PART II

STATUS OF RETAIL ACCESS AND COMPETITION

IN THE COMMONWEALTH

INTRODUCTION

In this part of the SCC's report to the Governor and to the Commission on Electric Utility Restructuring ("CEUR"), we provide an update regarding activities in Virginia related to competition in the electricity market. Since § 56-596 of the Restructuring Act[1] directs us to file a report each September 1st, the section on the status of competition in the Commonwealth will provide a history of the transition to competition. Each year we will prepare a chronology and summary to detail the progress of competition and activities of interest during the past twelve months.

During the past year this Commission has continued with the scheduled implementation of the Restructuring Act. Currently, the vast majority of the Commonwealth's 3.2 million electricity customers have the right to choose an alternative supplier of electricity. In compliance with the Act, all electricity customers of Virginia's investor-owned utilities and electric cooperatives are eligible to switch to a competitive supplier except for about 29,800 customers in the southwestern part of the Commonwealth[2] and approximately 7,700 customers served by Powell Valley Electric Cooperative.

As discussed later in this report, work continued during the past year to address restructuring issues such as those related to default service, market-based costs, and RTOs, to name a few. Virginia finds itself in a similar situation as last year in that there have not been any new competitive offers to provide electricity supply. Similarly to other states that offer retail access, competitive activity remains stagnant in Virginia. One supplier continues to serve

[1] Virginia Electric Utility Restructuring Act, Chapter 23 (§ 56-576 et seq.) of Title 56 of the Code of Virginia.

[2] Amending legislation passed by the 2003 Session of the General Assembly as House Bill 2637 to § 56-580 of the Code of Virginia, suspended application of the Restructuring Act to Kentucky Utilities operating in the Commonwealth as Old Dominion Power Company until such time as the utility provides retail electric services in any other service territory in any jurisdiction to customers who have the right to receive competitive retail electric energy.

a small portion of customers in northern Virginia with a limited renewable resource, but no other electricity supply offers have been made.

Despite modifications to the Commission approved pilot programs of Dominion Virginia Power ("Dominion" or "DVP") as a means to encourage competitive activity, there has been no activity other than the licensing of a few more competitive service providers ("CSPs"). Likewise, Commission approval of Dominion's and American Electric Power's ("AEP" or "APCo")[3] integration into PJM has not yet spurred any competitive activity. Further details will be discussed later in this report.

The Commission continues to implement the Restructuring Act. The following pages provide an overview of the continued transition to full retail access and updated information regarding a diverse list of activities and investigations devoted to the development of a competitive market.

[3] Doing business in Virginia as Appalachian Power Company, "Appalachian Power" or "APCo".

ACTIVITY RELATED TO RETAIL ACCESS

This section provides a review of activity during the past 12 months to further develop retail access in Virginia. In addition to supplying details on the number of customers who switched energy providers, there will also be discussions of the licensing of suppliers and aggregators and marketing activity.

Full Retail Access

Full retail access was available to practically all Virginia electric consumers on January 1, 2004. Allegheny Power ("AP")[4], APCo and Delmarva Power & Light ("Delmarva") implemented full customer choice within their respective Virginia service territories on January 1, 2002. To date, no CSP has registered with AP or APCo to provide service within their respective Virginia service territories. Only one CSP is fully registered with Delmarva but has not pursued serving customers.

Dominion's service area was fully opened to retail choice on January 1, 2003. To date, six CSPs and aggregators are registered with DVP to provide service within its Virginia territory. Only one CSP, Pepco Energy Services ("PES"), is currently serving customers. PES withdrew its offer in May 2003, but continues to serve about 1,600 customers. Although PES is not currently mass-marketing its service, it will accept enrollments for new customers to replace slots that become available as customers drop PES to return to DVP's capped rates. To date, all CSPs that have served customers in DVP's territory have been affiliates of an electric or natural gas utility.

[4] Doing business in Virginia as the Potomac Edison Company ("PE").

All of the electric distribution cooperatives,[5] complied with the Commission's Order in Case PUE-2000-00740 and implemented retail access in each of their respective territories by January 1, 2004. To date, there has been no competitive activity among the Cooperatives except for a small number of CSP inquiries regarding Rappahannock and Northern Virginia Electric Cooperatives.

Suppliers/Aggregators

The Commission is responsible under §§ 56-587 and 56-588 for licensing suppliers and aggregators interested in participating in the retail access programs in Virginia. The Staff has established a streamlined mechanism for processing license applications. To facilitate the prompt processing of license requests, the SCC website provides access to the licensing requirements.[6] Staff has an internal deadline of 45 days from the receipt of a complete application to the issuance of a license. Thus far, that deadline has been met for all applications. Currently, twenty-eight electric and natural gas CSPs and aggregators are licensed by the Commission to participate in full retail access. A list of licensed suppliers can be found at the end of this section.

