. Jibson **Ronald W. Jibson**	Director
/s/ John W. Harris **John W. Harris**	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/ David A. Wollard **David A. Wollard**	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

Table of Contents

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 28, 2017

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 28th day of February, 2017.

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

Table of Contents

Dominion 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 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 28, 2017

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 28th day of February, 2017.

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

Table of Contents

Exhibit Index

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
3.1.a	Dominion Resources, Inc. Articles of Incorporation as amended and restated, effective May 20, 2010 (Exhibit 3.1, Form 8-K filed May 20, 2010, 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 Gas Holdings, LLC (Exhibit 3.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
3.2.a	Dominion Resources, Inc. Amended and Restated Bylaws, effective December 17, 2015 (Exhibit 3.1, Form 8-K filed December 17, 2015, 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 Gas Holdings, LLC dated as of September 12, 2013 (Exhibit 3.2, Form S-4 filed April 4, 2014, File No. 333-195066).			X
4	Dominion Resources, Inc., Virginia Electric and Power Company and Dominion 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(iii), Form S-3 Registration Statement filed February 27, 1998, File No. 333-47119); Form of Twelfth Supplemental Indenture, dated January 1, 2006 (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255); 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); 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,	X	X	

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	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).			
4.4	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)) 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		
4.5	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		
4.6	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); Forms of Thirty-Fifth and Thirty-Sixth Supplemental Indentures, dated June 1, 2008 (Exhibits 4.2 and 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-Fourth Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 15, 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); 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).	X		
4.7	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,	X		

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	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 (filed herewith); 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).			
4.8	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); Fourth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.3, Form 8-K filed June 7, 2013, File No. 1-8489); Fifth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.4, Form 8-K filed June 7, 2013, 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).	X		
4.9	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		
4.10	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		
4.11	Series A Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.12	Series B Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.8, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.13	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		
4.14	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		

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
4.15	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); First Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.2, 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	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		
10.4	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	
10.5	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
10.6	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
10.7	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
10.8	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
10.9	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	
10.10	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	

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.11*	Dominion Resources, 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
10.12*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company, 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
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company 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 27, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.14*	Dominion Resources, 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
10.15*	Dominion Resources, 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
10.16*	Dominion Resources, 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
10.17*	Dominion Resources, 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
10.18*	Dominion Resources, 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		
10.19*	Dominion Resources, 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		
10.20*	Dominion Resources, 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		
10.21*	Dominion Resources, 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
10.22*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed December 23, 2004, File No. 1-8489).	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

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
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*	Supplemental Retirement Agreement dated December 12, 2000, between Dominion Resources, Inc. and David A. Christian (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2001 filed March 11, 2002, File No. 1-2255).	X	X	X
10.27*	Form of Advancement of Expenses for certain directors and officers of Dominion Resources, Inc., approved by the Dominion Resources, Inc. Board of Directors on 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
10.28*	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
10.29*	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
10.30*	Form of Restricted Stock Award Agreement for Mark F. McGettrick, Paul D. Koonce and David A. Christian approved December 17, 2012 (Exhibit 10.1, Form 8-K filed December 21, 2012, File No. 1-8489).	X	X	X
10.31*	Form of Restricted Stock Award Agreement under the 2012 Long-Term Incentive Program approved January 19, 2012 (Exhibit 10.2, Form 8-K filed January 20, 2012, File No. 1-8489).	X	X	X
10.32*	2013 Performance Grant Plan under the 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.1, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.33*	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
10.34*	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
10.35*	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
10.36*	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
10.37*	Form of Special Performance Grant for Thomas F. Farrell II and Mark F. McGettrick approved January 16, 2014 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.38*	Dominion Resources, 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
10.39	Registration Rights Agreement, dated as of October 22, 2013, by and among Dominion Gas Holdings, LLC and RBC Capital Markets, LLC, RBS Securities Inc. and Scotia Capital (USA) Inc., as the initial purchasers of the Notes (Exhibit 10.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.40	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

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.41*	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
10.42*	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
10.43*	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
10.44*	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
10.45*	2017 Performance Grant Plan under the 2017 Long-Term Incentive Program approved January 24, 2017 (filed herewith).	X	X	X
10.46*	Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Program approved January 24, 2017 (filed herewith).	X	X	X
10.47*	Base salaries for named executive officers of Dominion Resources, Inc. (filed herewith).	X		
10.48*	Non-employee directors' annual compensation for Dominion Resources, Inc. (filed herewith).	X		
12.a	Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith).	X		
12.b	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X	
12.c	Ratio of earnings to fixed charges for Dominion Gas Holdings, LLC (filed herewith).			X
21	Subsidiaries of Dominion Resources, Inc. (filed herewith).	X		
23	Consent of Deloitte & Touche LLP (filed herewith).	X	X	X
31.a	Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.b	Certification by Chief Financial Officer of Dominion Resources, 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 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 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 Resources, 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 Gas Holdings, LLC as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).			X

Table of Contents

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
101	The following financial statements from Dominion Resources, Inc. and Virginia Electric and Power Company Annual Report on Form 10-K for the year ended December 31, 2016, filed on February 28, 2017, 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*

Exhibit 4.7

DOMINION RESOURCES, INC.
Issuer

AND

DEUTSCHE BANK TRUST COMPANY AMERICAS
Trustee

Eighth Supplemental Indenture

Dated as of December 1, 2016

$250,000,000

2016 Series F 1.875% Senior Notes due 2018

TABLE OF CONTENTS*

* 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 EIGHTH SUPPLEMENTAL INDENTURE is made as of the 1st day of December, 2016, by and between DOMINION RESOURCES, INC., a Virginia corporation, having its principal office at 120 Tredegar Street, Richmond, Virginia 23219 (the "Company"), 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").

W I T N E S S E T H:

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 Eighth 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 Eighth 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
2016 SERIES F 1.875% SENIOR NOTES DUE 2018

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 2016 Series F 1.875% Senior Notes due 2018 (the "Series F Senior Notes").

There are to be authenticated and delivered $250,000,000 principal amount of Series F Senior Notes, and such principal amount of the Series F Senior Notes may be increased from time to time pursuant to the penultimate paragraph of Section 301 of the Base Indenture. All Series F 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 F Senior Notes. Any such additional Series F 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 F Senior Notes initially issued under this Eighth Supplemental Indenture. Further Series F Senior Notes may also be authenticated and delivered as provided by Sections 304, 305, 306, 905 or 1107 of the Base Indenture.

The Series F 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 F 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 F Senior Notes shall be in substantially the form set forth in Exhibit B hereto.

Each Series F 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 reference to a "Section" refers to a Section of this Eighth Supplemental Indenture.

"Adjusted Treasury Rate" means, with respect to any Redemption Date, the rate per annum equal to the semiannual equivalent yield to maturity or interpolated (on a day count basis) of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such Redemption Date.

"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.

"Comparable Treasury Issue" means the United States Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term of the Series F Senior Notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term in years and months of the Series F Senior Notes.

"Comparable Treasury Price" for any Redemption Date means (i) the average of the Reference Treasury Dealer Quotations for such Redemption Date, after excluding the highest and lowest Reference Treasury Dealer Quotations, or (ii) if the Independent Investment Banker obtains fewer than five such Reference Treasury Dealer Quotations, the average of all such quotations.

"Distribution Compliance Period" has the meaning set forth in Section 204.

“Independent Investment Banker” means Credit Suisse Securities (USA) LLC and its successors or affiliates, as selected by the Company, or if such firm is unwilling or unable to serve as such, an independent investment and banking institution of national standing appointed by the Company.

“Interest Payment Dates” means June 15 and December 15 of each year, commencing on June 15, 2017.

“Original Issue Date” means December 15, 2016.

“Outstanding,” when used with respect to the Series F Senior Notes, means, as of the date of determination, all Series F Senior Notes theretofore authenticated and delivered under the Indenture, except:

(i) Series F Senior Notes theretofore canceled by the Trustee or delivered to the Trustee for cancellation;

(ii) Series F 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 F Senior Notes, provided that, if such Series F Senior Notes are to be redeemed, notice of such redemption has been duly given pursuant to this Indenture or provision therefor satisfactory to the Trustee has been made;

(iii) Series F 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 F 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 F Senior Notes have been authenticated and delivered pursuant to the Indenture, other than any such Series F Senior Notes in respect of which there shall have been presented to the Trustee proof satisfactory to it that such Series F Senior Notes are held by a bona fide purchaser in whose hands such Series F Senior Notes are valid obligations of the Company; provided, however, that in determining whether the Holders of the requisite principal amount of Outstanding Series F 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 F Senior Notes for quorum purposes, Series F Senior Notes owned by the Company or any other obligor upon the Series F 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 F Senior Notes which a Responsible Officer of the Trustee actually knows to be so owned shall be so disregarded. Series F 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 F Senior Notes and (B) that the pledgee is not the Company or any other obligor upon the Series F Senior Notes or an Affiliate of the Company or such other obligor.

"Primary Treasury Dealer" means a primary United States government securities dealer in the United States as designated by the Federal Reserve Bank of New York.

"QIB" means a "qualified institutional buyer" as defined in Rule 144A.

"Reference Treasury Dealer" means (i) Credit Suisse Securities (USA) LLC and its successors or affiliates; provided that, if such firm or its successors ceases to be a Primary Treasury Dealer, the Company shall substitute another Primary Treasury Dealer; and (ii) up to four other Primary Treasury Dealers selected by the Company.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Redemption Date, the average, as determined by the Independent Investment Banker, of the bid and asked prices for the Comparable Treasury Issue related to the Series F Senior Notes being redeemed (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker at 3:30 p.m., New York City time, on the third Business Day preceding such Redemption Date.

"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 F Senior Notes that are not represented by one or more Global Securities, the Regular Record Date shall be the close of business on the 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.

"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 F Senior Notes" has the meaning set forth in Section 101.

"Stated Maturity" means December 15, 2018.

The terms "Company," "Trustee," "Base Indenture," and "Indenture" shall have the respective meanings set forth in the recitals to this Eighth Supplemental Indenture and the paragraph preceding such recitals.

SECTION 103. Payment of Principal and Interest. The principal of the Series F Senior Notes shall be due at the Stated Maturity (unless earlier redeemed). The unpaid principal amount of the Series F Senior Notes shall bear interest at the rate of 1.875% per annum 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 semi-annually in arrears on each Interest Payment Date to the Person in whose name the Series F Senior Notes are registered on the Regular Record Date for such Interest Payment Date; provided that interest payable at the Stated Maturity of principal or on a Redemption Date as provided herein 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 F 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 F 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 F 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.

Payments of interest on the Series F Senior Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series F Senior Notes shall be computed and paid on the basis of a 360-day year of twelve 30-day months. In the event that any date on which interest is payable on the Series F 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), in each case with the same force and effect as if made on the date the payment was originally payable.

Payment of the principal and interest on the Series F 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 F Senior Notes, upon redemption or repurchase being made upon surrender of such Series F 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. In the event that any date on which principal and interest is payable on the Series F Senior Notes is not a Business Day, then payment of the principal and 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), in each case with the same force and effect as if made on the date the payment was originally payable.

SECTION 104. Denominations. The Series F Senior Notes may be issued in denominations of $2,000, or any greater integral multiple of $1,000.

SECTION 105. Global Securities. The Series F 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 F 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 F Senior Notes represented by such Global Securities will not be exchangeable for, and will not otherwise be issuable as, Series F 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 F 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 F 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 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 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 F 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 F Senior Notes. Any Global Security that is exchangeable pursuant to the preceding sentence shall be exchangeable for Series F Senior Notes registered in such names as the Depositary shall direct.

SECTION 106. Redemption. The Series F Senior Notes are redeemable, in whole or in part, at any time and from time to time, at the option of the Company, at a Redemption Price equal to the greater of:

(i) 100% of the principal amount of Series F Senior Notes then Outstanding to be so redeemed, or

(ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Series F Senior Notes to be redeemed (not including any portion of such payments of interest accrued as of the Redemption Date) discounted to the Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the

Adjusted Treasury Rate, plus 12.5 basis points, as calculated by an Independent Investment Banker, plus, in either of the above cases, accrued and unpaid interest thereon to the Redemption Date.

The Adjusted Treasury Rate shall be calculated on the third Business Day preceding the Redemption Date.

Unless the Company defaults in the payment of the Redemption Price, on and after the Redemption Date, interest will cease to accrue on the Series F Senior Notes or portions thereof called for redemption.

In the event of the redemption of the Series F Senior Notes in part only, a new Series F Senior Note or Notes for the unredeemed portion will be issued in the name or names of the Holders thereof upon surrender thereof.

The Company shall notify the Trustee in writing of the Redemption Price promptly after the calculation thereof and the Trustee shall have no responsibility for such calculation. The notice of redemption shall be sent in accordance with the terms of the Base Indenture.

SECTION 107. Sinking Fund; Conversion. The Series F Senior Notes shall not have a sinking fund. The Series F Senior Notes are not convertible into or exchangeable for Equity Securities and/or any other securities.

SECTION 108. Additional Interest on Overdue Amounts. Any principal of and installment of interest on the Series F Senior Notes that is overdue shall bear interest at the rate of 1.875% (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. The Trustee shall initially serve as Paying Agent and Security Registrar with respect to the Series F 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 F 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 Eighth 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 F Senior Note (each a "Restricted Security") shall bear the following legend (the "Restricted Legend") on the face thereof:

THIS SERIES F 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 F 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 F SENIOR NOTE IS HEREBY NOTIFIED THAT THE SELLER OF THIS SERIES F 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 F SENIOR NOTE AGREES FOR THE BENEFIT OF THE COMPANY THAT (A) THIS SERIES F 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 F 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 F 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 F SENIOR NOTE, THE COMPANY MAY REQUIRE THE HOLDER OF THIS SERIES F 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 F 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 F Senior Note and, upon receipt of a Company Order, authenticate a replacement Series F 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 F 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 F 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 F Senior Note.

SECTION 204. Registration of Transfer or Exchange. The registration of transfer or exchange of any Series F 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 40th day after the later of the commencement of the offering of the Series F Senior Notes and the Original Issue Date (such period through and including such 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 S.A./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 F 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 F Senior Note bearing the Restricted Legend, each Holder of such a Series F Senior Note acknowledges the restrictions on registrations of transfer or exchange of such Series F Senior Note set forth in this Eighth Supplemental Indenture and in the Restricted Legend and agrees that it will register the transfer or exchange of such Series F Senior Note only as provided in this Eighth Supplemental Indenture. The Security Registrar shall not register a transfer or exchange of any Series F Senior Note unless such transfer or exchange complies with the restrictions on transfer or exchange of such Series F Senior Note set forth in this Eighth Supplemental Indenture. In connection with any registration of transfer or exchange of Series F Senior Notes, each Holder agrees by its acceptance of the Series F 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 F 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 F Senior Note in violation of any provision of this Eighth 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 Eighth Supplemental Indenture or under applicable law with respect to any registrations of transfer or exchange of any interest in any Series F 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 Eighth 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 Eighth Supplemental Indenture shall be read, taken and construed as one and the same instrument.

SECTION 302. Executed in Counterparts. This Eighth 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 Eighth Supplemental Indenture and of signature pages by facsimile or PDF transmission shall constitute effective execution and delivery of this Eighth Supplemental Indenture as to the parties hereto and may be used in lieu of the original, manually executed Eighth 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 F 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 F Senior Notes and of this Eighth 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 Eighth 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 Eighth 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 RESOURCES, 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/ Randy Kahn
Name: Randy Kahn
Title: Vice President

EXHIBIT A

FORM OF
2016 SERIES F 1.875% SENIOR NOTE
DUE 2018

[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 F 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 F SENIOR NOTE MAY NOT BE EXCHANGED IN WHOLE OR IN PART FOR A SECURITY REGISTERED, AND NO TRANSFER OF THIS SERIES F 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 F SENIOR NOTE AUTHENTICATED AND DELIVERED UPON REGISTRATION OF, TRANSFER OF, OR IN EXCHANGE FOR OR IN LIEU OF, THIS SERIES F SENIOR NOTE SHALL BE A GLOBAL SECURITY SUBJECT TO THE FOREGOING, EXCEPT IN SUCH LIMITED CIRCUMSTANCES.]**

[THIS SERIES F 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 F 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 F SENIOR NOTE IS HEREBY NOTIFIED THAT THE SELLER OF THIS SERIES F 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 F SENIOR NOTE AGREES FOR THE BENEFIT OF THE COMPANY THAT (A) THIS SERIES F 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

** Insert in Global Securities.
*** Insert in Restricted Securities

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 F 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 F 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 F SENIOR NOTE, THE COMPANY MAY REQUIRE THE HOLDER OF THIS SERIES F 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 F 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 RESOURCES, INC.

[Up to]** $_________
2016 SERIES F 1.875% SENIOR NOTE
DUE 2018

No. R- CUSIP No._________

Dominion Resources, Inc., a corporation duly organized and existing under the laws of Virginia (herein called the "Company", which term includes 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 ($_____________)] [specified in Schedule I hereto]** on December 15, 2018 and to pay interest thereon from December 15, 2016 or from the most recent Interest Payment Date to which interest has been paid or duly provided for, semi-annually in arrears on June 15 and December 15 of each year, commencing on June 15, 2017, at the rate of 1.875% per annum, 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 rate of 1.875% per annum (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 such Indenture, be paid to the Person in whose name this Series F 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 or on a Redemption Date 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 F 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 F 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 F Senior Notes not less than 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 F Senior Notes may be listed, and upon such notice as may be required by such exchange, all as more fully provided in said Indenture.

Payments of interest on the Series F Senior Notes will include interest accrued to but excluding the respective Interest Payment Dates. Interest payments for the Series F Senior Notes shall be computed and paid on the basis of a 360-day year of twelve 30-day months. In the event that any date on which interest is payable on the Series F 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), 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 F 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 F Senior Note, upon redemption or repurchase being made upon surrender of such Series F 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. In the event that any date on which principal and interest is payable on the Series F Senior Notes is not a Business Day, then payment of the principal and 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), in each such case with the same force and effect as if made on the date the payment was originally payable.

Reference is hereby made to the further provisions of this Series F 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 F 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 RESOURCES, INC.

By: ____________________
Name: ____________________
Title: ____________________

[REVERSE OF 2016 SERIES F 1.875% 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 an Eighth Supplemental Indenture dated as of December 1, 2016 (the "Eighth 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 F Senior Notes") which is unlimited in aggregate principal amount.

The Series F Senior Notes are redeemable, in whole or in part, at any time and from time to time in the manner and with the effect provided in the Indenture.

If an Event of Default with respect to Series F Senior Notes shall occur and be continuing, the principal of the Series F 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 F Senior Note shall be conclusive and binding upon such Holder and upon all future Holders of this Series F Senior Note and of any Series F 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 F Senior Note.

As provided in and subject to the provisions of the Indenture, the Holder of this Series F 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 F Senior Notes, the Holders of not less than a majority in principal amount of the Series F 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 F Senior Notes at the time Outstanding a direction inconsistent with such request, and shall have failed to institute any such proceeding for 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 F 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 F 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 F 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 F Senior Note is registrable in the Security Register, upon surrender of this Series F 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 F 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 F 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 F 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 F Senior Notes are exchangeable for a like aggregate principal amount of Series F 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 F Senior Note or Series F 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 F 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 F 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 F 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 F Senior Note and all rights thereunder, hereby irrevocably constituting and appointing

____ .

____ .

____ .

____ .

____ .

____ .

agent to transfer said Series F 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 RESOURCES, INC.

2016 SERIES F SENIOR NOTE

DUE 2018

No. R-____

SCHEDULE I**

The initial principal amount of this Series F 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 B

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:

Exhibit 10.45

DOMINION RESOURCES, INC.
2017 PERFORMANCE GRANT PLAN (TRANSITION GRANTS)

1. Purpose. The purpose of the 2017 Performance Grant Plan (Transition Grants) (the "Plan") is to set forth the terms of 2017 Transition Performance Grants ("Performance Grants") awarded by Dominion Resources, Inc., a Virginia corporation (the "Company"), pursuant to the Dominion Resources, Inc. 2014 Incentive Compensation Plan and any amendments thereto (the "2014 Incentive Compensation Plan"). 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. Capitalized terms used in this Plan not defined in this Section 2 will have the meaning assigned to such terms in the 2014 Incentive Compensation Plan.

a. 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.

b. Date of Grant. February 1, 2017.

c. Disability or Disabled. Means a "disability" as defined under Treasury Regulation Section 1.409A-3(i)(4). The Committee, as defined in the 2014 Incentive Compensation Plan document, will determine whether or not a Disability exists and its determination will be conclusive and binding on the Participant.

d. Participant. An officer of the Company or a Dominion Company who receives a Performance Grant on the Date of Grant.

e. Performance Period. The 24-month period beginning on January 1, 2017 and ending on December 31, 2018.

f. 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.

g. 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 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 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.

h. 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, 2019.

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 described in this Section 6 of the Performance Criteria 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
6.75% and above	200%
6.41%	125%
6.03% - 6.27%	100%
5.88%	50%
Below 5.88%	0%

- To the extent that the Company's ROIC Performance is greater than 5.88% and less than 6.03%, 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 6.27% and less than 6.41%, 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 6.41% and less than 6.75%, 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 twenty-three (23). 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 twenty-three (23).

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 prior to the end of the Performance Period, provided the Participant has remained continuously employed with Dominion 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. Application of Code Section 162(m). Performance Grants are intended to constitute "qualified performance-based compensation" within the meaning of section 1.162-27(e) of the Income Tax Regulations. The Committee will certify the achievement of the Performance Goals described in Section 6. To the maximum extent possible, this Plan will be interpreted and construed in accordance with this subsection 11(d).

e. Negative Discretion. Pursuant to Section 6(c) of the 2014 Incentive Compensation Plan, the Committee retains the authority to exercise negative discretion to reduce payments under this Plan as it deems appropriate.

f. Governing Law. This Plan shall be governed by the laws of the Commonwealth of Virginia, without regard to its choice of law provisions.

g. Conflicts. In the event of any material conflict between the provisions of the 2014 Incentive Compensation Plan and the provisions of this Plan, the provisions of the 2014 Incentive Compensation Plan will govern.

h. Participant Bound by Plan. By accepting a Performance Grant, a Participant acknowledges receipt of a copy of this Plan and the 2014 Incentive Compensation Plan document and prospectus, which are accessible on the Company Intranet, and agrees to be bound by all the terms and provisions thereof.

i. 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.

j. 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)).

EXHIBIT A

DOMINION RESOURCES, INC.
2017 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	Pacific Gas & Electric Company
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'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.

EXHIBIT A

Absolute TSR Performance will be the Company's total shareholder return on a compounded 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.

Return on Invested Capital

Return on Invested Capital (ROIC)

The following terms are used to calculate ROIC for purposes of the 2017 Performance Grant:

ROIC means Total Return divided by Average Invested Capital. Performance will be calculated for the two successive fiscal years within the Performance Period, added together and then divided by two 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 two 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 Resources, Inc. (Dominion) or its subsidiaries where Dominion 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.

Exhibit 10.46

DOMINION RESOURCES, INC.
RESTRICTED STOCK AWARD AGREEMENT

PARTICIPANT	DATE OF GRANT	NUMBER OF SHARES OF RESTRICTED STOCK GRANTED
«First_Name» «Last_Name»		«##,###»
PERSONNEL NUMBER	**VESTING DATE**	**VESTING SCHEDULE** Vesting Date / Percentage
«#####»		100%

THIS AGREEMENT, effective as of the Date of Grant shown above, between Dominion Resources, Inc., a Virginia Corporation (the "Company") and the Participant named above is made pursuant and subject to the provisions of the Dominion Resources, 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, ______ 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, ______ 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 Dominion 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, ______ to the Change of Control date, and the denominator of which is the number of whole months from February 1, ______ 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 Resources 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 Resources 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

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 10.47

Dominion Resources, Inc.
2017 Base Salaries for Named Executive Officers*

The 2017 base salaries for Dominion'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—$879,828; David A. Christian, Executive Vice President and Chief Innovation Officer—$703,960; Paul D. Koonce, Executive Vice President and President and Chief Executive Officer—Dominion Generation Group—$703,960; and David A. Heacock, President—Dominion Nuclear—$530,674 (Mr. Heacock retired effective March 1, 2017).

---

* Effective March 1, 2017

Exhibit 10.48

Dominion Resources, Inc.
Non-Employee Directors' Annual Compensation
As of December 31, 2016

Annual Retainer	**Amount**
Service as Director	$205,000 ($77,500 cash; $127,500 stock)
Service as Audit Committee or Compensation, Governance and Nominating Committee Chair	$22,500
Service as Finance and Risk Oversight Committee Chair	$15,000
Service as Lead Director	$27,500
Meeting Fees	
Board meetings	$2,000 per meeting
Committee meetings	$2,000 per meeting

Exhibit 6

Exhibit 12.a

Dominion Resources, Inc. and Subsidiaries
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Years Ended December 31,				
	2016(a)	2015(b)	2014(c)	2013(d)	2012(e)
Earnings, as defined:					
Income from continuing operations including noncontrolling interest before income tax expense	$2,867	$2,828	$1,778	$2,704	$2,265
Distributed income from unconsolidated investees, less equity in earnings	(32)	12	(8)	17	(13)
Fixed charges included in income	1,068	953	1,237	930	880
Total earnings, as defined	$3,903	$3,793	$3,007	$3,651	$3,132
Fixed charges, as defined:					
Interest charges	$1,033	$ 920	$1,208	$ 899	$ 845
Rental interest factor	35	33	29	31	35
Fixed charges included in income	1,068	953	1,237	930	880
Preference security dividend requirement of consolidated subsidiary	—	—	17	25	25
Capitalized Interest	124	67	39	28	24
Interest from discontinued operations	—	—	—	85	80
Total fixed charges, as defined	$1,192	$1,020	$1,293	$1,068	$1,009
Ratio of Earnings to Fixed Charges	**3.27**	**3.72**	**2.33**	**3.42**	**3.10**

(a) Earnings for the twelve months ended December 31, 2016 include a $197 million charge associated with future ash pond and landfill closure costs; a $65 million charge associated with an organizational design initiative; $74 million in transaction and transition costs associated with the Dominion Questar combination; a $23 million charge related to storm and restoration costs; 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 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.

(b) Earnings for the twelve months ended December 31, 2015 include a $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.

(c) 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; $121 million accrued charge associated with ash pond and landfill closure costs; $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.

(d) 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 Power'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; 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; a $29 million net benefit primarily resulting from the sale of 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.

(e) Earnings for the twelve months ended December 31, 2012 include $438 million of impairment and other charges related the planned shut-down of Kewaunee nuclear power station; $87 million of restoration costs associated with severe storms affecting our Dominion Virginia Power and Dominion North Carolina service territories; partially offset by a $36 million net gain related to our investments in nuclear decommissioning trust funds and $4 million net benefit related to other items. 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, 2012.

