Commonwealth of Virginia

State Corporation Commission

Report to the Governor and Members of the General Assembly

Assessing the Rates and Terms and Conditions of Incumbent Electric Utilities in the Commonwealth Pursuant to the Seventh Enactment Clause of Chapter 933 (SB 1416) of the 2007 Acts of Assembly

November 1, 2012

MARK C. CHRISTIE
COMMISSIONER

JAMES C. DIMITRI
COMMISSIONER

JUDITH WILLIAMS JAGDMANN
COMMISSIONER

COMMONWEALTH OF VIRGINIA

JOEL H. PECK
CLERK OF THE COMMISSION
P.O. BOX 1197
RICHMOND, VIRGINIA 23218-1197

STATE CORPORATION COMMISSION

November 1, 2012

TO: The Honorable Robert F. McDonnell
Governor, Commonwealth of Virginia

Members of the General Assembly of Virginia

The State Corporation Commission, in consultation with the Office of the Attorney General, hereby transmits the report assessing the rates and terms and conditions of incumbent electric utilities in the Commonwealth as required by Chapter 933 of the 2007 Acts of Assembly. As always, we will provide additional information or assistance upon request.

Respectfully submitted,

Original signed by

Mark C. Christie
Chairman

Original signed by

James C. Dimitri
Commissioner

Original signed by

Judith Williams Jagdmann
Commissioner

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GLOSSARY OF TERMS

AEP............................American Electric Power
A&N...........................A&N Electric Cooperative
APCo..........................Appalachian Power Company
BARC.........................BARC Electric Cooperative
Biennial Review.........review of two successive 12-month test periods for each utility's rates, terms, and conditions
CBEC.........................Craig-Botetourt Electric Cooperative
CEC............................Community Electric Cooperative
CPCN.........................certificate of public convenience and necessity
CVEC.........................Central Virginia Electric Cooperative
Chapter 933................Chapter 933 of the 2007 Acts of Assembly
Commission ....State Corporation Commission
Consumer Counsel.....Division of Consumer Counsel, Office of the Attorney General
DSM...........................demand-side management
DVP............................Virginia Electric and Power Company d/b/a Dominion Virginia Power
Dominion ....Virginia Electric and Power Company d/b/a Dominion Virginia Power
Duke...........................Duke Energy Carolinas
E&R ....Environmental and Reliability
E-RAC........................environmental rate adjustment clause
EEI ....Edison Electric Institute
Entergy.......................Entergy Mississippi
FP&L..........................Florida Power & Light Company
FERC..........................Federal Energy Regulatory Commission
G-RAC ....generation rate adjustment clause
Going-in Review........2009 rate case for IOUs
IOU ....investor-owned electric utility
IRP ....integrated resource plan
kWh............................kilowatt-hour
MEC...........................Mecklenburg Electric Cooperative
MW ....megawatt
NNEC.........................Northern Neck Electric Cooperative
NOVEC......................Northern Virginia Electric Cooperative
ODEC.........................Old Dominion Electric Cooperative
PGEC ....Prince George Electric Cooperative
PJM ....PJM Interconnection, LLC
RAC ....rate adjustment clause
REC............................Rappahannock Electric Cooperative
ROE............................return on common equity
RPS ....renewable energy portfolio standard
SCC............................State Corporation Commission
SCE&G ....South Carolina Electric & Gas
SEC ....Southside Electric Cooperative
Staff............................Commission Staff
SVEC ....Shenandoah Valley Electric Cooperative
T-RAC........................transmission rate adjustment clause

EXECUTIVE SUMMARY

On April 4, 2007, the General Assembly of Virginia enacted Chapter 933 of the 2007 Acts of Assembly ("Chapter 933") which, among other things, directs the State Corporation Commission ("Commission"), in consultation with the Office of Attorney General, to conduct a five-year assessment of "the rates and terms and conditions of incumbent electric utilities in the Commonwealth" and "the amount, reliability and type of generation facilities" used to serve Virginia native load. The following report describes the various provisions of Chapter 933 that potentially could influence Virginia's electric utility rates and service reliability and relates those provisions to numerous Commission proceedings and decisions involving Dominion Virginia Power ("Dominion" or "DVP"), Appalachian Power Company ("APCo"), and the electric cooperatives.

Since the 2007 enactment of Chapter 933, DVP, APCo, and the electric cooperatives have requested numerous rate changes or have undergone extensive rate reviews pursuant to various provisions of the chapter. During this period, Dominion has been authorized net revenue increases totaling approximately $1.3 billion[1] and on an annual basis currently has pending requests that would produce additional increases of approximately $120.1 million. It should be noted that many of the cost drivers that contributed to this increase may have existed in the absence of Chapter 933, and the level of increases otherwise that would have occurred simply cannot be determined. Certain increases likely would have occurred under other regulatory paradigms. For example, the $1.3 billion increase includes fuel-related increases of $589.6 million, much of which would have occurred with the previously scheduled expiration of

[1] This increase reflects the level of ongoing increases that currently are reflected in rates and excludes temporary base rate credits and certain increases or decreases that may have been in effect during a portion of this five-year review period. For example, the current fuel factor and transmission-related charges were at times higher or lower during the review period than they currently are.

capped rates. The combined effect of the approved increases for Dominion has been to increase the monthly bill for a residential customer using 1,000 kilowatt-hours ("kWh") by $16.63, or approximately 18%, since July 1, 2007. The $16.63 increase is comprised of a fuel cost increase of $4.74, transmission cost-related increases totaling $4.25, new generation rate riders totaling $6.94, and demand-side management ("DSM") rate adjustments totaling $0.70. The incremental changes in rates occurring since July 1, 2007, currently reflected in Dominion's monthly bill for residential customers using 1,000 kWh, and the associated statutory provision through which each increment was authorized, are detailed in Appendix 2 to this report.

APCo also has requested and has received a number of rate increases since July 1, 2007. While APCo has been authorized revenue increases totaling approximately $627.7 million on an annual basis, portions of those increases were approved for limited periods of time and have since expired. As such, the level of net revenue increases now reflected in APCo's rates is approximately $481.2 million. The combined effect of these net increases has been to increase the monthly bill for a residential customer using 1,000 kWh by $45.98, or approximately 69%, since July 1, 2007. Incremental changes occurring since July 1, 2007, that are currently reflected in APCo's monthly bill for residential customers using 1,000 kWh, and the associated statutory provisions, are detailed in Appendix 3 to this report.

The Seventh Enactment Clause of Chapter 933 specifically requires that this assessment report "include an analysis of, among other matters, the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load." Dominion, APCo, and the electric cooperatives are either directly or indirectly, through purchased power arrangements, members of PJM Interconnection, LLC ("PJM").[2] PJM's

[2] PJM is the regional transmission entity that, among other things, controls transmission facilities owned by DVP and APCo.

primary mission is to ensure the safety, reliability, and security of the bulk electric power system located in a 13-state area that encompasses portions of the United States' Midwest, Southeast and Northeast regions. As such, PJM analyzes, forecasts, and plans for the future electricity needs of the region to assure that the bulk power grid is sufficient for delivering power from available generation resources to loads within the PJM region. PJM also imposes generating capacity obligations on its load serving members, including APCo, DVP, and the electric cooperatives, and requires that those members make forward commitments for meeting those obligations. Consequently, the "amount and reliability" of generation needed to serve Virginia load is directly impacted by PJM planning activities and membership requirements.

It also should be noted that the Virginia General Assembly enacted Chapters 476 and 903 of the 2008 Acts of Assembly during its 2008 Session. These duplicate enactments added Chapter 24 (§ 56-597 *et seq.*) of Title 56 of the Code of Virginia. Chapter 24 directs Virginia's investor-owned electric utilities ("IOUs") to file integrated resource plans ("IRPs") with the Commission at least every two years. These IRPs effectively work in conjunction with the PJM processes by examining each IOU's existing and projected portfolio of supply- and demand-side resources necessary to meet projected demand over a 15-year planning period.

Dominion relies on its generating resources, purchased power contracts, DSM initiatives, and short-term capacity purchases for satisfying its load serving obligations. Dominion's internal capacity (*i.e.*, its owned capacity, capacity acquired through long-term non-utility generation purchased power agreements, and DSM reductions) has in recent years provided less than the total amount of generation capacity required to meet 100% of its load obligations at all times—principally during periods of peak demand; *e.g.*, the summer cooling season. This deficit typically has been covered through short-term purchases, including purchases from the PJM capacity market. This capacity deficit is expected to average around 1,100 MW for the period 2012-2015. Dominion's recent construction of the Bear Garden and Virginia City Hybrid Energy Center generating facilities has reduced this internal capacity deficit. Moreover, the Warren County facility that now is under construction and planned to be operational in 2015 essentially will eliminate this deficit in the near term.

APCo is a member of the American Electric Power ("AEP") system and historically has relied on its installed generation and an AEP Interconnection Agreement with other AEP affiliates to satisfy its load obligations. APCo's internal capacity historically has been insufficient to satisfy its load obligations, as determined under that interconnection agreement. However, the AEP system historically has had sufficient capacity to satisfy the needs of its affiliated members, thus making – in some respects – APCo's capacity deficit a function of AEP planning. Consequently, APCo's interconnection agreement related deficit has not posed a reliability concern for Virginia. APCo recently constructed the Dresden facility in Ohio which helps to eliminate a portion of APCo's shortfall.

APCo and other participants in the AEP Interconnection Agreement have provided notice of their intention to dissolve that agreement effective December 31, 2013. In lieu thereof, APCo's current plans envision that it will become a stand-alone entity within PJM, with some limited pooling arrangements with other AEP affiliates. Conceptually, APCo would be responsible for satisfying its internal capacity requirements on a stand-alone basis going forward, and APCo's capacity obligations would be determined through the PJM process. Under such a scenario, APCo expects that it would have sufficient capacity until 2014 based on its existing resources and expected capacity changes. Further, APCo anticipates purchasing existing generating capacity from other AEP pool members in conjunction with the dissolution of the AEP Interconnection Agreement.

Chapter 933 also requires that Virginia electric utilities be compared to "those in the peer group of such utilities that meet the criteria enumerated in subdivision A 2 of § 56-585.1 of the Code of Virginia."[3] The peer group utilities for APCo and Dominion currently include: Duke Energy Carolinas ("Duke"), Entergy Mississippi ("Entergy"), Florida Power & Light Company ("FP&L"), Georgia Power, Gulf Power, Mississippi Power, Progress Energy Carolinas, Progress Energy Florida, South Carolina Electric & Gas ("SCE&G"), and Tampa Electric Company. In response to the directive to conduct peer group comparisons, this report contrasts typical bill information for the peer group utilities with that of APCo and Dominion.

Dominion's January 1, 2012 residential rates produce typical bills that rank DVP 11th lowest out of the 17 companies examined and are below the U.S. averages and slightly above Edison Electric Institute's ("EEI") averages for the South Atlantic region. DVP's typical residential bill rankings have slipped five places since July 1, 2007, sliding from the upper to the lower half of the peer group; that is, Dominion's rates have become less competitive. Dominion's commercial rates still seem competitive despite some decline in rankings since July 1, 2007. Dominion's January 1, 2012 commercial rates produce typical bills that range from 7th to 11th lowest out of the 17 companies examined and are below the U.S. and South Atlantic region averages. Dominion's industrial rates still appear competitive with the rates of the peer group despite a continued decline in ranking. Dominion's January 1, 2012 industrial rates produce bills that range from 6th to 13th lowest out of the 17 companies examined and are below the U.S. average and, for the most part, are below the South Atlantic region average.

[3] Chapter 933 does not require peer group analysis of rates for electric cooperatives.

APCo's residential typical bill rankings for 2012 and July 1, 2007, are the same. APCo's January 1, 2012 residential rates produced typical bills that ranked 2nd lowest out of the 17 companies examined and are below the U.S. and South Atlantic region averages. APCo's commercial rates also continue to be competitive despite some decline in ranking for larger, higher load factor customers. APCo's January 1, 2012 commercial rates produced typical bills that range from 2nd to 4th lowest out of the 17 companies examined and are below the U.S. and South Atlantic regional averages. APCo's January 1, 2012 industrial typical bills are ranked 1st to 4th lowest out of the 17 companies examined and are below the U.S. and South Atlantic region averages. APCo's industrial bill rankings have slipped only slightly since July 1, 2007, and in some cases improved, which seems to indicate that APCo's industrial rates are still competitive.

A review of generating capacity reliability-related information for the peer group utilities did not show any discernible trends in reliability or any indication that Dominion's or APCo's overall ability to serve native load was notably different from that of the peer group. It should be noted that publicly available reliability-related information for the peer group is limited. As such, reliability differences only could be developed on a somewhat superficial level.

I. INTRODUCTION AND BACKGROUND

On April 4, 2007, the General Assembly of Virginia enacted Chapter 933.[4] The Seventh Enactment Clause of Chapter 933 directs:

> That the State Corporation Commission, in consultation with the Office of Attorney General, shall submit a report to the Governor and General Assembly by November 1, 2012, and every five years thereafter, assessing the rates and terms and conditions of incumbent electric utilities in the Commonwealth. Such report shall include an analysis of, among other matters, the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load, and provide a comparison of such utilities to those in the peer group of such utilities that meet the criteria enumerated in subdivision A 2 of § 56-585.1 of the Code of Virginia.

Chapter 933 contains numerous provisions that influence "the rates and terms and conditions of incumbent electric utilities in the Commonwealth" and "the amount, reliability and type of generation facilities" used to serve Virginia native load. Specifically, Chapter 933 establishes a new mechanism for regulating the rates of incumbent electric utilities and limits the ability of most consumers to purchase electric generation service from competing suppliers, as previously provided for under the Virginia Electric Utility Restructuring Act. This new ratemaking mechanism contained primarily in § 56-585.1 of the Code required the Commission to conduct a rate case for IOUs[5] in 2009 ("Going-in Review") and thereafter to review each utility's rates, terms, and conditions using two 12-month test periods ("Biennial Review"), with the first such review focusing on the two-year period ending December 31, 2010. In these

[4] Chapter 933 of the 2007 Acts of Assembly (SB 1416) amended and reenacted §§ 56-233.1, 56-234.2, 56-235.2, 56-235.6, 56-249.6, 56-576 through 56-581, 56-582, 56-584, 56-585, 56-587, 56-589, 56-590, and 56-594 of the Code of Virginia ("Code"); amended the Code by adding §§ 56-585.1, 56-585.2, and 56-585.3; and repealed §§ 56-581.1 and 56-583 of the Code relating to the regulation of electric utility service. Chapter 933 substantially rewrote existing Chapter 23 (§ 56-576 *et seq.*) of Title 56 of the Code, then titled the "Virginia Electric Utility Regulation Act." Subsequent to Chapter 933's enactment, Chapter 23 was re-titled in the published Code as the "Virginia Electric Utility Restructuring Act."