In order to participate in an LDC's retail choice program, a CSP must also complete a registration process with the utility. Electronic Data Interchange ("EDI")[7] testing between the CSP and the utility is required as part of the registration process. The testing must be completed before a supplier can begin enrolling customers.

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[5] A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Inc., Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative, Inc., collectively the "Cooperatives".

[6] Guidelines to become licensed as a competitive service provider or aggregator are available on the SCC's website at: http://www.vaenergychoice.org/suppliers/licensesteps.asp .

[7] EDI standards and guidelines are established by the Virginia Electronic Data Transfer Working Group ("VAEDT"). Further information may be found at http://www.vaedt.org .

Currently, six CSPs, Dominion Retail, Pepco Energy Services, Washington Gas Energy Services, Commerce Energy, ECONnergy Energy Company and WPS Energy Services are fully registered with DVP. Additionally, six aggregators, Advantage Energy, American PowerNet Management, Buckeye Energy Brokers, EnergyWindow, WPS Energy Services and Independent Energy Consultants are fully registered with DVP.

WGES is fully registered with Delmarva and Old Mill Power has completed EDI testing but not yet completed its registration with Delmarva.

Licensed Competitive Service Provider/Aggregator as of August 5, 2005

Company Name	Customer Class(es)	LDC Service Territories in which CSP registered	Services Provided
Pepco Energy Services	R, C, I	DVP, WG, SG, CGV	Natural gas, electric and aggregation (E&G)
Dominion Retail, Inc.	R, C,I	DVP, WG	Natural gas, electric and aggregation (E&G)
Washington Gas Energy Svcs	R, C, I	DPL, DVP WG, SG, CGV	Electric & natural gas
EnergyWindow, Inc.	R, C, I	DVP	Aggregation (E&G)
Advantage Energy	R, C, I	DVP	Aggregation (E&G)
Amerada Hess Corporation	C, I	WG, SG	Electric, natural gas and aggregation (E&G)
Energy Svcs Mgmt Va LLC, d/b/a Virginia Energy Consortium	C		Aggregation (E)
Bollinger Energy Corporation	C, I	WG, CGV	Natural gas
Tiger Natural Gas, Inc.	R, C, I	WG, SG, CGV	Natural gas
NOVEC Energy Solutions, Inc		WG, SG, CGV	Electric, natural gas and aggregation (E&G)
Utility Resource Solutions, LP			Natural gas
Old Mill Power Company	R, C, I	DVP (pending), DPL (pending)	Electric, natural gas and aggregation (E&G)
Metromedia Energy, Inc.	C, I	WG	Natural gas
Stand Energy Corporation	C, I		Natural gas
ACN Energy, Inc.	R	WG	Natural gas
AOBA Alliance, Inc.	C		Aggregation (E&G)
UGI Energy Services, Inc.	C, I		Natural gas
Constellation NewEnergy, Inc.	C,I	DVP (pending), WG, SG	Electric, natural gas and aggregation (E&G)
Select Energy, Inc.	C,I		Electric and natural gas
American PowerNet Management, LP	C,I	DVP	Aggregation (E&G)
JP Communications Group	R,C		Aggregation (E)
Buckeye Energy Brokers, Inc.	R,C,I	DVP	Aggregation (E &G)
ECONnergy Energy Co., Inc.	R,C	DVP	Natural Gas
Independent Energy Consultants, Inc.	R,C,I	DVP	Aggregation (E &G)
WPS Energy Services	R,C, I	DVP	Electric and aggregation (E)
Commerce Energy	R,C,I	DVP	Electric
Delta Energy LLC	C,I		Natural gas and aggregation (G)
Renaissance Energy, LLC	C,I		Electric and natural gas aggregation

Customer Type: "R" residential; "C" commercial; "I" industrial

LDC Service Territories:

AEP-VA = AEP Virginia
AP = Allegheny Power
DVP = Dominion Virginia Power
DPL = Delmarva Power & Light
CGV = Columbia Gas of VA
WG = Washington Gas
SG = Shenandoah Gas (division of WG)

Marketing

The only marketing activity that has taken place in any electricity retail access program is in DVP's service territory. Pepco Energy Services continues to provide "green power" to residential customers in Northern Virginia. The renewable generation source is biomass, consisting of landfill gas from a source in central Virginia. The offer consists of 51% renewable energy offered at a premium above DVP's price-to-compare.