Exhibit 12.b

Virginia Electric and Power Company
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Years Ended December 31, 2016	2015	2014	2013	2012
Earnings, as defined:					
Income from continuing operations before income tax expense	$1,945	$1,746	$1,406	$1,797	$1,703
Fixed charges included in income	495	474	438	401	418
Total earnings, as defined	$2,440	$2,220	$1,844	$2,198	$2,121
Fixed charges, as defined:					
Interest charges	$ 478	$ 457	$ 425	$ 388	$ 404
Rental interest factor	17	17	13	13	14
Total fixed charges, as defined	$ 495	$ 474	$ 438	$ 401	$ 418
Ratio of Earnings to Fixed Charges	**4.93**	**4.68**	**4.21**	**5.48**	**5.07**

Exhibit 12.c

Dominion Gas Holdings, LLC
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Years Ended December 31,				
	2016	2015	2014	2013	2012
Earnings, as defined:					
Income from continuing operations before income tax expense	$ 607	$ 740	$ 846	$ 762	$ 747
Distributed income from unconsolidated investees, less equity in earnings	0	(3)	(1)	(2)	2
Fixed charges included in income	109	86	39	43	65
Total earnings, as defined	$ 716	$ 823	$ 884	$ 803	$ 814
Fixed charges, as defined:					
Interest charges	$ 97	$ 74	$ 28	$ 30	$ 51
Rental interest factor	12	12	11	13	14
Total fixed charges, as defined	$ 109	$ 86	$ 39	$ 43	$ 65
Ratio of Earnings to Fixed Charges	**6.57**	**9.57**	**22.67**	**18.67**	**12.52**

Exhibit 6

Exhibit 21

DOMINION RESOURCES, INC.
SUBSIDIARIES OF THE REGISTRANT
AS OF FEBRUARY 15, 2017

Name	Jurisdiction of Incorporation	Name Under Which Business is Conducted
Dominion Resources, Inc.	Virginia	Dominion Resources, 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 Carolina Gas Services, Inc.	Virginia	Dominion Carolina Gas Services, Inc.
Dominion Cove Point, Inc.	Virginia	Dominion Cove Point, Inc.
Dominion MLP Holding Company, LLC	Delaware	Dominion MLP Holding Company, LLC
Dominion Midstream Partners, LP	Delaware	Dominion Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Cove Point LNG, LP	Delaware	Dominion Cove Point LNG, LP
Dominion Carolina Gas Transmission, LLC	South Carolina	Dominion Carolina Gas Transmission, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Questar Pipeline, LLC	Utah	Questar Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar Overthrust Pipeline, LLC	Utah	Questar Overthrust Pipeline, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, LLC
Dominion Midstream GP, LLC	Delaware	Dominion Midstream GP, LLC
Dominion Midstream Partners, LP	Delaware	Dominion Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Cove Point LNG, LP	Delaware	Dominion Cove Point LNG, LP
Dominion Carolina Gas Transmission, LLC	South Carolina	Dominion Carolina Gas Transmission, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Questar Pipeline, LLC	Utah	Questar Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar Overthrust Pipeline, LLC	Utah	Questar Overthrust Pipeline, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, LLC
Dominion Gas Projects Company, LLC	Delaware	Dominion Gas Projects Company, LLC
Dominion Cove Point LNG, LP	Delaware	Dominion Cove Point LNG, LP
Dominion Energy, Inc.	Virginia	Dominion Energy, 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 Manchester Street, Inc.	Virginia	Dominion Energy Manchester Street, Inc.
Dominion Energy Marketing, Inc.	Delaware	Dominion Energy Marketing, Inc.
Dominion Nuclear Connecticut, Inc.	Delaware	Dominion Nuclear Connecticut, Inc.
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.
Fairless Energy, LLC	Delaware	Fairless Energy, 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 CA, LLC	Delaware	Dominion Solar CA, LLC
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
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
Moffett Solar 1, LLC	Delaware	Moffett Solar 1, LLC
Ridgeland Solar Farm I, LLC	Delaware	Ridgeland Solar Farm I, LLC
Dominion Solar Projects D, Inc.	Virginia	Dominion Solar Projects C, Inc.
Dominion Solar Holdings IV, LLC	Virginia	Dominion Solar Holdings IV, LLC
Moffett Solar 1, LLC	Delaware	Moffett Solar 1, LLC
Ridgeland Solar Farm I, LLC	Delaware	Ridgeland Solar Farm I, 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.
Prairie Fork Wind Farm, LLC	Virginia	Prairie Fork Wind Farm, LLC
Dominion Fowler Ridge Wind, LLC	Virginia	Dominion Fowler Ridge Wind, LLC
Dominion Wind Development, LLC	Virginia	Dominion Wind Development, 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 Field Services, Inc.	Delaware	Dominion Field Services, Inc.
Dominion Gas Holdings, LLC	Virginia	Dominion Gas Holdings, LLC
Dominion Gathering & Processing, Inc.	Virginia	Dominion Gathering & Processing, Inc.
Dominion Iroquois, Inc.	Delaware	Dominion Iroquois, Inc.
Dominion Transmission, Inc.	Delaware	Dominion 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.
The East Ohio Gas Company	Ohio	Dominion East Ohio
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 Natrium Holdings, Inc.	Delaware	Dominion Natrium Holdings, Inc.
Dominion Oklahoma Texas Exploration & Production, Inc.	Delaware	Dominion Oklahoma Texas Exploration & Production, Inc.
Dominion Payroll Company, Inc.	Virginia	Dominion Payroll Company, 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 Questar Corporation	Utah	Dominion Questar Corporation

QPC Holding Company	Utah	QPC Holding Company
Dominion Midstream Partners, LP	Delaware	Dominion Midstream Partners, LP
Cove Point GP Holding Company, LLC	Delaware	Cove Point GP Holding Company, LLC
Dominion Cove Point LNG, LP	Delaware	Dominion Cove Point LNG, LP
Dominion Carolina Gas Transmission, LLC	South Carolina	Dominion Carolina Gas Transmission, LLC
Iroquois GP Holding Company, LLC	Delaware	Iroquois GP Holding Company, LLC
Questar Pipeline, LLC	Utah	Questar Pipeline, LLC
Questar Field Services, LLC	Utah	Questar Field Services, LLC
Questar Overthrust Pipeline, LLC	Utah	Questar Overthrust Pipeline, LLC
Questar White River Hub, LLC	Utah	Questar White River Hub, 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
QPC Services Company	Utah	QPC Services Company
Questar Gas Company	Utah	Questar Gas Company
Wexpro Company	Utah	Wexpro Company
Wexpro II Company	Utah	Wexpro II Company
Wexpro Development Company	Utah	Wexpro Development Company
Dominion Resources Capital Trust III	Delaware	Dominion Resources Capital Trust III
Dominion Resources Services, Inc.	Virginia	Dominion Resources Services, Inc.
Dominion Retail, Inc.	Delaware	Dominion Energy Solutions Dominion East Ohio Energy Dominion Peoples Plus
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
Dominion Technical Solutions, Inc.	Virginia	Dominion Technical Solutions, Inc.
Hope Gas, Inc.	West Virginia	Dominion Hope
Virginia Electric and Power Company	Virginia	Dominion Virginia Power (in Virginia) Dominion North Carolina Power (in North Carolina)
Virginia Power Fuel Corporation	Virginia	Virginia Power Fuel Corporation
Virginia Power Services, LLC	Virginia	Virginia Power Services, LLC
Dominion Generation Corporation	Virginia	Dominion Generation Corporation
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.
Virginia Power Energy Marketing, Inc.	Virginia	Virginia Power Energy Marketing, Inc.

Exhibit 6

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-201149 and 333-194409 on Form S-3 and Registration Statement Nos. 333-203952, 333-202366, 333-202364, 333-195768, 333-124256, 333-189581, 333-149993, 333-130570, 333-189580, 333-156027, 333-130566, 333-189579, 333-149989, 333-85094, 333-95795, 333-189578, 333-163805, 333-143916, 333-110332, 333-87529, 333-09167, 333-124257, 333-49725, 333-18391, 333-02733, 333-62705, 333-25587 and 333-78173 on Form S-8 of our reports dated February 28, 2017, relating to the consolidated financial statements of Dominion Resources, Inc. and subsidiaries and the effectiveness of Dominion Resources, Inc. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Dominion Resources, Inc. for the year ended December 31, 2016.

We consent to the incorporation by reference in Registration Statement No. 333-201153 on Form S-3 of our report dated February 28, 2017, relating to the consolidated financial statements of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries, appearing in this Annual Report on Form 10-K of Virginia Electric and Power Company for the year ended December 31, 2016.

We consent to the incorporation by reference in Registration Statement No. 333-197252 on Form S-3 of our report dated February 28, 2017, relating to the consolidated financial statements of Dominion Gas Holdings, LLC (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries, appearing in this Annual Report on Form 10-K of Dominion Gas Holdings, LLC for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 28, 2017

Exhibit 31.a

I, Thomas F. Farrell II, certify that:

1. I have reviewed this report on Form 10-K of Dominion Resources, 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 28, 2017

/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 Resources, 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 28, 2017

/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 28, 2017

/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 28, 2017

/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 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 28, 2017

/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 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 28, 2017

/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 Resources, Inc. (the “Company”), certify that:

1. the Annual Report on Form 10-K for the year ended December 31, 2016 (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, 2016, and for the period then ended.

/s/ Thomas F. Farrell II

Thomas F. Farrell II
President and Chief Executive Officer
February 28, 2017

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 28, 2017

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, 2016 (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, 2016, and for the period then ended.

/s/ Thomas F. Farrell II

Thomas F. Farrell II
Chief Executive Officer
February 28, 2017

/s/ Mark F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 28, 2017

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 Gas Holdings, LLC (the "Company"), certify that:

1. the Annual Report on Form 10-K for the year ended December 31, 2016 (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, 2016, and for the period then ended.

/s/ Thomas F. Farrell II

Thomas F. Farrell II
Chief Executive Officer
February 28, 2017

/s/ Mark. F. McGettrick

Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
February 28, 2017

Exhibit 6

Dominion Energy Inc., and Subsidiaries
Credit Ratings
As of January 3, 2018

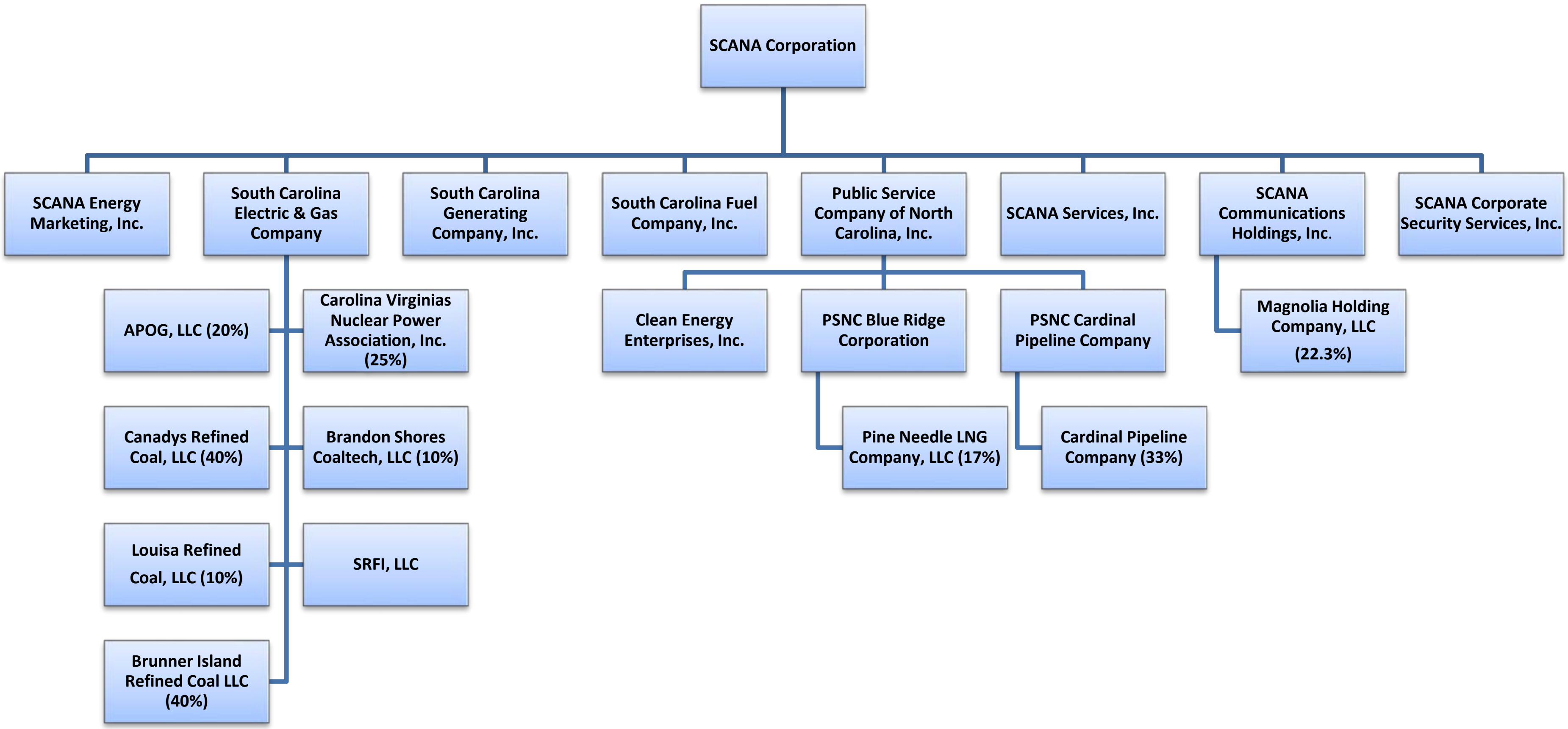
	Moody's	Standard & Poor's	Fitch
Dominion Energy, Inc.			
Issuer Rating/Corporate Credit Rating/Issuer Default Rating	Baa2	BBB+	BBB+
Senior Unsecured Debt	Baa2	BBB	BBB+
Junior Subordinated Debt	Baa3	BBB	BBB
Enhanced Junior Subordinated Debt	Baa3	BBB-	BBB-
Short-Term Debt (Commercial Paper)	P-2	A-2	F2
Rating Outlook	Negative	Negative	Stable
Virginia Electric and Power Company			
Issuer Rating/Corporate Credit Rating/Issuer Default Rating	A2	BBB+	A-
Senior Unsecured Debt	A2	BBB+	A
Short-Term Debt (Commercial Paper)	P-1	A-2	F2
Rating Outlook	Stable	Negative	Stable
Dominion Energy Gas Holdings			
Issuer Rating/Corporate Credit Rating/Issuer Default Rating	A2	BBB+	A-
Senior Unsecured Debt	A2	BBB+	A-
Short-Term Debt (Commercial Paper)	P-1	A-2	F2
Rating Outlook	Negative	Negative	Negative
Questar Gas Company			
Issuer Rating/Corporate Credit Rating/Issuer Default Rating	A2	BBB+	A-
Senior Unsecured Debt	A2	BBB+	A
Short-Term Debt (Commercial Paper)	P-1	A-2	F2
Rating Outlook	Stable	Negative	Stable
Dominion Energy Questar Pipeline, LLC			
Issuer Rating/Corporate Credit Rating/Issuer Default Rating	A3	BBB	N/A
Senior Unsecured Debt	A3	BBB	N/A
Short-Term Debt (Commercial Paper)	N/A	N/A	N/A
Rating Outlook	Stable	Negative	N/A

Recent Actions:

(1) On January 3, 2018, Moody's affirmed the ratings for DEI and revised its outlook to negative from stable.
(2) On January 3, 2018, S&P affirmed its ratings for DEI and DEI's rated subsidiaries and revised the rating outlook for DEI and its rated subsidiaries to negative from stable.
(3) On January 3, 2018, Fitch affirmed both its credit ratings and outlook for DEI.

SCANA Corporation Organizational Chart

All subsidiaries are 100% owned unless otherwise indicated

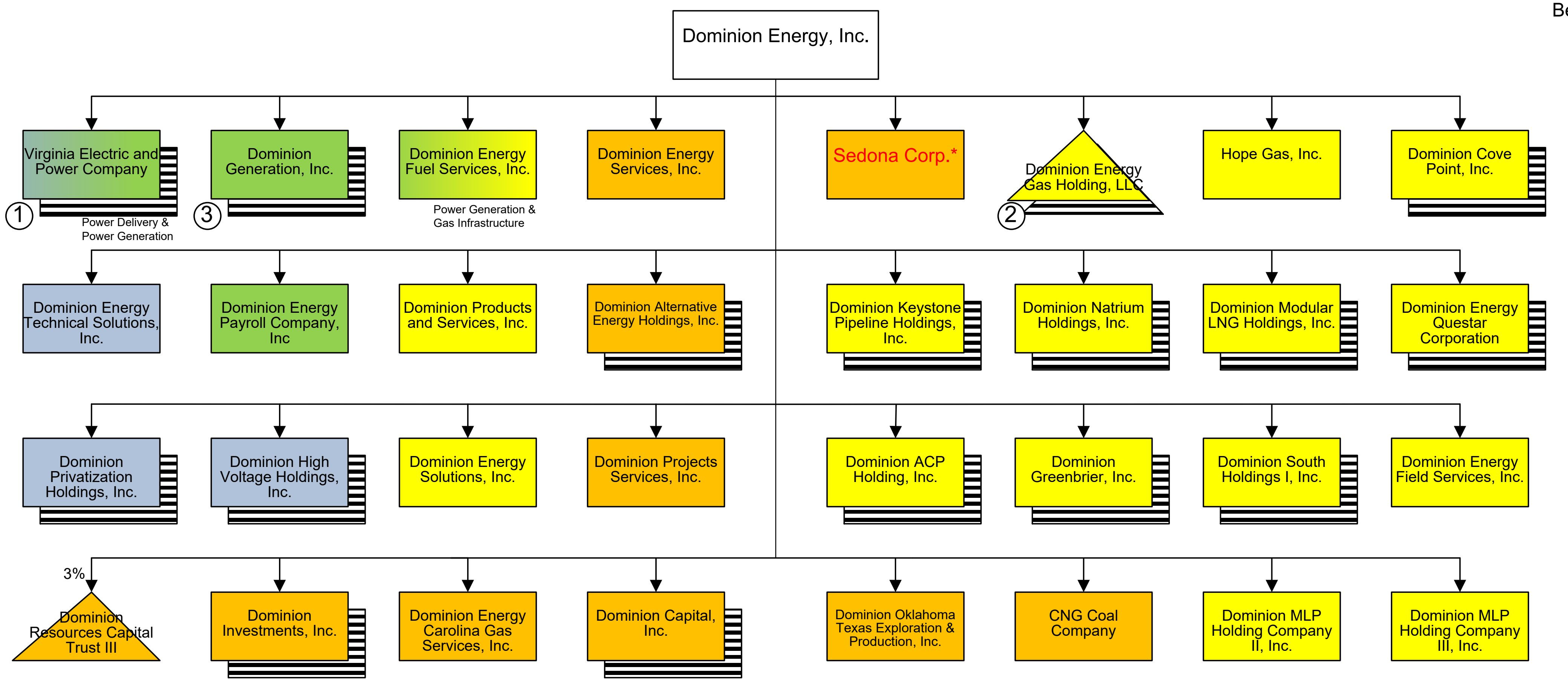


In addition to the entities listed above, SCE&G has an interest in two entities that are no longer utilized and are in the process of dissolution. The entities are SC Coaltech No. 1, LP (SCE&G 40% interest) and Coaltech No. 1, LP (SCE&G 25% interest), and both were incorporated in Delaware and registered to do business in South Carolina. Both entities have been dissolved in Delaware and are in the process of cancelling the entity registrations in South Carolina.

Additionally, SCANA Corporation and SCE&G have interests in the following nonprofit organizations: SCE&G Foundation, Inc., formerly SCANA Summer Foundation, (SCANA Corporation 100% interest); SCANA Employee Good Neighbor Fund (SCANA Corporation 100% interest); Otarre Property Owners Association, Inc. (membership comprised of SCE&G and all property owners in Otarre development); and South Carolina Electric & Gas Project Share (SCE&G 100% interest).

12-20-2016

Before SCANA Merger



1. See Attachment A for subsidiaries of Virginia Electric and Power Company.
2. See Attachment B for subsidiaries of Dominion Energy Gas Holdings.
3. See Attachment C for subsidiaries of Dominion Generation, Inc.

**Sedona Corp. will merge with SCANA Corporation, and SCANA Corporation will be the surviving entity.*

- Multiple lines under a box/triangle indicate that the entity shown has subsidiaries.
- Unless otherwise noted, ownership of 100%.

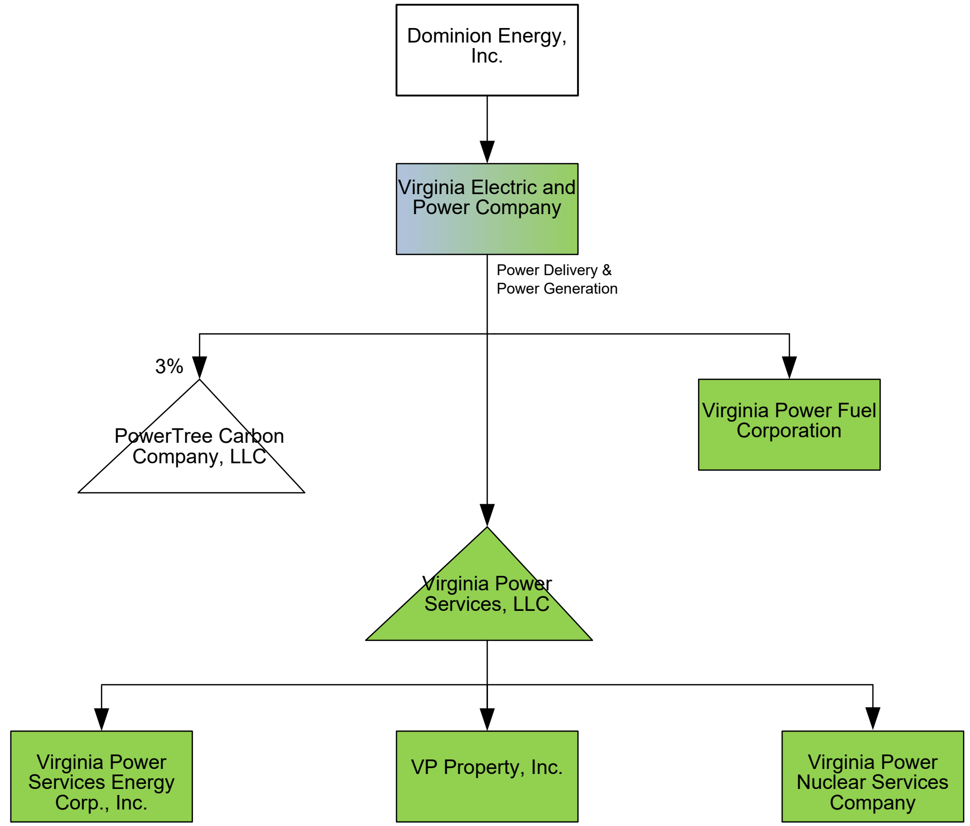
Updated as of 1/8/2018

Business Unit

Power Delivery	**Corporate & Other**
Gas Infrastructure	**Power Generation**

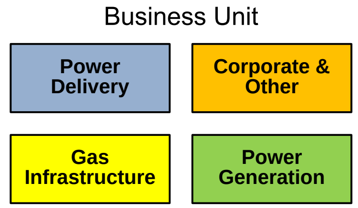
Before SCANA Merger

[Attachment A]

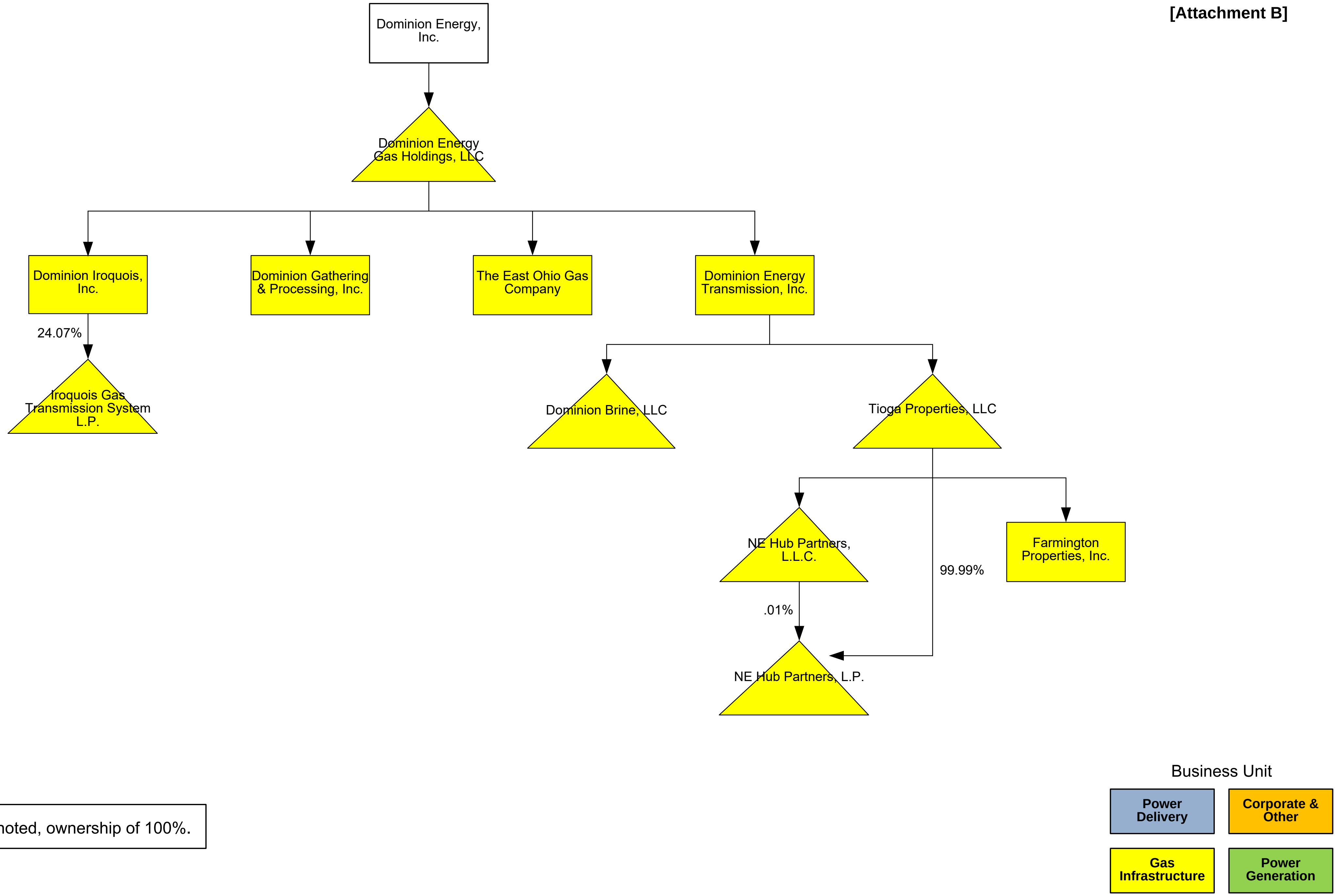


- Unless otherwise noted, ownership of 100%.