[5] Chapter 933 does not apply to one IOU in Virginia, Kentucky Utilities Company d/b/a Old Dominion Power Company.

Biennial Reviews, the SCC is to determine fair rates of return on common equity ("fair combined return" or "ROE") for the utility's generation and distribution services, using any methodology it finds consistent with the public interest. However, the return shall not be set lower than the average of the ROEs reported to the Securities and Exchange Commission for the three most recent annual periods by a majority of a peer group of the other vertically integrated IOUs in the southeastern United States. Chapter 933 authorizes, but does not require, the Commission to increase or decrease the resulting fair combined return by up to 100 basis points based on generating plant performance, customer service, and the operating efficiency of a utility, as compared to nationally recognized standards.

Chapter 933 authorizes, but does not require, each IOU to seek rate adjustment clauses ("RAC") to recover (i) costs for transmission services provided by PJM under applicable rates, terms, and conditions approved by the Federal Energy Regulatory Commission ("FERC") and costs of FERC-approved demand response programs; (ii) deferred environmental and reliability costs authorized under prior capped rate rules; (iii) costs of providing incentives for the utility to design and operate fair and effective demand-side management, conservation, energy efficiency, and load management programs; (iv) costs of participation in the new renewable energy portfolio standard ("RPS") program; and (v) costs of projects that the SCC finds to be necessary to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, which costs may include the enhanced ROE for new base load generation if the environmental compliance project would reduce the need for construction of new generation facilities by enabling the continued operation of existing generation facilities.

Because of the magnitude of such expenditures, Chapter 933 also allows IOUs to apply for RACs for recovery from customers of the costs of (i) a coal-fired generation facility that utilizes Virginia coal and is located in the coalfield region of the Commonwealth, (ii) one or more other generation facilities, or (iii) one or more major unit modifications of generation facilities to meet the utility's projected native load obligations. Utilities may recover an enhanced ROE associated with the type of project, which may include projects utilizing nuclear power, renewable technologies, carbon capture facilities, combined-cycle combustion turbines, and conventional coal facilities. Chapter 933 provides specified ranges within which the enhanced ROE may be collected depending on the type of facility. The SCC is required to consider petitions for each of the RACs described above on a stand-alone basis, without regard to the other costs or revenues of the utility.

Chapter 933 requires specific action if a utility earns either 50 basis points above or below the fair combined return ("earnings band"). Specifically, the SCC is to increase an IOU's rates to a level necessary to provide the opportunity to recover fully the costs of providing the utility's services and to earn such fair combined return, if it is determined in a Biennial Review that a utility's earnings on its generation and distribution services were below the earnings band, excluding provisions for new generation facilities. If the SCC determines in a Biennial Review that a utility's earnings return on its generation and distribution services exceeded the earnings band, excluding provisions for new generation facilities, the SCC is required to direct that 60% of such excess earnings be credited to customers' bills over a six to 12-month period. In addition, if the SCC determines that the utility's earnings exceeded this limit for two consecutive Biennial Review periods, it also shall order reductions to the utility's rates, provided that rates may not be reduced to levels below what would provide the utility with the opportunity to recover fully its costs and to earn a fair combined return on its generation and distribution services, excluding provisions for new generation facilities.[6]

Chapter 933 also establishes a voluntary RPS program under which participating utilities that meet specified percentage RPS goals for sales of eligible renewable energy are entitled to an incentive that increases the utility’s fair combined ROE for the utility by 50 basis points through the third succeeding Biennial Review if it continues to meet the RPS goals. This incentive is in lieu of any performance return adjustment assessed by the Commission.[7] Such utilities also are entitled to an enhanced rate of return on the costs associated with the construction of renewable energy generation facilities used to provide the renewable energy. Section 56-585.2 of the Code provides that a utility participating in such a program “shall have the right to recover all incremental costs incurred for the purpose of such participation” through a RAC and prohibits recovery of any such costs from large industrial customers purchasing electricity at large general service rates and at primary or transmission voltage levels.

Other provisions of Chapter 933 require that 75% of the margins from off-system sales be applied to reduce the utility's fuel expenses unless the SCC finds by clear and convincing evidence that a smaller percentage is in the public interest, with the remaining percentage being retained by the utility; require the use of certain ratemaking parameters when the Commission conducts its Biennial Reviews; and authorize distribution electric cooperatives to increase rates by not more than 5% over three years and to make certain other changes to terms and conditions of service without SCC approval.

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[6] Alternatively, the Commission may require a refund of 100% of earnings above the band in lieu of a combination of a 60% refund and rate reductions.

[7] If a utility’s performance return adjustment is less than 50 basis points, the utility could elect to use the 50 basis point RPS incentive instead. However, if the utility’s performance return adjustment is greater than 50 basis points, the utility could elect to use that adjustment instead of the RPS incentive.

In accordance with Chapter 933, this report will provide: (i) an assessment of the rates, terms and conditions of Dominion, APCo, and the electric cooperatives; (ii) a discussion of the amount and type of generation needed to serve Virginia load reliably; and (iii) contrast the rates and service reliability of the statutory peer group utilities with that of Virginia utilities.

II. RATE ASSESSMENT

Since enactment of Chapter 933, DVP, APCo, and the electric cooperatives have initiated numerous rate changes or have undergone extensive rate reviews. The following section separately discusses those rate reviews and rate changes and identifies the provisions of Chapter 933 that may have influenced those requests.[8] Appendix 1 to this report presents a comparison of the July 1, 2007 and July 1, 2012 monthly charges for residential customers using 1,000 kWh of electricity for APCo, Dominion, and the electric cooperatives.[9]

A. Dominion Virginia Power

Since July 1, 2007, DVP has been authorized net revenue increases totaling approximately $1.3 billion and has pending requests that would produce an additional increase of approximately $120.1 million. The combined effect of these approved increases has been to increase the monthly bill for a residential customer using 1,000 kWh by $16.63, or approximately 18%, since July 1, 2007. Pending requests, if approved, would increase the monthly bill for a residential customer using 1,000 kWh by an additional $1.30. Incremental changes occurring since January 1, 2007, that are currently reflected in Dominion's monthly bill for residential customers using 1,000 kWh and the associated statutory provisions are detailed in Appendix 2 to this report. These revenue changes are associated with the establishment and revision of numerous RACs as well as fuel factor revisions. Specifically, the $16.63 increase is

[8] While Chapter 933 fundamentally altered the form and process of many of the various rate changes, many of the underlying cost drivers for the increases would have existed under a traditional state regulatory paradigm.
[9] One thousand kWh is a commonly used reference point for a typical residential customer in Virginia.

comprised of a fuel cost increase of $4.74, transmission cost-related increases totaling $4.25, new generation rate riders totaling $6.94, and DSM rate adjustments totaling $0.70.

Dominion has not had any significant changes in its terms and conditions of service since July 1, 2007.

1. Rate Reviews

DVP has undergone two rate reviews pursuant to Chapter 933; a Going-in Review and a Biennial Review.

a. Going-in Review

On March 31, 2009, Dominion filed its Going-in Review with the Commission (Case No. PUE-2009-00019). After amending its original request, Dominion requested to increase base rates by $250.2 million, an increase of 7.9%, based on a requested ROE of 13.5%.[10] Subsequently, all participants in the case, including DVP, the Commission Staff ("Staff"), and the Office of Attorney General's Division of Consumer Counsel ("Consumer Counsel"), entered into a comprehensive settlement which, among other things, addressed the requested increase in base rates. On March 11, 2010, the Commission issued its Order Approving Stipulation and Addendum[11] that approved the going-in settlement. The going-in settlement provided that there would be no net increase in base rates prior to December 1, 2013, and that DVP's authorized fair combined return would be 11.9%. This 11.9% ROE included a performance-based adder of 60 basis points, or 0.6%. This ROE was agreed to solely for the purposes of the going-in settlement and was not intended to establish or otherwise be a precedent for a particular "peer group" floor or performance adder pursuant to § 56-585.1 A 1 d of the Code.

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[10] The originally requested ROE of 14% included a request for the maximum performance adder of 1% provided for in Chapter 933.

[11] *Application of Virginia Electric and Power Company, for a 2009 statutory review of rates, terms and conditions for the provision of generation, distribution, and transmission services pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUE-2009-00019, 2010 S.C.C. Ann. Rept. 301, Order Approving Stipulation and Addendum (Mar. 11, 2010).

The going-in settlement provided for a number of rate credits totaling $529 million, consisting of a base rate credit of $132 million, other credits totaling $268 million, and a refund of $129 million associated with financial transmission right revenues. In addition to these rate credits, Dominion agreed to waive recovery of $197 million of FERC-approved deferred transmission-related costs, bringing the total value of the rate case settlement to $726 million. While the Commission did not find, and Dominion did not acknowledge, that DVP had excessive earnings, the Staff, Consumer Counsel, and other parties to the proceeding submitted evidence in the Going-in Review settlement proceeding alleging that Dominion had over-earned in compared to a fair combined rate of return.

b. Biennial Review

Dominion submitted an application for its first biennial rate review on March 31, 2011, in Case No. PUE-2011-00027. DVP's application asserted that Dominion earned within its authorized earnings band of 11.4-12.4% and claimed that, as such, no rate credits were required pursuant to Chapter 933. Dominion requested that the Commission approve an ROE of 12.5%, which included a performance incentive of 1%.

On November 30, 2011, the Commission issued its Final Order[12] in the case, which found that DVP had earned an average ROE of 13.31% during the 2009 and 2010 Biennial Review test periods and noted that, pursuant to the settlement resulting from the Going-in Review, the authorized ROE for this period was 11.9%. The 13.31% earnings level was more than 50 basis points above the fair combined return of 11.9% established in the settlement; consequently, the

[12] *Application of Virginia Electric and Power Company, For a 2011 Biennial Review of the rates, terms, and conditions for the provision of generation, distribution, and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, 2011 S.C.C. Ann. Rept. 456, Final Order (Nov. 30, 2011); 2011 S.C.C. Ann. Rept. 468, Order Granting Reconsideration (Dec. 16, 2011).

Commission required Dominion to refund to its customers $78.3 million of the over earnings pursuant to § 56-585.1 A 8 ii of the Code. [13]

The Commission's Final Order also found that Dominion's ongoing market cost of equity[14] was within a range of 9.4 to 10.4% and that the top of the range, 10.4%, was reasonable under the circumstances for determining the company's fair rate of return. The Commission also examined the statutory floor below which the ROE cannot be set based on the returns of a statutory peer group and found that the majority of the peer group utilities had returns below 10.4%. The Commission noted that some of Dominion's performance metrics were positive and some were negative and that DVP had not proposed any specific metrics for evaluating operating efficiency. Accordingly, the Commission declined to approve a performance incentive. The Commission did, however, find that DVP had met the RPS goals pursuant to § 56-585.2 C of the Code and that Dominion was therefore entitled by statute to an RPS incentive return of 50 basis points in lieu of a performance adder.[15] As such, the Commission noted that an ROE of 10.9% will be used as the fair combined return for purposes of Dominion's next Biennial Review proceeding.[16]

2. Dominion Virginia Power Rate Adjustment Clauses

As noted earlier, Chapter 933 authorizes the establishment of a number of RACs. These clauses provide for the recovery of (i) costs associated with the construction of generating facilities; (ii) the costs of transmission service as approved by FERC; (iii) the costs of energy efficiency and conservation programs; (iv) deferred environmental and reliability costs;

[13] This represents 60% of earnings above the earnings band of 11.4-12.4%. Consequently, DVP retained $123.5 million of earnings above the 11.9% fair combined return.
[14] The term "market cost of equity" refers to the actual cost of equity in capital markets for companies comparable in risk to DVP that are seeking to attract equity capital and which results in a fair and reasonable ROE.
[15] The Commission's Final Order noted that the RPS incentive return of 50 basis points equates to approximately $38.5 million of annual revenue requirement based on DVP's average 2010 rate base and capital structure.
[16] Subsequently, Dominion appealed to the Virginia Supreme Court the Commission's decision; this matter is currently pending.

(v) certain costs associated with complying with state or federal environmental laws or regulations; and (vi) costs of participating in the RPS program. Dominion has proposed and has received approval for a number of these clauses. DVP's Riders S, R, W, and B, which represent generation-related monthly bill increases totaling $6.94 for a residential customer using 1,000 kWh, are associated with investments in generating facilities made in accordance with § 56-585.1 A 6 of the Code.[17] Dominion's Rider T and Riders C1 and C2 are associated with transmission costs, energy conservation, and energy efficiency costs, respectively. Riders T, C1 and C2 represent increases totaling $4.08 in the monthly bill of a residential customer using 1,000 kWh.

a. Rider S

Rider S is designed to recover costs associated with Dominion's construction and operation of the Virginia City Hybrid Energy Center, a 585 MW coal-fired generating facility located in Wise County, Virginia. Rider S initially was approved in Case No. PUE-2007-00066 and subsequently modified through a series of cases with the last modification being approved in Case No. PUE-2011-00067.[18] The currently approved Rider S reflects an annual overall revenue requirement of $226 million. This revenue requirement is based on an ROE of 11.4%, which includes a 100 basis points incentive return to the Company's ROE related to this facility pursuant to § 56-585.1 A 6 of the Code. The currently approved monthly Rider S charge for a residential customer using 1,000 kWh is $4.74.

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[17] It should be noted that Chapter 933 provides a utility with the right to recover all costs associated with facilities constructed in accordance with § 56-585.1 A 6 of the Code and, as such, essentially assures that the utility will earn the authorized return with the incentive adder.