Since full retail access began, PES's renewable energy offer is the only offer residential electricity customers have received. To date, about 1,600 residential and 20 commercial customers are enrolled with PES. No industrial customer has yet chosen a competitive electricity service provider.

Customer Participation

Pepco Energy Services began serving retail access customers in January 2002 and is currently the only active CSP. Out of approximately 3.2 million customers in Virginia who currently have the right to choose an alternative supplier of electric energy, about 1,600 customers are currently doing so, or less than 0.1%.

The following table provides the number of electricity customers in the Virginia LDC territories that are currently eligible to shop for a CSP and how many are enrolled with a CSP as of July 12, 2005.

Company	# of Eligible Residential Customers*	# of Eligible Nonresidential Customers*	# of Residential Customers Currently Served By a CSP	# of Non-Residential Customers Currently Served By a CSP
DVP	1,901,785	227,581	1,604	20
AEP-VA	426,723	69,257	0	0
AP	78,584	14,186	0	0
DPL	18,320	3,169	0	0
NOVEC	112,245	7,660	0	0
REC	82,344	4,415	0	0
SVEC	27,861	4,686	0	0
CEC	8,357	1,578	0	0
A&N	10,133	786	0	0
BARC	11,310	580	0	0
CVEC	28,103	2,772	0	0
CBEC	5,684	556	0	0
MEC	28,461	1,707	0	0
NNEC	15,791	956	0	0
PGEC	8,935	1,01	0	0
SSEC	47,730	2,134	0	0
TOTAL	2,818,887	344,218	1,604	20

***** Customer numbers as of December 31, 2004

FUNCTIONAL UNBUNDLING AND WIRES CHARGES

This section of the report will describe the steps involved with setting the price for energy while rate caps are in effect. Unbundled generation rates and market prices for generation are essential components to determine wires charges. Additionally, the generation market prices established by the Commission for each incumbent utility help competitive suppliers determine whether they can or will make competitive offers in utilities' service territories.[8]

The first step is the functional unbundling of rates into separate generation, transmission and distribution components as required under § 56-590 of the Restructuring Act. The next step is the calculation of the market price for generation which, when compared to the unbundled generation rate, will determine the amount of an appropriate wires charge, if any. The procedures for calculating market prices and wires charges are detailed in § 56-583 of the Act. A final important component of the pricing of energy is the determination of the price-to-compare for each incumbent electric utility. This benchmark price can then be used by consumers for comparison shopping.

Functional Unbundling

Section 56-590 of the Restructuring Act required Virginia's incumbent electric utilities to file plans detailing the proposed separation of the incumbents' generation, retail transmission and distribution functions. The cases provided the companies an opportunity to file proposed retail access tariffs applicable to customers and third party suppliers. As part of these cases, the Commission also "unbundled" the companies' retail rates for purposes of establishing wires charges.

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[8] It should be noted, however, that if a utility's unbundled generation rate is *less* than the Commission-determined market price for generation, then the price a CSP must "beat" in order to make a competitive offer would be the unbundled generation rate, and not the market price.

Rate unbundling in these cases consisted of separating the utilities' bundled rates,[9] for retail electricity service into separate components to reflect distribution, transmission and generation charges. Transmission charges were also unbundled into base and ancillary services. The companies' retail access tariffs addressed and defined the operational relationship between the utilities and competitive service providers in the provision of competitive generation service within the incumbents' respective service territories. These tariffs, among other things, addressed CSP creditworthiness requirements, noncompliance and default, load forecasting and scheduling procedures, and CSP billing. Each of the functional unbundling cases was discussed in previous Commission Reports and will not be restated here.

Wires Charges Calculations

The Restructuring Act directs the Commission to establish wires charges for each incumbent electric utility effective upon the commencement of customer choice. In order to establish such wires charges, the Commission must determine projected market prices for energy and subtract those projected market prices from each utility's embedded generation rate. According to the Act, these projected market prices and the resulting wires charges may be adjusted on no more than an annual basis. The embedded generation rate includes fuel costs as determined by the Commission pursuant to § 56-249.6 as amended by the General Assembly in 2004.

Market price determination for retail access began in 2001 with the market price and wires charges determinations for APCo and DVP.[10] In 2002, the Commission established the market price determination methodology for the electric distribution cooperatives within the Commonwealth and by early 2004 had completed the determination of wires charges for all

[9] A bundled rate is a single rate for electricity comprised of all service elements: generation, transmission and distribution.
[10] Delmarva and Potomac Edison waived their right to wires charges throughout the transition period.

relevant electric cooperatives in the Commonwealth.