Updated as of 1/8/2018



Before SCANA Merger
[Attachment B]

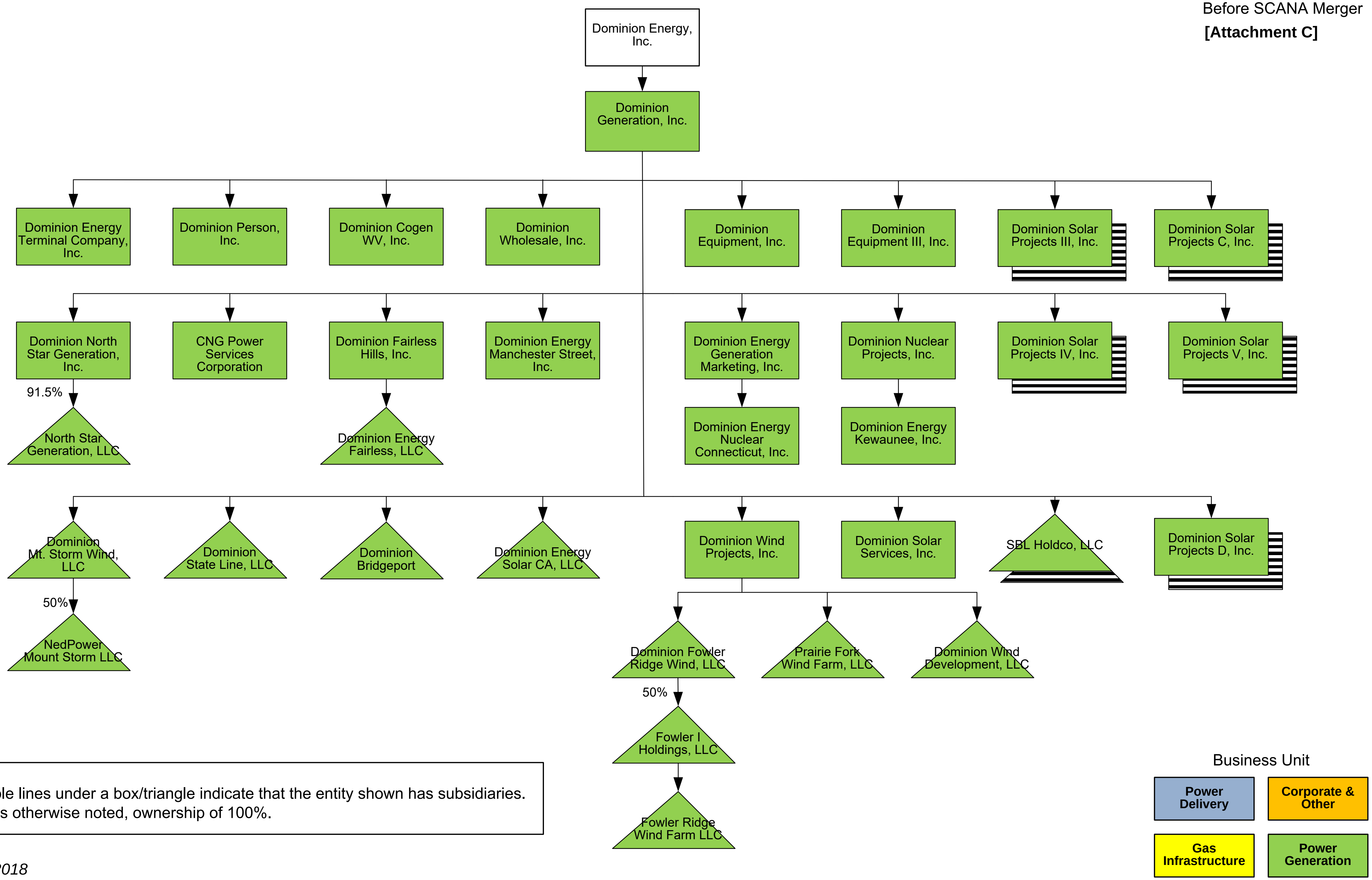


- Unless otherwise noted, ownership of 100%.

Updated as of 1/8/2018

Before SCANA Merger

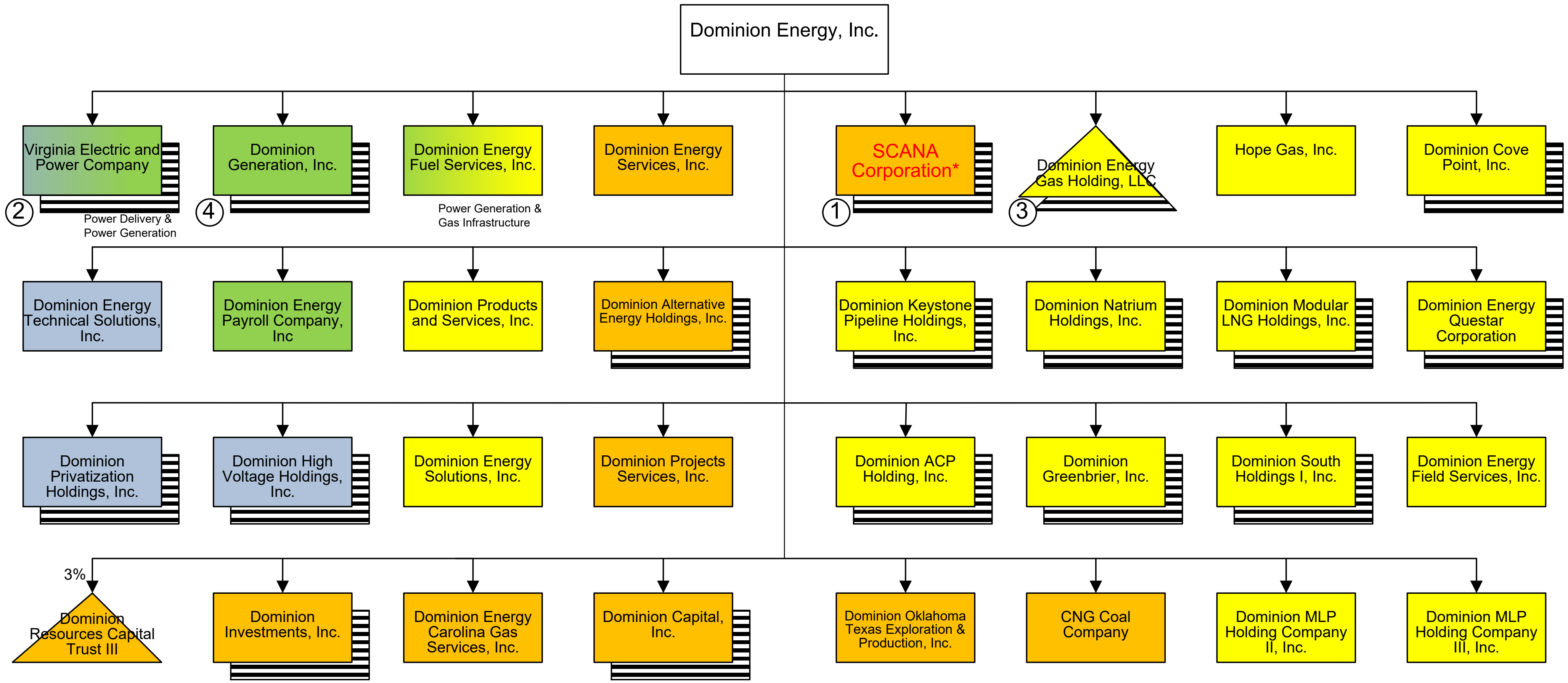
[Attachment C]



- Multiple lines under a box/triangle indicate that the entity shown has subsidiaries.
- Unless otherwise noted, ownership of 100%.

Updated as of 1/8/2018

After SCANA Merger

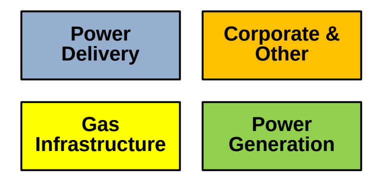


1. See Attachment A for subsidiaries of SCANA Corporation.
2. See Attachment B for subsidiaries of Virginia Electric and Power Company.
3. See Attachment C for subsidiaries of Dominion Energy Gas Holdings.
4. See Attachment D for subsidiaries of Dominion Generation, Inc.

**SCANA Corporation will be the surviving entity of its merger with the Dominion Energy merger subsidiary, Sedona Corp.*

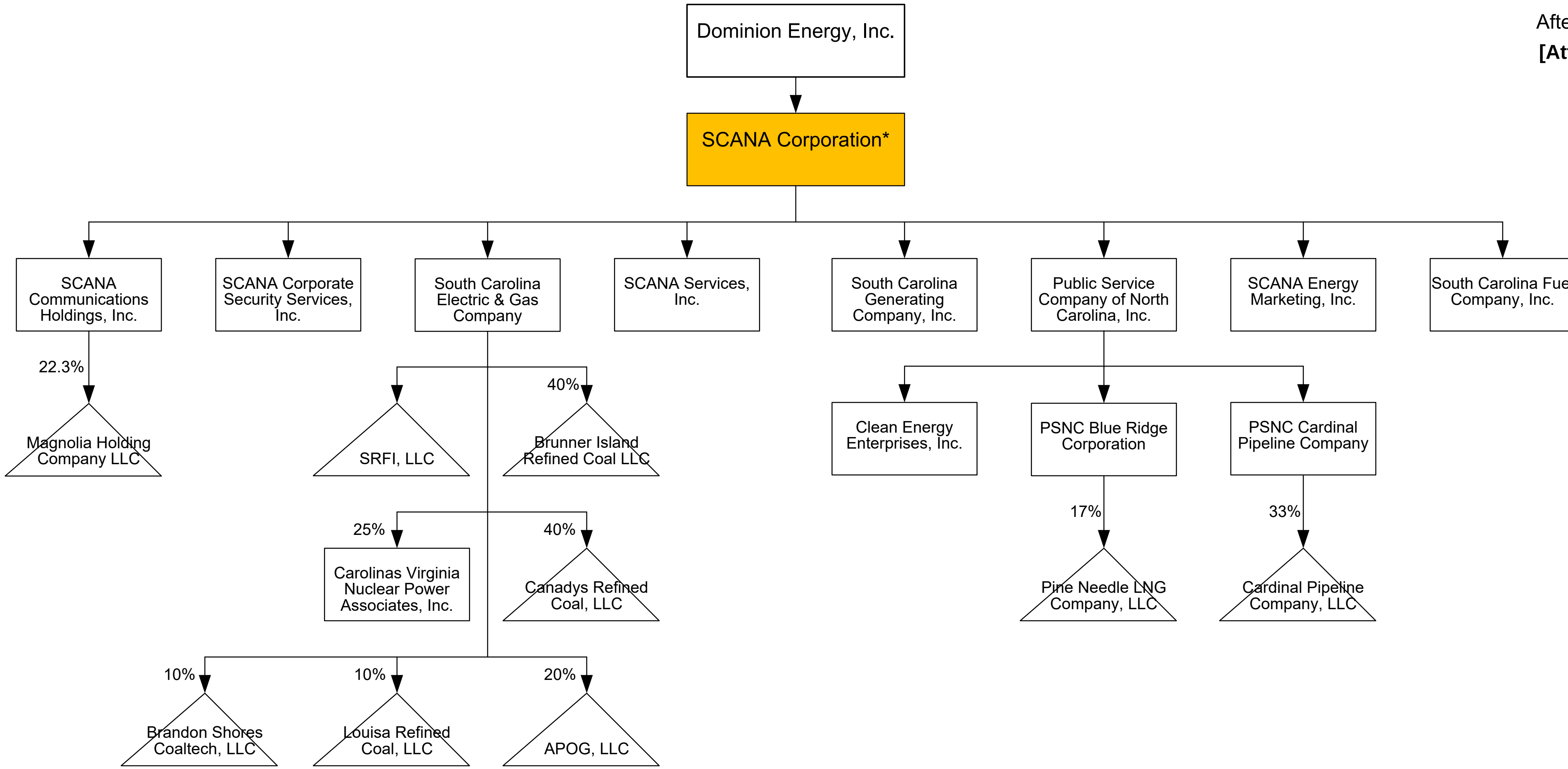
- Multiple lines under a box/triangle indicate that the entity shown has subsidiaries.
- Unless otherwise noted, ownership of 100%.

Business Unit



Updated as of 1/9/2018

After SCANA Merger
[Attachment A]



SCANA Corporation will be the surviving entity of its merger with the Dominion Energy merger subsidiary, Sedona Corp.
*****Business Unit designation of SCANA Corporation subsidiaries to be determined.***

- Unless otherwise noted, ownership of 100%.

Note: In addition to the entities listed above, SCE&G has an interest in two entities that are no longer utilized and are in the process of dissolution. The entities are SC Coaltech No. 1, LP (SCE&G 40% interest) and Coaltech No. 1, LP (SCE&G 25% interest), and both were incorporated in Delaware and registered to do business in South Carolina. Both entities have been dissolved in Delaware and are in the process of cancelling the entity registrations in South Carolina.

Additionally, SCANA Corp. and SCE&G have interests in the following nonprofit organizations: SCE&G Foundation, Inc., formerly SCANA Summer Foundation, (SCANA Corp. 100% interest); SCANA Employee Good Neighbor Fund (SCANA Corp. 100% interest); Otarre Property Owners Association, Inc. (membership comprised of SCE&G and all property owners in Otarre development); and South Carolina Electric & Gas Project Share (SCE&G 100% interest).

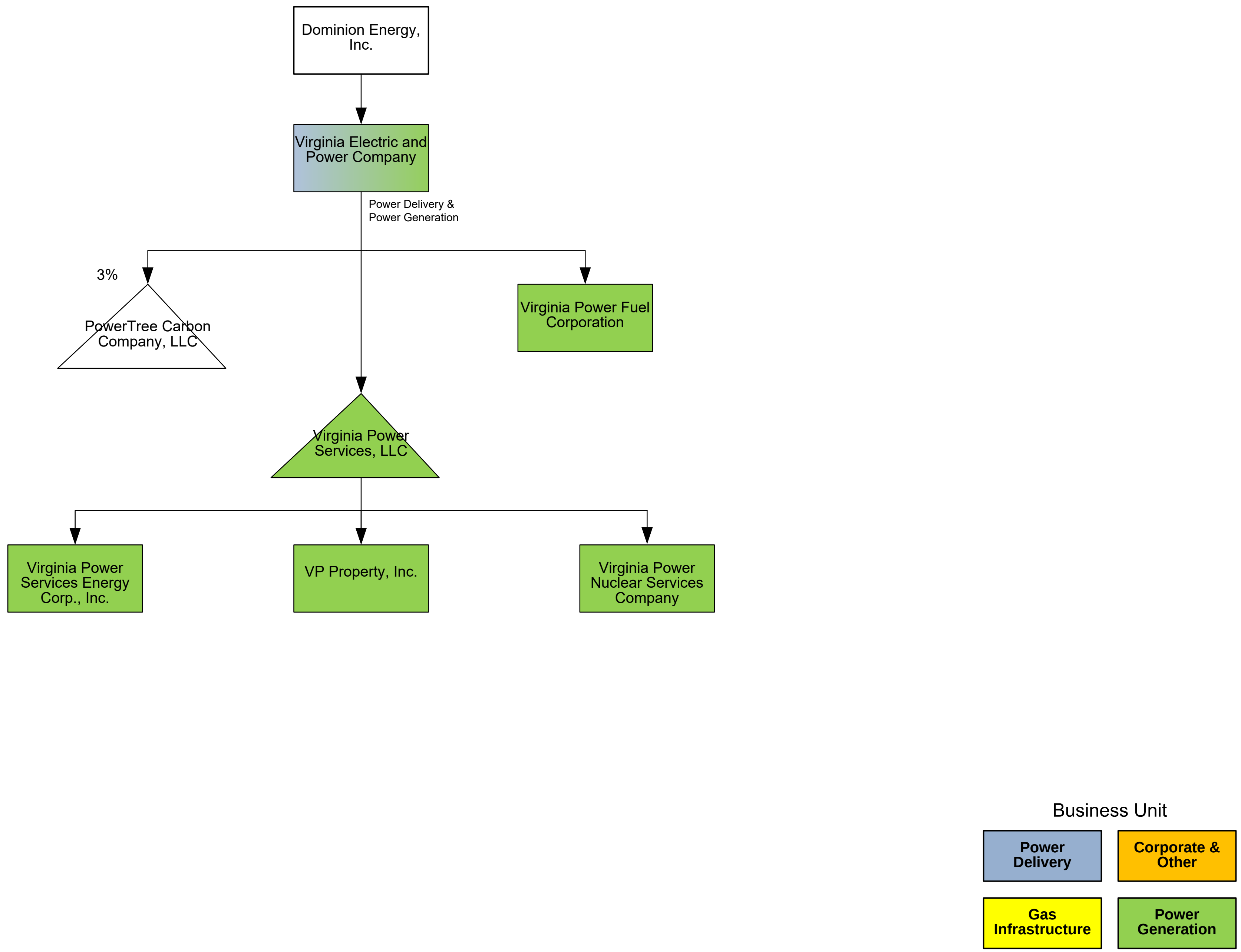
Updated as of 1/9/2018

Business Unit**

Power Delivery	**Corporate & Other**
Gas Infrastructure	**Power Generation**

After SCANA Merger

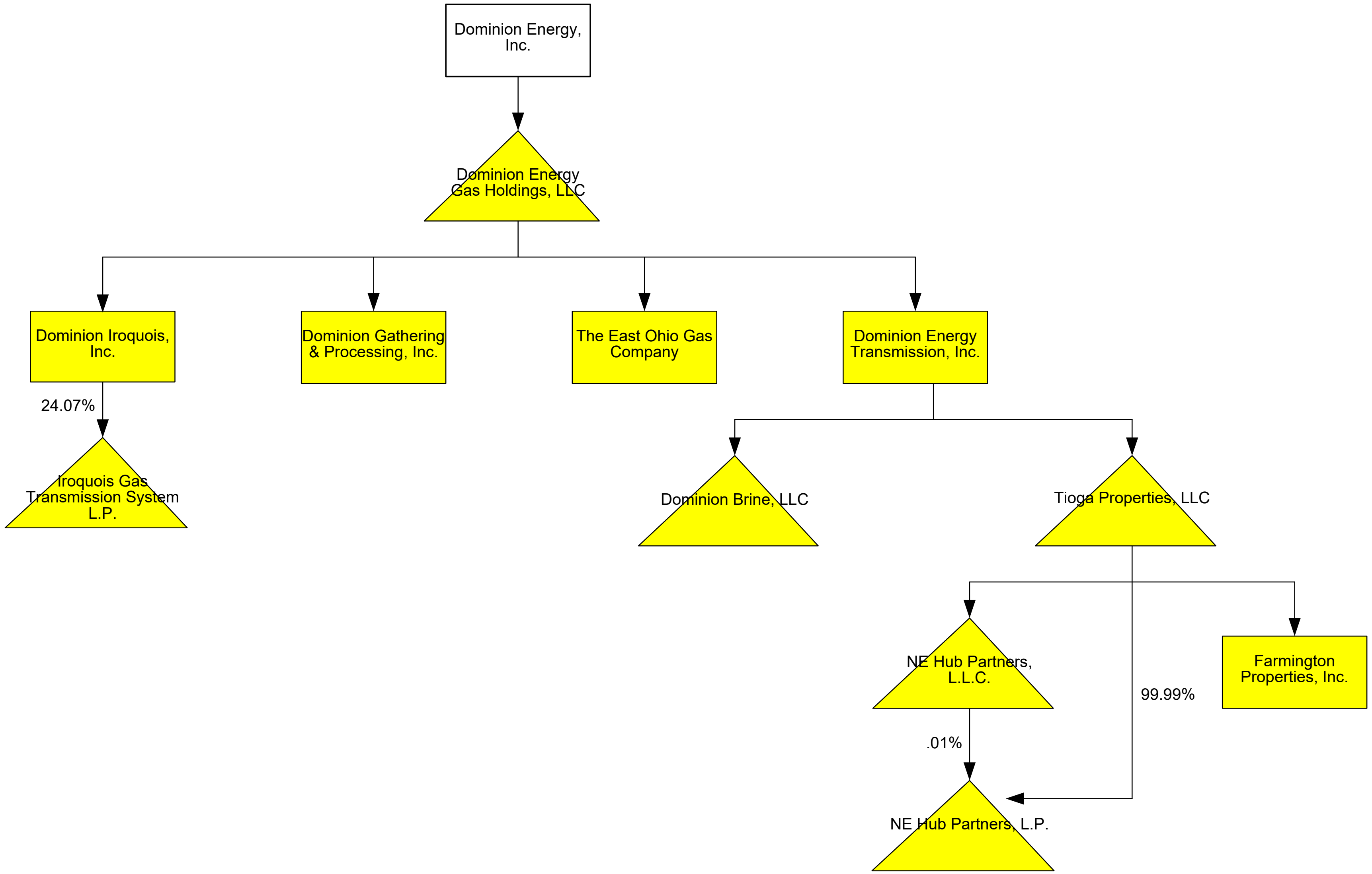
[Attachment B]



- Unless otherwise noted, ownership of 100%.

Updated as of 1/9/2018

After SCANA Merger
[Attachment C]



Business Unit

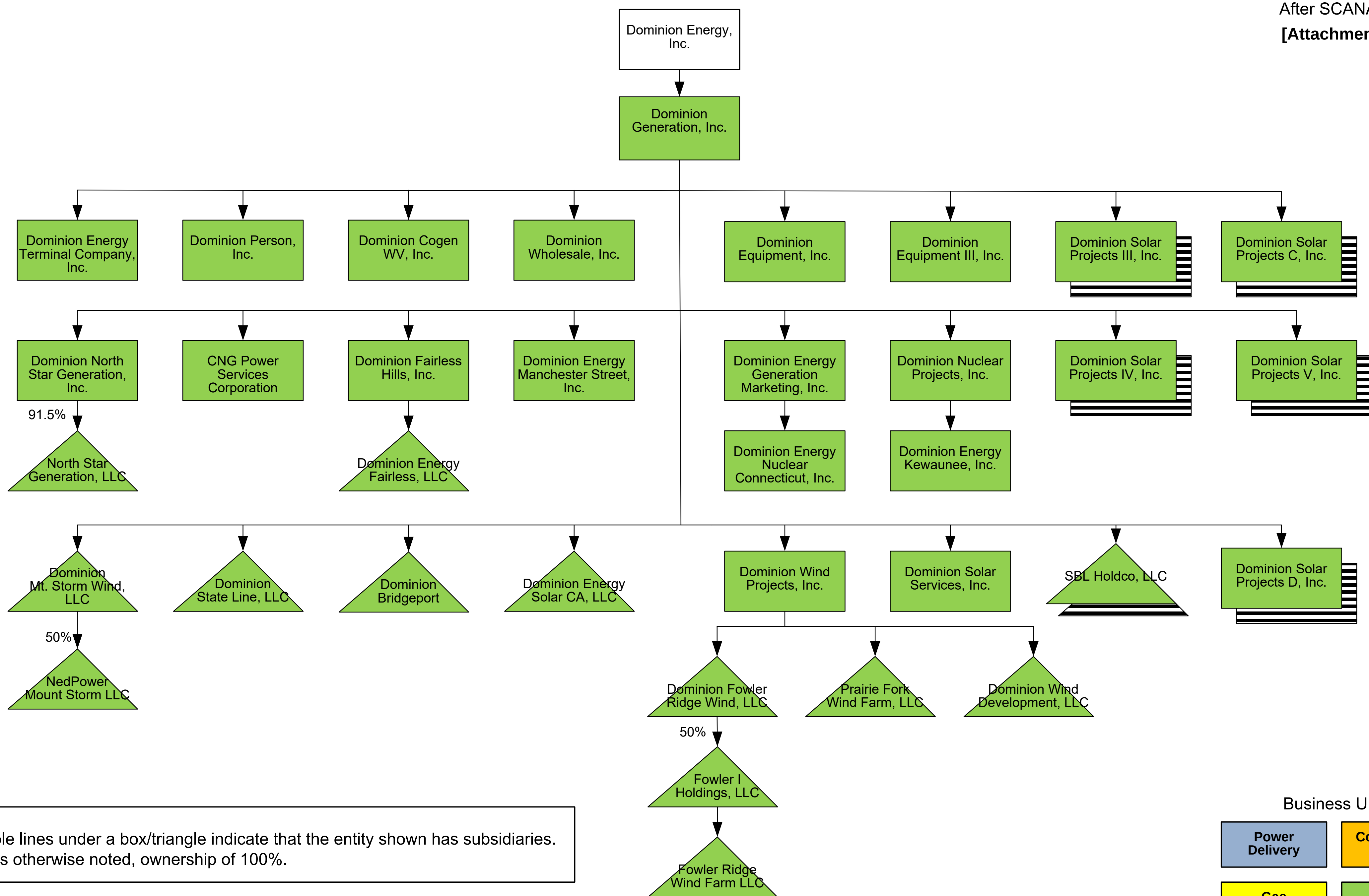
Power Delivery	**Corporate & Other**
Gas Infrastructure	**Power Generation**

- Unless otherwise noted, ownership of 100%.

Updated as of 1/9/2018

After SCANA Merger

[Attachment D]



- Multiple lines under a box/triangle indicate that the entity shown has subsidiaries.
- Unless otherwise noted, ownership of 100%.

Business Unit

Power Delivery | Corporate & Other | Gas Infrastructure | Power Generation

Updated as of 1/9/2018

Key Provisions of the
No Merger Benefits Plan

1. The customer mitigation provisions of the No Merger Benefits Plan are as follows:

a. **No Revised Rates Increases:** SCE&G will not seek further revised rates increases under the BLRA associated with the abandonment of the new nuclear project until new retail electric rates are set by the Commission in a general rate case.

b. **Rate Reduction:** SCE&G will provide each retail electric customer class a rate reduction, as shown in the proposed tariffs attached as ***Exhibit 12*** to the Joint Petition, of three and a half percent (3.5%) compared to May 2017 retail electric rates. The rate reduction will take effect following issuance by the Commission of an order adopting the No Merger Benefits Plan and will remain in effect until new retail electric rates are set by the Commission in a general rate case. Under the No Merger Benefits Plan, tariff language indicating that the tariffs are subject to annual adjustment arising under the Capital Cost Recovery Rider would be removed from the tariff sheets attached as ***Exhibit 12***.

c. **New Capacity:** Through its acquisition of the Columbia Energy Center in Gaston, South Carolina, SCE&G will add 540 MW of replacement generation capacity to its system and will contribute the approximately

$180 million capital cost, with only the ongoing costs such as fuel costs, operations and maintenance expenses, and maintenance or improvement capital investments associated with the plant to be recovered in future rates.

d. **Solar RFP:** SCE&G will issue a request for proposals for 100 MW of new solar capacity with associated battery storage to be located on SCE&G's system.

e. **Toshiba Corporation Guarantee Settlement Payment:** The Toshiba Corporation Guarantee Settlement Payments, net of amounts used to satisfy project liens, will benefit customers through a reduction of the capital cost of the abandoned new nuclear development project to be recovered in rates.

f. **Recovery of the Capital Costs of the Units:** All capital costs of the NND Project, less a $490 million write-off, will be amortized into retail electric rates on a straight line basis over a fixed 50-year period at approximately $63 million annually. The increase in utility expenses associated with this amortization will not result in a change in customer rates in this proceeding.

g. **Tax Rider:** The Tax Rider as shown in ***Exhibit 12*** shall apply.

2. The following accounting and other provisions that apply under the Customer Benefits Plan would also apply under the No Merger Benefits Plan:

a. Transmission Investments will be subject to the accounting and ratemaking treatment provided for Transmission Investments under the Customer Benefits Plan as described in Paragraphs 105-108 of the Joint Petition;

b. In addition, the "Transfers" on ***Exhibit 13*** in the amount of approximately $85 million represent investment associated with the switchyard and other NND Project assets that are prudent investments in assets that are used and useful in operating V.C. Summer Unit 1 and should be subject to the same prudence and other determinations requested in in Paragraphs 105-108 of the Joint Petition;

c. The Company requests a determination of the prudency of the decision to abandon the project as described in Paragraph 127 of the Joint Petition;

d. The Company requests a determination of the prudency of the Capital Costs set forth on ***Exhibit 13*** as described in Paragraphs 128-129 of the Joint Petition; and

e. The Company requests that the Commission adopt the cost schedule as set forth in ***Exhibit 13*** as described in Paragraph 130 of the Joint Petition as the cost schedules for the project in abandonment.

3. The capital cost for the NND Project shall be included in a regulatory asset and that regulatory asset, as well as related deferred tax assets and liabilities, shall be recovered through rates over a straight line 20-year amortization and recovery period.