[18] *Application of Virginia Electric and Power Company, For a certificate of public convenience and necessity to construct and operate an electric generation facility in Wise County, Virginia, and for approval of a rate adjustment clause under §§ 56-585.1, 56-580 D, and 56-46.1 of the Code of Virginia*, Case No. PUE-2007-00066, 2008 S.C.C. Ann. Rept. 385, Final Order (Mar. 3, 2008); and *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider S, Virginia Center Hybrid Energy Center, for the rate year commencing April 1, 2012*, Case No. PUE-2011-00067, Doc. Con. Cen. No. 120320294, Final Order (Mar. 23, 2012).

A pending application seeks to increase the Rider S total annual revenue requirement to $248.6 million. This increase would be placed into effect on April 11, 2013, if approved.

b. Rider R

Rider R is associated with DVP's construction of the Bear Garden Generating Station; a 580 MW natural gas-fired generating facility located in Buckingham County, Virginia. Rider R was initially approved in Case No. PUE-2009-00017 and subsequently was modified through a series of cases with the last modification being approved in Case No. PUE-2011-00066.[19] The currently approved Rider R reflects an overall revenue requirement of $73.9 million. This revenue requirement is based on an ROE of 11.4% which includes a 100 basis points incentive return pursuant to § 56-585.1 A 6 of the Code. The currently approved monthly Rider R charge for a residential customer using 1,000 kWh is $1.42.

A pending application seeks to increase the Rider R total annual revenue requirement to $80.5 million. This increase would be placed into effect on April 11, 2013, if approved.

c. Rider W

On February 2, 2012, the Commission issued a Final Order in Case No. PUE-2011-00042[20] approving Dominion's plans to construct, by January 1, 2015, a 1,329 MW natural gas-fired generating unit to be located in Warren County, Virginia. That same order established Rider W for the purposes of recovering related costs. The initial Rider W was

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[19] *Application of Virginia Electric and Power Company, For Approval of a Rate Adjustment Clause for Recovery of the Costs of the Bear Garden Generating Station and Bear Garden-Bremo 230 kV Transmission Interconnection Line*, Case No. PUE-2009-00017, 2009 S.C.C. Ann. Rept. 416, Order Approving Rate Adjustment Clause (Dec. 16, 2009); and *Application of Virginia Electric and Power Company, For revision of rate adjustment clause: Rider R, Bear Garden Generating Station for the rate year commencing April 1, 2012*, Case No. PUE-2011-00066, Doc. Con. Cen. No. 120320206, Final Order (Mar. 20, 2012).

[20] *Application of Virginia Electric and Power Company, For approval and certification of the proposed Warren County Power Station electric generation and related transmission facilities under §§ 56-580 D, 56-265.2, and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated as Rider W, under 56-585.1 A 6 of the Code of Virginia,* Case No. PUE-2011-00042, Doc. Con. Cen. No. 120210139, Final Order (Feb. 2, 2012).

designed to collect an annual revenue requirement of approximately $34 million based on an ROE of 11.4%, which includes a 100 basis points incentive adder. The currently approved monthly Rider W charge for a residential customer using 1,000 kWh is $0.66. This charge will increase as Dominion's related construction expenditures grow. DVP recently filed an application to update Rider W in Case No. PUE-2012-00067. If approved, that application would increase the Rider W related total annual revenue requirement to $86 million effective April 1, 2013.

d. Rider B

Rider B was established earlier this year to recover costs incurred by DVP for converting its coal-fired Altavista, Hopewell, and Southampton Power Stations into biomass facilities.[21] The initially approved Rider B was designed to recover a revenue requirement of $6.4 million based on an ROE of 12.4%, the fair combined ROE of 10.4%, plus a 200 basis point adder pursuant to § 56-585.1 A 6.[22] The currently approved monthly Rider B charge for a residential customer using 1,000 kWh is $0.12. Dominion recently requested a revised Rider B that would increase the Rider B revenue requirement to approximately $18.7 million in Case No. PUE-2012-00072.

e. Rider T

DVP's Rider T was established to recover the company's transmission costs of service and related costs associated with Dominion's participation in PJM in accordance with

[21] *Applications of Virginia Electric and Power Company, For approval and certification of the proposed biomass conversions of the Altavista, Hopewell, and Southampton Power Stations under §§ 56-580 D and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated as Rider B, under § 56-585.1 A 6 of the Code of Virginia*, Case No. PUE-2011-00073, Final Order (Mar. 16, 2012).

[22] This Code section requires higher incentive adders for nuclear units, carbon capture compatible clean coal units, and renewable generation. Biomass is considered a form of renewable energy pursuant to § 56-576 of the Code.

§ 56-585.1 A 4 of the Code.[23] The first Rider T, established in Case No. PUE-2009-00018, replaced the unbundled transmission component of the previously approved base rates and effectively increased rates by $68 million.[24] Subsequent revisions resulted in further increases to Rider T. Pursuant to § 56-585.1 A 3 of the Code, the Commission's Final Order in Dominion's 2011 Biennial Review directed that the then effective Rider T be combined with base rates. Subsequently, a new Rider T1 was implemented to reflect projected changes in Dominion's transmission-related costs for the rate year September 1, 2012, through August 31, 2013. The combined effect of these transmission-related rate changes effectively increased the overall transmission revenue requirement now reflected in combined rates by approximately $223.5 million. This represents an increase of $4.25 in the monthly bill of a residential customer using 1,000 kWh.

f. Riders C1 and C2

Dominion's Riders C1 and C2 were established to recover the company's costs related to peak shaving and energy efficiency programs in accordance with § 56-585.1 A 5 of the Code. Chapter 933 requires that the costs of energy efficiency programs not be recovered from customers with demands of 10 MWs or more. Consequently, the conservation and energy efficiency riders distinguish between those customer groups subject to the energy efficiency costs and those customers that are not subject to those costs. Rider C1 includes both efficiency and peak shaving costs while Rider C2 reflects only peak shaving related costs. Pursuant to § 56-585.1 A 3, the Commission's Final Order in Dominion's 2011 Biennial Review directed that the then effective Riders C1 and C2 be combined with base rates. Subsequently, Dominion

[23] This Code section effectively requires that the transmission costs be based on the FERC-approved rates which provide for projected rate bases, deferred accounting, and the FERC-approved ROE. Such costs incurred by the utility are deemed reasonable and prudent.

[24] *Application of Virginia Electric and Power Company, For approval of a rate adjustment clause pursuant to § 56-585.5.1 A 4,* Case No. PUE-2009-00018, 2010 S.C.C. Ann. Rept. 301, Order Approving Stipulation and Addendum (Mar. 11, 2010).

sought and received approval for new Riders C1A and C2A, which were implemented to reflect new conservation and energy efficiency programs.[25] The combined effect of these conservation and energy efficiency related rate changes effectively increased the associated revenue requirement now reflected in combined rates by approximately $35.2 million. This represents an increase of $.70 in the monthly bill of a residential customer using 1,000 kWh.[26] In Case No. PUE-2012-00100, Dominion requested approval to continue Riders C1A and C2A with a proposed total revenue requirement of $26.6 million.

3. Fuel Factor

Dominion's fuel factor has been modified several times since the enactment of Chapter 933. These changes are generally driven by increases or decreases in Dominion's generating fuel and purchased power costs. Chapter 933 allows DVP to retain 25% of the profits associated with off-system sales of electricity. Collectively, fuel factor revisions have increased rates by approximately $589.6 million since enactment of Chapter 933. These fuel-related changes represent an increase since 2007 of $4.74 per month for a residential customer using 1,000 kWh per month.[27]

B. Appalachian Power Company

APCo has been authorized net revenue increases totaling approximately $627.7 million since July 1, 2007. Certain of these increases were approved for a limited period of time and have since expired. As such, the level of increases approved since the enactment of Chapter 933

[25] *Application of Virginia Electric and Power Company, For approval to implement new demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia*, Case No. PUE-2011-00093, Doc. Con. Cen. No. 120440041, Order (Apr. 30, 2012).

[26] Section 56-585.1 A 5 of the Code provides for the recovery of net revenues lost as a result of energy efficiency programs. Such programs may include measures that reduce energy consumption and consequently cause lost revenue. The current C1 revenue related impact does not reflect these lost revenues and as such does not reflect the full potential rate impact of the energy efficiency programs that have been put into place.

[27] The current fuel factor represents a total monthly charge of $27.06 for a residential customer using 1,000 kWh. This represents approximately 25% of the total monthly bill.

that continue to impact current rates is approximately $481.2 million. The combined effect of these remaining increases have been to increase the monthly bill for a residential customer using 1,000 kWh by $45.98, or by approximately 69% since July 1, 2007. Incremental changes, occurring since January 1, 2007, that are currently reflected in APCo's monthly bill for residential customers using 1,000 kWh and the associated statutory provision are detailed in Appendix 3 to this report. These revenue changes are associated with (i) revisions to base rates; (ii) establishment and revision of numerous RACs; and (iii) fuel factor revisions.

APCo has not had any significant changes in its terms and conditions of service since July 1, 2007.

1. Base Rate Increases and Rate Reviews

APCo has filed a general rate increase and has undergone two rate reviews (a Going-in Review and a Biennial Review) since July 1, 2007.

a. Base Rate Increase

On May 30, 2008, APCo filed an application for a general base rate increase of $207.9 million based on a requested ROE of 11.75% pursuant to § 56-582 of the Code.[28] Subsequently, APCo entered into a stipulation with the Commission's Staff and other parties to the proceeding which recommended a base rate increase of $167.9 million based on an ROE of 10.2%. On November 17, 2008, the Commission issued a Final Order[29] adopting the proposed stipulation. This base rate change increased the monthly bill for a residential customer using 1,000 kWh by $13.12, or by approximately 17%.

[28] Section 56-582, enacted prior to Chapter 933, authorized APCo to seek a one-time adjustment to capped rates during the period January 1, 2008 to July 1, 2009. As such, this base rate increase was not directly influenced by Chapter 933 but is discussed here because it took place after Chapter 933's effective date of July 1, 2007.

[29] *Application of Appalachian Power Company, For an increase in electric rates,* Case No. PUE-2008-00046, 2008 S.C.C. Ann. Rept. 547, Final Order (Nov. 17, 2008).

b. Going-in Review

On July 15, 2009, APCo filed its Going-in Review with the Commission (Case No. PUE-2009-00030). In the amended filing, APCo requested to increase base rates by $154 million based on a requested ROE of 13.35%.[30] The Commission issued its Final Order[31] on July 15, 2010, which, among other things, found that a market cost of equity within the range of 9.5 to 10.5% would result in a fair and reasonable ROE. The Commission also examined the statutory floor below which the ROE cannot be set based on the returns of a statutory peer group and found that the majority of the peer group utilities had an average return of 10.53%. The Commission rejected the company's request for a performance incentive. Accordingly, the Commission utilized the statutory floor as required by Chapter 933 to establish an authorized ROE of 10.53%. Based on this ROE and other ratemaking adjustments, the Commission approved an overall base rate increase of approximately $61.5 million. This base rate change increased the monthly bill for a residential customer using 1,000 kWh by $5.09, or by approximately 4.9%.

c. Biennial Review

APCo submitted an application for its first biennial rate review on March 31, 2011, in Case No. PUE-2011-00037. APCo's filing sought to support a base rate increase of approximately $126.4 million. APCo subsequently amended its requested increase to $117 million based on an ROE of 11.65%, which included a 50 basis points ROE adder as an RPS Incentive in accordance with § 56-585.2 C of the Code. The Commission issued its Final Order on November 30, 2011, finding, among other things, that APCo's fair ROE for the test

[30] The requested ROE of 13.35% included a request for a performance incentive of 0.85% as provided for in Chapter 933.

[31] *Application of Appalachian Power Company, For a statutory review of the rates, terms and conditions for the provisions of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, 2010 S.C.C. Ann. Rept. 308, Final Order (July 15, 2010).

period under review was 10.53% and noting that the company had earned more than 50 basis points below a fair combined rate of return during the test periods under review.[32] Accordingly, the Commission was required to order rate increases in accordance with Chapter 933.

Chapter 933 requires that the Commission utilize a utility's end-of-test-period cost of capital to establish new rates. The Commission found that a fair market cost of equity of 10.4% should be used in determining the end-of-test-period cost of capital. The Commission then found that a 50 basis points RPS incentive should be added pursuant to § 56-585.2 C of the Code. Based on an ROE of 10.9% and other ratemaking adjustments, the Commission approved an overall base rate increase of approximately $55 million.[33] This base rate change increased the monthly bill for a residential customer using 1,000 kWh by $4.83.

2. Rate Adjustment Clauses

Similar to Dominion, APCo has proposed and received approval for a number of RACs as provided for in Chapter 933. APCo's generation RAC ("G-RAC") is associated with investments in a new generating facility made in accordance with § 56-585.1 A 6 of the Code. APCo also has implemented several riders for recovering environmental and reliability related costs and a rider for recovering costs associated with APCo's voluntary compliance with the RPS goals.