The Commission approved the basic methodology for APCo and DVP in its order of November 19, 2001 in Case No. PUE-2001-00306. This order set a general schedule for making annual changes to wires charges for each calendar year. If either company wishes to revise its wires charges for the upcoming calendar year, it must file market price and, if applicable, fuel factor applications with the Commission by July 1 of the current year. This allows wires charge determinations to be finalized in October or about three months before they will be implemented and enables the companies to make necessary calculations and carry out compliance filings before the implementation date. Such a timely determination also allows time for CSPs to formulate and implement pricing and marketing strategies for the following year.

In its November 19, 2001 order, the Commission also decided that the projected market prices for generation to be used in wires charge calculations should be based on "forward prices"[11] for electric power traded in the wholesale market. The Commission made this decision in the belief that forward prices are the most appropriate indicators of projected market prices and that forward markets were functioning reasonably well.

The forward price method considers prices at two delivery or receipt points (Cinergy and PJM West) for a calendar year of data. Although DVP has incorporated a value for capacity in its projected market price formulation, there is no explicit inclusion of a capacity value within the generally approved methodology. Price adjustments for load-shaping are accomplished using methods similar to those employed in the pilot programs. Finally, the Commission specified a method for adjusting market prices in order to consider the cost to transport power to distant markets.

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[11] "Forward prices" generally refer to agreements made today for the future purchase and sale of a specified

This methodology has been modified only slightly following the Commission's November 19, 2001 Order. In 2002, the Commission allowed DVP to incorporate a capacity adder into the projected market price for the company's service territory for the calendar year 2003 and beyond based on the historical monthly values of capacity as reflected in the PJM Capacity Credit Market. Subsequent to the Commission's Order, DVP has incorporated the capacity adder into its market price calculations. This adder, by raising market prices, lowers the resulting wires charges and, thus, provides some additional "headroom" for any CSP competing in the Virginia retail electricity market.

Projected market prices for DVP during 2005 were above the company's capped generation rates for most rate classes meaning that there would be no wires charges for the company's customers in these classes. In light of this, DVP waived any applicable wire charges for the remaining classes for 2005; therefore, wires charges are not applicable to any DVP customers that choose to take service from a CSP during 2005. On July 1, 2005, DVP submitted an application to potentially impose wires charges in 2006. This application is currently under review by Staff.

This year, APCo has informed the Commission that, as has been the case since 2001, the company does not seek to impose a wires charge for any of its Virginia customers for the upcoming year. APCo's decision not to seek wires charges for 2006 implies that projected market prices for 2006 within its service territory will again be above its capped generation rate.

With respect to the Cooperatives, on May 24, 2002 in Case No. PUE-2001-00306, the Commission adopted a proposal from the Cooperatives and ruled that the basic methodology for calculating generation market prices that it approved for DVP and APCo should be utilized

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quantity of electric power at some specified location for a specified time period.

by the Virginia electric distribution cooperatives,[12] subject to the Commission's continued review. There is, however, one basic difference in the methodology as applied to the Cooperatives as opposed to that for DVP and APCo. Whereas, the capped rates for generation for the investor-owned utilities are adjusted annually for the cost of fuel on a prospective basis, the capped rates for the Cooperatives are adjusted monthly on an historical basis. This distinction is to allow the Cooperatives to continue a decades-old practice that allows them to make monthly adjustments for their wholesale cost of power. For consistency, the Commission allows the Cooperatives to vary the market price monthly by the same amount as the wholesale cost of power adjustment in order to maintain a constant wires charge throughout the year.

For the most part, projected market prices among the Cooperatives for 2005 were below the capped generation rates for the Cooperatives, although this situation was not universal. Central Virginia Electric Cooperative, once again, did not seek to collect wires charges. In addition, projected market prices for BARC Electric Cooperative and Craig-Botetourt Electric Cooperative were above the respective cooperatives' capped rates, meaning that neither cooperative is collecting wires charges in 2005. With respect to the remaining cooperatives, each imposed a wires charge for one or more of its rate schedules for 2005.

Price-to-Compare

Once rates have been unbundled and the appropriate wires charges have been calculated, a company's price-to-compare can be determined. The price-to-compare is a cents per kilowatt-hour benchmark value that can be used by a customer to evaluate offers from competitive service providers.

[12] A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Inc., Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative.