4. That capital costs included in this regulatory asset shall include the costs reflected on ***Exhibit 13,*** net of investment in Transmission Projects, the switchyard and investments in assets serving V.C. Summer Unit 1. The capital costs shall be reduced by the net proceeds of the Toshiba Corporation Guarantee Settlement Payment, and by a one-time write down of $490 million. The amortization expense associated with these capital costs shall be reflected in retail electric revenue requirements without offset or disallowance until the balance in that regulatory asset is fully recovered.

5. The cost of capital that applies to the unrecovered balance in the regulatory asset account shall be as set forth in Paragraph 126 of the Joint Petition and shall apply to the balance of that account until the capital costs are fully recovered.

6. Regarding miscellaneous accounting matters, under the No Merger Benefits Plan, SCE&G seeks the same regulatory and accounting treatment for these amounts as is requested in Paragraph 57(c) of the Joint Petition and will write down regulatory assets valued at approximately $320 million, consistent with the provision of the Customer Benefits Plan.

Key Provisions of the Base Request

The Base Request will become SCE&G's request only if the Customer Benefits Plan is not approved or the Merger does not close, and the Commission also rejects the No Merger Benefits Plan. The key provisions of the Base Request are as follows:

1. There are no rate mitigation terms under the Base Request apart from the Company's decision not to seek rate relief in the current docket.

2. The following accounting provisions which apply under the Customer Benefits Plan would apply also under the Base Request:

   a. Transmission Investments, switchyard investments, and investments in assets used in operating V.C. Summer Unit 1 will be subject to the accounting treatment provided for Transmission Investments under the Customer Benefits Plan as described in Paragraph 105-108 of the Joint Petition and Paragraph 2(a) of ***Exhibit 10;***

   b. The Company requests a determination of the prudency of the decision to abandon the project as described in Paragraph 127 of the Joint Petition;

   c. The Company requests a determination of the prudency of the Capital Costs set forth on ***Exhibit 13*** as described in Paragraphs 128-129 of the Joint Petition; and

d. The Company requests that the Commission adopt the cost schedule as set forth in ***Exhibit 13*** as the cost schedule for the project in abandonment;

3. The following accounting provisions which apply under the No Merger Benefits Plan would apply equally under the Base Request:

a. The accounting for the Toshiba Corporation Guarantee Settlement Payments described in Paragraphs 1(e) of the ***Exhibit 10***; and

b. The provisions of the No Merger Benefits Plan concerning the accounting treatment of the capital costs of the NND Project although there is no write down of these costs.

4. SCE&G does not seek any rate changes of any kind under the Base Request.

5. Regarding miscellaneous accounting matters, under the Base Request, SCE&G would not write down regulatory assets valued at approximately $320 million, as described in the Customer Benefits Plan, but instead requests that the Commission:

a. Authorize SCE&G to continue to defer as a regulatory asset, as authorized under the provisions of Order No. 2013-776, the net costs of certain interest rate swap agreements which are not already being amortized, which interest rate swaps SCE&G executed in order to lock in interest rates for debt it planned to issue to finance the units, and authorize

SCE&G to begin amortizing these costs over 50 years upon the issuance of the order in this proceeding;

b. Affirm that the deferral of the cost of benefits lost under Section 199 of the Internal Revenue Code, 26 U.S.C.A. § 199, as authorized in Order No. 2016-820, shall also apply to benefits lost as a result of the abandonment of the Units; and

c. Reaffirm prior orders with respect to the amortization of other regulatory assets described in the Customer Benefits Plan.

EXHIBIT 12

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ELECTRIC RATE SCHEDULES

Listed are the proposed electric rate schedules included as follows:

Rate	Description
	Capital Cost Component Rider
	Tax Rider
1	Good Cents Residential Service
2	Low Use Residential Service
3	Municipal Power Service
5	Time-of-Use Residential Service
6	Energy Saver / Conservation Residential Service
7	Time-of-Use Demand Residential Service
8	Residential Service
9	General Service
10	Small Construction Service
11	Irrigation Service
12	Church Service
13	Municipal Lighting Service
14	Farm Service
15	Supplementary and Standby Service
16	Time-of-Use General Service
17	Municipal Street Lighting
18	Underground Street Lighting
20	Medium General Service
	Rider to Rates 20 & 23 – Service for Cool Thermal Storage
21	General Service Time-of-Use Demand
21A	Experimental Program – General Service Time-of-Use Demand
22	School Service
23	Industrial Power Service
24	Large General Service Time-of-Use
25	Overhead Floodlighting
26	Overhead Private Street Lighting
27	Large Power Service Real Time Pricing (Experimental)
28	Small General Service Time-of-Use Demand (Experimental)
	Residential Subdivision Street Lighting
	Contract Rates

RIDER TO RETAIL RATES **CAPITAL COST RIDER COMPONENT (Page 1 of 2)**

APPLICABILITY

This rider applies to and is a part of the Basic Facilities Charges, Demand Charges, and Energy Charges in the Company's Residential (1, 2, 5, 6, 7, and 8), Small General Service (3, 9, 10, 11, 12, 13, 14, 16, 22, and 28), Medium General Service (20, 21, and 21A), and Large General Service (23, 24, and 27 baseline charges) retail electric rate schedules. It does not apply to the Company's Lighting class rates.

DESCRIPTION

In Order No. 2018-[___], the Public Service Commission of South Carolina (the "Commission"), directed SCE&G to remove from retail electric rates annual revenues of $413 million associated with its investment in certain new nuclear project assets (the "Capital Costs") and ordered SCE&G to recover the costs under the terms of this Capital Cost Rider.

Capital Cost Rider Calculation

The revenue requirements to be recovered under this Capital Cost Rider equal:

Amortization + Return on Capital Cost Rate Base = Revenue Requirement

Where:

1. The Amortization equals the annual amortization expense associated with the Capital Costs, calculated as Capital Costs divided by 20 to reflect a 20 year amortization and recovery of the Capital Costs.
2. The Capital Costs equal the cost approved by the Commission for inclusion in the Capital Costs Rate Base established in Order No. 2018-[___].
3. Return on Capital Cost Rate Base equals the Cost of Capital times the balance in the Cost of Capital Rate Base .
4. The Capital Cost Rate Base equals the Unamortized Capital Costs Minus the Deferred Tax Liability Plus the Deferred Tax Asset.
5. The Cost of Capital equals the weighted average cost of capital as approved in Order No. Order No. 2018-[___].

SCE&G shall compute the Revenue Requirement each year.

The Revenue Requirement shall be allocated among customer classes and rates using SCE&G's most current study of contribution to system peak demand by customer class.

Each year, SCE&G shall prepare new retail electric rate schedules which include rates which have been adjusted for changes arising out of this Capital Cost Rider. SCE&G shall file the updated rates with the Commission no less than thirty (30) days prior to the first billing cycle during which the new rate schedule shall apply.

Refund Credit to Capital Cost Rider

In Docket No. 2017-370-E, Dominion Energy Inc. will underwrite $575M in refunds by SCE&G for amounts previously collected under the NND Project (the "Refund Pool") thereby establishing a regulatory liability. The refund will be credited back to customers based on a design to lower customer bills on a customer class basis by an average of 3.5% compared to May 2017 levels. In Order No. 2018-[___], the Commission determined that these refunds should be allocated by year so as to ensure that they would offset any amount of the Rider Revenue Requirements that exceeded $328 million. Offsetting any Rider Revenue Requirements in excess of $328 million with refunds results in an approximate 3.5% reduction in electric bills from 2017 levels.

Under this rider:

1. Each year SCE&G shall compute the Rider Revenue Requirement and shall determine the amount of the refund necessary to reduce the Rider Revenue Requirement to $328 million (the "Refund Amount").
2. SCE&G shall provide refunds of this amount to customers by transferring the Refund Amount from the Refund Pool to its retail electric revenues and in computing rates shall reduce its Rider Revenue Requirements by that amount.
3. Refund Amounts shall be applied to the rate calculation until the funds available in the Refund Pool are exhausted.

SALES AND FRANCHISE TAX

The Rider will apply before adding any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

TERM OF CONTRACT

The contract terms will be the same as those incorporated in the rate tariff under which customer receives electric service.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are part of this rider.

RIDER TO RETAIL RATES **TAX RIDER**

APPLICABILITY

This rider applies to and is a part of the Basic Facilities Charges, Demand Charges, Energy Charges, and Lighting Charges in all of the Company's retail electric rate schedules.

DESCRIPTION

Tax Cuts and Jobs Act Rider
In recognition of the Tax Cuts and Jobs Act of 2017 ("Tax Reform"), SCE&G shall provide customers a retail electric service bill credit equal to 1.5% of their billed rate schedule charges, excluding past due amounts, interest, penalties, non-standard service charges, franchise fees, and sales taxes. This bill credit shall remain in place unless and until the Public Service Commission of South Carolina replaces it with a different calculation for applying the impact of the Tax Reform.

SALES AND FRANCHISE TAX

The Rider reduction will be applied before calculating any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

TERM OF CONTRACT

The contract terms will be the same as those incorporated in the rate tariff under which customer receives electric service.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are part of this rider.

RATE 1

RESIDENTIAL SERVICE
GOOD CENTS RATE

AVAILABILITY

Effective January 15, 1996 this schedule is closed and not available to any new structure.

This rate is available to customers who meet the Company's Good Cents requirements and use the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residence and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

CERTIFICATION REQUIREMENTS

Prior to construction, the customer or prospective customer must contact the Company to ascertain the requirements of the Good Cents Program and to arrange for on-site inspections for compliance.

The dwelling unit must be certified by the Company to meet or exceed the Company's Good Cents Program requirements in force at the time of application in order to qualify for service under this rate schedule.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

	Summer (Billing Months June-September)		Winter (Billing Months October-May)	
Basic Facilities Charge:	$ 10.00		$ 10.00	
Plus Energy Charge:				
First 800 kWh @	$ 0.12687	per kWh	$ 0.12687	per kWh
Excess over 800 kWh @	$ 0.13955	per kWh	$ 0.12179	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02513 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $0.91 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00276 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when customer pays the difference in costs between non-standard service and standard service or pays the Company its normal monthly facility charge based on such difference in

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 2 **LOW USE RESIDENTIAL SERVICE**

AVAILABILITY

This rate is available to customers that meet the special conditions listed below, and are served by the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

SPECIAL CONDITIONS OF SERVICE

1) This rate schedule is available to those accounts where the consumption has not exceeded 400 kWh for each of the twelve billing months preceding the billing month service is to be initially billed under this rate schedule. The customer must have occupied the dwelling unit for the entire time necessary to determine eligibility under this rate schedule.

2) Consumption during a billing period of more than 30 days, used to determine eligibility under this rate schedule, shall be adjusted to a 30 day billing period by application of a fraction, the numerator of which shall be 30 and the denominator of which shall be the actual number of days in the billing period.

3) The second billing month within a twelve billing month period that consumption under this rate schedule exceeds 400 kWh will terminate eligibility under this rate schedule.

4) Service will be billed under the previous rate schedule the next twelve billing periods before the customer will again be eligible for the Low Use Rate.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

Basic Facilities Charge:	$ 10.00	
Plus Energy Charge:		
All kWh @	$ 0.10200	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02513 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $0.91 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00276 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 3

MUNICIPAL POWER SERVICE

AVAILABILITY

This rate is available to municipal customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system. This includes all municipally owned and operated facilities for power purposes including, but not restricted to public buildings and pumping stations. It is not available for resale or standby service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

Basic Facilities Charge:	$ 22.75	
Plus Energy Charge:		
All kWh @	$ 0.10852	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

Service shall not be supplied under this rate for establishments of a commercial nature, nor to operations primarily non-municipal. Under no conditions will the Company allow the service to be resold to or shared with others.

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than ten (10) years.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 5

RESIDENTIAL SERVICE
TIME OF USE

AVAILABILITY

This rate is available on a voluntary basis to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

I. Summer Months of June-September

A. Basic Facilities Charge:	$ 14.00	
B. Energy Charge:		
All on-peak kWh @	$ 0.30327	per kWh
All off-peak kWh @	$ 0.10109	per kWh

C. Minimum Bill:
The monthly minimum charge shall be the basic facilities charge and the Distributed Energy Resource Program charge, as stated below.

II. Winter Months of October-May

A. Basic Facilities Charge:	$ 14.00	
B. Energy Charge:		
All on-peak kWh @	$ 0.27294	per kWh
All off-peak kWh @	$ 0.10109	per kWh

C. Minimum Bill:
The monthly minimum charge shall be the basic facilities charge and the Distributed Energy Resource Program charge, as stated below.

DETERMINATION OF ON-PEAK HOURS

A. On-Peak Hours:

Summer Months of June-September:

The on-peak summer hours are defined as the hours between 2:00 p.m.-7:00 p.m., Monday-Friday, excluding holidays.*

Winter Months of October-May:

The on-peak winter hours are defined as the hours between 7:00 a.m.-12:00 noon, Monday-Friday, excluding holidays.*

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02513 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $0.91 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00276 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

The Company shall have the right to install and operate special metering equipment to measure customer's loads or any part thereof and to obtain any other data necessary to determine the customer's load characteristics.

The Company's levelized payment plans are not available to customers served under this rate schedule.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 6

RESIDENTIAL SERVICE
ENERGY SAVER / CONSERVATION RATE

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

The builder or homeowner must provide the following:

1) For new homes only - Proof that home meets the Council of American Building Officials Model Energy Code.
2) Receipts showing the purchase and installation of a new AC unit that meets the requirements as shown below.
3) A certificate issued by an installer showing a wall total cavity R value of 15 (R-15).
4) Certification from builder stating that requirements have been met.

The Company may perform an on-site audit to verify that customer meets availability requirements as stated herein.

THERMAL AND AIR CONDITIONING REQUIREMENTS FOR ENERGY CONSERVATION

The following requirements are predicated on the Council of American Building Officials Model Energy Code and subject to change with a change in the Council of American Building Officials Model Energy Code. Sufficient application of thermal control products and specified air conditioning requirements must be met to satisfy the minimum standards outlined below:

Ceilings: Ceilings of newly constructed homes shall be insulated with a total "as installed" thermal resistance (R) value of 30 (R-30).
Ceilings of manufactured housing shall be insulated with a thermal resistance (R) value of 30 (R-30).
Ceilings of existing housing shall be insulated with a total "as installed" thermal resistance (R) value of 38 (R-38).

Lighting: Recessed ceiling lights shall be sealed.

Walls: Walls exposed to the full temperature differential (TD), or unconditioned areas, shall have a total cavity R value of 15 (R-15).
*This is not a requirement for existing housing.

Floors: Floors over crawl space or crawl space walls shall have insulation installed having a total R value of 19 (R-19).
100% of the exposed earth in a crawl space shall be covered with a vapor barrier of no less than (4) mills.

Windows: Windows shall be insulated (double) glass or have storm windows.

Doors: Doors exposed to full TD areas must be weather-stripped on all sides and of solid construction.

Ducts: Air ducts located outside of conditioned space must have: 1) all joints properly fastened and sealed, and, 2) the duct shall have a minimum installed insulation R-value of 6.0. All joints in ductwork outside of the conditioned space must be permanently sealed with the application of duct sealant. Transverse joints, take-offs, transitions, supply/return connections to the air handler, boot connections to the floor/ceiling/wall, and framed-in and panned passages must be made airtight with duct sealant.

Attic Vent: Attic ventilation must be a minimum of one square foot of net free area for each 150 square feet attic floor area.

Water Heaters: Electric water heaters must have insulation surrounding the tank with minimum total R value of 8 (R-8).

Air Condition: All air conditioners must have a SEER rating of 1.0 SEER higher than the rating shown in the Council of American Building Officials Model Energy Code or any federal or state mandated energy codes, whichever is higher.

Other: Chimney flues and fireplaces must have tight fitting dampers.

*Insulation thermal resistance values are shown for insulation only, framing corrections will not be considered.

The "as installed" thermal resistance (R) value for all loose fill or blowing type insulation materials must be verifiable either by installed density using multiple weighted samples, the manufacturer's certification methods, Federal Trade Commission's procedures or other methods specified by local governing agencies.

RATE 6

RESIDENTIAL SERVICE
ENERGY SAVER / CONSERVATION RATE

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

	Summer (Billing Month June-September)	Winter (Billing Month October-May)
Basic Facilities Charge:	$ 10.00	$ 10.00
Plus Energy Charge:		
First 800 kWh @	$ 0.12687 per kWh	$ 0.12687 per kWh
Excess over 800 kWh @	$ 0.13955 per kWh	$ 0.12179 per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02513 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $0.91 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00276 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 7

RESIDENTIAL SERVICE
TIME-OF-USE DEMAND

AVAILABILITY

This rate is available on a voluntary basis to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartments structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total or more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

I. Basic Facilities Charge: $ 14.00

II. Demand Charge:

A. On-Peak Billing Demand

Summer Months of June-September @	$ 11.62	per KW
Non-Summer Months of October-May @	$ 8.30	per KW

III. Energy Charge:

All on-peak kWh @	$ 0.09273	per kWh
All off-peak kWh @	$ 0.08206	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below.

BILLING DEMAND

The maximum integrated fifteen minute demand for the current month occurring during the on-peak hours specified below. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.

DETERMINATION OF ON-PEAK HOURS

A. On-Peak Hours:

Summer Months of June-September:

The on-peak summer hours are defined as the hours between 2:00 p.m.-7:00 p.m., Monday-Friday, excluding holidays.*

Non-Summer Months of October-May:

The on-peak winter hours are defined as the hours between 7:00 a.m.-12:00 noon, Monday-Friday, excluding holidays.*

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02513 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $0.91 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00276 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

The Company shall have the right to install and operate special metering equipment to measure customer's loads or any part thereof and to obtain any other data necessary to determine the customer's load characteristics.

The Company's levelized payment plans are not available to customers served under this rate schedule.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 8 **RESIDENTIAL SERVICE**

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system to individually metered private residences and individually metered dwelling units in apartment structures or other multi-family residential structures. It is not available for resale service nor shall service be supplied to dwelling units having a total of more than ten rooms, five or more of which are rented or offered for rent to any person or persons not a member, or members, of the immediate family of the owner or lessor of the dwelling units.

A dwelling unit is defined as a room or group of rooms having, in addition to living quarters, kitchen facilities for the sole use of the family or individual occupying such dwelling unit.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, 120 volts, 2 wire or 120/240 volts 3 wire.

RATE PER MONTH

	Summer (Billing Month June-September)		Winter (Billing Month October-May)	
Basic Facilities Charge:	$ 10.00		$ 10.00	
Plus Energy Charge:				
First 800 kWh @	$ 0.13129	per kWh	$ 0.13129	per kWh
Excess over kWh @	$ 0.14442	per kWh	$ 0.12604	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02513 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $0.91 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00276 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 9 **GENERAL SERVICE**

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for general light and/or power purposes such as commercial, industrial, religious, charitable and eleemosynary institutions. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

	Summer (Billing Months June-September)		Winter (Billing Months October-May)	
I. Basic Facilities Charge:	$ 22.75		$ 22.75	
II. Demand Charge:				
First 250 KVA of Billing Demand	No Charge		No Charge	
Excess over 250 KVA of Billing Demand @	$ 3.99	per KVA	No Charge	

The Billing Demand (to the nearest whole KVA) shall be the maximum integrated fifteen (15) minute demand measured during the billing months of June through September.

	Summer		Winter	
III. Energy Charge:				
First 3,000 kWh @	$ 0.12602	per kWh	$ 0.12602	per kWh
Over 3,000 kWh @	$ 0.13421	per kWh	$ 0.11720	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

POWER FACTOR

If the power factor of the Customer's installation falls below 85%, the Company may adjust the billing to a basis of 85% power factor.

TEMPORARY SERVICE

Temporary service for construction and other purposes will be supplied under this rate in accordance with the Company's Terms and Conditions covering such service.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

This rate is available for residential service where more than one dwelling unit is supplied through a single meter, provided service to such dwelling unit was established prior to July 1, 1980.

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

UNMETERED SERVICE PROVISION

When customer's usage can be determined and in the sole opinion of the Company, installation of metering equipment is impractical or uneconomical, monthly kWh may be estimated by the Company and billed at the above rate per month, except that the basic facilities charge shall be $8.65.

TERM OF CONTRACT

Contracts for installation of a permanent nature shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 10 **SMALL CONSTRUCTION SERVICE**

AVAILABILITY

This rate is available as a temporary service for builders using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for general lighting and/or power purposes during construction. It is not available for resale or standby service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, single phase, two or three wire at Company's standard secondary service voltages of 240 volts or less.

RATE PER MONTH

Basic Facilities Charge:	$ 10.00	
Plus Energy Charge:		
All kWh @	$ 0.13045	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

If providing temporary service requires the Company to install transformers and other facilities which must be removed when temporary service is no longer required, then the customer may be required to pay the cost of installing and removing the Company's temporary facilities.

TERM OF CONTRACT

Contracts shall be written for a period of time commencing with establishment of service and ending when construction is suitable for occupancy or one year, which is less. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 11 **IRRIGATION SERVICE**

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system. It is not available for resale. This schedule is available for service furnished for the operation of electric motor driven pumps and equipment supplying water for the irrigation of farmlands and plant nurseries, and irrigation to provide adequate moisture for vegetative cover to control erosion and provide runoff. The pumping units served hereunder shall be used solely for the purpose of irrigation.

All motors of more than 5 H.P. shall be approved by the Company. The Company reserves the right to deny service to any motor which will be detrimental to the service of other customers. Upon request, customer may pay all cost associated with upgrading the system to the point at which starting the customer's motor will not degrade the service to the other customers.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

I. Summer Months of June-September			
A. Basic Facilities Charge:	$	26.40	
B. Energy Charge:			
All on-peak kWh @	$	0.23643	per kWh
All shoulder kWh @	$	0.14186	per kWh
All off-peak kWh @	$	0.07849	per kWh
II. Winter Months of October-May			
A. Basic Facilities Charge:	$	26.40	
B. Energy Charge:			
All kWh @	$	0.07849	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, except when the revenue produced by the customer does not sufficiently support the investment required to serve the load. The Company will determine in each case the amount and form of payment required to correct the revenue deficiency.

DETERMINATION OF ON-PEAK SHOULDER, AND OFF-PEAK HOURS

A. On-Peak Hours:

Summer Months of June-September:

The on-peak summer hours are defined as the hours between 2:00 p.m.-6:00 p.m., Monday-Friday, excluding holidays.*

B. Shoulder Hours:

Summer Months of June-September:

The shoulder summer hours are defined as the hours between 10:00 a.m.-2:00 p.m. and 6:00 p.m.-10:00 p.m., Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak or shoulder hours.

*Holidays are Independence Day and Labor Day.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

The Company shall have the right to install and operate special metering equipment to measure customer's loads or any part thereof and obtain any other data necessary to determine the customer's load characteristics.

TERM OF CONTRACT

Contracts for installations shall be written for a period of not less than ten (10) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 12 **CHURCH SERVICE**

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for general light and/or power service to churches. It is not available for resale or standby service. It is only available to recognized churches.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

Basic Facilities Charge:	$	17.05	
Plus Energy Charge:			
All kWh @	$	0.10772	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Under no conditions will the Company allow the service to be resold to or shared with others. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

When a church offers activities that, in the sole opinion of the Company, are of a commercial nature such as day care, camps or recreational activities, the Company may require that the account be served under the appropriate general service rate.

TERM OF CONTRACT

Contracts shall be written for a period of not less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 13 **MUNICIPAL LIGHTING SERVICE**

AVAILABILITY

This rate is available to municipal customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system. This includes all municipally owned and operated facilities for lighting streets, highways, parks and other public areas, or other signal system service. It is not available for resale or standby service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

Basic Facilities Charge:	$	22.75	
Plus Energy Charge:			
All kWh @	$	0.10092	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

Service shall not be supplied under this rate for establishments of a commercial nature, nor to operations primarily non-municipal. Under no circumstances will the Company allow the service to be resold or shared with others.

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

Contracts shall be written for a period of not less than ten (10) years.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 14 **FARM SERVICE**

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system on farms for producing but not processing agricultural, dairy, poultry and meat products.

Service shall not be supplied under this rate for establishments of a commercial nature such as stores, shops, stands, restaurants, service stations or any non-farm operations; nor for processing, distributing or selling farm or other products not originating through production on the premises served. Motors rated in excess of 20 H.P. will not be served on this rate. It is available for farm commercial operations including irrigation, grain elevators and crop drying for farm products produced on the premises served. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

	Summer (Billing Months June-September)	Winter (Billing Months October-May)
Basic Facilities Charge:	$ 10.00	$ 10.00
Plus Energy Charge:		
First 800 kWh @	$ 0.13045 per kWh	$ 0.13045 per kWh
Excess over 800 kWh @	$ 0.14358 per kWh	$ 0.12520 per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state and governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period of not less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 15 **SUPPLEMENTARY AND STANDBY SERVICE**

AVAILABILITY

Available to Small Power Producers and co-generators that are a Qualifying Facility as defined by the Federal Energy Regulatory Commission (FERC) Order No. 70 under Docket No. RM 79-54. This schedule is not available to Qualifying Facilities with a power production capacity greater than 100 KW.

SUPPLEMENTARY SERVICE

Supplementary service is defined herein as power supplied by the Company to a Qualifying Facility in addition to that which the Qualifying Facility generates itself. Supplementary service will be provided by the Company under a retail electric service schedule which the customer will establish in conjunction with the implementation of this Supplementary and Standby Service rate.

SUPPLEMENTARY SERVICE

1) Standby service under this schedule is defined herein as power supplied by the Company to a Qualifying Facility to replace energy ordinarily generated by a Qualifying Facility during a scheduled or unscheduled outage.
2) Standby service is available to customers establishing a firm demand which is billed under a retail electric service schedule of the Company. If no firm demand is established by the customer for the purpose of taking Supplementary power, then Standby service will be provided as Supplementary service and billed on the applicable retail electric service schedule.
3) Standby service is defined for each 15-minute interval as the minimum of: (1) the Standby contracted demand, and, (2) the difference between the measured load and the contracted firm demand, except that such difference shall not be less than zero.
4) Supplementary Service is defined as all power supplied by the Company not defined herein as Standby Service.
5) The Standby contract demand shall be limited to the power production capacity of the Qualifying Facility.

STANDBY SERVICE POWER RATE PER MONTH

Basic Facilities Charge	$	225.00	
Demand Charge per KW of Contract Demand	$	5.86	
Energy Charge:			
On-Peak kWh @	$	0.06104	per kWh
Off-Peak kWh @	$	0.04695	per kWh

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

A. On-Peak Hours:
On-peak hours are defined to be 10:00 a.m. - 10:00 p.m. for the months of June-September, excluding weekends.

B. Off-Peak Hours:
All hours not defined as on-peak hours are considered to be off-peak.

POWER FACTOR

The customer must maintain a power factor of as near unity as practicable. If the power factor of the customer's installation falls below 85%, the Company shall adjust the billing demand to a basis of 85% power factor.

LIMITING PROVISION

The Standby Service power rate will be available for 1325 annual hours of consumption beginning in May and ending in April, or for a prorated share thereof for customers who begin to receive service in months other than May. Accounts on this rate are subject to the following condition: Standby service will be available for a maximum of 120 On-Peak Hours.

If this account exceeds: (1) 1325 hours of Standby service annually, or (2) 120 on-peak hours of Standby service, the account will be billed on the rate normally applied to customer's Supplementary service load for the current billing month and the subsequent eleven months.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02495 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00197 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The customer is responsible for all costs associated with interconnection to the Company's system for the purpose of obtaining Supplementary or Standby power.