[32] *Application of Appalachian Power Company, For a 2011 biennial review of the rates, terms and conditions for the provisions of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUE-2011-00037, Final Order (Nov. 30, 2011).
[33] The Commission's order noted that the statutorily required addition of 50 basis points for meeting the RPS goal accounted for approximately $7.75 million of the annual rate increase.

a. Generation Rate Adjustment Clause

On January 3, 2012, the Commission issued a Final Order[34] in Case No. PUE-2011-00036 approving APCo's proposed Rider G to complete the construction of a 580 MW gas-fired generating unit to be located near Dresden, Ohio. The initial G-RAC was designed to collect an annual revenue requirement of approximately $26.1 million based on an ROE of 11.4% that includes a 100 basis points incentive adder pursuant to § 56-585.1 A 6 for this type of generating facility. This revenue requirement would be reduced if Dresden was not placed into service on or before March 1, 2012. The currently approved monthly G-RAC charge for a residential customer using 1,000 kWh is $2.15.

b. Transmission Rate Adjustment Clause

APCo's transmission rider ("T-RAC") was established to recover the company's transmission costs of service and related costs associated with its participation in PJM in accordance with § 56-585.1 A 4.[35] This T-RAC replaced the unbundled transmission component of the previously approved base rates and effectively increased rates by $21.7 million. This represented an increase of $2.76 in the monthly bill of a residential customer using 1,000 kWh.[36]

c. Environmental and Reliability Surcharges

On July 16, 2007, APCo filed an application to revise its surcharge for the recovery of incremental environmental and transmission and distribution system reliability costs ("E&R surcharge") pursuant to § 56-582 B (vi) of the Code.[37] The Commission subsequently approved

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[34] *Petition of Appalachian Power Company, For approval of a rate adjustment clause pursuant to § 56-585.1 A 6 of the Code of Virginia to recover the costs of the Dresden Generating Plant*, Case No. PUE-2011-00036, Doc. Con. Cen. No. 120110002, Final Order (Jan. 3, 2012).
[35] *Petition of Appalachian Power Company, For approval of a rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia*, Case No. PUE-2009-00031, 2009 S.C.C. Ann. Rept. 450, Final Order (Oct. 6, 2009).
[36] Transmission-related charges currently represent $7.42, or 6.6%, of the total monthly bill for an APCo residential customer using 1,000 kWh.
[37] Section 56-582 B (vi) of the Code was unaffected by Chapter 933.

a revised surcharge that resulted in an increase of $27.6 million.[38] APCo sought a further revision of its E&R surcharge in Case No. PUE-2008-00045. By Final Order dated October 15, 2008, in that proceeding, the Commission approved an additional E&R related increase of approximately $11.7 million.[39] A third E&R adjustment, which resulted in a further increase of $28.9 million, was approved on January 14, 2010, in Case No. PUE-2009-00039.[40] Chapter 933 effectively eliminates APCo's ability to collect E&R costs incurred beyond the end of the capped rate period. Consequently, the E&R surcharge expired on January 1, 2011. APCo, however, was subsequently authorized a final true-up surcharge to collect a residual amount of the E&R costs that had been deferred but not completely collected via the earlier surcharges. This amount, $4.6 million, is currently being collected pursuant to Chapter 933 and will be removed from rates on January 31, 2013. APCo's aggregate collection of incremental E&R costs will total approximately $224.9 million once this residual surcharge amount is collected.

Although Chapter 933 effectively ended the E&R surcharge, it authorizes the establishment of RACs for the collection of generation-related costs incurred for compliance with state or federal environmental laws or regulations. On March 31, 2011, APCo filed an application requesting establishment of an environmental RAC ("E-RAC") to collect generation-related environmental compliance costs of $77 million over a two-year period, pursuant to § 56-585.1 A 5 e of the Code.[41] By order[42] dated November 30, 2011, the

[38] *Application of Appalachian Power Company, For adjustment to capped electric rates pursuant to § 56-582 B (vi) of the Code of Virginia*, Case No. PUE-2007-00069, 2007 S.C.C. Ann. Rept. 474, Final Order (Dec. 13, 2007).
[39] *Application of Appalachian Power Company, For adjustment to capped electric rates pursuant to § 56-582 B(vi) of the Code of Virginia*, Case No. PUE-2008-00045, 2008 S.C.C. Ann. Rept. 543, Final Order (Oct. 15, 2008).
[40] *Application of Appalachian Power Company, For recovery of environmental and reliability costs*, Case No. PUE-2009-00039, 2010 S.C.C. Ann. Rept. 324, Order Approving Surcharge (Jan. 14, 2010).
[41] Chapter 933 included this provision as § 56-585.1 A 5 d. This provision was subsequently redesignated as subsection e due to the inclusion of a new subsection b.
[42] *Application of Appalachian Power Company, For approval of a rate adjustment clause, E-RAC, to recover costs incurred in complying with state and federal environmental laws and regulations, pursuant to Va. Code § 56-585.1 A 5 e*, Case No. PUE-2011-00034, 2011 S.C.C. Ann. Rept. 474, Order Approving Rate Adjustment Clause (Nov. 30, 2011).

Commission rejected much of APCo's request and approved an E-RAC designed to collect $30 million over a one-year period.[43] This E-RAC, which will expire on January 29, 2013, represents a monthly charge of $2.42 for a residential customer using 1,000 kWh.

d. Renewable Energy Portfolio Standard Program

Chapter 933 authorizes the establishment of RACs for costs related to a utility's voluntary participation in a RPS program pursuant to § 56-585.2 of the Code. On March 31, 2011, APCo filed an application in Case No. PUE-2011-00034 requesting authority to establish an RPS-RAC. By order dated November 3, 2011, the Commission approved APCo's request to collect $6.3 million through this rate.[44] This RPS-RAC represents a monthly charge of $0.65 for a residential customer using 1,000 kWh. Large industrial customers are exempt by statute from paying for these costs.

3. Fuel Factor

APCo's fuel factor has been modified several times since the enactment of Chapter 933. These changes are generally driven by increases or decreases in the cost of generating fuel, changes in the cost of power from the AEP system, a general decline in off-system sales margins, and changes associated with the provision of Chapter 933, which allows APCo to retain 25% of the margins associated with off-system sales of electricity. Collectively, these fuel factor revisions have resulted in a net increase in rates of approximately $276 million since the enactment of Chapter 933. These fuel-related increases represent an increase of $16.41 per month for a residential customer using 1,000 kWh.[45]

[43] APCo has appealed this decision to the Supreme Court of Virginia. That appeal is currently pending.

[44] *Petition of Appalachian Power Company, For approval of a rate adjustment clause, RPS-RAC, to recover the incremental costs of participation in the Virginia renewable energy portfolio standard program, pursuant to Va. Code §§ 56-585.1 A 5 d and 56-585.2 E*, Case No. PUE-2011-00034, 2011 S.C.C. Ann. Rept. 471, Order Approving Rate Adjustment Clause (Nov. 3, 2011).

[45] Fuel-related charges currently represent $29.53, or 26.2%, of the total monthly bill for an APCo residential customer using 1,000 kWh.

C. Electric Cooperatives

Chapter 933 establishes significant new provisions for electric cooperatives. These provisions, which are contained in § 56-585.3 of the Code, authorize, among other things, the electric cooperatives to increase or decrease rates for distribution service at any time provided that the increase or decrease does not exceed a change in excess of 5% during any three-year period and to adjust certain fees without Commission approval. A subsequent change to this Code section allows electric cooperatives, without Commission approval, to modify their rate designs to collect all customer-related costs through a fixed monthly charge rather than through volumetric charges. The electric cooperatives have implemented a number of changes pursuant to these provisions as well as through a more traditional approval process. The electric cooperatives also have passed changes in the collection of purchased power costs through wholesale power cost adjustment clauses.

1. A&N Electric Cooperative

A&N Electric Cooperative ("A&N") has not made changes pursuant to the new provisions of Chapter 933. However, A&N has had several major proceedings before the Commission related to its acquisition of the Virginia portion of the distribution service territory and related facilities of Delmarva Power & Light Company. These proceedings were associated with approval of the acquisition, transfer of certificates, and transitional rates, terms and conditions of service. In approving the acquisition and related matters, the Commission required that A&N file a base rate case to implement a cost-based rate for its combined system on or before January 1, 2012. A&N complied with this requirement by filing a base rate application on November 22, 2011, in Case No. PUE-2011-00096. On July 25, 2012, the Commission issued its Final Order in that proceeding which, among other things, approved a stipulation that resulted in a $503,514 reduction in A&N's base rates.[46]

2. BARC Electric Cooperative

BARC Electric Cooperative ("BARC") administratively revised certain fees pursuant to § 56-585.3 A 3 of the Code. Specifically, on November 1, 2011, BARC increased its fees related to reconnection of service, collection of delinquent accounts, returned checks, trouble calls, and meter testing deposits. Additionally, BARC administratively increased its rates by 5% on January 1, 2012, in accordance with § 56-585.3 A 2 of the Code. BARC also has sought Commission approval of a seasonal reconnection charge in Case No. PUE-2012-00066. That case is currently pending before the Commission.

3. Craig-Botetourt Electric Cooperative

Craig-Botetourt Electric Cooperative ("CBEC") has not made changes pursuant to the new provisions of Chapter 933. CBEC did, however, seek Commission approval of a base rate change in Case No. PUE-2009-00065. By Final Order dated June 16, 2010, the Commission approved an increase of $1,397,132 effective for service rendered on and after April 27, 2010.[47]

4. Community Electric Cooperative

On July 1, 2009, Community Electric Cooperative ("CEC") administratively increased its rates by 5% in accordance with § 56-585.3 A 2 of the Code. Additionally, CEC filed an application for a base rate increase on June 19, 2012, in Case No. PUE-2012-00041. In its application, CEC is seeking an increase of approximately $1.18 million. That case is currently pending and proposed rates were placed in effect subject to refund on August 24, 2012.

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[46] *Application of A&N Electric Cooperative, For a revenue-neutral adjustment of its electric rates and consolidation of tariffs*, Case No. PUE-2011-00096, Doc. Con. Cen. No. 120730158, Final Order (July 25, 2012).
[47] *Application of Craig-Botetourt Electric Cooperative, For a general increase in electric rates*, Case No. PUE-2009-00065, 2010 S.C.C. Ann. Rept. 360, Final Order (June 16, 2010).

5. Central Virginia Electric Cooperative

Central Virginia Electric Cooperative ("CVEC") administratively revised certain of its fees pursuant to § 56-585.3 A 3. Specifically, on September 1, 2009, CVEC increased its fees related to reconnection of service, collection of delinquent accounts, and meter testing. Additionally, CVEC sought Commission approval of three base rate increases in Case Nos. PUE-2009-00013, PUE-2010-00095, and PUE-2012-00045. By order dated March 30, 2009, in Case No. PUE-2009-00013, the Commission approved an increase of approximately $2.3 million effective April 2, 2009.[48] In Case No. PUE-2010-00095, the Commission approved a stipulation which provided for a base rate increase of approximately $2.9 million to be effective May 1, 2011.[49] Case No. PUE-2012-00045 is currently pending before the Commission. CVEC seeks to increase rates by $15.2 million in that proceeding. This requested increase is largely attributable to increased purchased power costs.

6. Mecklenburg Electric Cooperative

Mecklenburg Electric Cooperative ("MEC") has not made changes to its rates, Schedule F fees or terms and conditions as permitted by Chapter 933.[50] However, the Commission approved a base rate increase of $7.1 million by Final Order dated September 17, 2009, in Case No. PUE-2009-00006.[51]

7. Northern Neck Electric Cooperative

On August 15, 2008, Northern Neck Electric Cooperative ("NNEC") filed an application in Case No. PUE-2008-00076 requesting an increase of $2.22 million. NNEC also proposed a

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[48] *Application of Central Virginia Electric Cooperative, For a Streamlined Increase in Rates*, Case No. PUE-2009-00013, 2009 S.C.C. Ann. Rept. 401, Order (Mar. 30, 2009).
[49] *Application of Central Virginia Electric Cooperative, For general rate relief*, Case No. PUE-2010-00095, 2011 S.C.C. Ann. Rept. 356, Final Order (Sept. 7, 2011).
[50] *See* specifically Va. Code § 56-585.3.
[51] *Application of Mecklenburg Electric Cooperative, For a general increase in electric rates*, Case No. PUE-2009-00066, 2009 S.C.C. Ann. Rept. 387, Final Order (Sept. 17, 2009).

significant rate design change that would have increased the fixed monthly access charge for residential customers. On January 13, 2009, the Commission issued a Final Order which, among other things, approved an increase of $2 million and lowered NNEC's proposed residential access charge of $22.23 per month to $16 per month.[52] Subsequently, NNEC exercised its authority pursuant to § 56-585.3 A 4 of the Code to increase administratively its monthly access fees in conjunction with a corresponding reduction in its delivery charges. This change increased the monthly access charge for residential customers from $16 to $22.23.

8. Northern Virginia Electric Cooperative

Northern Virginia Electric Cooperative ("NOVEC") has not made changes to its rates, Schedule F fees or terms and conditions as permitted by Chapter 933.[53] NOVEC did, however, propose a base rate reduction of approximately $9.8 million in Case No. PUE-2010-00044. By Final Order dated July 27, 2011, the Commission approved a base rate reduction of $17.5 million and directed that NOVEC return certain over-collections of purchased power costs through a special cash-back process.[54]

9. Prince George Electric Cooperative

Prince George Electric Cooperative ("PGEC") has not made changes to its rates, Schedule F fees or terms and conditions as permitted by Chapter 933.[55] However, PGEC was authorized to increase base rates by $2.3 million by Final Order dated April 6, 2010, in Case No. PUE-2009-00089.[56]

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[52] *Application of Northern Neck Electric Cooperative*, For a general increase in electric rates, Case No. PUE-2008-00076, 2009 S.C.C. Ann. Rept. 336, Final Order (Jan. 13, 2009).
[53] *See* specifically Va. Code § 56-585.3.
[54] *Application of Northern Virginia Electric Cooperative, For general rate relief,* Case No. PUE-2010-00044, 2011 S.C.C. Ann. Rept. 329, Final Order (July 27, 2011).
[55] *See* specifically Va. Code § 56-585.3.
[56] *Application of Prince George Electric Cooperative, For a general increase in electric rates*, Case No. PUE-2009-00089, 2010 S.C.C. Ann. Rept. 377, Final Order (Apr. 6, 2010).

10. Rappahannock Electric Cooperative

Rappahannock Electric Cooperative ("REC") administratively revised its terms and conditions of service and modified certain of its fees pursuant to § 56-585.3 A 3 of the Code. Specifically, on October 1, 2009, REC increased its fees related to temporary service, reconnection of service, collection of delinquent accounts, and meter testing deposits. Additionally, REC administratively increased its distribution rates effective November 1, 2009, in accordance with § 56-585.3 A 2 of the Code. REC also had two proceedings before the Commission related to its acquisition of a portion of the Virginia distribution service territory and related facilities of the Potomac Edison Company. These proceedings were associated with approval of the acquisition, transfer of certificates, and transitional rates, terms and conditions of service.

11. Southside Electric Cooperative

Southside Electric Cooperative ("SEC") has not made changes to rates, Schedule F fees or terms and conditions as permitted by Chapter 933.[57] The Commission granted SEC approval to establish a late payment fee of 1.5% in Case No. PUE-2011-00004.[58]

12. Shenandoah Valley Electric Cooperative

Shenandoah Valley Electric Cooperative ("SVEC") administratively revised its terms and conditions of service and eliminated certain fees pursuant to § 56-585.3 A 3 of the Code on April 15, 2010. SVEC also had two proceedings before the Commission related to its acquisition of a portion of the Virginia distribution service territory and certain facilities of the Potomac

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[57] *See* specifically Va. Code § 56-585.3.