The price-to-compare is determined by taking the sum of the unbundled generation rate and the unbundled transmission rate and subtracting the wires charge. If a company does not have a wires charge, because its embedded generation rate is less than the current estimated market price, or if a company has waived its right to a wires charge, the price-to-compare is the sum of the unbundled generation and unbundled transmission rates.

As described above, none of the investor-owned utilities imposed a wires charge component within its prices-to-compare during 2005, while all but three of the Cooperatives included a wires charge component within the respective prices-to-compare for at least one or more of its rate schedules.

The table below shows the prices-to-compare for the investor-owned utilities in Virginia. A similar table for the electric distribution cooperatives is not shown given that, as described above, the Cooperatives' price-to-compare changes on a monthly basis due to the application of monthly wholesale power adjustments.

The 2005 price-to-compare values for the subject investor-owned utilities are:

Customer Class	DVP	APCo	PE	Delmarva
Residential	6.078¢/kWh	3.366¢/kWh	3.87¢/kWh	6.47¢/kWh
Small Commercial	5.699¢/kWh	3.187¢/kWh	3.96¢/kWh	7.00¢/kWh
Large Commercial	5.435¢/kWh	3.705¢/kWh	3.90¢/kWh	Not applicable
Small Industrial	4.629¢/kWh	3.082¢/kWh	3.55¢/kWh	6.73¢/kWh
Large Industrial	4.217¢/kWh	2.901¢/kWh	3.34¢/kWh	6.00¢/kWh
Churches	6.651¢/kWh	3.104¢/kWh	Not applicable	Not applicable

As can be seen, the price-to-compare differs among classes of customers. The values above are averages for each customer class. The actual price-to-compare for an individual customer will vary depending upon that customer's usage and rate schedule.

New market price and wires charge calculations are scheduled to be completed in October for use in 2006. Soon after that time, the new price-to-compare values will also be available. Price-to-compare information will appear on the monthly bill of customers who have not yet chosen an alternative supplier.

The Restructuring Act as amended by the 2004 Session of the General Assembly as Senate Bill 651, directs the Commission to promulgate rules and regulations, and adopt certain market-based pricing methodologies, in order to implement two new provisions of the Act. One of the new statutory provisions relate to the permissible wires charges pursuant to § 56-583 of the Act. The Commission initiated a proceeding with its Order of June 16, 2004 in Case No. PUE-2004-00068[13], to permit an exemption to any wires charges imposed by the electric LDC.

The statutory exemption permits such customers to elect up-front to forego paying an LDC's wires charges when switching supply service to a CSP, and agreeing to forego capped-rate service and pay market-based costs upon any future return to the LDC. The process to establish this exemption program parallels the process to establish another exemption program regarding minimum stay provisions. The status of these programs is further discussed in the section regarding minimum stay.

[13] Dockets regarding restructuring issues may be found on the SCC's website at: http://www.scc.virginia.gov/caseinfo.htm.

CONSUMER EDUCATION

The Virginia Energy Choice ("VEC") consumer education program continued for the past year in a state of limited activity. The main functions of the program consisted of responding to public inquiries about the status of retail competition and maintaining information resources on the restructured energy market available to consumers on a website and a toll-free information line. The program distributed over 4,000 VEC consumer guides and other publications over the last year.

The VEC website (www.vaenergychoice.org) has extensive information on the changes coming to the energy market in Virginia and is routinely updated. The site receives between 8,700 and 10,600 individual visits per month. Web visitors can print information sheets or request consumer guides be mailed to them. The SCC also responds to a monthly average of 15 email inquiries from the site.

The VEC toll-free information line (1-877-YES-2004) is supported by an automated system that provides callers with the choice of listening to a brief recording on energy restructuring, leaving address information to receive consumer education materials, or requesting a call from SCC staff. The information line continues to receive between 500 and 600 calls per month. In an average month, 18 callers leave messages for SCC staff to respond to general questions about choice and energy related topics.

Staff is experiencing an increase in the number of calls and emails regarding the lack of electric choice and limited natural gas choice. Consumers are contacting CSPs from the list of suppliers on the website only to find that no CSP is offering energy supply at a price to which the customer may attribute savings. Rising energy costs encourage consumers to seek relief by contacting the utilities, which in turn refer the consumers to the VEC's website, only to find no competitive offerings among alternative CSPs.

In the coming year, the SCC expects to maintain the VEC consumer education program at the existing modest level and provide for necessary updates to education materials. Conditions in the competitive energy supply market will determine the size and scope of future energy choice outreach activities.