TERM OF CONTRACT

Contracts shall be written for a period of not less than three (3) years.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 16

GENERAL SERVICE
TIME-OF-USE
(Page 1 of 2)

AVAILABILITY

This rate is available to any non-residential customer using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for power and light requirements and having an on-peak demand of less than 1,000 KW. The second billing month within a twelve billing month period that on-peak demand exceeds 1,000 KW will terminate eligibility under this rate schedule. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

I. Basic Facilities Charge:	$ 26.40	
II. Energy Charge:		
A. On-Peak kWh		
1. Months of June-September	$ 0.23643	per kWh
2. Months of October-May	$ 0.17967	per kWh
B. Off-Peak kWh		
First 1,000 off-peak kWh @	$ 0.09457	per kWh
Excess over 1,000 off-peak kWh @	$ 0.09977	per kWh

DETERMINATION OF ON-PEAK HOURS

A. On-Peak Hours:

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

October-May:

The on-peak non-summer hours are defined as those hours between 6:00 a.m.-10:00 a.m. and 6:00 p.m.-10:00 p.m. Monday-Friday, excluding holidays.*

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

EXPERIMENTAL UNIFORM LOAD PROVISION

For applications where the customer has an expectation of their equipment operating at a constant level, or 100% Load Factor (same usage level for every hour of a billing period), the Company may use a standard meter, without time-of-use capability, to record monthly energy usage. In such instances, the customer will be required to submit to the Company engineering specifications, meter history results, or other pertinent data that would demonstrate the expectation of a constant, or uniform load. The Company will make the final determination as to whether an account qualifies for service under this provision.

The Rate Per Month for qualifying accounts under this provision consists of a Basic Facilities Charge of $10.00 plus the product of the customer's actual metered energy times the kWh Energy Charge as determined in the table below:

Tier	Average Energy Usage per Month	Energy Charge
A	0 - 999 kWh	$ 0.11868 per kWh
B	1,000 - 1,999 kWh	$ 0.11868 per kWh
C	2,000 - 3,000 kWh	$ 0.12007 per kWh

For purposes of determining the appropriate Tier for each specific account, Average Energy Usage per Month will be determined by taking a simple average of the last 12 months of historical energy consumption. For new accounts, a Company calculation will be performed based upon the customer technical data requirements mentioned earlier. The Company may also take into account any other such data as deemed appropriate for Tier assignment. When an account has been assigned to a Tier, it shall be billed under the associated Energy Charge each month until an equipment change noted by the customer or Company test result that may nullify eligibility as specified below. Tier assignments will not change on a month to month basis. Accounts averaging more than 3,000 kWh per month will not be eligible for service under this Provision and will be metered under the standard Time-of-Use provisions of Rate 16. The Company will make the final determination as to the appropriate Tier assignment for all accounts.

The customer shall notify the Company in writing if the customer's equipment or method of operation change such that a 100% Load Factor is no longer expected. The Company will conduct an annual review of all Uniform Load Provision accounts, and reserves the right to periodically verify load patterns and characteristics through testing for any and all accounts covered by this Provision. This would generally be accomplished by the installation of demand or other Time-of-Use capable meters. If any account is found to have a load pattern producing less than 100% Load Factor or an average usage above 3,000 kWh per month, it will no longer be billed under the Uniform Load Provision. The Company will install a traditional Rate 16 type meter and bill the customer under the standard Time-of-Use provisions noted in the Rate Per Month section above.

The tiered charges under this Uniform Load Provision will be adjusted for any and all retail electric rate actions approved by the Public Service Commission of South Carolina including, but not limited to changes in the Adjustment for Fuel and Variable Environmental Costs, Rate Reduction and Tax Credit Rider, Rider related to Demand Side Management, and requests for Revised Rates under the Base Load Review Act.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. Contracts for installations of a permanent nature shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 17

MUNICIPAL
STREET LIGHTING

AVAILABILITY

This rate is available to municipal customers using the Company's electric service for area and street lighting.

RATE

All night street lighting service where fixtures are mounted on Company's existing standard wooden poles which are a part of Company's overhead distribution system will be charged for at the following rates:

SIZE AND DESCRIPTION			Lamp Charges per Month	kWh per Month
9,000	Lumens	(MH) (100W) Closed Type	$ 10.56	37
15,000	Lumens	(HPS) (150W) Open Type	$ 10.21	57
15,000	Lumens	(HPS) (150W) Closed Type	$ 10.42	62
30,000	Lumens	(MH) (320W) Closed Type	$ 17.59	123
50,000	Lumens	(HPS) (400W) Closed Type	$ 18.26	158

The following fixtures are available for new installations only to maintain pattern sensitive areas:

9,500	Lumens	(HPS) (100W) Open Type	$ 9.27	38
9,500	Lumens	(HPS) (100W) Open Type (non-directional) - Retrofit	$ 9.27	38
9,500	Lumens	(HPS) (100W) Closed Type	$ 10.02	38
15,000	Lumens	(HPS) (150W) Open Type - Retrofit	$ 10.19	63
15,000	Lumens	(HPS) (150W) Closed Type - Retrofit	$ 10.45	63
27,500	Lumens	(HPS) (250W) Closed Type	$ 15.93	102
45,000	Lumens	(HPS) (360W) Closed Type - Retrofit	$ 17.57	144

All night street lighting service in areas being served from Company's underground distribution system:

The following fixtures which are available for new installations where excavation and back filling are provided for the Company and existing fixtures previously billed as residential subdivision street lighting will be charged for at the following rates:

Post-Top Mounted Luminaries			Traditional Lamp Charges per Month	Modern Lamp Charges per Month	Classic Lamp Charges per Month	kWh per Month
9,000	Lumens	(MH) (100W)	$ 22.36	$ 22.36	$ 26.13	37
15,000	Lumens	(HPS) (150W)	$ 22.52	$ 22.52	$ 26.58	62

The following fixture is available for new installations only to maintain pattern sensitive areas:

9,500	Lumens	(HPS) (100W) Traditional	$ 20.91			37
15,000	Lumens	(HPS) (150W) - Retrofit	$ 22.50		$ 26.56	63
15,000	Lumens	(HPS) (150W) - Retrofit		$ 22.52		62

Effective January 2009, selected existing light sets will no longer be available for new installations. Replacment light sets will only be available until inventory is depleted and will be replaced on a first-come, first-served basis. Affected lights are as follows:

4,000	Lumens	(Mercury) (100W) Open Type (non-directional)	$ 8.33	37
7,500	Lumens	(Mercury) (175W - Traditional)	$ 21.98	69
7,500	Lumens	(Mercury) (175W - Modern)	$ 21.98	69
7,500	Lumens	(Mercury) (175W - Classic)	$ 25.86	69
7,500	Lumens	(Mercury) (175W) Closed Type	$ 10.37	69
7,500	Lumens	(Mercury) (175W) Open Type (non-directional)	$ 9.16	69
10,000	Lumens	(Mercury) (250W) Closed Type	$ 13.95	95
20,000	Lumens	(Mercury) (400W) Closed Type	$ 17.34	159

MINIMUM CHARGE

When construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02451 per kWh are included in the monthly lamp charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

TERM OF CONTRACT

Contracts under this rate shall be written for a period of not less than ten (10) years; and such contract shall include a provision that the Municipality must purchase all of its electrical requirements from the Company. The Company reserves the right to remove its facilities when subject to vandalism or for other cogent reasons.

SPECIAL PROVISIONS

The Company will furnish, erect, operate and maintain all necessary equipment in accordance with its standard specifications. It is the customer's responsibility to notify the Company when equipment fails to operate properly. Non-standard service requiring underground, special fixtures and/or poles will be furnished only when the customer pays the difference in costs between such non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 18

UNDERGROUND STREET LIGHTING

AVAILABILITY

This rate is available to customers, including municipal customers, using the Company's electric service for street and area lighting served from existing underground distribution facilities.

APPLICABILITY

Applicable only to outdoor lighting high intensity discharge fixtures, either high pressure sodium (HPS), or metal halide (MH), and with poles conforming to Company specifications. Services will be rendered only at locations that, solely in the opinion of the Company, are readily accessible for maintenance. If the Company is required to install light fixtures on poles other than those described herein, the Company will determine in each case the amount and form of payment required.

RATE PER LUMINARIES

SIZE AND DESCRIPTION				per Month	kWh per Month
9,000	Lumens	(MH) (100W)	(Acorn, Round, or Octagonal Style)*	$ 16.74	41
15,000	Lumens	(HPS) (150W)	(Acorn, Round, or Octagonal Style)*	$ 16.78	62
9,000	Lumens	(MH) (100W)	(Traditional)	$ 12.56	37
15,000	Lumens	(HPS) (150W)	(Traditional)	$ 12.72	62
9,000	Lumens	(MH) (100W)	(Shepherd)	$ 25.01	41
15,000	Lumens	(HPS) (150W)	(Shepherd)	$ 27.33	62
42,600	Lumens	(MH) (400W)	Hatbox	$ 31.07	159
50,000	Lumens	(HPS) (400W)	Hatbox	$ 29.87	158
110,000	Lumens	(MH) (1000W)	Hatbox	$ 47.31	359
140,000	Lumens	(HPS) (1000W)	Hatbox	$ 42.89	368
30,000	Lumens	(MH) (320W)	Shoebox Type	$ 29.95	123
45,000	Lumens	(HPS) (400W)	Shoebox Type	$ 22.02	158
30,000	Lumens	(MH) (320W)	Cobra Flex	$ 29.97	120
50,000	Lumens	(HPS) (400W)	Cobra Flex	$ 29.74	152

The following fixtures are available for new installations only to maintain pattern sensitive areas:

9,000	Lumens	(MH) (100W)	(Modern)	$ 12.56	37
15,000	Lumens	(HPS) (150W)	(Modern)	$ 12.72	62
9,000	Lumens	(MH) (100W)	(Classic)	$ 16.34	37
15,000	Lumens	(HPS) (150W)	(Classic)	$ 17.55	62

Effective January 2009, selected existing light sets will no longer be available for new installations. Replacment light sets will only be available until inventory is depleted and will be replaced on a first-come, first-served basis. Affected lights are as follows:

7,500	Lumens	(MV) (175W)	(Acorn, Round, or Octagonal Style)*	$ 16.07	69
7,500	Lumens	(MV) (175W)	(Traditional)	$ 12.18	69
7,500	Lumens	(MV) (175W)	(Shepherd)	$ 24.09	69
7,500	Lumens	(MV) (175W)	(Modern)	$ 12.08	69
7,500	Lumens	(MV) (175W)	(Classic)	$ 16.72	69
10,000	Lumens	(MV) (250W)	(Acorn, Round, or Octagonal Style)*	$ 17.24	95
20,000	Lumens	(MV) (400W)	Shoebox Type	$ 20.34	159
36,000	Lumens	(MH) (400W)	Hatbox	$ 31.27	159
40,000	Lumens	(MH) (400W)	Shoebox Type	$ 27.37	159

RATE PER POLE

15' Aluminum Shepherd's Crook / Direct Buried (Mounted Height)	$ 29.95
15' Aluminum Shepherd's Crook / Base Mounted (Mounted Height)	$ 37.60
12' Smooth/Fluted Aluminum (Mounted Height)	$ 23.20
14' Smooth/Fluted Aluminum (Mounted Height)	$ 23.85
17' Standard Fiberglass (Mounted Height)	$ 9.95
42' Square Aluminum/Direct Buried (35' Mounted Height)	$ 26.80
42' Round Aluminum/Direct Buried (35' Mounted Height)	$ 27.80
35' Round Aluminum/Base Mounted (Add Base To Determine Mounted Height)	$ 32.70
35' Square Aluminum/Base Mounted (Add Base To Determine Mounted Height)	$ 35.70

RESIDENTIAL SUBDIVISION CUSTOMER CHARGE

*The lights described above may be installed in new or existing residential subdivisions at the ratio of one light for either every four (4) or six (6) metered residences. An administrative charge of $2.70 will be added to each fixture billed under this provision. Each monthly bill rendered will include an amount for the installed lighting. Such amount will be determined by adding the appropriate charges above for the installed luminaries, pole, and administrative charge and dividing such charge by either four (4) or six (6). This provision is applicable only if no other lighting option is available for the residential subdivision. This provision is not available for lighting parking lots, shopping centers, other public or commercial areas nor the streets of an incorporated municipality.

REPLACEMENT OF EXISTING SYSTEMS

In the event that the customer desires to replace an existing lighting system owned and operated by the company, the customer shall be required to pay to the Company an amount equal to the provision for early contract termination listed below.

PROVISION FOR EARLY CONTRACT TERMINATION

In the event that the customer terminates the contract prior to the end of the contract term, the customer shall pay as the termination charge the appropriate charges above excluding fuel for the remainder of the contract term; plus the sum of original cost of the installed equipment , less accumulated depreciation through the effective termination date, plus removal and disposal costs, plus environmental remediation costs less any applicable salvage values, the total of which shall in no case be less than zero.

MINIMUM CHARGE

When construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02451 per kWh are included in the monthly lamp charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

TERM OF CONTRACT

Contracts under this rate shall be written for a period of not less than ten (10) years. The Company reserves the right to remove its facilities when subject to vandalism or for other cogent reasons.

SPECIAL PROVISIONS

The Company will furnish, erect, operate and maintain all necessary equipment in accordance with its standard specifications. Standard service for post top decorative lamps requiring underground wiring shall include one hundred twenty five feet of service conductor, all necessary trenching and back-filling in normal, unimproved soil. Non-standard equipment or installation in extraordinary conditions such as, but not limited to, landscaped areas, paved areas, or extremely rocky or wet soil will require the customer to pay the difference in cost between such non-standard equipment and/or extraordinary conditions and the standard service installed under normal conditions or pay to the Company its normal monthly facility charge based on such difference in costs.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule. Service hereunder is subject to Rules and Regulations for Electric Service of the Public Service Commission of South Carolina.

RATE 20 **MEDIUM GENERAL SERVICE**

AVAILABILITY

This rate is available to any non-residential customer using the Company's standard service for power and light requirements and having a contract demand of 75 KVA or over. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. Basic Facilities Charge	$	210.00	
II. Demand Charge:			
All KVA of Billing Demand @	$	18.99	per KVA

The billing demand (to the nearest whole KVA) shall be the greatest of: (1) the maximum integrated fifteen minute demand measured (which may be on a rolling time interval) during the current month; or (2) eighty percent (80%) of the highest demand occurring during the billing months June through September in the eleven preceding months; or (3) sixty percent (60%) of the highest demand occurring during the billing months of October through May in the eleven preceding months; or (4) the contract demand; or (5) 75 KVA.

III. Energy Charge:

First 75,000 kWh @	$	0.05217	per kWh
Excess over 75,000 kWh @	$	0.04806	per kWh

MINIMUM CHARGE

The monthly minimum charge is the demand as determined above. It shall also include the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below. The Company may allow a buildup period not to exceed six months for new and expanding accounts during which time the contract demand and/or the minimum demand specified in the rate schedule may be waived. The Company shall not commit itself to a buildup period exceeding six months without prior approval of the Commission for the specific account involved.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02495 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00197 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period of less than five (5) years. A separate contract shall be written for each meter.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RIDER TO RATES 20 AND 23

SERVICE FOR COOL THERMAL STORAGE

AVAILABILITY

This rider is available to customers served under Rate Schedules 20 and 23 for thermal storage during billing months June through September. Service under this rider shall be available at customer's request and with Company Certification of customer's installed thermal storage system. The qualifying thermal storage unit must be capable of removing at least thirty percent (30%) of the customer's actual or expected load during the on-peak hours. The provisions of Rate Schedules 20 and 23 are modified only as shown herein.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

A. On-Peak Hours:

The on-peak hours during June through September are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: Independence Day and Labor Day.

BILLING DEMAND DETERMINATION

Billing Months June Through September

The on-peak billing demand (to the nearest whole number) shall be the greatest of the following and shall be billed on the Applicable Rate Demand charge:

(1) The maximum, integrated fifteen minute demand measured (which may be on a rolling time interval) during the hours of 1:00 p.m. to 9:00 p.m., Monday-Friday;

(2) 90% of the demand registered during these hours for the previous June through September billing period, if service was supplied under this rider. If customer is receiving initial service under this rider, the ratchet during the June through September billing period will be waived.

(3) The contract demand.

(4) Applicable Rate Minimum.

Billing Months October Through May

The billing demand (to the nearest whole number) shall be the greatest of the following and shall be billed on the Applicable Rate Demand charge:

(1) The maximum, integrated fifteen minute demand measured (which may be on a rolling time interval).

(2) 60% of the highest demand occurring during the preceding October through May billing period.

(3) The contract demand.

(4) Applicable Rate Minimum.

EXCESS BILLING DEMAND

Billing Months June Through September

The excess billing demand shall be the positive difference between the maximum integrated fifteen minute demand measured during off-peak hours minus the on-peak billing demand.

RATES PER MONTH

Excess Billing Demand Applicable to Rate 20	$ 4.99	per KVA
Excess Billing Demand Applicable to Rate 23	$ 4.99	per KW

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of these riders.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

RATE 21

GENERAL SERVICE
TIME-OF-USE-DEMAND

AVAILABILITY

This rate is available to any customer using the Company's standard service for power and light requirements and having a contract demand of 50 KVA and a maximum demand of less than 1,000 KVA. It is not available for resale service.

CHARACTER OF SERVICE

Alternating current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. Basic Facilities Charge:	$	225.00	
II. Demand Charge:			
A. On-Peak Biling Demand:			
1. Summer Months of June-September @	$	24.13	per KVA
2. Non-Summer Months of October-May @	$	16.29	per KVA
B. Off-Peak Billing Demand			
1. All Off-Peak Billing Demand @	$	5.19	per KVA
III. Energy Charge:			
A. On-Peak kWh			
1. Summer Months of June-September @	$	0.09390	per kWh
2. Non-Summer Months of October-May @	$	0.06104	per kWh
B. Off-Peak kWh			
1. All Off-Peak @	$	0.04695	per kWh

BILLING DEMAND

The billing demands will be rounded to the nearest whole KVA. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.

For the summer months, the on-peak billing demand shall be the maximum integrated fifteen minute demand measured during the on-peak hours of the current month.

For the non-summer months, the on-peak billing demand will be the greater of: (1) the maximum integrated fifteen minute demand measured during the on-peak hours of the current month, or (2) eighty percent (80%) of the maximum integrated demand occurring during the on-peak hours of the preceding summer months.

The off-peak billing demand shall be the greatest of the following positive differences: (1) the maximum integrated fifteen minute demand measured during the off-peak hours minus the on-peak billing demand, (2) the contract demand minus the on-peak billing demand or (3) 50 KVA minus the on-peak billing demand.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

A. On-Peak Hours During Summer Months:

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

B. On-Peak Hours During Non-Summer Months:

May and October:

The on-peak non-summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

November-April:

The on-peak non-summer hours are defined as these hours between 6:00 a.m.-12:00 noon and 5:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Effective upon Approval of the
Public Service Commission of South Carolina

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02495 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00197 per kWh for Demand Side Management expenses.

PENSION COST COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 21A

EXPERIMENTAL PROGRAM - GENERAL SERVICE
TIME-OF-USE-DEMAND

AVAILABILITY

This rate is available on a voluntary "first come, first serve" basis to the first 250 Rate 20 customer accounts and any Rate 21 customer account that qualify under the provisions of the stipulation approved by the South Carolina Public Service Commission in Docket #2002-223-E order No. 2003-38 dated January 31, 2003. This rate will be closed after the initial participant group is established, except there will be 25 additional customer accounts that will be allowed to participate on a "first come first serve' basis for new facilities constructed by customers in the initial participant group and as provided for in the stipulation as referenced above. The stipulation referenced above shall provide guidance as to any issue regarding availability on this rate. It is not available for resale service.

CHARACTER OF SERVICE

Alternating current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. Basic Facilities Charge:	$	225.00	
II. Demand Charge:			
A. On-Peak Billing Demand:			
1. Summer Months of June-September @	$	23.32	per KVA
2. Non-Summer Months of October-May @	$	13.99	per KVA
B. Off-Peak Billing Demand			
1. All Off-Peak Billing Demand @	$	5.19	per KVA
III. Energy Charge:			
A. On-Peak kWh			
1. Summer Months of June-September @	$	0.08447	per kWh
2. Non-Summer Months of October-May @	$	0.05543	per kWh
B. Off-Peak kWh			
1. All Off-Peak @	$	0.04434	per kWh

BILLING DEMAND

The billing demands will be rounded to the nearest whole KVA. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.

For the summer months, the on-peak billing demand shall be the maximum integrated fifteen minute demand measured during the on-peak hours of the current month.

For the non-summer months, the on-peak billing demand will be the greater of: (1) the maximum integrated fifteen minute demand measured during the on-peak hours of the current month, or (2) eighty percent (80%) of the maximum integrated demand occurring during the on-peak hours of the preceding summer months.

The off-peak billing demand shall be the greatest of the following positive differences: (1) the maximum integrated fifteen minute demand measured during the off-peak hours minus the on-peak billing demand, (2) the contract demand minus the on-peak billing demand or (3) 50 KVA minus the on-peak billing demand.

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

A. On-Peak Hours During Summer Months:

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

B. On-Peak Hours During Non-Summer Months:

May and October:

The on-peak non-summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

November-April:

The on-peak non-summer hours are defined as these hours between 6:00 a.m.-12:00 noon and 5:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02495 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00197 per kWh for Demand Side Management expenses.

PENSION COST COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. The contract for this experimental program shall be written for a period of 48 months as provided for in the stipulation approved by the South Carolina Public service Commission in docket No. 2002-223-E, order No. 2003-38 dated July 31, 2003. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 22 **SCHOOL SERVICE**

AVAILABILITY

This rate is available to customers using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for general light and/or power service to schools. It is not available for resale service. It is only available to recognized non-boarding schools with up through grade twelve.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

Basic Facilities Charge:	$	17.05	
Plus Energy Charge:			
First 50,000 kWh @	$	0.11128	per kWh
Excess over 50,000 kWh @	$	0.12908	per kWh

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Under no conditions will the Company allow the service to be resold to or shared with others. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

When a school offers activities that, in the sole opinion of the Company, are of a commercial nature such as day care, camps or recreational activities, the Company may require that the account be served under the appropriate general service rate.

TERM OF CONTRACT

Contracts shall be written for a period of not less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 23 **INDUSTRIAL POWER SERVICE**

AVAILABILITY

This rate is available to any customer classified in the major industrial group of manufacturing with 10-14 or 20-39 as the first two digits of the Standard Industrial Classification or 21 or 31-33 as the first two digits of the six digit North American Industry Classification System using the Company's standard service for power and light requirements and having a contract demand of 1,000 KW or over. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. Basic Facilities Charge	$ 2,050.00	
II. Demand Charge:		
All KW of Billing Demand @	$ 15.90	per KW

The billing demand (to the nearest whole KW) shall be the greatest of: (1) the maximum integrated fifteen minute demand measured (which may be on a rolling time interval) during the current month; or (2) eighty percent (80%) of the highest demand occurring during the billing months of June through September in the eleven preceding months; or (3) sixty (60%) of the highest demand occurring during the billing months of October through May in the eleven preceding months; or (4) the contract demand; or (5) 1,000 KW.

The customer shall maintain a power factor of as near unity as practicable. If the power factor of the customer's installation falls below 85%, the Company will adjust the billing demand to a basis of 85% power factor.

III. Energy Charge:		
All kWh @	$ 0.04671	per kWh

DISCOUNT

A discount of $0.60 per KW of billing demand will be allowed when the service is supplied at a delivery voltage of 46,000 volts or higher.

MINIMUM CHARGE

The monthly minimum charge is the demand as determined above. It shall also include the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below. The Company may allow a buildup period not to exceed six months for new and expanding accounts during which time the contract demand and/or the minimum demand specified in the rate schedule may be waived. The Company shall not commit itself to a buildup period exceeding six months without prior approval of the Commission for the specific account involved.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02478 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $100.00 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00149 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 24

LARGE GENERAL SERVICE
TIME-OF-USE

AVAILABILITY

This rate is available to any customer using the Company's standard service for power and light requirements and having a contract demand of 1,000 KW or over. It is not available for resale service.

CHARACTER OF SERVICE

Alternating Current, 60 hertz, three phase, metering at the delivery voltage which shall be standard to the Company's operation.

RATE PER MONTH

I. Basic Facilities Charge:	$	2,050.00	
II. Demand Charge:			
A. On-Peak Billing Demand			
1. Summer Months of June-September @	$	19.56	per KW
2. Non-Summer Months of October-May @	$	13.79	per KW
B. Off-Peak Billing Demand			
1. All Off-Peak Billing Demand @	$	5.86	per KW
III. Energy Charge:			
A. On-Peak kWh			
1. Summer Months of June-September @	$	0.07814	per kWh
2. Non-Summer Months of October-May @	$	0.05591	per kWh
B. Off-Peak kWh			
1. All Off-Peak @	$	0.04287	per kWh

BILLING DEMAND

The billing demands will be rounded to the nearest whole KW. If the power factor of the customer's current month maximum integrated fifteen minute KW demand for the on-peak and off-peak time periods are less than 85%, then the Company will adjust same to 85%. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.

For the summer months, the on-peak billing demand shall be the maximum integrated fifteen minute demand measured during the on-peak hours of the current month.

For the non-summer months, the on-peak billing demand will be the greater of: (1) the maximum integrated fifteen minute demand measured during the on-peak hours of the current month, or (2) eighty percent (80%) of the maximum integrated demand occurring during the on-peak hours of the preceding summer months.

The off-peak billing demand shall be the greatest of the following positive differences: (1) the maximum integrated fifteen minute demand measured during the off-peak hours minus the on-peak billing demand, or (2) the contract demand minus the on-peak billing demand, or (3) 1,000 KW minus the on-peak billing demand.

June-September:
The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

B. On-Peak Hours During Non-Summer Months:

May and October:
The on-peak non-summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

November-April:
The on-peak non-summer hours are defined as those hours between 6:00 a.m.-12:00 noon and 5:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

C. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

MINIMUM CHARGE

The monthly minimum charge is the demand as determined above. It shall also include the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below. The Company may allow a buildup period not to exceed six months for new and expanding accounts during which time the contract demand and/or the minimum demand specified in the rate schedule may be waived. The Company shall not commit itself to a buildup period exceeding six months without prior approval of the Commission for the specific account involved.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02478 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $100.00 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00149 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmnetal body.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. No contract shall be written for a period of less than five (5) years. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and a part of this rate schedule.

RATE 25

OVERHEAD FLOODLIGHTING

AVAILABILITY

This rate is available to customers using the Company's electric service for Overhead Floodlighting.

RATE

All night floodlighting service where fixtures are mounted on Company's standard wooden poles which are part of Company's distribution system will be charged for at the following rates:

SIZE AND DESCRIPTION			Lamp Charges per Month	kWh per Month
22,350	Lumens	(LED) (240W)	$ 24.08	80
30,000	Lumens	(MH) (320W)	$ 24.20	123
32,300	Lumens	(LED) (360W)	$ 31.49	121
45,000	Lumens	(HPS) (400W)	$ 22.23	158
110,000	Lumens	(Metal Halide) (1,000W)	$ 46.85	359
140,000	Lumens	(HPS) (1,000W) Flood	$ 39.40	368

The following fixtures are available for new installations only to maintain pattern sensitive areas:

45,000	Lumens	(HPS) (360W) - Retrofit	$ 22.65	164
130,000	Lumens	(HPS) (940W) - Retrofit	$ 39.85	370

Effective January 2009, selected existing light sets will no longer be available for new installations. Replacement light sets will only be available until inventory is depleted and will be replaced on a first-come, first-served basis. Affected lights are as follows:

20,000	Lumens	(Mercury) (400W)	$ 21.54	159
40,000	Lumens	(Metal Halide) (400W)	$ 28.36	159
55,000	Lumens	(Mercury) (1,000W)	$ 33.38	359

Cost per month for each additional pole:

25' (Fiberglass)	30'	35'	40'	45'
$10.65	$5.20	$5.75	$6.90	$8.35

MINIMUM CHARGE

When construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02451 per kWh are included in the monthly lamp charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

TERM OF CONTRACT

The initial term of this contract shall be for a period of five (5) years and, thereafter, for like periods until terminated by either party on thirty days' written notice, but the Company may require a contract of initial term up to ten (10) years and may require an advance deposit not to exceed one half of the estimated revenue for the term of the initial contract. The Company reserves the right to remove its facilities when subject to vandalism or for other cogent reasons.