[58] *Application of Southside Electric Cooperative, For approval of revisions to its existing terms and conditions, including a request to be allowed to implement a late fee,* Case No. PUE-2011-00004, 2011 S.C.C. Ann. Rept. 424, Final Order (Oct. 5, 2011)

Edison Company. These proceedings were associated with approval of the acquisition, transfer of certificates, and transitional rates, terms and conditions of service.

III. NEEDED GENERATION FACILITIES

The Seventh Enactment Clause of Chapter 933 specifically requires that this assessment report "include an analysis of, among other matters, the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load." Dominion, APCo, and the electric cooperatives are, either directly or indirectly through purchased power arrangements, members of PJM. PJM's primary mission is to ensure the safety, reliability and security of the bulk electric power system. In conjunction with this mission, PJM analyzes and forecasts the future electricity needs of the region and undertakes a planning process that is intended to ensure that the growth of the electric transmission system takes place efficiently and in an orderly fashion and that reliability is maintained. PJM's long-term transmission planning process seeks to identify future reliability violations and the upgrades necessary to prevent such violations. This process is intended to assure that the bulk power grid is sufficient to deliver power from available generation resources to loads within the PJM region. Transmission owners within PJM are obligated to construct these needed facilities, provided that they can obtain all necessary regulatory and environmental approvals, arrange financing, and acquire needed rights-of-way. PJM also imposes generating capacity obligations on its load serving members and requires that those members make forward commitments for meeting those obligations. Those commitments reflect needed reserve margins, including consideration of the forced outage rates of generation used to meet those obligations. As such, the "amount and reliability" of generation needed to serve Virginia load is directly impacted by PJM.

While Virginia historically has been a net importer of electrical energy strictly from the perspective of state geographical boundaries, this "importation" is not necessarily indicative that the "amount and reliability" of existing generating capability needed to serve Virginia load is inadequate. This "importation" is due primarily to the fact that Virginia utilities either own or financially support generating facilities that are located outside of the geographic borders of Virginia and that electrical system boundaries are not identical to state geographical boundaries. For example, Dominion owns the Mt. Storm generating station located in West Virginia, and APCo owns generating resources located in West Virginia and Ohio. In 2010, approximately 91% of the total supply of energy to Virginia's investor-owned electric utility customers was produced from facilities under the Commission's rate setting jurisdiction even though some of those facilities were located outside the geographic borders of the Commonwealth. These generating resources, while physically located outside Virginia's boundaries are nevertheless "jurisdictional" to Virginia and calling the power they produce "imports" can be misleading. Further, Virginia utilities historically have made economical purchases of energy from outside of Virginia when that energy has been cheaper than what can be produced in Virginia. As noted earlier, PJM seeks to assure that power can be delivered to load from available generation resources within the PJM region. As such, PJM seeks to assure that there is adequate transmission to serve Virginia load reliably even though some of the resources utilized to serve Virginia load are located outside of the Commonwealth.

It should be noted that the Virginia General Assembly enacted Chapters 476 and 903 of the 2008 Acts of Assembly during its 2008 Session. These duplicate enactments added Chapter 24 (§ 56-597 *et seq.*) of Title 56 to the Code. Chapter 24, entitled "Electric Utility Integrated Resource Planning" directs Virginia's IOUs to file IRPs with the Commission at least every two years, with the first filing due on September 1, 2009. These IRPs (most recently filed in 2011) require Virginia IOUs to detail their forecasts of load obligations and their plans to meet forecasted obligations through supply-side and demand-side resources to ensure adequate and reliable service.[59] Each IRP is reviewed by the Commission in a public proceeding in which the Commission ultimately must determine whether the IRPs are "reasonable and in the public interest."[60]

These IRPs examine the costs associated with future resource alternatives and how those resource alternatives would be dispatched in conjunction with existing resources. This type of analysis seeks to identify the optimum type or mix of future resources to serve Virginia load in a least cost and reliable manner. Thus, IRPs effectively work in conjunction with the PJM processes to address "the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load"[61] by examining each IOU's existing and projected portfolio of supply and demand side resources necessary to meet projected demand over a 15-year planning period.

The following discussion will briefly discuss the future needs of Dominion, APCo, and the electric cooperatives and the respective plans for meeting those needs.

A. Dominion Virginia Power

As a participant in PJM, Dominion relies on its generating resources, purchased power contracts, DSM initiatives, and short-term capacity purchases for satisfying its load serving obligations. Dominion's internal capacity (owned capacity, capacity acquired through long-term non-utility generation purchased power agreements, and DSM reductions) has been insufficient for meeting its obligations in recent years. This capacity deficit has been satisfied through

[59] Va. Code § 56-597 (definition of "Integrated Resource Plan") and § 56-598.1.
[60] Va. Code § 56-599 E.
[61] 7th Enactment Clause, Chapter 933, Virginia Acts of Assembly (2007).

short-term purchases including purchases from the PJM capacity market and is expected to average around 1,100 MW for the period 2012-2015. There has been ample available capacity within PJM to satisfy these shortfalls, and the transmission system has had sufficient deliverability for these short-term purchases. As such, this capacity deficit has not posed reliability concerns for Virginia. Dominion's recent construction of the Bear Garden and Virginia City Hybrid Energy Center generating facilities has reduced this internal capacity deficit. The Warren County facility that is now under construction and planned to be operational in 2015 essentially will eliminate this deficit for a brief period. Appendix 4 presents a graph of Dominion's expected net capacity position for the period 2013-2027. This expected net capacity position essentially represents, among other things, Dominion's expectations of the "amount" of new capacity necessary to serve Virginia native load requirements.

This new capacity can be comprised of differing types of resources with differing characteristics such as dispatch costs, renewable attributes, environmental emissions, etc. Consequently, the type of generation is driven by assessments of what mix of future resource additions will best meet native load needs and satisfy environmental requirements and public policy objectives in a least cost manner. The IRP process is intended to identify future capacity needs and the best mix of additions or demand-side measures for satisfying those needs. Further, the IRP process allows the Staff and other interested parties an opportunity to comment on Dominion's future plans and for the Commission to examine the appropriateness of those plans.

Once Dominion decides to develop a particular generating addition, it must first show that the facility is in the public interest. This showing is made either in the context of a certificate of public convenience and necessity ("CPCN") proceeding for approval of construction or a rate proceeding. In considering whether a facility is in the public interest, the

Commission examines whether there is a need (the "amount") for the proposed facility and whether the facility is the optimal least cost alternative (the "type") for satisfying that need. This combination of IRP, CPCN, and rate proceedings helps to ensure that the right "amount and type" of generating facilities are in place to serve Virginia's native load reliably and economically.

B. Appalachian Power Company

APCo is a member of the AEP system and historically has relied on the AEP Interconnection Agreement with other AEP affiliates to satisfy its shortfall. APCo's internal capacity historically has been insufficient to satisfy its obligations as determined under that interconnection agreement. The AEP system, however, historically has had sufficient capacity to satisfy the needs of its affiliated members. Consequently, APCo's interconnection agreement related deficit has not posed a reliability concern for Virginia. APCo recently constructed the Dresden facility in Ohio, which helps to eliminate a portion of APCo's shortfall. The need for Dresden was examined in the context of Case No. PUE-2011-00036.[62]

APCo and other members of the AEP Interconnection Agreement have provided notice of their intention to dissolve the AEP Interconnection Agreement effective December 31, 2013. In lieu of that agreement, APCo's current plans would be for APCo to become a stand-alone entity within PJM with some limited pooling arrangements with other AEP affiliates. Conceptually, APCo would be responsible for satisfying its internal requirements on a stand-alone basis going forward and APCo's capacity obligations would be determined under the PJM process. APCo's expected capacity position under such a scenario is detailed in Appendix 5 to this report. Under such a scenario, APCo expects that it would have sufficient capacity until 2014 based on its

[62] *Petition of Appalachian Power Company, For approval of a rate adjustment clause pursuant to § 56-585.1 A 6 of the Code of Virginia to recover the costs of the Dresden Generating Plant*, Case No. PUE-2011-00036, Doc. Con. Cen. No. 120110002, Final Order (Jan. 3, 2012).

existing resources and expected capacity changes. APCo plans to purchase existing generating capacity from other AEP pool members in conjunction with the dissolution of the AEP Interconnection Agreement. APCo's most recent projections indicate that this purchase would enable APCo to meet its needs through 2023.

The dissolution of the AEP Interconnection Agreement, the development of a new agreement, and APCo's acquisition of additional capacity will require approvals from the FERC and other state commissions as well as from the Commission. Commission approval of any such plans would examine whether these generating capacity acquisitions are appropriate under Virginia law. APCo has not yet sought SCC approval for the acquisition of additional capacity beyond that which the Dresden facility will provide. Additionally, APCo's generating plans will continue to be examined in the context of IRP proceedings and possibly future capacity-related cost recovery proceedings.

C. Electric Cooperatives

The majority of the electric cooperatives rely on Old Dominion Electric Cooperative ("ODEC") for satisfying their power supply needs. ODEC meets the needs of its members through a combination of its own generation and purchased power arrangements. ODEC is a member of PJM and is subject to meeting PJM's load serving obligations and undertakes its own planning process for determining how best to meet its future needs. ODEC is regulated by the FERC and is not subject to the Virginia IRP process.

Three Cooperatives, CBEC, CVEC, and NOVEC, are not members of ODEC and meet their internal needs through a combination of purchased power arrangements and owned generation. CBEC and CVEC rely almost entirely on purchased power arrangements.[63] CBEC purchases power from APCo and Dominion. CVEC relies on longer term purchased power

[63] CVEC owns a small amount of generation.

arrangements developed through a request for proposal process. NOVEC has entered into a number of longer term purchased power arrangements as well as purchases some power from short-term markets, and is involved in the construction of a 49.9 MW biomass generating facility in Halifax County, Virginia.

IV. PEER GROUP COMPARISON

Chapter 933 requires that Virginia electric utilities be compared to "those in the peer group of such utilities that meet the criteria enumerated in subdivision A 2 of § 56-585.1 of the Code of Virginia."[64] The peer group utilities for APCo and Dominion currently include: Duke, Entergy, FP&L, Georgia Power, Gulf Power, Mississippi Power, Progress Energy Carolinas, Progress Energy Florida, SCE&G, and Tampa Electric Company. In response to the directive to conduct peer group comparisons, this report contrasts typical bill information for the peer group with that of APCo and Dominion. Appendices 6, 7, and 8 present peer group bill comparisons and rankings.

Typical bill information was developed using information from various EEI publications. The EEI information was used to develop typical bills for residential, commercial, and industrial customers for Dominion, APCo and the peer group utilities. These typical bills then were used to examine the competitiveness of DVP's and APCo's rates with those of its peers that were in effect on July 1, 2007, and on January 1, 2012.[65] It should be noted that the typical bill comparisons are based on the annualized rates[66] in effect on January 1, 2012, and as such, do not reflect any subsequent or pending rate changes.

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[64] Chapter 933 does not require peer group analysis of rates for electric cooperatives.
[65] The latest information available from EEI analyses typical bills as of January 2, 2012.
[66] Annualized rates reflect a weighted average of summer and winter rates for those utilities that have such rates.

Dominion's January 1, 2012 annualized residential rates produce typical bills that rank DVP 11th lowest out of the 17 companies[67] examined and are below the U.S. averages and slightly above EEI's averages for the South Atlantic region.[68] DVP's typical residential bill rankings have slipped five places since July 1, 2007, sliding from the upper to the lower half of the peer group; that is, Dominion's rates have become less competitive. Dominion's commercial rates still seem competitive despite some decline in rankings since July 1, 2007. Dominion's January 1, 2012 annualized commercial rates produce typical bills that range from 7th to 11th lowest out of the 17 companies examined and are below the U.S. and South Atlantic regional averages. Dominion's industrial rates still appear competitive with the rates of the peer group despite a continued decline in rank. Dominion's January 1, 2012 annualized industrial rates produce bills that range from 6th to 13th lowest out of the 17 companies examined and are below the U.S. average and, for the most part, are below the South Atlantic regional average.

APCo's residential typical bill rankings for 2012 and July 1, 2007, are the same. APCo's January 1, 2012 residential rates produced typical bills that ranked 2nd lowest out of the 17 companies examined and are below the U.S. and South Atlantic regional averages. APCo's commercial rates also continue to be competitive despite some decline in rank for larger, higher load factor customers. APCo's January 1, 2012 annualized commercial rates produced typical bills that range from 2nd to 4th lowest out of the 17 companies examined and are below the U.S. and South Atlantic regional averages. APCo's January 1, 2012 industrial typical bills are ranked 1st to 4th lowest out of the 17 companies examined and are below the U.S. and South Atlantic regional averages. APCo's industrial bill rankings have slipped only slightly since July 1, 2007,

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[67] Many of the peer group companies serve in more than one state and have differing typical bills depending on the respective state. Consequently, the typical bill comparison may include multiple listings for certain peer group companies.

[68] EEI's South Atlantic region includes Delaware, the District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia.

and in some cases have improved, which seems to indicate that APCo's industrial rates are still competitive.

A review of reliability-related information for the peer group utilities did not show any discernible trends in reliability or any indication that Dominion's or APCo's overall ability to serve native load was notably different from that of the peer group. It should be noted that publicly available reliability related information for the peer group is limited. As such, reliability differences could only be developed on a somewhat superficial level.

Specific information regarding each peer group utility is provided below.

A. Alabama Power

Alabama Power's typical bills for January 1, 2012, were among the highest of the peer group for all classes of customers, and the associated rankings had slipped since July 1, 2007. Alabama Power's 2012 residential bills exceeded the average for the South Atlantic Region but were generally below the national average. Commercial bills were above the South Atlantic and national averages while industrial bills were generally below both averages for high load factor customers. Information regarding Alabama Power's generating reserves and resource planning activities was not publically available.

B. Duke Energy Carolinas

Duke's typical bills for 2012 were among the lowest of the peer group for all classes of customers. The associated rankings for residential customers were slightly below those for 2007 while the rankings for commercial and industrial customers were generally improved. Duke's 2012 typical bills were below both the South Atlantic and national averages. Duke meets the needs of its customers with a diverse range of resources including renewable, nuclear, coal, and gas generation resources, purchased power contracts, as well as energy efficiency and demand-side management programs.