DEVELOPMENT OF A COMPETITIVE STRUCTURE

This section details activities underway to continue the establishment of the framework within which effective competition may develop. While these activities cannot, in and of themselves, assure that competition will flourish, there is no doubt that a competitive market will require both rules to guide behavior and systems to control business operations. In addition, the continuing development of our energy infrastructure, including power plants, transmission lines and natural gas pipelines, is an essential element of future energy reliability. Finally, properly functioning regional transmission organizations are generally recognized as a necessity for an effective competitive wholesale market, which is a precursor to an effective retail market.

Rules Governing Retail Access

The Restructuring Act directed the SCC to promulgate regulations to guide the transition.[14] The Rules Governing Retail Access to Competitive Energy Services ("Retail Access Rules" or "Rules"), adopted by Commission Order in Case No. PUE-2001-00013,[15] currently consist of 12 sections in Chapter 312 (20 VAC 5-312-10 et seq.) of Title 20 of the Virginia Administrative Code and pertain to various relationships among the local distribution companies, competitive service providers and retail customers.

The Commission's Staff continues to monitor and evaluate the development of the energy marketplace, including our experiences in Virginia, and recommend further adjustments to such Rules, if necessary. Future legislative or Commission decisions may also affect the

[14] The rules were to be developed for both a competitive electricity market and a competitive natural gas market. Our focus in this report is the electricity market.
[15] The Rules Governing Retail Access to Competitive Energy Services are available on the Commission's website at: http://www.scc.virginia.gov/division/restruct/rules.htm .

developing energy marketplace. The Retail Access Rules will be revised and amended as needed to incorporate future rules that may be adopted by the SCC.[16]

Minimum Stay

The current Retail Access Rules permit the local distribution companies under certain circumstances, to require large commercial and industrial customers who return to capped rate service to remain a customer of the LDC for a minimum period of 12 months.[17] The Restructuring Act as amended by the 2004 Session of the General Assembly as Senate Bill 651, directs the Commission to promulgate rules and regulations, and adopt certain market-based pricing methodologies, in order to implement two new provisions of the Act. One of the new statutory provisions relates to the minimum stay requirements adopted by the Commission pursuant to § 56-577 E of the Act. The Commission initiated a proceeding with its Order of June 16, 2004 in Case No. PUE-2004-00068[18], to permit an exemption to the current minimum stay requirement.

The statutory exemption permits such customers to elect to accept market-based costs for electric energy as an alternative to being subject to the 12-month minimum stay provision. The recent Commission Order charged the Staff to invite interested parties to participate in a work group to assist the development of the rules, as well as an appropriate methodology, necessary to implement this new statutory provision. Several questions were also included in the Commission Order for interested parties to provide responses to prompt discussion at the initial work group meeting held on August 19, 2004. Two additional meetings were held on

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[16] Dockets regarding restructuring issues may be found on the SCC's website at: http://www.scc.virginia.gov/caseinfo.htm.

[17] Retail Access Rule 20 VAC 5-312-80 Q

[18] Dockets regarding restructuring issues may be found on the SCC's website at: http://www.scc.virginia.gov/caseinfo.htm.

September 10th and 21st, to further assist Staff in developing its report which was submitted to the Commission on November 19, 2004.

The SCC issued an Order Inviting Comments on December 6, 2004. This Order directed electric utilities to submit compliance plans with the proposed rules by January 10, 2005 and interested parties to submit comments regarding Staff's report, the proposed rules, and the utilities' compliance plans by February 7, 2005. Staff was directed to submit any reply comments by February 21, 2005. Upon review of the information submitted, Staff realized the need for more extensive discussions with each utility to thoroughly understand the respective proposals. Staff sought and was granted extensions to submit its report by May 27, 2005, upon which it complied.

Further comments were submitted by various parties narrowing the list of outstanding issues. Generally, the proposed rules appeared acceptable and issues regarding the "reasonable margin" and "administrative costs" components of market-based costs clearly became the most controversial. Suggestions regarding further work group discussions to attempt to resolve the wide range of opinions among the parties regarding the two large outstanding issues were accepted by Staff. Such a meeting was held on July 19, 2005 and the discussions have led to further settlement discussions among the parties, which are not yet complete.

Staff is hopeful that these further discussions will lead to a settlement of issues to move forward without a hearing to adopt the rules governing the exemption programs and to establish the methodology to determine market-based costs to be used in these programs.

Competitive Metering Provisions

On August 19, 2002, the Commission entered an Order in Case No. PUE-2001-00298 approving rules implementing competitive electricity metering services for the elements of meter data availability and accessibility effective January 1, 2003. Subsequently, on July 11, 2003, the Commission entered an Order adopting rules implementing customer ownership of meters by large industrial and large commercial customers effective January 1, 2004.