SPECIAL PROVISIONS

The Company will furnish, erect, operate and maintain all necessary equipment in accordance with its standard specifications. It is the customer's responsibility to notify the Company when equipment fails to operate properly. Non-standard service requiring underground, special fixtures and/or poles will be furnished only when the customer pays the difference in costs between such non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 26

OVERHEAD PRIVATE STREET LIGHTING

AVAILABILITY

This rate is available to customers using the Company's electric service for overhead street lighting.

RATE

All night street lighting service where fixtures are mounted on Company's existing standard wooden poles which are a part of Company's distribution system will be charged for at the following rates:

SIZE AND DESCRIPTION			Lamp Charges per Month	kWh per Month
4,800	Lumens	(LED) (50W) Open Type	$ 9.40	16
9,000	Lumens	(MH) (100W) Closed Type	$ 10.89	37
15,000	Lumens	(HPS) (150W) Open Type	$ 10.21	57
15,000	Lumens	(HPS) (150W) Closed Type	$ 11.72	62
30,000	Lumens	(MH) (320W) Closed Type	$ 17.63	123
50,000	Lumens	(HPS) (400W) Closed Type	$ 18.83	158

The following fixtures are available for new installations only to maintain pattern sensitive areas:

9,500	Lumens	(HPS) (100W) Open Type	$ 10.40	38
9,500	Lumens	(HPS) (100W) Closed Type	$ 10.72	38
15,000	Lumens	(HPS) (150W) Open Type - Retrofit	$ 10.15	63
27,500	Lumens	(HPS) (250W) Closed Type	$ 16.62	102
45,000	Lumens	(HPS) (360W) Closed Type - Retrofit	$ 18.95	164

Effective January 2009, selected existing light sets will no longer be available for new installations. Replacement light sets will only be available until inventory is depleted and will be replaced on a first-come, first-served basis. Affected lights are as follows:

7,500	Lumens	(Mercury) (175W) Open Type	$ 9.57	69
7,500	Lumens	(Mercury) (175W) Closed Type	$ 11.67	69
10,000	Lumens	(Mercury) (250W) Open Type	$ 14.09	95
20,000	Lumens	(Mercury) (400W) Closed Type	$ 17.37	159

Cost per month for each additional pole:

25' (Fiberglass)	30'	35'	40'	45'
$10.65	$5.20	$5.75	$6.90	$8.35

MINIMUM CHARGE

When construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02451 per kWh are included in the monthly lamp charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

TERM OF CONTRACT

The initial term of this contract shall be for a period of five (5) years and, thereafter, for like periods until terminated by either party on thirty days' written notice, but the Company may require a contract of initial term up to ten (10) years and may require an advance deposit not to exceed one half of the estimated revenue for the term of the initial contract. The Company reserves the right to remove its facilities when subject to vandalism or for other cogent reasons.

SPECIAL PROVISIONS

The Company will furnish, erect, operate and maintain all necessary equipment in accordance with its standard specifications. It is the customer's responsibility to notify the Company when equipment fails to operate properly. Non-standard service requiring underground, special fixtures and/or poles will be furnished only when the customer pays the difference in costs between such non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RATE 28
(EXPERIMENTAL)

SMALL GENERAL SERVICE
TIME-OF-USE DEMAND

AVAILABILITY

This rate is available to any non-residential customer using the Company's standard service which is specified as a single point of delivery per premises from an existing overhead distribution system for power and light requirements and having an on-peak demand of not more than 100KW. The second billing month within a twelve billing month period that on-peak demand exceeds 100 KW will terminate eligibility under this rate schedule. It is not available for resale service. This rate is available to a maximum of 25 customers not enrolled under the Company's Rider to Rates 7 & 28 - Net Metering For Renewable Energy Facilities.

CHARACTER OF SERVICE

Alternating Current, 60 hertz. Voltage and phase at the option of the Company.

RATE PER MONTH

I. Basic Facilities Charge:	$	26.40	
II. Demand Charge:			
A. On-Peak Billing Demand:			
1. Summer months of June-September @	$	19.82	per KW
2. Non-Summer months of October-May @	$	12.39	per KW
B. Off-Peak Billing Demand			
1. All Off-Peak Billing Demand @	$	3.96	per KW
III. Energy Charge:			
A. On-Peak kWh			
1. All On-Peak @	$	0.11242	per kWh
B. Off-Peak kWh			
2. All Off-Peak @	$	0.08657	per kWh

BILLING DEMAND

The billing demands will be rounded to the nearest whole KW. The maximum integrated fifteen minute demand for any period may be recorded on a rolling time interval.
For the summer months, the on-peak billing demand shall be the maximum integrated fifteen minute demand measured during the on-peak hours of the current month.
For the non-summer months, the on-peak billing demand will be the greater of: (1) the maximum integrated fifteen minute demand measured during the on-peak hours of the current month, or (2) eighty percent (80%) of the maximum integrated demand occurring during the on-peak hours of the preceding summer months.
The off-peak billing demand shall be the greatest of the following positive differences: (1) the maximum integrated fifteen minute demand measured during the off-peak hours minus the on-peak billing demand or (2) the contract demand minus the on-peak billing demand.

DETERMINATION OF ON-PEAK HOURS

A. On-Peak Hours:

June-September:

The on-peak summer hours are defined as the hours between 1:00 p.m.-9:00 p.m., Monday-Friday, excluding holidays.*

October-May:

The on-peak non-summer hours are defined as those hours between 6:00 a.m.-10:00 a.m. and 6:00 p.m.-10:00 p.m. Monday-Friday, excluding holidays.*

B. Off-Peak Hours:

The off-peak hours in any month are defined as all hours not specified as on-peak hours.

*Holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

MINIMUM CHARGE

The monthly minimum charge shall be the basic facilities charge as stated above, and the Distributed Energy Resource Program charge, as stated below, provided however, when construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02503 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina. A charge of $3.29 per account per month will be added to the charges above for the recovery of approved Distributed Energy Resource Program incremental costs.

DEMAND SIDE MANAGEMENT COMPONENT

The energy charges above include a DSM component of $.00202 per kWh for Demand Side Management expenses.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

POWER FACTOR

If the power factor of the customer's installation falls below 85%, the Company may adjust the billing to a basis of 85% power factor.

PAYMENT TERMS

All bills are net and payable when rendered.

SPECIAL PROVISIONS

The Company will furnish service in accordance with its standard specifications. Non-standard service will be furnished only when the customer pays the difference in costs between non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

The Company shall have the right to install and operate special metering equipment to measure customer's loads or any part thereof and to obtain any other data necessary to determine the customer's load characteristics.

TERM OF CONTRACT

The contract terms will depend on the conditions of service. Contracts for installations of a permanent nature shall be written for a period of not less than one (1) year. A separate contract shall be written for each meter at each location.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

RESIDENTIAL SUBDIVISION STREET LIGHTING

AVAILABILITY

Available to residential subdivisions located on the Company's distribution system. Residents of established subdivisions must first execute a street lighting agreement with the Company. This rate schedule is not available for lighting parking lots, shopping centers, other public or commercial areas or the streets of an incorporated municipality nor if other lighting options are available for new residential subdivisions.

RATE

All night street lighting service where fixtures are mounted on Company's existing standard wooden poles which are a part of Company's overhead distribution system will be charged for at the following rates:

The following amount will be added to each monthly bill rendered for residential electric service within the subdivision:

Bracket Mounted Luminaries					
1 light per 8 customers or fraction thereof			**Lamp Charges per Month**		
9,000	Lumens	(MH) (100W) Closed Type	$	2.35	per customer
15,000	Lumens	(HPS) (150W) Open Type	$	2.26	per customer
15,000	Lumens	(HPS) (150W) - Retrofit	$	2.26	per customer

The following metal halide fixtures are available for new installations only to maintain pattern sensitive areas:

1 light per 4 customers or fraction thereof					
9,000	Lumens	(MH) (100W) Closed Type	$	4.70	per customer
1 light per 3 customers or fraction thereof					
9,000	Lumens	(MH) (100W) Closed Type	$	6.26	per customer
1 light per 2 customers or fraction thereof					
9,000	Lumens	(MH) (100W) Closed Type	$	9.40	per customer

All night street lighting service in subdivisions being served from Company's underground distribution system:

The following amount will be added to each monthly bill rendered for residential electric service within the subdivision:

Post-Top Mounted Luminaries			**Traditional Lamp Charges per Month**	**Modern Lamp Charges per Month**	**Classic Lamp Charges per Month**	
1 light per 6 customers or fraction thereof						
9,000	Lumens	(MH) (100W)	$ 4.20	$ 4.20	$ 4.83	per customer
15,000	Lumens	(HPS) (150W) - Retrofit	$ 4.23	$ 4.23	$ 5.03	per customer
1 light per 4 customers or fraction thereof						
9,000	Lumens	(MH) (100W)	$ 6.30	$ 6.30	$ 7.25	per customer
15,000	Lumens	(HPS) (150W) - Retrofit	$ 6.34	$ 6.34	$ 7.55	per customer

The following fixture is available for new installations only to maintain pattern sensitive areas:

1 light per 6 customers or fraction thereof					
9,500	Lumens	(HPS) (100W) - Traditional	$	4.23	per customer

Effective January 2009, selected existing light sets will no longer be available for new installations. Replacment light sets will only be available until inventory is depleted and will be replaced on a first-come, first-served basis. Affected lights are as follows:

Open Type Globe - 1 light per 8 customers or fraction thereof					
7,500	Lumens	(Mercury) (175W) Open Type	$	2.18	per customer
7,500	Lumens	(Mercury) (175W) Closed Type	$	2.45	per customer
Open Type Globe - 1 light per 4 customers or fraction thereof					
7,500	Lumens	(Mercury) (175W) Open Type	$	4.37	per customer
7,500	Lumens	(Mercury) (175W) Closed Type	$	4.89	per customer
Open Type Globe - 1 light per 3 customers or fraction thereof					
7,500	Lumens	(Mercury) (175W) Open Type	$	5.82	per customer
7,500	Lumens	(Mercury) (175W) Closed Type	$	6.52	per customer
Open Type Globe - 1 light per 2 customers or fraction thereof					
7,500	Lumens	(Mercury) (175W) Open Type	$	8.74	per customer
7,500	Lumens	(Mercury) (175W) Closed Type	$	9.79	per customer

Post-Top Mounted Luminaries			**Traditional Lamp Charges per Month**	**Modern Lamp Charges per Month**	**Classic Lamp Charges per Month**
1 light per 6 customers or fraction thereof					
7,500	Lumens	(Mercury) (175W)	$ 4.14	$ 4.12	$ 4.90
1 light per 4 customers or fraction thereof					
7,500	Lumens	(Mercury) (175W)	$ 6.21	$ 6.18	$ 7.34

RESIDENTIAL SUBDIVISION STREET LIGHTING

MINIMUM CHARGE

When construction costs exceed four (4) times the estimated annual revenue excluding fuel revenue to be derived by the Company, the customer may make a contribution in aid of construction of the excess cost or pay the Company's standard facility rate on the excess construction cost in addition to the rate charges above.

ADJUSTMENT FOR FUEL, VARIABLE ENVIRONMENTAL & AVOIDED CAPACITY, AND DISTRIBUTED ENERGY RESOURCE COSTS

Fuel costs of $.02451 per kWh are included in the monthly lamp charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

PENSION COSTS COMPONENT

The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

STORM DAMAGE COMPONENT

Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

SALES AND FRANCHISE TAX

To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

PAYMENT TERMS

All bills are net and payable when rendered.

TERM OF CONTRACT

The initial term of this contract shall be for a period of five (5) years and, thereafter, for like periods until terminated by either party on thirty days' written notice, but the Company may require a contract of initial term up to ten (10) years and may require an advance deposit not to exceed one half of the estimated revenue for the term of the initial contract. The Company reserves the right to remove its facilities when subject to vandalism or for other cogent reasons.

SPECIAL PROVISIONS

The Company will furnish, erect, operate and maintain all necessary equipment in accordance with its standard specifications. It is the customer's responsibility to notify the Company when equipment fails to operate properly. Non-standard service requiring underground, special fixtures and/or poles will be furnished only when the customer pays the difference in costs between such non-standard service and standard service or pays to the Company its normal monthly facility charge based on such difference in costs.

GENERAL TERMS AND CONDITIONS

The Company's General Terms and Conditions are incorporated by reference and are a part of this rate schedule.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

ELECTRIC CONTRACTED RATES

Name of Customer	Rate			
State Line Accounts*	**23**			
INTERNATIONAL PAPER **Eastover Mills**				
Economy Power Rate	**Administrative Charges:**	$	2,050.00	per month
	On-Peak Energy Charge:			
	Fuel cost of highest cost generation unit or purchased power (other than cogeneration) plus	$	0.02741	per kWh
	Off-Peak Energy Charge:			
	Fuel cost of highest cost generation unit or purchased power (other than cogeneration) plus	$	0.01499	per kWh
	Excess Demand Charge:	$	20.00	per KW
Standby Power Rate	**Demand Charge:**			
	On-peak June-September	$	0.47540	per KW/Day
	On-peak October-May	$	0.28570	per KW/Day
	Off-peak	$	0.17293	per KW/Day
	Energy Charge:			
	Same as that for Economy Power above			
	Excess Demand Charge:	$	20.00	per KW
Maintenance Power Rate	**Demand Charge:**	$	0.05030	per KW/Day
	Energy Charge:	$	0.04671	per kWh
	Company Provided KVAR	$	0.14773	per KVAR
	Renewable Energy Resources:	$	100.00	per month

Contracted lighting, signal and roadway lighting, etc.

* After contractual (1925 and 1955) adjustments

Note: (1) Fuel costs of $.02478 per kWh are included in the energy charge and are subject to adjustment by order of the Public Service Commission of South Carolina.

(2) Inclusion of a storm damage component has been indefinitely suspended until further order of the Public Service Commission of South Carolina.

CAPITAL COST RIDER COMPONENT

The above charges reflect the Capital Cost Component Rider adjustment as approved by the Public Service Commission of South Carolina.

TAX RIDER

The above charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

RATE 27

**LARGE POWER SERVICE
REAL TIME PRICING
(EXPERIMENTAL)
(Page 1 of 3)**

AVAILABILITY

This rate is available for Large Commercial and Industrial Customers. Qualifying Customers must have a monthly maximum demand of not less than 1000 kW.

This rate schedule is not available in conjunction with the Company's Interruptible Rider. Also, this rate is not available for resale service.

METERING OF LOAD

Standard metering for Real Time Pricing (RTP) is the conventional interval demand recording meter typically used for Customers with loads of 1000 kW or greater.

CHARGES PER MONTH

Baseline Charges: The Baseline Charges for each Customer are calculated using the current version of the Customer's otherwise applicable tariff and the Baseline Billing determinants. If there is a change in the filed tariff rates used to calculate the baseline charges or if the base fuel rate changes, these changes will be reflected in the baseline charges.

Marginal Energy Charge: The Energy Charge is an hourly cents per kWh charge. It consists of the incremental energy cost and any other directly related marginal production costs including line losses for that hour. This charge will be communicated to the Customer as described in the Billing Determination below.

Rationing Charge: The Rationing Charge is an hourly cents per kWh charge. It consists of generation costs only. These costs will be applied when regional available generation capacity is low. If these conditions do not occur, the Rationing Charge will be zero. The Rationing Charge will be communicated to the Customer as described in the Notice and Billing Determination below.

Risk Adder: $.005 per kWh will be applied to the incremental kilowatt hours above and below the Customer Base Load.

Transmission Charge: All new RTP load above the Customer Baseline Load (CBL) will carry a per kWh transmission charge plus charges for two ancillary services, scheduling and dispatch service and reactive supply and voltage control service. The transmission charge for RTP load above the CBL is $.00469 per kWh.

Demand Side Management Component: The energy charges above include a DSM component of $.00149 per kWh for Demand Side Management expenses.

Pension Costs Component: The energy charges above include a Pension Costs component of $.00033 per kWh as approved by the Public Service Commission of South Carolina.

Administrative Charge: An administrative charge of $200 per month will be charged to cover billing, administrative, and communication costs associated with the LPS (Large Power Service)-RTP program.

Sales Tax and Franchise Charge: To the above will be added any applicable sales tax, franchise fee or business license tax which may be assessed by any state or local governmental body.

BILL DETERMINATION

LPS-RTP Bill $_{Mo.}$ = Baseline Charges. $_{Mo.}$ + (Σ ((Price $_{Hr.}$ x New Load $_{Hr.}$) – (Price $_{Hr.}$ x Reduced Load $_{Hr.}$))) + (Transmission Charge $_{Hr.}$ * New Load $_{Hr.}$) + Admn. Charges + Applicable Taxes.

Where:

LPS-RTP Bill $_{Mo.}$ = Total Customer's RTP bill.

Baseline Charge $_{Mo.}$ = Monthly charge calculated using the Customer approved Baseline Billing Determinants and the current version of the Customer's otherwise applicable rate schedule.

Σ = Sum of all hours of the monthly billing period.

Price $_{Hr.}$ = The hourly marginal energy charge plus the hourly rationing charge plus the risk adder.

New Load $_{Hr.}$ = The Customer's metered hourly actual load less the hourly baseline load when the hourly actual load exceeds the hourly baseline load.

Reduced Load $_{Hr.}$ = The Customer's metered hourly actual load less the hourly baseline load when the hourly baseline load exceeds the hourly actual load.

Transmission Charges $_{Hr.}$ = Per kWh charge on the new RTP load recorded in the monthly billing period above the CBL.

Administrative Charge = The monthly charge for administration of Rate 27.

Applicable Taxes = The monthly applicable sales tax, franchise fee and / or business license tax.

NOTICE AND BILLING DETERMINATION

Pricing Period: Each hour of each day is a separate pricing period and the corresponding quoted energy price is applicable to energy consumption during that hour that differs from the CBL. Each day begins at 12:00:01 a.m. and ends at 12:00 midnight. Each hour begins at the one second mark and ends on the hour mark.

Marginal Energy Charge and Rationing Charge Notification: Each business day by 4:00 p.m., 24 hourly prices consisting of the hourly incremental energy charge, the Risk Adder, if applicable and the hourly Rationing Charge, for the following day will be communicated to the Customer via a method specified by the Company. Prices for weekends, including Mondays and holidays, may be communicated to the Customer by 4:00 p.m. the business day prior to the weekend or holiday. Holidays are defined in the conventional Company tariffs. The Company reserves the right to change any hourly price by 4:00 p.m. on the day prior to the affected day. The Customer shall supply the Company the name and 24 hour telephone number of a contact person. It is the Customer's responsibility to notify the Company if the pricing information is not received. If, for any reason, the Customer fails to receive the pricing information by 5:00 p.m. and fails to notify the Company that it has not received the prices, the Company is under no obligation to change or alter the prices it has posted and will bill the Customer according to the provisions set forth above. The Company is not responsible for a Customer's failure to act upon the hourly RTP prices.

Power Factor Adjustment: The Customer shall maintain a power factor of as near unity as practical. If the average hourly monthly power factor falls below 85%, a power factor adjustment charge will be assessed as follows:

Power Factor Adj. = ((MkVA * 85%) – MkW) * kW Charge

Where:

MkVA	=	kVA measured at the time of MkW
MkW	=	Maximum kW in any 15 minute period during the current month
kW Charge	=	Kilowatt Charge from standard rate schedule

CBL Calculation

At the beginning of each year, except for the Customer's initial subscription year on RTP, the Customer's current CBL shall be adjusted following the rules and procedures described below as a condition for continued subscription to RTP. Failure by the Customer to approve the revised CBL as part of the RTP contract shall result in the cancellation of the RTP contract and the Customer's service shall be billed under the rate schedule applicable prior to subscription or under such rate schedule as is appropriate to the Customer's service classification.

Standard CBL Adjustment

At the beginning of each year, the previous calendar year's billing determinants will be reviewed to determine the level of demand and energy that is subject to real time pricing. If the level of demand or energy or both exceeds 20% of the total demand or energy or both, then the CBL will be adjusted in order to limit the amount of load subject to real time pricing to 20% of the previous calendar year's total load. If the level of demand or energy subject to RTP is less than 20% of the previous calendar year's total load, then no adjustment to the CBL will be required.

Baseline Billing Determinants: The Baseline Billing Determinants are developed using a complete year of hourly load data that accurately represents the Customer's electrical load pattern. This is negotiated and agreed to by the Customer and the Company as representative of the Customer's operation. The Baseline Billing Determinants will be used to measure changes in consumption for Rate 27 billing. The Customer and the Company must agree on the Baseline Bill Determinants before the Customer is put on Rate 27. Once agreed upon, the Baseline Billing Determinants cannot be changed except for the reasons outlined in CBL Calculation and Standard CBL Adjustment or the following:

- Any permanent plant additions or improvements that affect load levels as verified to the Company's satisfaction
- Any permanent plant shutdowns
- Any adjustments that reflect the Customer's response to Company sponsored load management program

Any changes in the Baseline Billing Determinants resulting from the reasons above, must be agreed upon by the Company and the Customer. The Customer must provide documentation sufficient to substantiate the requested CBL adjustment. The Company, at its sole discretion, will determine whether to adjust the CBL. If changes in the Customer's electricity usage level cause the Company to change out, modify, or enhance any equipment associated with service delivery voltage, the Customer shall reimburse the Company for all cost incurred as a condition for continuing on Rate 27.

SPECIAL PROVISIONS

Adjustment for Fuel Costs: The Company's Adjustment for Fuel, Variable Environmental & Avoided Capacity, and Distributed Energy Resource Costs is incorporated as part of, and will apply to all service supplied under this Rate Schedule, including the determination of the Baseline Charge.

Capital Cost Component Rider: The Capital Cost Component Rider reflects the Capital Cost Component Rider adjustment to the Baseline Billing rates as approved by the Public Service Commission of South Carolina.

Tax Rider: The Baseline Billing charges will be reduced by 1.5% to reflect the Tax Rider as approved by the Public Service Commission of South Carolina.

Payment Terms: All bills are net and payable when rendered.

Terms of Contract: The term of contract for this rate is five (5) years with a minimum of twenty-four (24) months termination notice requirement. Upon termination, the Customer may not return to Rate 27 pricing for a minimum of twelve (12) months. If the Customer reverts to the rate schedule under which service was received prior to Rate 27 or any other eligible rate, usage under Rate 27 will not affect the Customer's billing determinants under that rate schedule nor will it affect the term of the Customer's new contract. Following the minimum 12 month absence, should a customer elect to return to Rate 27, the Customer will be treated as a new Rate 27 customer for purposes of administering this tariff.

Billing Cycle: The Customer shall be billed on a calendar month basis.

Facility Charges: Facility Charges will be billed under the Baseline Charges. Any extra facility charges will be calculated according to Company policy and procedure, and billed as part of the total bill.

General Terms and Conditions: The Company's General Terms and Conditions, including curtailment provisions, are incorporated by reference and are part of this rate schedule.

Exhibit 13

RESTATED and UPDATED CONSTRUCTION EXPENDITURES

(Thousands of $)

V.C. Summer Units 2 and 3 - Summary of SCE&G Capital Cost Components

Actual through through September 2017 plus Adjustments

		Actual											
Plant Cost Categories	**Total**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Transfers**
Fixed with No Adjustment	1,738,708	4,628	35,199	22,066	67,394	50,551	66,057	22,960	11,634	366,348	727,099	419,018	(54,246)
Firm with Fixed Adjustment A	266,750	-	-	63,250	27,500	24,200	75,075	42,900	7,700	26,125	-	-	-
Firm with Fixed Adjustment B	238,868	-	5,499	35,768	49,513	39,371	45,043	31,048	22,834	9,791	-	-	-
Firm with Indexed Adjustment	873,741	-	45,869	148,713	115,172	137,871	118,769	150,530	129,994	26,822	0	-	-
Actual Craft Wages	133,306	-	312	1,937	9,779	11,682	21,091	25,217	38,785	24,503	0	-	-
Non-Labor Costs	406,936	-	1,271	31,255	79,778	9,298	65,227	70,154	105,390	44,564	(0)	-	-
Time & Materials	15,787	-	1,013	155	1,004	764	1,878	2,300	4,055	2,048	2,461	109	-
Owners Costs	411,688	17,096	8,198	15,206	23,743	29,276	43,643	47,245	51,807	56,885	73,152	76,058	(30,621)
Total Base Project Costs(2007 $)	4,085,783	21,723	97,360	318,349	373,883	303,013	436,784	392,354	372,200	557,085	802,712	495,186	(84,867)
Total Project Escalation	387,161	-	3,516	20,907	23,688	32,930	68,787	81,553	86,682	47,711	12,575	8,812	-
Total Revised Project Cash Flow	4,472,944	21,723	100,876	339,256	397,571	335,943	505,571	473,907	458,882	604,797	815,287	503,997	(84,867)
Cumulative Project Cash Flow(Revised)		21,723	122,600	461,856	859,427	1,195,370	1,700,941	2,174,848	2,633,730	3,238,526	4,053,813	4,557,811	4,472,944
AFUDC(Capitalized Interest)	172,373	645	3,495	10,539	17,099	14,039	17,538	23,723	21,563	18,713	27,366	17,653	-
Gross Construction	4,645,317	22,368	104,371	349,795	414,670	349,981	523,109	497,631	480,445	623,510	842,653	521,650	(84,867)
Construction Work in Progress		22,368	126,739	476,535	891,205	1,241,186	1,764,295	2,261,926	2,742,371	3,365,881	4,208,534	4,730,184	4,645,317

***Applicable index escalation rates for 2017 are estimated. Escalation is subject to restatement when actual indices for 2017 are final.**

Notes:

Current Period AFUDC rate applied 6.06%

Escalation rates vary from reporting period to reporting period according to the terms of Commission Order 2009-104(A).
These projections reflect current escalation rates. Future changes in escalation rates could substatially change these projections.
The AFUDC rate applied is the current SCE&G rate. AFUDC rates can vary with changes in market interest rates,
SCE&G's embedded cost of capital, capitalization ratios, construction work in process, and SCE&G's short-term debt outstanding.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - TOTAL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)		
Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments	Total As Adjusted
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,626,725,028	(16,307,817)	2,610,417,211
2	Operating Expenses			
3	O&M Expenses - Fuel	649,424,435	-	649,424,435
4	O&M Expenses - Other	598,179,439	4,840,606	603,020,045
5	Depreciation & Amortization Expenses	274,006,765	169,044,100	443,050,865
6	Taxes Other Than Income	210,682,693	5,987,155	216,669,848
7	Total Income Taxes	194,685,466	(63,666,801)	131,018,665
8	Total Operating Expenses	1,926,978,798	116,205,060	2,043,183,858
9	Operating Return	699,746,230	(132,512,877)	567,233,353
10	Customer Growth	3,329,938	(625,263)	2,704,675
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	701,962,102	(133,138,140)	568,823,962
13	Rate Base			
14	Plant in Service	9,847,762,591	309,945,931	10,157,708,522
15	Reserve for Depreciation	3,865,657,956	8,553,861	3,874,211,817
16	Net Plant	5,982,104,635	301,392,070	6,283,496,705
17	Construction Work in Progress	5,044,195,701	(4,835,688,277)	208,507,424
18	Deferred Debits / Credits	10,207,489	1,516,588,388	1,526,795,877
19	Total Working Capital	20,431,080	7,227,847	27,658,927
20	Materials & Supplies	437,304,695	(110,422,518)	326,882,177
21	Accumulated Deferred Income Taxes	(1,168,308,900)	446,869,559	(721,439,341)
22	Total Rate Base	10,325,934,700	(2,674,032,931)	7,651,901,769
23	Rate of Return	6.80%		7.43%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books ($000's)	Pro-Forma Adjustments ($000's)	Total As Adjusted ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,573,825,310	(16,307,817)	2,557,517,493
2	Operating Expenses			
3	O&M Expenses - Fuel	623,287,164	-	623,287,164
4	O&M Expenses - Other	583,711,611	4,392,040	588,103,651
5	Depreciation & Amortization Expenses	267,744,349	168,999,884	436,744,233
6	Taxes Other Than Income	206,069,444	5,853,628	211,923,072
7	Total Income Taxes	189,028,533	(63,366,097)	125,662,436
8	Total Operating Expenses	1,869,841,101	115,879,455	1,985,720,556
9	Operating Return	703,984,209	(132,187,272)	571,796,937
10	Customer Growth	3,329,938	(625,263)	2,704,675
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	706,200,081	(132,812,535)	573,387,546
13	Rate Base			
14	Plant in Service	9,642,974,430	299,539,492	9,942,513,922
15	Reserve for Depreciation	3,777,308,466	8,289,303	3,785,597,769
16	Net Plant	5,865,665,964	291,250,189	6,156,916,153
17	Construction Work in Progress	4,885,050,807	(4,835,688,162)	49,362,645
18	Deferred Debits / Credits	9,547,089	1,516,587,862	1,526,134,951
19	Total Working Capital	17,474,474	7,171,777	24,646,251
20	Materials & Supplies	422,196,596	(105,928,322)	316,268,274
21	Accumulated Deferred Income Taxes	(1,144,013,449)	446,869,559	(697,143,890)
22	Total Rate Base	10,055,921,481	(2,679,737,097)	7,376,184,384
23	Rate of Return	7.02%		7.77%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

			($000's)	
Line No.	Description	Retail As Adjusted	Hypothetical Increase*	Total After Hypothetical Increase
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,557,517,493	44,962,565	2,602,480,058
2	Operating Expenses			
3	O&M Expenses - Fuel	623,287,164		623,287,164
4	O&M Expenses - Other	588,103,651		588,103,651
5	Depreciation & Amortization Expenses	436,744,233		436,744,233
6	Taxes Other Than Income	211,923,072	199,993	212,123,065
7	Total Income Taxes	125,662,436	17,121,684	142,784,120
8	Total Operating Expenses	1,985,720,556	17,321,677	2,003,042,233
9	Operating Return	571,796,937	27,640,888	599,437,825
10	Customer Growth	2,704,675	130,697	2,835,372
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	573,387,546	27,771,585	601,159,131
13	Rate Base			
14	Plant in Service	9,942,513,922	-	9,942,513,922
15	Reserve for Depreciation	3,785,597,769	-	3,785,597,769
16	Net Plant	6,156,916,153	-	6,156,916,153
17	Construction Work in Progress	49,362,645	-	49,362,645
18	Deferred Debits / Credits	1,526,134,951	-	1,526,134,951
19	Total Working Capital	24,646,251	-	24,646,251
20	Materials & Supplies	316,268,274	-	316,268,274
21	Accumulated Deferred Income Taxes	(697,143,890)	-	(697,143,890)
22	Total Rate Base	7,376,184,384	-	7,376,184,384
23	Rate of Return	7.77%		8.15%
23	Return on Equity	9.52%		10.25%

*No rate case is proposed in this proceeding. The analysis of the hypothetical rate increase is calculated to show the size of the revenue shortfall under this proposal.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
TOTAL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CAPITAL
1	WAGES, BENEFITS & PAYROLL TAXES		24,175,897		1,708,189	(1,294,204)	(8,606,459)							3,021,987
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,520,312)		(497,347)	350,883	2,333,372							(815,039)
3	ANNUALIZE HEALTH CARE		(619,011)			30,951	205,821							(77,376)
4	REMOVE EMPLOYEE CLUBS			(135,839)		6,792	45,166	(5,558,780)	(2,153,741)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	NEW NUCLEAR ADJUSTMENTS	(118,000,000)		166,509,178	(524,864)	(14,199,216)	(111,714,784)	315,499,877	7,887,497	(4,835,683,443)	(125,302,713)	279,717,059	1,953,568,934	6,622,772
7	CWIP							4,834		(4,834)				
8	ANNUALIZE DEPRECIATION WITH CURRENT RATES			2,670,761		(133,538)	(888,028)		2,820,105					
9	ADJUST PROPERTY TAXES				4,848,850	(242,443)	(1,612,242)							
10	ANNUALIZE INSURANCE EXPENSE		(508,340)			25,417	169,023							(63,543)
11	OPEB		(31,504)			1,575	10,475						19,454	(3,938)
12	TAX EFFECT OF ANNUALIZED INTEREST					3,746,657	24,915,269							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	APPLY REFUND FROM REGULATORY LIABILITY	138,000,000			613,824	6,869,309	45,680,903					167,152,500	(437,000,000)	
15	FOSSIL FUEL INVENTORY										14,880,195			
	TOTAL	(16,307,817)	4,840,606	169,044,100	5,987,155	(6,062,327)	(57,604,474)	309,945,931	8,553,861	(4,835,688,277)	(110,422,518)	446,869,559	1,516,588,388	7,227,847

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
RETAIL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CAPITAL
1	WAGES, BENEFITS & PAYROLL TAXES		23,523,148		1,662,068	(1,259,261)	(8,374,084)							2,940,394
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,344,264)		(483,919)	341,409	2,270,371							(793,033)
3	ANNUALIZE HEALTH CARE		(602,298)			30,115	200,264							(75,287)
4	REMOVE EMPLOYEE CLUBS			(132,734)		6,637	44,134	(5,443,183)	(2,104,517)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	REMOVE NEW NUCLEAR AMOUNTS	(118,000,000)		166,509,178	(524,864)	(14,199,216)	(111,714,784)	304,977,956	7,624,449	(4,835,683,443)	(120,202,893)	279,717,059	1,953,568,934	6,622,772
7	CWIP							4,719		(4,719)				
8	ANNUALIZE DEPRECIATION WITH CURRENT RATES			2,623,440		(131,172)	(872,294)		2,769,371					
9	ADJUST PROPERTY TAXES				4,748,016	(237,401)	(1,578,715)							
10	ANNUALIZE INSURANCE EXPENSE		(497,769)			24,888	165,508							(62,221)
11	OPEB		(30,653)			1,533	10,192						18,928	(3,832)
12	TAX EFFECT OF ANNUALIZED INTEREST					3,754,649	24,968,418							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	APPLY REFUND FROM REGULATORY LIABILITY	138,000,000			613,824	6,869,309	45,680,903					167,152,500	(437,000,000)	
15	FOSSIL FUEL INVENTORY										14,274,571			
	TOTAL	(16,307,817)	4,392,040	168,999,884	5,853,628	(6,023,020)	(57,343,077)	299,539,492	8,289,303	(4,835,688,162)	(105,928,322)	446,869,559	1,516,587,862	7,171,777

New Nuclear items associated with the abandonment are assumed to be 100% retail electric.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF PROPOSED INCREASE
RETAIL ELECTRIC OPERATIONS
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Requested ($000's)
	(Col. 1)	(Col. 2)
1	Jurisdictional Rate Base	7,376,184,384
2	Required Rate of Return	8.15%
3	Required Return	601,159,027
4	Actual Return Earned	573,387,546
5	Required Increase to Return	27,771,481
6	Factor to Remove Customer Growth	1.004730
7	Additional Return Required from Revenue Increase	27,640,737
8	Composite Tax Factor	0.61475
9	Required Revenue Increase	44,962,565
10	Proposed Revenue Increase	44,962,565
	Additional Expenses	
11	Gross Receipts Tax @ .004448	199,993
12	State Income Tax @ 5%	2,238,129
13	Federal Income Tax @ 35%	14,883,555
14	Total Taxes	17,321,677
15	Additional Return	27,640,888
16	Additional Customer Growth	130,697
17	Total Additional Return	27,771,585
18	Earned Return	573,387,546
19	Total Return as Adjusted	601,159,131
20	Rate Base	7,376,184,384
21	Rate of Return	8.15%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF FIXED ASSETS - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Gross Plant in Service				
1	Intangible Plant	74,699,960	104	74,700,065	73,146,647
2	Production	4,658,637,485	-	4,658,637,485	4,510,958,676
3	Transmission	1,323,838,257	315,501,004	1,639,339,261	1,584,667,296
4	Distribution	3,259,344,267	(15)	3,259,344,252	3,258,985,723
5	General	202,819,781	-	202,819,781	198,602,063
6	Common (1)	328,422,841	(5,555,162)	322,867,679	316,153,516
7	Total Gross Plant in Service	9,847,762,591	309,945,931	10,157,708,522	9,942,513,922
	Construction Work in Progress				
8	Production	4,588,062,052	(4,835,683,443)	(247,621,391)	(393,062,959)
9	Transmission	363,391,847	(1,127)	363,390,720	351,271,640
10	Distribution	16,649,128	15	16,649,144	16,647,312
11	General	36,279,624	-	36,279,624	35,525,175
12	Intangible	38,314,863	(104)	38,314,759	37,517,988
13	Common (1)	1,498,187	(3,618)	1,494,569	1,463,489
14	Total Construction Work in Progress	5,044,195,701	(4,835,688,277)	208,507,424	49,362,645

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF DEPRECIATION RESERVES - ELECTRIC
AT SEPTEMBER 30, 2017

Line No.	Description	($000's) Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Production	2,187,904,354	543,004	2,188,447,358	2,119,073,577
2	Transmission	363,297,903	9,271,956	372,569,859	360,162,889
3	Distribution	1,017,664,277	1,450,131	1,019,114,408	1,019,002,305
4	General & Intangible Plant	151,843,680	(258,411)	151,585,269	148,120,792
5	Common (1)	144,947,742	(2,452,819)	142,494,923	139,238,206
6	Total	3,865,657,956	8,553,861	3,874,211,817	3,785,597,769

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
MATERIALS AND SUPPLIES - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Fuel Stock				
1	Nuclear	258,391,568	(125,302,713)	133,088,855	127,672,138
2	Fossil	43,119,770	14,880,195	57,999,965	55,639,366
3	Total Fuel Stock	301,511,338	(110,422,518)	191,088,820	183,311,504
4	Emission Allowances	638,559	-	638,559	612,570
5	Other Electric Materials and Supplies	135,154,798	-	135,154,798	132,344,200
6	Total	437,304,695	(110,422,518)	326,882,177	316,268,274

DEFERRED DEBITS / CREDITS - ELECTRIC
AT SEPTEMBER 30, 2017

7	Environmental	(370,500)	-	(370,500)	(360,119)
8	Wateree Scrubber Deferral	15,041,992	-	15,041,992	14,565,160
9	FASB 106	(104,231,832)	19,454	(104,212,378)	(101,398,645)
10	Pension Deferral	32,857,618	-	32,857,618	31,970,463
11	Canadys Retirement	66,910,211	-	66,910,211	64,789,157
12	Customer Rate Refund		(437,000,000)	(437,000,000)	(437,000,000)
13	New Nuclear Abandonment	-	1,953,568,934	1,953,568,934	1,953,568,934
14	Total	10,207,489	1,516,588,388	1,526,795,877	1,526,134,951

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WORKING CAPITAL INVESTMENT - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Working Cash	118,264,371	605,075	118,869,446	121,789,707
2	Prepayments	84,883,295	-	84,883,295	84,561,428
3	Total Investor Advanced Funds	203,147,666	605,075	203,752,741	206,351,135
4	Less: Customer Deposits	(54,354,631)	-	(54,354,631)	(54,354,631)
5	Average Tax Accruals	(118,015,305)	6,622,772	(111,392,533)	(117,253,805)
6	Nuclear Refueling	(1,760,363)	-	(1,760,363)	(1,688,716)
7	Injuries and Damages	(8,586,287)	-	(8,586,287)	(8,407,732)
8	Total Working Capital	20,431,080	7,227,847	27,658,927	24,646,251

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WEIGHTED COST OF CAPITAL
RETAIL ELECTRIC OPERATIONS
AT SEPTEMBER 30, 2017

Regulatory Capitalization for Electric Operations as of September 30, 2017

			As Adjusted		After Proposed Increase	
Description (Col. 1)	Pro Forma Amount (Col. 2) $	Pro Forma Ratio (Col. 3) %	Pro Forma Embedded Cost/Rate (Col. 4) %	Overall Cost/Rate (Col. 5) %	Pro Forma Embedded Cost/Rate (Col. 6) %	Overall Cost/Rate (Col. 7) %
Long Term Debt	4,928,770,000	47.82%	5.86%	2.80%	5.86%	2.80%
Preferred Stock	100,000	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	5,377,832,362	52.18%	**9.52%**	4.97%	**10.25%**	5.35%
Total	10,306,702,362	100.00%		7.77%		8.15%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - TOTAL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments	Total As Adjusted
		($000's)		
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,626,725,028	(126,307,817)	2,500,417,211
2	Operating Expenses			
3	O&M Expenses - Fuel	649,424,435	-	649,424,435
4	O&M Expenses - Other	598,179,439	4,840,606	603,020,045
5	Depreciation & Amortization Expenses	274,006,765	65,447,979	339,454,744
6	Taxes Other Than Income	210,682,693	5,497,875	216,180,568
7	Total Income Taxes	194,685,466	(56,038,588)	138,646,878
8	Total Operating Expenses	1,926,978,798	19,747,872	1,946,726,670
9	Operating Return	699,746,230	(146,055,689)	553,690,541
10	Customer Growth	3,433,501	(711,439)	2,722,062
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	702,065,665	(146,767,128)	555,298,537
13	Rate Base			
14	Plant in Service	9,847,762,591	394,812,732	10,242,575,323
15	Reserve for Depreciation	3,865,657,956	10,539,769	3,876,197,725
16	Net Plant	5,982,104,635	384,272,963	6,366,377,598
17	Construction Work in Progress	5,044,195,701	(4,835,688,277)	208,507,424
18	Deferred Debits / Credits	10,207,489	1,903,611,263	1,913,818,752
19	Total Working Capital	20,431,080	7,227,847	27,658,927
20	Materials & Supplies	437,304,695	(110,422,518)	326,882,177
21	Accumulated Deferred Income Taxes	(1,168,308,900)	279,717,059	(888,591,841)
22	Total Rate Base	10,325,934,700	(2,371,281,663)	7,954,653,037
23	Rate of Return	6.80%		6.98%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)		
Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments	Total As Adjusted
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,573,825,310	(126,307,817)	2,447,517,493
2	Operating Expenses			
3	O&M Expenses - Fuel	623,287,164	-	623,287,164
4	O&M Expenses - Other	583,711,611	4,392,040	588,103,651
5	Depreciation & Amortization Expenses	267,744,349	65,403,763	333,148,112
6	Taxes Other Than Income	206,069,444	5,364,348	211,433,792
7	Total Income Taxes	189,028,533	(55,598,866)	133,429,667
8	Total Operating Expenses	1,869,841,101	19,561,285	1,889,402,386
9	Operating Return	703,984,209	(145,869,102)	558,115,107
10	Customer Growth	3,433,501	(711,439)	2,722,062
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	706,303,644	(146,580,541)	559,723,103
13	Rate Base			
14	Plant in Service	9,642,974,430	381,575,985	10,024,550,415
15	Reserve for Depreciation	3,777,308,466	10,208,981	3,787,517,447
16	Net Plant	5,865,665,964	371,367,004	6,237,032,968
17	Construction Work in Progress	4,885,050,807	(4,835,688,162)	49,362,645
18	Deferred Debits / Credits	9,547,089	1,903,610,737	1,913,157,826
19	Total Working Capital	17,480,148	7,171,777	24,651,925
20	Materials & Supplies	422,196,596	(105,928,322)	316,268,274
21	Accumulated Deferred Income Taxes	(1,144,013,449)	279,717,059	(864,296,390)
22	Total Rate Base	10,055,927,155	(2,379,749,907)	7,676,177,248
23	Rate of Return	7.02%		7.29%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)		
Line No.	Description	Retail As Adjusted	Hypothetical Increase*	Total After Hypothetical Increase
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,447,517,493	94,227,968	2,541,745,461
2	Operating Expenses			
3	O&M Expenses - Fuel	623,287,164		623,287,164
4	O&M Expenses - Other	588,103,651		588,103,651
5	Depreciation & Amortization Expenses	333,148,112		333,148,112
6	Taxes Other Than Income	211,433,792	419,126	211,852,918
7	Total Income Taxes	133,429,667	35,881,882	169,311,549
8	Total Operating Expenses	1,889,402,386	36,301,008	1,925,703,394
9	Operating Return	558,115,107	57,926,960	616,042,067
10	Customer Growth	2,722,062	282,476	3,004,538
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	559,723,103	58,209,436	617,932,539
13	Rate Base			
14	Plant in Service	10,024,550,415	-	10,024,550,415
15	Reserve for Depreciation	3,787,517,447	-	3,787,517,447
16	Net Plant	6,237,032,968	-	6,237,032,968
17	Construction Work in Progress	49,362,645	-	49,362,645
18	Deferred Debits / Credits	1,913,157,826	-	1,913,157,826
19	Total Working Capital	24,651,925	-	24,651,925
20	Materials & Supplies	316,268,274	-	316,268,274
21	Accumulated Deferred Income Taxes	(864,296,390)	-	(864,296,390)
22	Total Rate Base	7,676,177,248	-	7,676,177,248
23	Rate of Return	7.29%		8.05%
23	Return on Equity	8.73%		10.25%

*No rate case is proposed in this proceeding. The analysis of the hypothetical rate increase is calculated to show the size of the revenue shortfall under this proposal.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
TOTAL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CAPITAL
1	WAGES, BENEFITS & PAYROLL TAXES		24,175,897		1,708,189	(1,294,204)	(8,606,459)							3,021,987
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,520,312)		(497,347)	350,883	2,333,372							(815,039)
3	ANNUALIZE HEALTH CARE		(619,011)			30,951	205,821							(77,376)
4	REMOVE EMPLOYEE CLUBS			(135,839)		6,792	45,166	(5,558,780)	(2,153,741)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	NEW NUCLEAR ADJUSTMENTS	(90,000,000)		62,913,057	(400,320)	(7,625,637)	(50,710,485)	400,366,678	9,873,405	(4,835,683,443)	(125,302,713)	279,717,059	1,903,591,809	6,622,772
7	CWIP							4,834		(4,834)				
8	ANNUALIZE DEPRECIATION WITH CURRENT RATES			2,670,761		(133,538)	(888,028)		2,820,105					
9	ADJUST PROPERTY TAXES				4,848,850	(242,443)	(1,612,242)							
10	ANNUALIZE INSURANCE EXPENSE		(508,340)			25,417	169,023							(63,543)
11	OPEB		(31,504)			1,575	10,475						19,454	(3,938)
12	TAX EFFECT OF ANNUALIZED INTEREST					2,779,408	18,483,065							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	FOSSIL FUEL INVENTORY										14,880,195			
	TOTAL	(126,307,817)	4,840,606	65,447,979	5,497,875	(7,325,306)	(48,713,282)	394,812,732	10,539,769	(4,835,688,277)	(110,422,518)	279,717,059	1,903,611,263	7,227,847

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
RETAIL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CAPITAL
1	WAGES, BENEFITS & PAYROLL TAXES		23,523,148		1,662,068	(1,259,261)	(8,374,084)							2,940,394
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,344,264)		(483,919)	341,409	2,270,371							(793,033)
3	ANNUALIZE HEALTH CARE		(602,298)			30,115	200,264							(75,287)
4	REMOVE EMPLOYEE CLUBS			(132,734)		6,637	44,134	(5,443,183)	(2,104,517)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	NEW NUCLEAR ADJUSTMENTS	(90,000,000)		62,913,057	(400,320)	(7,625,637)	(50,710,485)	387,014,449	9,544,127	(4,835,683,443)	(120,202,893)	279,717,059	1,903,591,809	6,622,772
7	CWIP							4,719		(4,719)				
8	ANNUALIZE DEPRECIATION WITH CURRENT RATES			2,623,440		(131,172)	(872,294)		2,769,371					
9	ADJUST PROPERTY TAXES				4,748,016	(237,401)	(1,578,715)							
10	ANNUALIZE INSURANCE EXPENSE		(497,769)			24,888	165,508							(62,221)
11	OPEB		(30,653)			1,533	10,192						18,928	(3,832)
12	TAX EFFECT OF ANNUALIZED INTEREST					2,805,573	18,657,059							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	FOSSIL FUEL INVENTORY										14,274,571			
	TOTAL	(126,307,817)	4,392,040	65,403,763	5,364,348	(7,267,826)	(48,331,040)	381,575,985	10,208,981	(4,835,688,162)	(105,928,322)	279,717,059	1,903,610,737	7,171,777

New Nuclear items associated with the abandonment are assumed to be 100% retail electric.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF PROPOSED INCREASE
RETAIL ELECTRIC OPERATIONS
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Requested ($000's)
	(Col. 1)	(Col. 2)
1	Jurisdictional Rate Base	7,676,177,248
2	Required Rate of Return	8.05%
3	Required Return	617,932,268
4	Actual Return Earned	559,723,103
5	Required Increase to Return	58,209,165
6	Factor to Remove Customer Growth	1.004877
7	Additional Return Required from Revenue Increase	57,926,643
8	Composite Tax Factor	0.61475
9	Required Revenue Increase	94,227,968
10	Proposed Revenue Increase	94,227,968
	Additional Expenses	
11	Gross Receipts Tax @ .004448	419,126
12	State Income Tax @ 5%	4,690,442
13	Federal Income Tax @ 35%	31,191,440
14	Total Taxes	36,301,008
15	Additional Return	57,926,960
16	Additional Customer Growth	282,476
17	Total Additional Return	58,209,436
18	Earned Return	559,723,103
19	Total Return as Adjusted	617,932,539
20	Rate Base	7,676,177,248
21	Rate of Return	8.05%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF FIXED ASSETS - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Gross Plant in Service				
1	Intangible Plant	74,699,960	104	74,700,065	73,146,648
2	Production	4,658,637,485	-	4,658,637,485	4,510,958,676
3	Transmission	1,323,838,257	400,367,805	1,724,206,062	1,666,703,789
4	Distribution	3,259,344,267	(15)	3,259,344,252	3,258,985,723
5	General	202,819,781	-	202,819,781	198,602,063
6	Common (1)	328,422,841	(5,555,162)	322,867,679	316,153,516
7	Total Gross Plant in Service	9,847,762,591	394,812,732	10,242,575,323	10,024,550,415
	Construction Work in Progress				
8	Production	4,588,062,052	(4,835,683,443)	(247,621,391)	(393,062,959)
9	Transmission	363,391,847	(1,127)	363,390,720	351,271,640
10	Distribution	16,649,128	15	16,649,143	16,647,312
11	General	36,279,624	-	36,279,624	35,525,175
12	Intangible	38,314,863	(104)	38,314,759	37,517,988
13	Common (1)	1,498,187	(3,618)	1,494,569	1,463,489
14	Total Construction Work in Progress	5,044,195,701	(4,835,688,277)	208,507,424	49,362,645

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF DEPRECIATION RESERVES - ELECTRIC
AT SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books	Adjustments ($000's)	As Adjusted ($000's)	Allocated to Retail ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Production	2,187,904,354	543,004	2,188,447,358	2,119,073,577
2	Transmission	363,297,903	11,257,864	374,555,767	362,082,567
3	Distribution	1,017,664,277	1,450,131	1,019,114,408	1,019,002,305
4	General & Intangible Plant	151,843,680	(258,411)	151,585,269	148,120,792
5	Common (1)	144,947,742	(2,452,819)	142,494,923	139,238,206
6	Total	3,865,657,956	10,539,769	3,876,197,725	3,787,517,447

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
MATERIALS AND SUPPLIES - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Fuel Stock				
1	Nuclear	258,391,568	(125,302,713)	133,088,855	127,672,138
2	Fossil	43,119,770	14,880,195	57,999,965	55,639,366
3	Total Fuel Stock	301,511,338	(110,422,518)	191,088,820	183,311,504
4	Emission Allowances	638,559	-	638,559	612,570
5	Other Electric Materials and Supplies	135,154,798	-	135,154,798	132,344,200
6	Total	437,304,695	(110,422,518)	326,882,177	316,268,274

DEFERRED DEBITS / CREDITS - ELECTRIC
AT SEPTEMBER 30, 2017

7	Environmental	(370,500)	-	(370,500)	(360,119)
8	Wateree Scrubber Deferral	15,041,992	-	15,041,992	14,565,160
9	FASB 106	(104,231,832)	19,454	(104,212,378)	(101,398,645)
10	Pension Deferral	32,857,618	-	32,857,618	31,970,463
11	Canadys Retirement	66,910,211	-	66,910,211	64,789,157
12	New Nuclear Abandonment	-	1,903,591,809	1,903,591,809	1,903,591,809
13	Total	10,207,489	1,903,611,263	1,913,818,752	1,913,157,826

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WORKING CAPITAL INVESTMENT - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Working Cash	118,264,371	605,075	118,869,446	115,166,935
2	Prepayments	84,883,295	-	84,883,295	84,561,428
3	Total Investor Advanced Funds	203,147,666	605,075	203,752,741	199,728,363
4	Less: Customer Deposits	(54,354,631)	-	(54,354,631)	(54,354,631)
5	Average Tax Accruals	(118,015,305)	6,622,772	(111,392,533)	(110,625,359)
6	Nuclear Refueling	(1,760,363)	-	(1,760,363)	(1,688,716)
7	Injuries and Damages	(8,586,287)	-	(8,586,287)	(8,407,732)
8	Total Working Capital	20,431,080	7,227,847	27,658,927	24,651,925

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WEIGHTED COST OF CAPITAL
RETAIL ELECTRIC OPERATIONS
AT SEPTEMBER 30, 2017