C. Entergy Mississippi

Entergy's typical bills for 2012 were among the lowest of the peer group for residential and commercial customers while typical bills for industrial users were in the low to mid range. All of Entergy's typical bill rankings were significantly improved since July 1, 2007. Entergy's 2012 typical bills were below both the South Atlantic and national averages. Information regarding Entergy's resource mix and generating reserves was largely unavailable.

D. Florida Power & Light

FP&L's typical bills for 2012 were among the lowest of the peer group for residential customers while typical bills for industrial and commercial customers were in the mid to high range. All of FP&L's typical bill rankings were significantly improved since July 1, 2007. FP&L's 2012 typical bills were below both the South Atlantic and national averages. FP&L meets the needs of its customers with a diverse range of resources including renewable, nuclear, coal, and gas generation resources, purchased power contracts as well as energy efficiency and demand-side management programs. FP&L is planning to meet future needs with a combination of new gas units; upgrading some existing units to gas-fired, combined-cycle facilities; nuclear unit upgrades; and additional DSM activities.

E. Georgia Power

With a decline in rankings for all customer classes since 2007, Georgia Power's typical residential bills for 2012 were in the high range of the peer group while typical bills for industrial and commercial customers were among the highest of the peer group. Georgia Power's 2012 residential bills exceeded the average for the South Atlantic Region but were generally below the national average. Commercial bills and bills for larger industrial users were above the South Atlantic and national averages. Georgia Power also is developing new nuclear generation; other publicly available information regarding Georgia Power's generating reserves and resource planning activities is limited.

F. Gulf Power

Gulf Power's typical bills for 2012 were in the high range of the peer group for all customer groups with a slight decline in rankings as compared to July 1, 2007. Gulf Power's 2012 typical bills were generally higher than both the South Atlantic and national averages. Gulf Power meets the needs of its customers with a range of resources including coal and gas generation resources, purchased power contracts, as well as energy efficiency and demand-side management programs. Gulf Power is planning to meet future needs through purchased power arrangements.

G. Mississippi Power

Mississippi Power's typical residential bills for 2012 were in the high range of the peer group while typical bills for industrial and commercial customers were in the mid-range of the peer group. Rankings for the residential and commercial customers were roughly the same as in 2007 while the rankings for industrial typical bills were slightly better in 2012. Mississippi Power's 2012 residential bills exceeded the average for the South Atlantic Region but were generally below the national average. Commercial and industrial bills were generally below both averages. Publicly available information regarding Mississippi Power's generating reserves and resource planning activities was limited.

H. Progress Energy Carolinas

Progress Energy Carolinas' typical residential and industrial bills for 2012 were in the mid-range of the peer group while typical bills for commercial customers were in the low to mid-range. Changes in rankings between 2007 and 2012 varied depending on the state and differing usage levels. Progress Energy Carolinas' 2012 typical bills were generally below both the South Atlantic and national averages. Progress Energy Carolinas meets the needs of its customers with a range of resources including nuclear, coal, hydro and gas generation resources, purchased power contracts as well as energy efficiency and demand-side management programs. Progress Energy Carolinas is planning to meet future needs with combustion turbines and increased DSM. Progress Energy Carolinas also will continue to consider nuclear and advanced clean coal generation alternatives.

I. Progress Energy Florida

Progress Energy Florida's typical bills for 2012 were in the high range of the peer group for all customer groups. Changes in rankings between 2007 and 2012 varied up and down depending on the different usage levels. Progress Energy Florida's 2012 residential and commercial bills exceeded the average for the South Atlantic Region but were generally below the national average while typical bills for larger industrial customers exceeded both of those averages. Progress Energy Florida's generating resources reflect a range of resources including nuclear, coal, and gas generation resources, purchased power contracts as well as energy efficiency and demand-side management programs. Progress Energy Florida is planning to meet future needs with the construction of a natural gas-fired, combined-cycle facility and a nuclear unit.

J. South Carolina Electric & Gas

SCE&G's typical bills for 2012 were in the high range of the peer group for all customer groups with rankings generally declining since 2007. SCE&G's 2012 residential and commercial bills exceeded both the average for the South Atlantic Region and national averages. Industrial bills typically exceeded the South Atlantic average but were below the national average. SCE&G currently owns coal, natural gas, and hydro generating facilities and purchases power from cogeneration projects. SCE&G also is developing new nuclear generation.

K. Tampa Electric

Tampa Electric's typical bills for 2012 were in the mid-range of the peer group for residential customers, the mid to high-range for commercial customers, and the high-range for industrial customers with rankings generally improving since 2007. Tampa Electric's 2012 residential bills were generally below the South Atlantic and national averages. Commercial bills were generally above the South Atlantic average but below the national average while industrial bills for larger users generally exceeded both averages. Tampa Electric owns fossil steam units, combined-cycle units, combustion turbine units, internal combustion diesel units, and an integrated coal gasification combined-cycle unit. Tampa Electric plans to meet its future needs by constructing a combined-cycle facility and a combustion turbine facility.

RESIDENTIAL
CONSUMER ELECTRIC RATES IN VIRGINIA
Expressed in $ per 1000 kWh

Utilities	Jul-07	Jul-12	Change	Percent Increase
IOU				
Appalachian Power Company	$66.61	$112.59	$45.98	69.03%
Dominion Virginia Power	$90.60	$105.74	$15.14	16.71%
Old Dominion/Kentucky Utilities	$67.57	$93.35	$25.78	38.15%
Electric Cooperative				
A&N	$122.59	$117.27	-$5.32	-4.34%
BARC	$123.18	$123.50	$0.32	0.26%
Central Virginia	$83.04	$123.19	$40.15	48.35%
Community	$122.37	$107.72	-$14.65	-11.97%
Craig Botetourt	$114.90	$148.28	$33.38	29.05%
Mecklenburg	$121.71	$130.54	$8.83	7.25%
Northern Neck	$126.35	$130.67	$4.32	3.42%
Northern Virginia	$129.20	$119.24	-$9.96	-7.71%
Prince George	$118.62	$123.59	$4.97	4.19%
Rappahannock	$127.72	$123.43	-$4.29	-3.36%
Shenandoah Valley	$115.12	$109.23	-$5.89	-5.12%
Southside	$133.32	$127.49	-$5.83	-4.37%

Notes
1. Sales and Use, Consumption and Local Utility taxes are not included in the rate calculations.
2. DVP's 2012 rates are annualized and include the Biennial Review Credit. DVP's rates exclude changes in Riders S and T1, effective July 16 and Sept. 1, respectively.

DOMINION VIRGINIA POWER
Residential Bill Increases Since July 1, 2007

Bill as of 7/1/2007	$90.60
Increases Granted Per Code Section:	
56-585.1 A 4 (Transmission Rate Adj)	$4.25
56-585.1 A 5 (DSM Rate Adj)	$0.70
56-585.1 A 6 Generation Rate Riders:	
Rider R	$1.42
Rider S	$4.74
Rider W	$0.66
Rider B	$0.12
Fuel	$4.74
Bill as of 9/1/2012	**$107.23**
Pending Increases Per Code Section:	
56-585.1 A 5 (DSM Rate Adj)	$0.19
56-585.1 A 6 (Generation Rate Adj)	$1.11
Bills as of 4/1/2013	**$108.53**

Note:

The 50 basis point increase on ROE for meeting the Renewable Energy Portfolio Standard and the resulting fair combined return on equity will be reflected in Dominion's next biennial review and could potentially impact rate levels or refunds.

These calculations exclude a temporary base rate credit of $1.32.

APPENDIX 3

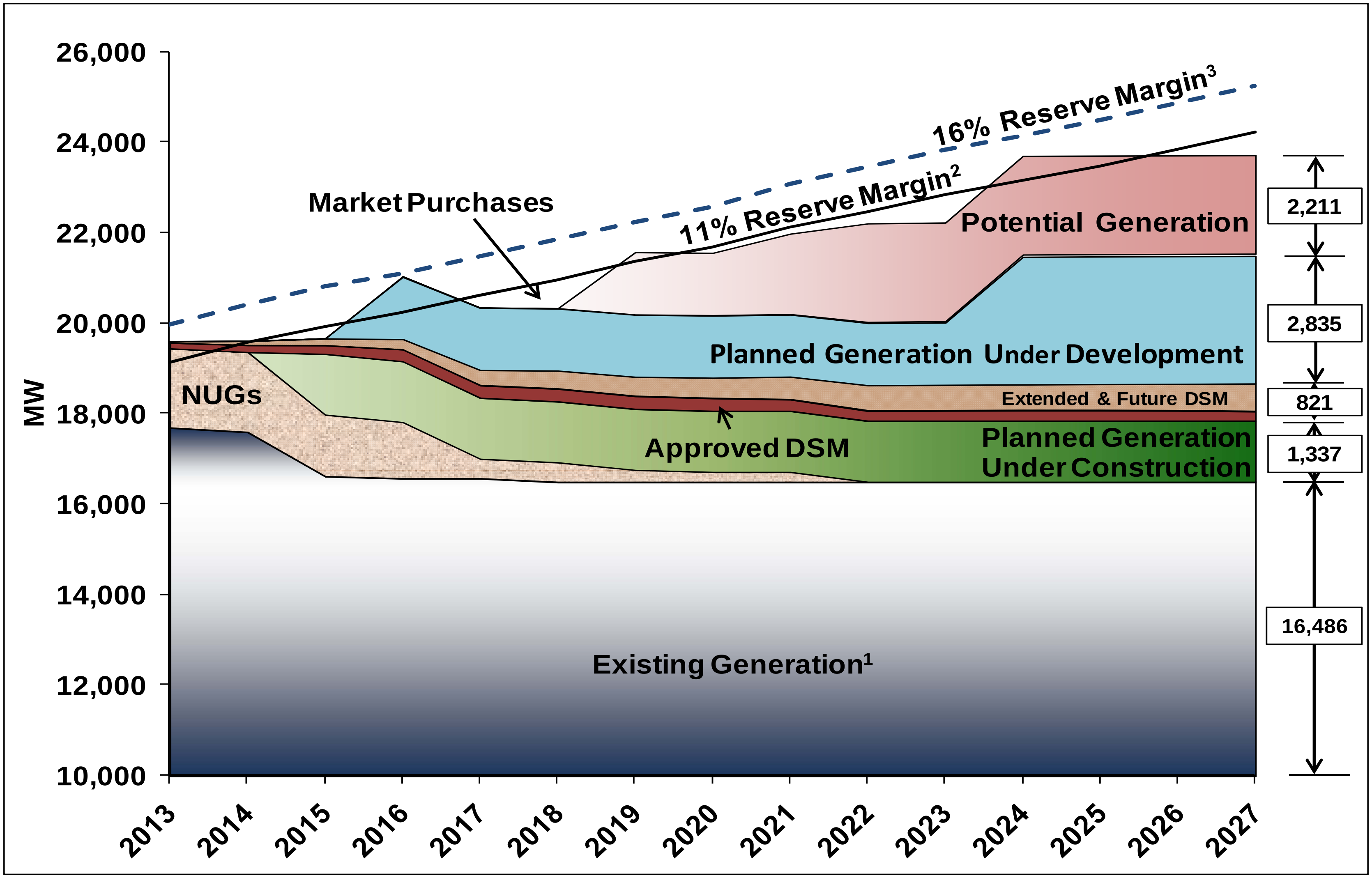
APPALACHIAN POWER COMPANY
Residential Bill Increases Since
July 1, 2007

Bill as of 7/1/07	$66.61
Increases Granted Per Code Section:	
56-582 C (Base Rate Increase)	$13.12
56-582 B (Reliability & Environmental Adj)	($1.84)
56-585.1 A (Going-In & Biennial Rate Reviews)[1]	$9.92
56-585.1 A 4 (Transmission Rate Adj)	$2.76
56-585.1 A 5 (Environmental Rate Adj)	$3.46
56-585.1 A 6 (Generation Rate Adj)	$2.15
Fuel	$16.41
Bill as of 9/1/12	**$112.59**

Note:

[1]Includes effect of 50 basis point increase on ROE for meeting the Renewable Energy Portfolio Standard.

Dominion Virginia Power Expected Capacity Position



APPENDIX 5

APCo Expected Capacity Position

	2012 (MW)	2013 (MW)	2014 (MW)	2015 (MW)	2016 (MW)	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2026 (MW)
Total Existing Capacity	5,874	5,933	8,039	7,036	6,881	6,882	6,882	6,917	6,910	6,902	6,896	6,897	6,892	6,447	6,443
Expected New Capacity	494	496	491	496	499	499	499	499	499	499	499	499	499	853	853
Net Generation Capacity	**6,368**	**6,429**	**8,531**	**7,532**	**7,380**	**7,381**	**7,382**	**7,416**	**7,409**	**7,401**	**7,395**	**7,396**	**7,391**	**7,300**	**7,296**
Expected Demand-side Reductions	**133**	**133**	**190**	**232**	**287**	**351**	**369**	**384**	**411**	**435**	**453**	**470**	**487**	**498**	**504**
Available Capacity Resources	**6,501**	**6,562**	**8,721**	**7,764**	**7,667**	**7,733**	**7,750**	**7,800**	**7,820**	**7,835**	**7,848**	**7,866**	**7,878**	**7,798**	**7,801**
Expected PJM Capacity Obligation	**6,261**	**6,325**	**6,964**	**7,130**	**7,352**	**7,409**	**7,476**	**7,544**	**7,604**	**7,700**	**7,774**	**7,827**	**7,888**	**7,989**	**8,069**
Net Utility Capacity Position	**240**	**236**	**1,757**	**634**	**315**	**324**	**275**	**256**	**216**	**136**	**74**	**39**	**-10**	**-190**	**-268**

Note: Capacity values have been adjusted to reflect expected unforced unit availabilty factors.