Following additional investigation, the Commission issued an Order on July 16, 2004, indicating that it was premature to implement additional elements of competitive metering. The Commission directed the Staff to continue to monitor regulated and competitive market developments in metering and to report on any notable developments, including appropriate corresponding recommendations for the implementation of additional elements of competitive metering. At the current time, Staff has not observed significant developments with respect to metering activity nationally that would warrant consideration of additional elements of competitive metering in Virginia.

Competitive Billing Provisions

On August 31, 2002, the Commission issued an Order in Case No. PUE-2001-00297, adopting rules for CSP consolidated billing. The Commission also found that an EDI workaround approach for implementation of CSP consolidated billing was reasonable on an interim basis, recognizing that such an approach will need to be replaced with standardized EDI protocols as the competitive market develops and the volume of competitive billing increases. At the present time, the development of a competitive retail electricity market in Virginia has been extremely limited; no competitive retail suppliers have expressed interest in CSP consolidated billing.

Aggregation

The Restructuring Act authorizes the provision of aggregation services for the Commonwealth's retail electricity customers. Section 56-576 of the Act defines aggregator,

§56-588 details the licensing of aggregators, and §56-589 authorizes municipal and state aggregation. Aggregation service is the purchasing or arrangement of the purchase of electric energy for sale to two or more retail customers.

The Commission established an investigation of aggregation issues with Case No. PUE-2002-00174. Although there has not been any market activity since the Commission's Order of August 24, 2004, including DVP's municipal aggregation pilot program, four additional aggregators have been licensed by the Commission.

Distributed Generation

Distributed generation involves moving the generation of electricity away from large central units to smaller units located closer to the point of consumption.[19] In accordance with §56-578 of the Restructuring Act, the Commission instructed the Staff to work with interested parties to develop proposed interconnection standards for distributed generation. The Act specifies that the interconnection standards "shall not be inconsistent with nationally recognized standards acceptable to the Commission."

Following several work group meetings and assistance of interested stakeholders, Staff drafted proposed interconnection standards for Virginia. The National Association of Regulatory Utility Commissioners ("NARUC") has since adopted a set of distributed generation rules that States are encouraged to adopt. Staff awaits further direction and decision of the Institute for Electrical and Electronic Engineers ("IEEE") and its efforts to set national standards for distributed generation interconnections ("IEEE-1547"), and of the Federal Energy Regulatory Commission's activities to develop interconnection procedures.

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[19] In May of 2000, the Commission issued rules governing net energy metering promulgated pursuant to § 56-594 of the Restructuring Act. The net metering rules establish interconnection guidelines and tariffs under which an electric customer may interconnect a small wind, hydro or solar generating facility to the grid. The rules may be found at: http://www.scc.virginia.gov/caseinfo/pue/e990788.htm .

Chapter 827 of the 2004 Acts of the General Assembly amended the net metering provisions of the Code of Virginia, Section 56-594 of the Restructuring Act to revise the definition of eligible customer generator. The definition now refers to a nonresidential customer that owns and operates an electric generation facility that, among other things, has a capacity of not more than 500 kW. The capacity limit for nonresidential customers previously was 25 kW.

In response to this statutory change, by Order dated June 3, 2004, the Commission initiated Case No. PUE-2004-00060. Many parties were involved in the proceeding including APCO, the Virginia Department of Environmental Quality, Virginia Power, the Maryland, District of Columbia, Virginia Solar Energy Industries Association, Virginia Wind Energy Collaborative, and the Old Mill Power Company. The proceeding involved a workgroup meeting that lead to a Staff report. After considering substantial comments by the parties to the proceeding, by Order dated April 20, 2005, the Commission adopted final regulations governing net energy metering.

Business Practices

The North American Energy Standards Board ("NAESB") serves to develop and promote standards leading to a seamless marketplace for wholesale, and retail, natural gas and electricity.[20] NAESB is accredited as a standards-setting body from the American National Standards Institute, charged by the FERC to develop business practices for use by market participants while moving toward a more uniform marketplace. NAESB ensures that its implementation standards and business practices will receive and utilize the input of all industry sectors through its open membership and balanced voting processes. This process

[20] Additional information regarding the NAESB may be found at: http://www.naesb.org .

continues to pursue the development of national standards regarding electronic protocols for regions to converge to the same EDI standards and consistent business rules to better promote a robust competitive energy market.

Staff continues to monitor the activities of each quadrant and the various subcommittees to establish standards and business practices. Staff also participates with NAESB's monthly conference calls to update regulators and continues to serve on the Advisory Committee to NAESB.