Regulatory Capitalization for Electric Operations as of September 30, 2017

			As Adjusted		After Proposed Increase	
Description (Col. 1)	Pro Forma Amount (Col. 2) $	Pro Forma Ratio (Col. 3) %	Pro Forma Embedded Cost/Rate (Col. 4) %	Overall Cost/Rate (Col. 5) %	Pro Forma Embedded Cost/Rate (Col. 6) %	Overall Cost/Rate (Col. 7) %
Long Term Debt	4,928,770,000	50.15%	5.86%	2.94%	5.86%	2.94%
Preferred Stock	100,000	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	4,898,363,995	49.85%	**8.73%**	4.35%	**10.25%**	5.11%
Total	9,827,233,995	100.00%		7.29%		8.05%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - TOTAL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)		
Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments	Total As Adjusted
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,626,725,028	(36,307,817)	2,590,417,211
2	Operating Expenses			
3	O&M Expenses - Fuel	649,424,435	-	649,424,435
4	O&M Expenses - Other	598,179,439	4,840,606	603,020,045
5	Depreciation & Amortization Expenses	274,006,765	83,303,570	357,310,335
6	Taxes Other Than Income	210,682,693	5,898,195	216,580,888
7	Total Income Taxes	194,685,466	(26,529,235)	168,156,231
8	Total Operating Expenses	1,926,978,798	67,513,136	1,994,491,934
9	Operating Return	699,746,230	(103,820,953)	595,925,277
10	Customer Growth	3,401,421	(500,065)	2,901,356
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	702,033,585	(104,321,018)	597,712,567
13	Rate Base			
14	Plant in Service	9,847,762,591	394,812,732	10,242,575,323
15	Reserve for Depreciation	3,865,657,956	10,539,769	3,876,197,725
16	Net Plant	5,982,104,635	384,272,963	6,366,377,598
17	Construction Work in Progress	5,044,195,701	(4,835,688,277)	208,507,424
18	Deferred Debits / Credits	10,207,489	2,200,134,763	2,210,342,252
19	Total Working Capital	20,431,080	7,227,847	27,658,927
20	Materials & Supplies	437,304,695	(110,422,518)	326,882,177
21	Accumulated Deferred Income Taxes	(1,168,308,900)	279,717,059	(888,591,841)
22	Total Rate Base	10,325,934,700	(2,074,758,163)	8,251,176,537
23	Rate of Return	6.80%		7.24%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)		
Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments	Total As Adjusted
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,573,825,310	(36,307,817)	2,537,517,493
2	Operating Expenses			
3	O&M Expenses - Fuel	623,287,164	-	623,287,164
4	O&M Expenses - Other	583,711,611	4,392,040	588,103,651
5	Depreciation & Amortization Expenses	267,744,349	83,259,354	351,003,703
6	Taxes Other Than Income	206,069,444	5,764,668	211,834,112
7	Total Income Taxes	189,028,533	(26,226,603)	162,801,930
8	Total Operating Expenses	1,869,841,101	67,189,459	1,937,030,560
9	Operating Return	703,984,209	(103,497,276)	600,486,933
10	Customer Growth	3,401,421	(500,065)	2,901,356
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	706,271,564	(103,997,341)	602,274,223
13	Rate Base			
14	Plant in Service	9,642,974,430	381,575,985	10,024,550,415
15	Reserve for Depreciation	3,777,308,466	10,208,981	3,787,517,447
16	Net Plant	5,865,665,964	371,367,004	6,237,032,968
17	Construction Work in Progress	4,885,050,807	(4,835,688,162)	49,362,645
18	Deferred Debits / Credits	9,547,089	2,200,134,237	2,209,681,326
19	Total Working Capital	17,473,050	7,171,777	24,644,827
20	Materials & Supplies	422,196,596	(105,928,322)	316,268,274
21	Accumulated Deferred Income Taxes	(1,144,013,449)	279,717,059	(864,296,390)
22	Total Rate Base	10,055,920,057	(2,083,226,407)	7,972,693,650
23	Rate of Return	7.02%		7.55%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

($000's)

Line No.	Description	Retail As Adjusted	Hypothetical Increase*	Total After Hypothetical Increase
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,537,517,493	80,768,140	2,618,285,633
2	Operating Expenses			
3	O&M Expenses - Fuel	623,287,164		623,287,164
4	O&M Expenses - Other	588,103,651		588,103,651
5	Depreciation & Amortization Expenses	351,003,703		351,003,703
6	Taxes Other Than Income	211,834,112	359,257	212,193,369
7	Total Income Taxes	162,801,930	30,756,398	193,558,328
8	Total Operating Expenses	1,937,030,560	31,115,655	1,968,146,215
9	Operating Return	600,486,933	49,652,485	650,139,419
10	Customer Growth	2,901,356	239,857	3,141,213
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	602,274,223	49,892,342	652,166,565
13	Rate Base			
14	Plant in Service	10,024,550,415	-	10,024,550,415
15	Reserve for Depreciation	3,787,517,447	-	3,787,517,447
16	Net Plant	6,237,032,968	-	6,237,032,968
17	Construction Work in Progress	49,362,645	-	49,362,645
18	Deferred Debits / Credits	2,209,681,326	-	2,209,681,326
19	Total Working Capital	24,644,827	-	24,644,827
20	Materials & Supplies	316,268,274	-	316,268,274
21	Accumulated Deferred Income Taxes	(864,296,390)	-	(864,296,390)
22	Total Rate Base	7,972,693,650	-	7,972,693,650
23	Rate of Return	7.55%		8.18%
23	Return on Equity	9.06%		10.25%

*No rate increase is proposed in this proceeding. The analysis of the hypothetical rate increase is calculated to show the size of the revenue shortfall under this proposal.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
TOTAL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CAPITAL
1	WAGES, BENEFITS & PAYROLL TAXES		24,175,897		1,708,189	(1,294,204)	(8,606,459)							3,021,987
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,520,312)		(497,347)	350,883	2,333,372							(815,039)
3	ANNUALIZE HEALTH CARE		(619,011)			30,951	205,821							(77,376)
4	REMOVE EMPLOYEE CLUBS			(135,839)		6,792	45,166	(5,558,780)	(2,153,741)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	NEW NUCLEAR ADJUSTMENTS			72,713,057	-	(3,635,653)	(24,177,091)	400,366,678	9,873,405	(4,835,683,443)	(125,302,713)	279,717,059	2,200,115,309	6,622,772
7	CWIP							4,834		(4,834)				
8	ANNUALIZE DEPRECIATION WITH CURRENT RATES			2,670,761		(133,538)	(888,028)		2,820,105					
9	ADJUST PROPERTY TAXES				4,848,850	(242,443)	(1,612,242)							
10	ANNUALIZE INSURANCE EXPENSE		(508,340)			25,417	169,023							(63,543)
11	OPEB		(31,504)			1,575	10,475						19,454	(3,938)
12	TAX EFFECT OF ANNUALIZED INTEREST					3,049,635	20,280,077							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	AMORTIZE SWAP LOSS DEFERRAL			3,479,346		(173,967)	(1,156,883)							
15	AMORTIZE ADIT CAPITALIZED INTEREST COSTS			4,576,245		(228,812)	(1,521,602)							
16	FOSSIL FUEL INVENTORY										14,880,195			
	TOTAL	(36,307,817)	4,840,606	83,303,570	5,898,195	(3,467,874)	(23,061,361)	394,812,732	10,539,769	(4,835,688,277)	(110,422,518)	279,717,059	2,200,134,763	7,227,847

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
RETAIL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CAPITAL
1	WAGES, BENEFITS & PAYROLL TAXES		23,523,148		1,662,068	(1,259,261)	(8,374,084)							2,940,394
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,344,264)		(483,919)	341,409	2,270,371							(793,033)
3	ANNUALIZE HEALTH CARE		(602,298)			30,115	200,264							(75,287)
4	REMOVE EMPLOYEE CLUBS			(132,734)		6,637	44,134	(5,443,183)	(2,104,517)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	NEW NUCLEAR ADJUSTMENTS			72,713,057	-	(3,635,653)	(24,177,091)	387,014,449	9,544,127	(4,835,683,443)	(120,202,893)	279,717,059	2,200,115,309	6,622,772
7	CWIP							4,719		(4,719)				
8	ANNUALIZE DEPRECIATION WITH CURRENT RATES			2,623,440		(131,172)	(872,294)		2,769,371					
9	ADJUST PROPERTY TAXES				4,748,016	(237,401)	(1,578,715)							
10	ANNUALIZE INSURANCE EXPENSE		(497,769)			24,888	165,508							(62,221)
11	OPEB		(30,653)			1,533	10,192						18,928	(3,832)
12	TAX EFFECT OF ANNUALIZED INTEREST					3,057,880	20,334,901							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	AMORTIZE SWAP LOSS DEFERRAL			3,479,346		(173,967)	(1,156,883)							
15	AMORTIZE ADIT CAPITALIZED INTEREST COSTS			4,576,245		(228,812)	(1,521,602)							
16	FOSSIL FUEL INVENTORY										14,274,571			
	TOTAL	(36,307,817)	4,392,040	83,259,354	5,764,668	(3,428,314)	(22,798,289)	381,575,985	10,208,981	(4,835,688,162)	(105,928,322)	279,717,059	2,200,134,237	7,171,777

New Nuclear items associated with the abandonment are assumed to be 100% retail electric.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF PROPOSED INCREASE
RETAIL ELECTRIC OPERATIONS
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Requested ($000's)
	(Col. 1)	(Col. 2)
1	Jurisdictional Rate Base	7,972,693,650
2	Required Rate of Return	8.18%
3	Required Return	652,166,341
4	Actual Return Earned	602,274,223
5	Required Increase to Return	49,892,118
6	Factor to Remove Customer Growth	1.004832
7	Additional Return Required from Revenue Increase	49,652,214
8	Composite Tax Factor	0.61475
9	Required Revenue Increase	80,768,140
10	Proposed Revenue Increase	80,768,140
	Additional Expenses	
11	Gross Receipts Tax @ .004448	359,257
12	State Income Tax @ 5%	4,020,444
13	Federal Income Tax @ 35%	26,735,954
14	Total Taxes	31,115,655
15	Additional Return	49,652,486
16	Additional Customer Growth	239,857
17	Total Additional Return	49,892,342
18	Earned Return	602,274,223
19	Total Return as Adjusted	652,166,565
20	Rate Base	7,972,693,650
21	Rate of Return	8.18%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF FIXED ASSETS - ELECTRIC
AT SEPTEMBER 30, 2017

Line No.	Description	($000's) Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Gross Plant in Service				
1	Intangible Plant	74,699,960	104	74,700,065	73,146,648
2	Production	4,658,637,485	-	4,658,637,485	4,510,958,676
3	Transmission	1,323,838,257	400,367,805	1,724,206,062	1,666,703,789
4	Distribution	3,259,344,267	(15)	3,259,344,252	3,258,985,723
5	General	202,819,781	-	202,819,781	198,602,063
6	Common (1)	328,422,841	(5,555,162)	322,867,679	316,153,516
7	Total Gross Plant in Service	9,847,762,591	394,812,732	10,242,575,323	10,024,550,415
	Construction Work in Progress				
8	Production	4,588,062,052	(4,835,683,443)	(247,621,391)	(393,062,959)
9	Transmission	363,391,847	(1,127)	363,390,720	351,271,640
10	Distribution	16,649,128	15	16,649,143	16,647,312
11	General	36,279,624	-	36,279,624	35,525,175
12	Intangible	38,314,863	(104)	38,314,759	37,517,988
13	Common (1)	1,498,187	(3,618)	1,494,569	1,463,489
14	Total Construction Work in Progress	5,044,195,701	(4,835,688,277)	208,507,424	49,362,645

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF DEPRECIATION RESERVES - ELECTRIC
AT SEPTEMBER 30, 2017

			($000's)		
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Production	2,187,904,354	543,004	2,188,447,358	2,119,073,577
2	Transmission	363,297,903	11,257,864	374,555,767	362,082,567
3	Distribution	1,017,664,277	1,450,131	1,019,114,408	1,019,002,305
4	General & Intangible Plant	151,843,680	(258,411)	151,585,269	148,120,792
5	Common (1)	144,947,742	(2,452,819)	142,494,923	139,238,206
6	Total	3,865,657,956	10,539,769	3,876,197,725	3,787,517,447

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
MATERIALS AND SUPPLIES - ELECTRIC
AT SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books ($000's)	Adjustments ($000's)	As Adjusted ($000's)	Allocated to Retail ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Fuel Stock				
1	Nuclear	258,391,568	(125,302,713)	133,088,855	127,672,138
2	Fossil	43,119,770	14,880,195	57,999,965	55,639,366
3	Total Fuel Stock	301,511,338	(110,422,518)	191,088,820	183,311,504
4	Emission Allowances	638,559	-	638,559	612,570
5	Other Electric Materials and Supplies	135,154,798	-	135,154,798	132,344,200
6	Total	437,304,695	(110,422,518)	326,882,177	316,268,274

DEFERRED DEBITS / CREDITS - ELECTRIC
AT SEPTEMBER 30, 2017

Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
7	Environmental	(370,500)	-	(370,500)	(360,119)
8	Wateree Scrubber Deferral	15,041,992	-	15,041,992	14,565,160
9	FASB 106	(104,231,832)	19,454	(104,212,378)	(101,398,645)
10	Pension Deferral	32,857,618	-	32,857,618	31,970,463
11	Canadys Retirement	66,910,211	-	66,910,211	64,789,157
12	New Nuclear Abandonment	-	2,200,115,309	2,200,115,309	2,200,115,309
13	Total	10,207,489	2,200,134,763	2,210,342,252	2,209,681,326

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WORKING CAPITAL INVESTMENT - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Working Cash	118,264,371	605,075	118,869,446	121,789,707
2	Prepayments	84,883,295	-	84,883,295	84,561,428
3	Total Investor Advanced Funds	203,147,666	605,075	203,752,741	206,351,135
4	Less: Customer Deposits	(54,354,631)	-	(54,354,631)	(54,354,631)
5	Average Tax Accruals	(118,015,305)	6,622,772	(111,392,533)	(117,255,229)
6	Nuclear Refueling	(1,760,363)	-	(1,760,363)	(1,688,716)
7	Injuries and Damages	(8,586,287)	-	(8,586,287)	(8,407,732)
8	Total Working Capital	20,431,080	7,227,847	27,658,927	24,644,827

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WEIGHTED COST OF CAPITAL
RETAIL ELECTRIC OPERATIONS
AT SEPTEMBER 30, 2017

Regulatory Capitalization for Electric Operations as of September 30, 2017

			As Adjusted		After Proposed Increase	
Description (Col. 1)	Pro Forma Amount (Col. 2) $	Pro Forma Ratio (Col. 3) %	Pro Forma Embedded Cost/Rate (Col. 4) %	Overall Cost/Rate (Col. 5) %	Pro Forma Embedded Cost/Rate (Col. 6) %	Overall Cost/Rate (Col. 7) %
Long Term Debt	4,928,770,000	47.23%	5.86%	2.77%	5.86%	2.77%
Preferred Stock	100,000	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	5,507,507,362	52.77%	**9.06%**	4.78%	**10.25%**	5.41%
Total	10,436,377,362	100.00%		7.55%		8.18%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - TOTAL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)		
Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments	Total As Adjusted
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,626,725,028	(420,836,831)	2,205,888,197
2	Operating Expenses			
3	O&M Expenses - Fuel	649,424,435	-	649,424,435
4	O&M Expenses - Other	598,179,439	4,840,606	603,020,045
5	Depreciation & Amortization Expenses	274,006,765	2,534,922	276,541,687
6	Taxes Other Than Income	210,682,693	4,187,810	214,870,503
7	Total Income Taxes	194,685,466	(157,375,720)	37,309,746
8	Total Operating Expenses	1,926,978,798	(145,812,382)	1,781,166,416
9	Operating Return	699,746,230	(275,024,449)	424,721,781
10	Customer Growth	3,401,421	(1,325,825)	2,075,596
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	702,033,585	(276,350,274)	425,683,311
13	Rate Base			
14	Plant in Service	9,847,762,591	(5,553,946)	9,842,208,644
15	Reserve for Depreciation	3,865,657,956	666,364	3,866,324,320
16	Net Plant	5,982,104,635	(6,220,310)	5,975,884,324
17	Construction Work in Progress	5,044,195,701	209,995,166	5,254,190,867
18	Deferred Debits / Credits	10,207,489	19,454	10,226,943
19	Total Working Capital	20,431,080	605,075	21,036,155
20	Materials & Supplies	437,304,695	14,880,195	452,184,890
21	Accumulated Deferred Income Taxes	(1,168,308,900)	(847,614,600)	(2,015,923,500)
22	Total Rate Base	10,325,934,700	(628,335,020)	9,697,599,679
23	Rate of Return	6.80%		4.39%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

		($000's)		
Line No.	Description	Regulatory Per Books	Pro-Forma Adjustments	Total As Adjusted
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,573,825,310	(420,836,831)	2,152,988,479
2	Operating Expenses			
3	O&M Expenses - Fuel	623,287,164	-	623,287,164
4	O&M Expenses - Other	583,711,611	4,392,040	588,103,651
5	Depreciation & Amortization Expenses	267,744,349	2,490,706	270,235,055
6	Taxes Other Than Income	206,069,444	4,054,283	210,123,727
7	Total Income Taxes	189,028,533	(157,370,941)	31,657,592
8	Total Operating Expenses	1,869,841,101	(146,433,912)	1,723,407,189
9	Operating Return	703,984,209	(274,402,919)	429,581,290
10	Customer Growth	3,401,421	(1,325,825)	2,075,596
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	706,271,564	(275,728,744)	430,542,820
13	Rate Base			
14	Plant in Service	9,642,974,430	(5,438,464)	9,637,535,966
15	Reserve for Depreciation	3,777,308,466	664,854	3,777,973,320
16	Net Plant	5,865,665,964	(6,103,318)	5,859,562,646
17	Construction Work in Progress	4,885,050,807	203,338,281	5,088,389,088
18	Deferred Debits / Credits	9,547,089	18,928	9,566,017
19	Total Working Capital	17,473,050	549,005	18,022,055
20	Materials & Supplies	422,196,596	14,274,571	436,471,167
21	Accumulated Deferred Income Taxes	(1,144,013,449)	(820,745,217)	(1,964,758,666)
22	Total Rate Base	10,055,920,057	(608,667,750)	9,447,252,307
23	Rate of Return	7.02%		4.56%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED SEPTEMBER 30, 2017

			($000's)	
Line No.	Description	Retail As Adjusted	Hypothetical Increase*	Total After Hypothetical Increase
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,152,988,479	554,041,101	2,707,029,580
2	Operating Expenses			
3	O&M Expenses - Fuel	623,287,164		623,287,164
4	O&M Expenses - Other	588,103,651		588,103,651
5	Depreciation & Amortization Expenses	270,235,055		270,235,055
6	Taxes Other Than Income	210,123,727	2,464,375	212,588,102
7	Total Income Taxes	31,657,592	210,978,098	242,635,690
8	Total Operating Expenses	1,723,407,189	213,442,473	1,936,849,662
9	Operating Return	429,581,290	340,598,628	770,179,918
10	Customer Growth	2,075,596	1,645,613	3,721,209
11	Interest on Customer Deposits	(1,114,066)	-	(1,114,066)
12	Return	430,542,820	342,244,241	772,787,061
13	Rate Base			
14	Plant in Service	9,637,535,966	-	9,637,535,966
15	Reserve for Depreciation	3,777,973,320	-	3,777,973,320
16	Net Plant	5,859,562,646	-	5,859,562,646
17	Construction Work in Progress	5,088,389,088	-	5,088,389,088
18	Deferred Debits / Credits	9,566,017	-	9,566,017
19	Total Working Capital	18,022,055	-	18,022,055
20	Materials & Supplies	436,471,167	-	436,471,167
21	Accumulated Deferred Income Taxes	(1,964,758,666)	-	(1,964,758,666)
22	Total Rate Base	9,447,252,307	-	9,447,252,307
23	Rate of Return	4.56%		8.18%
23	Return on Equity	3.39%		10.25%

*No rate increase is proposed in this proceeding. The analysis of the hypothetical rate increase is calculated to show the size of the revenue shortfall under this proposal.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
TOTAL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CAPITAL
1	WAGES, BENEFITS & PAYROLL TAXES		24,175,897		1,708,189	(1,294,204)	(8,606,459)							3,021,987
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,520,312)		(497,347)	350,883	2,333,372							(815,039)
3	ANNUALIZE HEALTH CARE		(619,011)			30,951	205,821							(77,376)
4	REMOVE EMPLOYEE CLUBS			(135,839)		6,792	45,166	(5,558,780)	(2,153,741)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	NEW NUCLEAR ADJUSTMENTS	(384,529,014)		-	(1,710,385)	(19,140,931)	(127,287,194)	-	-	210,000,000		(847,614,600)	-	
7	CWIP							4,834		(4,834)				
8	ANNUALIZE DEPRECIATION WITH CURRENT RATES			2,670,761		(133,538)	(888,028)		2,820,105					
9	ADJUST PROPERTY TAXES				4,848,850	(242,443)	(1,612,242)							
10	ANNUALIZE INSURANCE EXPENSE		(508,340)			25,417	169,023							(63,543)
11	OPEB		(31,504)			1,575	10,475						19,454	(3,938)
12	TAX EFFECT OF ANNUALIZED INTEREST					1,048,019	6,969,325							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	FOSSIL FUEL INVENTORY										14,880,195			
	TOTAL	(420,836,831)	4,840,606	2,534,922	4,187,810	(20,571,989)	(136,803,731)	(5,553,946)	666,364	209,995,166	14,880,195	(847,614,600)	19,454	605,075

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
RETAIL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED SEPTEMBER 30, 2017

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	MATERIALS & SUPPLIES	ADIT	DEFERRED DBT/CRDT	WORKING CAPITAL
1	WAGES, BENEFITS & PAYROLL TAXES		23,523,148		1,662,068	(1,259,261)	(8,374,084)							2,940,394
2	INCENTIVE COMPENSATION ADJUSTMENT		(6,344,264)		(483,919)	341,409	2,270,371							(793,033)
3	ANNUALIZE HEALTH CARE		(602,298)			30,115	200,264							(75,287)
4	REMOVE EMPLOYEE CLUBS			(132,734)		6,637	44,134	(5,443,183)	(2,104,517)	-				-
5	PROPERTY RETIREMENTS							-	-					
6	NEW NUCLEAR ADJUSTMENTS	(384,529,014)		-	(1,710,385)	(19,140,931)	(127,287,194)	-	-	203,343,000		(820,745,217)	-	
7	CWIP							4,719		(4,719)				
8	ANNUALIZE DEPRECIATION WITH CURRENT RATES			2,623,440		(131,172)	(872,294)		2,769,371					
9	ADJUST PROPERTY TAXES				4,748,016	(237,401)	(1,578,715)							
10	ANNUALIZE INSURANCE EXPENSE		(497,769)			24,888	165,508							(62,221)
11	OPEB		(30,653)			1,533	10,192						18,928	(3,832)
12	TAX EFFECT OF ANNUALIZED INTEREST					1,017,328	6,765,232							
13	REMOVE AMOUNTS ASSOCIATED WITH DSM	(36,307,817)	(11,656,124)		(161,497)	(1,224,510)	(8,142,990)							(1,457,016)
14	FOSSIL FUEL INVENTORY										14,274,571			
	TOTAL	(420,836,831)	4,392,040	2,490,706	4,054,283	(20,571,365)	(136,799,576)	(5,438,464)	664,854	203,338,281	14,274,571	(820,745,217)	18,928	549,005

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF PROPOSED INCREASE
RETAIL ELECTRIC OPERATIONS
12 MONTHS ENDED SEPTEMBER 30, 2017

Line No.	Description	Requested ($000's)
	(Col. 1)	(Col. 2)
1	Jurisdictional Rate Base	9,447,252,307
2	Required Rate of Return	8.18%
3	Required Return	772,785,239
4	Actual Return Earned	430,542,820
5	Required Increase to Return	342,242,419
6	Factor to Remove Customer Growth	1.004832
7	Additional Return Required from Revenue Increase	340,596,767
8	Composite Tax Factor	0.61475
9	Required Revenue Increase	554,041,101
10	Proposed Revenue Increase	554,041,101
	Additional Expenses	
11	Gross Receipts Tax @ .004448	2,464,375
12	State Income Tax @ 5%	27,578,836
13	Federal Income Tax @ 35%	183,399,261
14	Total Taxes	213,442,473
15	Additional Return	340,598,628
16	Additional Customer Growth	1,645,613
17	Total Additional Return	342,244,241
18	Earned Return	430,542,820
19	Total Return as Adjusted	772,787,061
20	Rate Base	9,447,252,307
21	Rate of Return	8.18%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF FIXED ASSETS - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Gross Plant in Service				
1	Intangible Plant	74,699,960	104	74,700,064	73,146,647
2	Production	4,658,637,485	-	4,658,637,485	4,510,958,676
3	Transmission	1,323,838,257	1,127	1,323,839,384	1,279,689,340
4	Distribution	3,259,344,267	(15)	3,259,344,252	3,258,985,723
5	General	202,819,781	-	202,819,781	198,602,063
6	Common (1)	328,422,841	(5,555,162)	322,867,679	316,153,516
7	Total Gross Plant in Service	9,847,762,591	(5,553,946)	9,842,208,644	9,637,535,966
	Construction Work in Progress				
8	Production	4,588,062,052	210,000,000	4,798,062,052	4,645,963,484
9	Transmission	363,391,847	(1,127)	363,390,720	351,271,640
10	Distribution	16,649,128	15	16,649,143	16,647,312
11	General	36,279,624	-	36,279,624	35,525,175
12	Intangible	38,314,863	(104)	38,314,759	37,517,988
13	Common (1)	1,498,187	(3,618)	1,494,569	1,463,489
14	Total Construction Work in Progress	5,044,195,701	209,995,166	5,254,190,867	5,088,389,088

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF DEPRECIATION RESERVES - ELECTRIC
AT SEPTEMBER 30, 2017

			($000's)		
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Production	2,187,904,354	543,004	2,188,447,358	2,119,073,577
2	Transmission	363,297,903	1,384,459	364,682,362	352,538,440
3	Distribution	1,017,664,277	1,450,131	1,019,114,408	1,019,002,305
4	General & Intangible Plant	151,843,680	(258,411)	151,585,269	148,120,792
5	Common (1)	144,947,742	(2,452,819)	142,494,923	139,238,206
6	Total	3,865,657,956	666,364	3,866,324,320	3,777,973,320

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
MATERIALS AND SUPPLIES - ELECTRIC
AT SEPTEMBER 30, 2017

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Fuel Stock				
1	Nuclear	258,391,568	-	258,391,568	247,875,031
2	Fossil	43,119,770	14,880,195	57,999,965	55,639,366
3	Total Fuel Stock	301,511,338	14,880,195	316,391,533	303,514,397
4	Emission Allowances	638,559	-	638,559	612,570
5	Other Electric Materials and Supplies	135,154,798	-	135,154,798	132,344,200
6	Total	437,304,695	14,880,195	452,184,890	436,471,167

DEFERRED DEBITS / CREDITS - ELECTRIC
AT SEPTEMBER 30, 2017

7	Environmental	(370,500)	-	(370,500)	(360,119)
8	Wateree Scrubber Deferral	15,041,992	-	15,041,992	14,565,160
9	FASB 106	(104,231,832)	19,454	(104,212,378)	(101,398,645)
10	Pension Deferral	32,857,618	-	32,857,618	31,970,463
11	Canadys Retirement	66,910,211	-	66,910,211	64,789,157
12	New Nuclear Abandonment	-	-	-	-
13	Total	10,207,489	19,454	10,226,943	9,566,017

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WORKING CAPITAL INVESTMENT - ELECTRIC
AT SEPTEMBER 30, 2017

Line No.	Description		($000's) Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)		(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Working Cash		118,264,371	605,075	118,869,446	115,166,935
2	Prepayments		84,883,295	-	84,883,295	84,561,428
3	Total Investor Advanced Funds		203,147,666	605,075	203,752,741	199,728,363
4	Less:	Customer Deposits	(54,354,631)	-	(54,354,631)	(54,354,631)
5		Average Tax Accruals	(118,015,305)	-	(118,015,305)	(117,255,229)
6		Nuclear Refueling	(1,760,363)	-	(1,760,363)	(1,688,716)
7		Injuries and Damages	(8,586,287)	-	(8,586,287)	(8,407,732)
8	Total Working Capital		20,431,080	605,075	21,036,155	18,022,055

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WEIGHTED COST OF CAPITAL
RETAIL ELECTRIC OPERATIONS
AT SEPTEMBER 30, 2017

Regulatory Capitalization for Electric Operations as of September 30, 2017

			As Adjusted		After Proposed Increase	
Description (Col. 1)	Pro Forma Amount (Col. 2) $	Pro Forma Ratio (Col. 3) %	Pro Forma Embedded Cost/Rate (Col. 4) %	Overall Cost/Rate (Col. 5) %	Pro Forma Embedded Cost/Rate (Col. 6) %	Overall Cost/Rate (Col. 7) %
Long Term Debt	4,928,770,000	47.23%	5.86%	2.77%	5.86%	2.77%
Preferred Stock	100,000	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	5,507,507,362	52.77%	**3.39%**	1.79%	**10.25%**	5.41%
Total	10,436,377,362	100.00%		4.56%		8.18%