Peer Group Bill Comparison and Rankings
Residential

Monthly Usage of 500 kWh:

	Jul-07	**Jan-12**	**Percentage Change**	**2007 Rank**	**2012 Rank**	**Rankings Change**
Alabama Power	$58.25	$68.43	17.48%	13	14	-1
Appalachian Power Company (Va)	$37.60	$51.53	37.05%	2	2	0
Appalachian Power Company (WV)	$37.32	$53.90	44.43%	1	5	-4
Dominion North Carolina Power	$51.84	$56.82	9.61%	8	9	-1
Dominion Virginia Power	$49.70	$60.58	21.89%	6	11	-5
DUKE Energy Carolinas (NC)	$45.78	$54.41	18.85%	4	6	-2
DUKE Energy Carolinas (SC)	$42.29	$51.91	22.75%	3	3	0
Entergy Mississippi, Inc	$59.18	$53.62	-9.40%	14	4	10
FP&L Company	$54.45	$50.85	-6.61%	11	1	10
Georgia Power	$47.84	$62.63	30.92%	5	12	-7
Gulf Power	$56.07	$68.49	22.15%	12	15	-3
Mississippi Power	$70.04	$72.06	2.88%	17	17	0
Progress Energy Carolinas, Inc. (NC)	$51.16	$56.66	10.75%	7	8	-1
Progress Energy Carolinas, Inc. (SC)	$52.08	$55.84	7.22%	9	7	2
Progress Energy Florida, Inc.	$59.29	$66.09	11.47%	15	13	2
SCE&G	$54.30	$69.16	27.37%	10	16	-6
Tampa Electric Company	$61.64	$58.84	-4.54%	16	10	6
Average For South Atlantic	$54.35	$59.86	10.14%			
USA Average	$59.34	$66.63	12.29%			

Peer Group Bill Comparison and Rankings
Residential

Monthly Usage of 750 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$82.59	$95.21	15.28%	14	15	-1
Appalachian Power Company (Va)	$52.16	$73.12	40.18%	2	2	0
Appalachian Power Company (WV)	$50.93	$75.33	47.91%	1	5	-4
Dominion North Carolina Power	$73.00	$80.31	10.01%	7	7	0
Dominion Virginia Power	$71.04	$87.34	22.94%	6	11	-5
DUKE Energy Carolinas (NC)	$66.05	$76.76	16.21%	4	6	-2
DUKE Energy Carolinas (SC)	$60.35	$74.47	23.40%	3	4	-1
Entergy Mississippi, Inc	$78.57	$71.15	-9.44%	11	1	10
FP&L Company	$78.95	$73.24	-7.24%	12	3	9
Georgia Power	$68.60	$89.30	30.17%	5	12	-7
Gulf Power	$78.97	$97.14	23.01%	13	16	-3
Mississippi Power	$92.48	$94.72	2.42%	17	14	3
Progress Energy Carolinas, Inc. (NC)	$73.36	$81.33	10.86%	8	9	-1
Progress Energy Carolinas, Inc. (SC)	$74.87	$80.51	7.53%	9	8	1
Progress Energy Florida, Inc.	$84.81	$94.64	11.59%	15	13	2
SCE&G	$77.70	$99.48	28.03%	10	17	-7
Tampa Electric Company	$88.10	$82.87	-5.94%	16	10	6
Average For South Atlantic	$78.09	$85.87	9.96%			
USA Average	$85.68	$96.22	12.30%			

Peer Group Bill Comparison and Rankings
Residential

Monthly Usage of 1000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$104.94	$119.91	14.27%	14	14	0
Appalachian Power Company (Va)	$66.72	$94.69	41.92%	2	2	0
Appalachian Power Company (WV)	$64.55	$96.75	49.88%	1	4	-3
Dominion North Carolina Power	$94.17	$103.79	10.22%	7	7	0
Dominion Virginia Power	$90.59	$112.31	23.98%	6	11	-5
DUKE Energy Carolinas (NC)	$86.33	$99.11	14.80%	4	6	-2
DUKE Energy Carolinas (SC)	$78.42	$97.03	23.73%	3	5	-2
Entergy Mississippi, Inc	$98.00	$88.74	-9.45%	10	1	9
FP&L Company	$103.46	$95.63	-7.57%	13	3	10
Georgia Power	$90.23	$117.15	29.83%	5	12	-7
Gulf Power	$101.87	$125.80	23.49%	12	16	-4
Mississippi Power	$114.76	$117.22	2.14%	17	13	4
Progress Energy Carolinas, Inc. (NC)	$95.56	$106.00	10.93%	8	9	-1
Progress Energy Carolinas, Inc. (SC)	$96.33	$103.85	7.81%	9	8	1
Progress Energy Florida, Inc.	$110.34	$123.19	11.65%	15	15	0
SCE&G	$101.10	$129.97	28.56%	11	17	-6
Tampa Electric Company	$114.54	$106.90	-6.67%	16	10	6
Average For South Atlantic	$101.70	$111.80	9.93%			
USA Average	$111.68	$125.91	12.74%			

Peer Group Bill Comparison and Rankings
Commercial

Demand of 3 kW and Usage of 375 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$53	$77	45.28%	10	13	-3
Appalachian Power Company (Va)	$30	$40	33.33%	2	2	0
Appalachian Power Company (WV)	$28	$39	39.29%	1	1	0
Dominion North Carolina Power	$47	$51	8.51%	5	6	-1
Dominion Virginia Power	$45	$52	15.56%	3	7	-4
DUKE Energy Carolinas (NC)	$49	$60	22.45%	7	9	-2
DUKE Energy Carolinas (SC)	$46	$52	13.15%	4	7	-3
Entergy Mississippi, Inc	$55	$51	-7.27%	11	6	5
FP&L Company	$49	$44	-9.88%	7	3	4
Georgia Power	$58	$74	28.12%	12	12	0
Gulf Power	$50	$60	20.00%	8	9	-1
Mississippi Power	$69	$72	4.35%	13	11	2
Progress Energy Carolinas, Inc. (NC)	$50	$60	20.00%	8	9	-1
Progress Energy Carolinas, Inc. (SC)	$48	$50	4.17%	6	5	1
Progress Energy Florida, Inc.	$51	$56	9.80%	9	8	1
SCE&G	$50	$64	28.00%	8	10	-2
Tampa Electric Company	$48	$49	2.88%	6	4	2
Average For South Atlantic	$50	$55	10.00%			
USA Average	$55	$61	10.91%			

Peer Group Bill Comparison and Rankings
Commercial

Demand of 3kW and Usage of 1000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$123	$232	88.62%	13	16	-3
Appalachian Power Company (Va)	$66	$129	95.45%	2	2	0
Appalachian Power Company (WV)	$62	$133	114.52%	1	4	-3
Dominion North Carolina Power	$97	$151	55.67%	6	5	1
Dominion Virginia Power	$95	$160	68.42%	5	7	-2
DUKE Energy Carolinas (NC)	$113	$184	62.83%	9	12	-3
DUKE Energy Carolinas (SC)	$110	$183	66.40%	7	11	-4
Entergy Mississippi, Inc	$130	$156	20.00%	14	6	8
FP&L Company	$115	$130	13.22%	11	3	8
Georgia Power	$134	$249	85.54%	15	17	-2
Gulf Power	$112	$198	76.79%	8	14	-6
Mississippi Power	$137	$172	25.55%	16	9	7
Progress Energy Carolinas, Inc. (NC)	$92	$170	84.78%	3	8	-5
Progress Energy Carolinas, Inc. (SC)	$94	$175	86.17%	4	10	-6
Progress Energy Florida, Inc.	$118	$186	57.63%	12	13	-1
SCE&G	$110	$199	80.91%	7	15	-8
Tampa Electric Company	$114	$114	-0.24%	10	1	9
Average For South Atlantic	$114	$172	50.88%			
USA Average	$122	$183	50.00%			

Peer Group Bill Comparison and Rankings
Commercial

Demand of 40 kW and Usage of 10,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$1,094	$1,288	17.73%	17	15	2
Appalachian Power Company (Va)	$619	$846	36.67%	2	3	-1
Appalachian Power Company (WV)	$614	$951	54.89%	1	8	-7
Dominion North Carolina Power	$780	$867	11.15%	5	4	1
Dominion Virginia Power	$836	$1,020	22.01%	7	11	-4
DUKE Energy Carolinas (NC)	$757	$825	8.98%	4	1	3
DUKE Energy Carolinas (SC)	$733	$834	13.82%	3	2	1
Entergy Mississippi, Inc	$1,041	$936	-10.09%	13	7	6
FP&L Company	$1,055	$988	-6.33%	14	10	4
Georgia Power	$1,089	$1,394	28.01%	16	17	-1
Gulf Power	$905	$1,133	25.19%	9	13	-4
Mississippi Power	$1,009	$971	-3.77%	12	9	3
Progress Energy Carolinas, Inc. (NC)	$803	$884	10.09%	6	5	1
Progress Energy Carolinas, Inc. (SC)	$839	$899	7.15%	8	6	2
Progress Energy Florida, Inc.	$971	$1,299	33.78%	11	16	-5
SCE&G	$945	$1,198	26.77%	10	14	-4
Tampa Electric Company	$1,065	$1,040	-2.31%	15	12	3
Average For South Atlantic	$992	$1,066	7.46%			
USA Average	$1,081	$1,195	10.55%			

Peer Group Bill Comparison and Rankings
Commercial

Demand of 40 kW and Usage of 14,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$1,378	$1,617	17.34%	16	15	1
Appalachian Power Company (Va)	$775	$1,028	32.65%	1	2	-1
Appalachian Power Company (WV)	$786	$1,225	55.85%	2	10	-8
Dominion North Carolina Power	$1,032	$1,152	11.63%	8	6	2
Dominion Virginia Power	$999	$1,238	23.92%	6	11	-5
DUKE Energy Carolinas (NC)	$985	$1,053	6.90%	5	3	2
DUKE Energy Carolinas (SC)	$951	$1,005	5.67%	3	1	2
Entergy Mississippi, Inc	$1,354	$1,209	-10.71%	14	7	7
FP&L Company	$1,355	$1,215	-10.36%	15	8	7
Georgia Power	$1,263	$1,616	27.94%	11	14	-3
Gulf Power	$1,164	$1,474	26.63%	9	13	-4
Mississippi Power	$1,262	$1,222	-3.17%	10	9	1
Progress Energy Carolinas, Inc. (NC)	$982	$1,092	11.20%	4	4	0
Progress Energy Carolinas, Inc. (SC)	$1,030	$1,111	7.86%	7	5	2
Progress Energy Florida, Inc.	$1,299	$1,733	33.41%	12	17	-5
SCE&G	$1,315	$1,666	26.69%	13	16	-3
Tampa Electric Company	$1,488	$1,452	-2.40%	17	12	5
Average For South Atlantic	$1,287	$1,371	6.53%			
USA Average	$1,387	$1,535	10.67%			

Peer Group Bill Comparison and Rankings
Commercial

Demand of 500 kW and Usage of 150,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$15,449	$17,621	14.06%	17	17	0
Appalachian Power Company (Va)	$8,967	$11,683	30.29%	2	4	-2
Appalachian Power Company (WV)	$8,673	$13,405	54.56%	1	9	-8
Dominion North Carolina Power	$11,465	$12,761	11.30%	8	7	1
Dominion Virginia Power	$10,371	$13,349	28.71%	5	8	-3
DUKE Energy Carolinas (NC)	$10,306	$10,888	5.65%	4	1	3
DUKE Energy Carolinas (SC)	$9,852	$11,365	15.35%	3	3	0
Entergy Mississippi, Inc	$12,482	$10,907	-12.62%	9	2	7
FP&L Company	$14,829	$13,779	-7.08%	15	10	5
Georgia Power	$13,175	$16,852	27.91%	11	15	-4
Gulf Power	$13,008	$16,382	25.94%	10	14	-4
Mississippi Power	$13,570	$13,872	2.23%	12	11	1
Progress Energy Carolinas, Inc. (NC)	$10,913	$11,744	7.61%	6	5	1
Progress Energy Carolinas, Inc. (SC)	$11,451	$12,129	5.92%	7	6	1
Progress Energy Florida, Inc.	$13,914	$15,362	10.41%	14	13	1
SCE&G	$13,871	$17,580	26.74%	13	16	-3
Tampa Electric Company	$14,907	$14,937	0.20%	16	12	4
Average For South Atlantic	$13,854	$14,557	5.07%			
USA Average	$14,480	$15,889	9.73%			

Peer Group Bill Comparison and Rankings
Commercial

Demand of 500 kW and Usage of 180,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$17,580	$20,152	14.63%	17	17	0
Appalachian Power Company (Va)	$9,707	$12,964	33.55%	1	4	-3
Appalachian Power Company (WV)	$9,959	$15,321	53.84%	2	9	-7
Dominion North Carolina Power	$13,016	$14,510	11.48%	8	8	0
Dominion Virginia Power	$11,146	$14,447	29.62%	3	7	-4
DUKE Energy Carolinas (NC)	$12,010	$12,574	4.70%	5	2	3
DUKE Energy Carolinas (SC)	$11,380	$12,301	8.09%	4	1	3
Entergy Mississippi, Inc	$14,480	$12,602	-12.97%	9	3	6
FP&L Company	$16,986	$15,327	-9.77%	15	10	5
Georgia Power	$14,486	$18,515	27.81%	10	14	-4
Gulf Power	$14,680	$18,646	27.02%	11	15	-4
Mississippi Power	$15,310	$15,635	2.12%	13	11	2
Progress Energy Carolinas, Inc. (NC)	$12,257	$13,252	8.12%	6	5	1
Progress Energy Carolinas, Inc. (SC)	$12,884	$13,680	6.18%	7	6	1
Progress Energy Florida, Inc.	$16,346	$17,940	9.75%	14	13	1
SCE&G	$14,915	$19,035	27.62%	12	16	-4
Tampa Electric Company	$17,136	$16,854	-1.64%	16	12	4
Average For South Atlantic	$15,838	$16,422	3.69%			
USA Average	$16,506	$18,055	9.38%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 75 kW and Usage of 15,000 kWh:

	Jul-07	**Jan-12**	**Percentage Change**	**2007 Rank**	**2012 Rank**	**Rankings Change**
Alabama Power	$1,646	$1,914	16.28%	14	15	-1
Appalachian Power Company (Va)	$945	$1,314	39.05%	1	4	-3
Appalachian Power Company (WV)	$982	$1,508	53.56%	2	8	-6
Dominion North Carolina Power	$1,153	$1,283	11.27%	5	3	2
Dominion Virginia Power	$1,368	$1,711	25.07%	8	11	-3
DUKE Energy Carolinas (NC)	$1,140	$1,245	9.21%	4	2	2
DUKE Energy Carolinas (SC)	$1,112	$1,174	5.60%	3	1	2
Entergy Mississippi, Inc	$1,582	$1,424	-9.99%	12	5	7
FP&L Company	$1,668	$1,626	-2.53%	15	10	5
Georgia Power	$1,814	$2,270	25.13%	17	17	0
Gulf Power	$1,423	$1,771	24.46%	10	12	-2
Mississippi Power	$1,598	$1,523	-4.69%	13	9	4
Progress Energy Carolinas, Inc. (NC)	$1,317	$1,445	9.72%	6	7	-1
Progress Energy Carolinas, Inc. (SC)	$1,354	$1,426	5.32%	7	6	1
Progress Energy Florida, Inc.	$1,505	$2,017	34.02%	11	16	-5
SCE&G	$1,407	$1,783	26.72%	9	13	-4
Tampa Electric Company	$1,715	$1,811	5.59%	16	14	2
Average For South Atlantic	$1,531	$1,691	10.45%			
USA Average	$1,699	$1,879	10.59%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 75 kW and Usage of 30,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$2,758	$3,231	17.15%	15	15	0
Appalachian Power Company (Va)	$1,534	$2,077	35.40%	1	3	-2
Appalachian Power Company (WV)	$1,625	$2,431	49.60%	2	8	-6
Dominion North Carolina Power	$2,098	$2,350	12.01%	8	6	2
Dominion Virginia Power	$1,981	$2,478	25.09%	5	11	-6
DUKE Energy Carolinas (NC)	$1,943	$1,976	1.70%	4	2	2
DUKE Energy Carolinas (SC)	$1,914	$1,930	0.82%	3	1	2
Entergy Mississippi, Inc	$2,712	$2,406	-11.28%	13	7	6
FP&L Company	$2,792	$2,475	-11.36%	16	10	6
Georgia Power	$2,473	$3,100	25.35%	11	14	-3
Gulf Power	$2,394	$3,049	27.36%	9	13	-4
Mississippi Power	$2,548	$2,466	-3.22%	12	9	3
Progress Energy Carolinas, Inc. (NC)	$1,991	$2,201	10.55%	6	4	2
Progress Energy Carolinas, Inc. (SC)	$2,093	$2,224	6.26%	7	5	2
Progress Energy Florida, Inc.	$2,733	$3,647	33.44%	14	17	-3
SCE&G	$2,472	$3,241	31.11%	10	16	-6
Tampa Electric Company	$2,830	$2,770	-2.14%	17	12	5
Average For South Atlantic	$2,553	$2,729	6.89%			
USA Average	$2,760	$3,060	10.87%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 75 kW and
Usage of 50,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$4,144	$4,887	17.93%	14	17	-3
Appalachian Power Company (Va)	$2,027	$2,931	44.60%	1	3	-2
Appalachian Power Company (WV)	$2,169	$3,237	49.24%	2	6	-4
Dominion North Carolina Power	$3,110	$3,504	12.67%	8	8	0
Dominion Virginia Power	$2,513	$3,280	30.52%	3	7	-4
DUKE Energy Carolinas (NC)	$2,738	$2,673	-2.37%	5	2	3
DUKE Energy Carolinas (SC)	$2,548	$2,560	0.48%	4	1	3
Entergy Mississippi, Inc	$4,217	$3,714	-11.93%	15	10	5
FP&L Company	$4,291	$3,607	-15.94%	16	9	7
Georgia Power	$3,298	$4,141	25.55%	10	13	-3
Gulf Power	$3,688	$4,753	28.88%	11	16	-5
Mississippi Power	$3,815	$3,724	-2.39%	12	11	1
Progress Energy Carolinas, Inc. (NC)	$2,838	$3,158	11.28%	6	4	2
Progress Energy Carolinas, Inc. (SC)	$2,999	$3,209	7.00%	7	5	2
Progress Energy Florida, Inc.	$4,117	$4,437	7.77%	13	15	-2
SCE&G	$3,201	$4,316	34.83%	9	14	-5
Tampa Electric Company	$4,316	$4,048	-6.22%	17	12	5
Average For South Atlantic	$3,747	$3,910	4.35%			
USA Average	$4,079	$4,519	10.79%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 1,000 kW
and Usage of 200,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$17,040	$17,834	4.66%	7	5	2
Appalachian Power Company (Va)	$12,080	$16,143	33.63%	2	4	-2
Appalachian Power Company (WV)	$11,816	$18,537	56.88%	1	6	-5
Dominion North Carolina Power	$16,827	$18,610	10.60%	6	7	-1
Dominion Virginia Power	$18,032	$22,913	27.07%	8	13	-5
DUKE Energy Carolinas (NC)	$14,138	$15,769	11.54%	4	3	1
DUKE Energy Carolinas (SC)	$13,569	$14,476	6.68%	3	1	2
Entergy Mississippi, Inc	$16,792	$14,652	-12.74%	5	2	3
FP&L Company	$22,428	$22,346	-0.37%	15	12	3
Georgia Power	$24,315	$30,673	26.15%	17	17	0
Gulf Power	$20,282	$25,043	23.47%	11	16	-5
Mississippi Power	$20,366	$20,729	1.78%	12	8	4
Progress Energy Carolinas, Inc. (NC)	$21,238	$22,242	4.73%	14	11	3
Progress Energy Carolinas, Inc. (SC)	$20,473	$21,437	4.71%	13	9	4
Progress Energy Florida, Inc.	$19,582	$21,979	12.24%	9	10	-1
SCE&G	$19,638	$24,446	24.48%	10	15	-5
Tampa Electric Company	$22,471	$23,425	4.24%	16	14	2
Average For South Atlantic	$19,365	$21,318	10.09%			
USA Average	$21,543	$23,711	10.06%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 1,000 kW
and Usage of 400,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$27,526	$28,898	4.98%	7	5	2
Appalachian Power Company (Va)	$18,905	$25,278	33.71%	1	2	-1
Appalachian Power Company (WV)	$19,611	$29,814	52.03%	2	6	-4
Dominion North Carolina Power	$27,553	$30,894	12.13%	8	8	0
Dominion Virginia Power	$23,198	$30,227	30.30%	3	7	-4
DUKE Energy Carolinas (NC)	$24,195	$25,566	5.67%	5	3	2
DUKE Energy Carolinas (SC)	$23,465	$25,192	7.36%	4	1	3
Entergy Mississippi, Inc	$29,876	$25,684	-14.03%	10	4	6
FP&L Company	$36,809	$32,666	-11.26%	16	11	5
Georgia Power	$33,422	$42,194	26.25%	14	17	-3
Gulf Power	$31,431	$40,139	27.71%	12	16	-4
Mississippi Power	$32,072	$32,599	1.64%	13	10	3
Progress Energy Carolinas, Inc. (NC)	$30,726	$32,688	6.39%	11	12	-1
Progress Energy Carolinas, Inc. (SC)	$29,721	$31,469	5.88%	9	9	0
Progress Energy Florida, Inc.	$35,797	$39,168	9.42%	15	15	0
SCE&G	$26,566	$34,764	30.86%	6	13	-7
Tampa Electric Company	$37,244	$36,206	-2.79%	17	14	3
Average For South Atlantic	$31,333	$33,395	6.58%			
USA Average	$34,242	$37,273	8.85%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 1,000 kW
and Usage of 650,000 kWh:

	Jul-07	**Jan-12**	**Percentage Change**	**2007 Rank**	**2012 Rank**	**Rankings Change**
Alabama Power	$39,160	$41,216	5.25%	8	7	1
Appalachian Power Company (Va)	$24,996	$32,608	30.45%	1	1	0
Appalachian Power Company (WV)	$25,197	$39,313	56.02%	2	5	-3
Dominion North Carolina Power	$38,946	$42,494	9.11%	7	8	-1
Dominion Virginia Power	$29,656	$39,371	32.76%	3	6	-3
DUKE Energy Carolinas (NC)	$35,566	$34,292	-3.58%	6	3	3
DUKE Energy Carolinas (SC)	$33,147	$33,190	0.13%	4	2	2
Entergy Mississippi, Inc	$42,782	$36,017	-15.81%	11	4	7
FP&L Company	$53,718	$45,959	-14.44%	16	12	4
Georgia Power	$44,083	$55,569	26.06%	12	15	-3
Gulf Power	$45,368	$59,009	30.07%	14	17	-3
Mississippi Power	$45,315	$45,839	1.16%	13	11	2
Progress Energy Carolinas, Inc. (NC)	$41,331	$44,490	7.64%	10	10	0
Progress Energy Carolinas, Inc. (SC)	$40,703	$43,431	6.70%	9	9	0
Progress Energy Florida, Inc.	$52,713	$56,819	7.79%	15	16	-1
SCE&G	$35,226	$46,692	32.55%	5	13	-8
Tampa Electric Company	$55,711	$52,183	-6.33%	17	14	3
Average For South Atlantic	$45,106	$47,070	4.35%			
USA Average	$49,130	$53,310	8.51%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 50,000 kW
and Usage of 15,000,000 kWh:

	Jul-07	**Jan-12**	**Percentage Change**	**2007 Rank**	**2012 Rank**	**Rankings Change**
Alabama Power	$1,096,080	$1,149,069	4.83%	7	7	0
Appalachian Power Company (Va)	$696,139	$960,520	37.98%	1	3	-2
Appalachian Power Company (WV)	$701,199	$1,146,501	63.51%	2	6	-4
Dominion North Carolina Power	$1,146,269	$1,309,072	14.20%	9	10	-1
Dominion Virginia Power	$1,013,942	$1,314,225	29.62%	5	11	-6
DUKE Energy Carolinas (NC)	$862,988	$1,005,677	16.53%	4	5	-1
DUKE Energy Carolinas (SC)	$801,751	$881,069	9.89%	3	1	2
Entergy Mississippi, Inc	$1,075,416	$928,877	-13.63%	6	2	4
FP&L Company	$1,216,104	$970,123	-20.23%	11	4	7
Georgia Power	$1,228,754	$1,548,836	26.05%	13	16	-3
Gulf Power	$1,285,055	$1,621,075	26.15%	15	17	-2
Mississippi Power	$1,224,279	$1,235,612	0.93%	12	8	4
Progress Energy Carolinas, Inc. (NC)	$1,259,600	$1,331,496	5.71%	14	12	2
Progress Energy Carolinas, Inc. (SC)	$1,149,025	$1,301,825	13.30%	10	9	1
Progress Energy Florida, Inc.	$1,377,733	$1,521,305	10.42%	16	15	1
SCE&G	$1,096,300	$1,411,450	28.75%	8	13	-5
Tampa Electric Company	$1,480,056	$1,487,905	0.53%	17	14	3
Average For South Atlantic	$1,194,536	$1,271,281	6.42%			
USA Average	$1,305,418	$1,427,612	9.36%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 50,000 kW
and Usage of 25,000,000 kWh:

	Jul-07	Jan-12	Percentage Change	2007 Rank	2012 Rank	Rankings Change
Alabama Power	$1,553,774	$1,635,001	5.23%	7	7	0
Appalachian Power Company (Va)	$936,782	$1,251,920	33.64%	2	1	1
Appalachian Power Company (WV)	$933,799	$1,515,191	62.26%	1	6	-5
Dominion North Carolina Power	$1,602,003	$1,773,072	10.68%	9	9	0
Dominion Virginia Power	$1,272,262	$1,678,845	31.96%	4	8	-4
DUKE Energy Carolinas (NC)	$1,340,713	$1,341,237	0.04%	5	4	1
DUKE Energy Carolinas (SC)	$1,242,936	$1,258,775	1.27%	3	2	1
Entergy Mississippi, Inc	$1,584,464	$1,317,989	-16.82%	8	3	5
FP&L Company	$1,868,045	$1,425,680	-23.68%	15	5	10
Georgia Power	$1,662,124	$2,096,443	26.13%	11	14	-3
Gulf Power	$1,842,501	$2,375,858	28.95%	14	17	-3
Mississippi Power	$1,788,838	$1,804,448	0.87%	13	11	2
Progress Energy Carolinas, Inc. (NC)	$1,734,000	$1,853,796	6.91%	12	12	0
Progress Energy Carolinas, Inc. (SC)	$1,611,425	$1,803,425	11.91%	10	10	0
Progress Energy Florida, Inc.	$2,058,918	$2,232,366	8.42%	16	16	0
SCE&G	$1,442,700	$1,888,550	30.90%	6	13	-7
Tampa Electric Company	$2,218,723	$2,126,981	-4.13%	17	15	2
Average For South Atlantic	$1,747,675	$1,807,927	3.45%			
USA Average	$1,885,249	$2,051,067	8.80%			

Peer Group Bill Comparison and Rankings
Industrial

Demand of 50,000 kW
and Usage of 32,500,000 kWh:

	Jul-07	**Jan-12**	**Percentage Change**	**2007 Rank**	**2012 Rank**	**Rankings Change**
Alabama Power	$1,897,045	$1,999,450	5.40%	7	8	-1
Appalachian Power Company (Va)	$1,117,264	$1,470,470	31.61%	2	1	1
Appalachian Power Company (WV)	$1,078,126	$1,777,783	64.90%	1	6	-5
Dominion North Carolina Power	$1,943,803	$2,121,072	9.12%	9	9	0
Dominion Virginia Power	$1,466,002	$1,952,310	33.17%	3	7	-4
DUKE Energy Carolinas (NC)	$1,674,698	$1,609,769	-3.88%	5	3	2
DUKE Energy Carolinas (SC)	$1,482,015	$1,504,673	1.53%	4	2	2
Entergy Mississippi, Inc	$1,966,250	$1,609,823	-18.13%	10	4	6
FP&L Company	$2,357,002	$1,767,349	-25.02%	15	5	10
Georgia Power	$1,971,914	$2,486,949	26.12%	11	14	-3
Gulf Power	$2,072,465	$2,748,632	32.63%	13	16	-3
Mississippi Power	$2,171,316	$2,184,503	0.61%	14	12	2
Progress Energy Carolinas, Inc. (NC)	$2,027,025	$2,182,746	7.68%	12	11	1
Progress Energy Carolinas, Inc. (SC)	$1,929,308	$2,150,708	11.48%	8	10	-2
Progress Energy Florida, Inc.	$2,628,573	$2,833,209	7.79%	16	17	-1
SCE&G	$1,702,500	$2,246,375	31.95%	6	13	-7
Tampa Electric Company	$2,772,723	$2,606,289	-6.00%	17	15	2
Average For South Atlantic	$2,145,019	$2,198,476	2.49%			
USA Average	$2,302,376	$2,500,935	8.62%			