Generation and Transmission Additions

Since 1998, eleven generating plants have been built and placed into commercial operation within the Commonwealth, adding 4,150 megawatts ("MW") to existing generation physically located in Virginia.[21] Approval of six additional facilities has been granted by this Commission summing to 3,865 MW, of which one facility of 680 MW has since been withdrawn. The remaining facilities, totaling 3,185 MW, are in various stages of development to move forward, but have not yet begun construction. The table at the end of this section provides further detail regarding applications for new facilities.

Changes within the electricity marketplace under a competitive regime, actions by the FERC, and the financial investment and capital markets have caused the electric industry to explore alternatives to traditional integrated resource planning. Evolvement of RTOs to include a broader number of market participants and to cover wider service areas has changed the complexion of the future electric industry. New capacity, generation as well as transmission, will be realized when market participants recognize and react to market signals such as reliability, price, customer service, load growth and economics. Such response will

[21] These new plants are comprised of three Dominion generating stations, two ODEC facilities, and six independent power plants, representing 1,500 MW, 940 MW, and 1,710 MW, respectively.

likely include physical construction and enhancement as well as contractual and financial alternatives.

As more independent generators begin commercial operation and suppliers utilize a variety of capacity purchases to serve customer load, the traditional reserve margin loses significance. Difficulties arise in determining which supply sources and which customer loads should be included at any particular time to determine such a calculation.

Expansion of transmission facilities is also needed to accommodate expected customer demand and required energy supply. Construction of AEP's 765-kV electric transmission line in southwestern Virginia continues with a target operation date during the summer of 2006. Certificates for two shorter transmission lines were granted in 2004 and two certificate applications are currently pending before the Commission. Additionally, several new natural gas pipelines are now in service or have been approved.

Summary of Construction Activity in Virginia
As of August 1, 2005

Company/Facility	***Size***	***Location***	***Docket***	***Fuel***	***C.O.D.****	***Hearing***	***Order***
New power plants in operation							
Commonwealth Chesapeake	300 MW	Accomack County	PUE960224	3-OilCT	sum 01	1/23/97	8/5/98
Dominion Virginia Power	600 MW	Fauquier County Remington	PUE980462	4-GasCT	sum 00	1/05/99	5/14/99
Wolf Hills Energy, LLC	250 MW	Washington County Bristol	PUE990785	5-GasCT	sum 01	4/27/00	5/2/00
Dominion Virginia Power	360 MW	Caroline County Ladysmith	PUE000009	2-GasCT	sum 01	5/23/00	10/10/00
Doswell Limited Partnership	171 MW	Hanover County Doswell	PUE000092	1-GasCT	sum 01	6/13/00	6/15/00
Allegheny Energy Supply	88 MW	Buchanan County	PUE010657	2-C/GCT	Jun 02	none	6/25/02
Dominion Virginia Power-Possum	540 MW	Prince William County PP	PUE000343	convert/GasCC	May 03	1/16/01	3/12/01
Louisa Generation, LLC (ODEC)	472 MW	Louisa County BoswllTavrn	PUE010303	5-Gas CT	Jun 03	11/14/01	7/17/02
Tenaska Virginia Partners I, LP	885 MW	Fluvanna County	PUE010039	Gas CC	May 04	3/13/02	4/19/02
INGENCO Wholesale Power, LLC	16 MW	Chesterfield County	PUE-2003-00538	48-LFGas	Jun 04	none	4/12/04
Marsh Run Generation, LLC (ODEC)	468 MW	Fauquier County	PUE020003	3-GasCT	Sep 04	5/21/02	11/6/02
	4,150 MW						
New power plants with SCC certificates currently under construction.							
New power plants with SCC certificates, but not yet under construction.							
Competitive Power Ventures (8/31/01/2/02)	520 MW	Fluvanna County	PUE010477	Gas CC	spr 06	1/9/02	SCC app 10/7/02
Tenaska Virginia Partners II, LP (8/15/01)	900 MW	Buckingham County	PUE010429	Gas CC	n/a	5/28/02	SCC app 1/9/03
CPV Warren, LLC (2/14/02)	520 MW	Warren County	PUE020075	2-GasCC	spr 05	7/24/02	SCC app 3/13/03
Chickahominy Power, LLC (1/4/02)	665 MW	Charles City County	PUE010659	Gas CT	n/a	5/1/02	SCC app 3/12/04
James City Energy Park, LLC (3/8/02)	580 MW	James City County	PUE-2002-00150	2-GasCC	win 05	9/18/02	SCC app 3/12/04
White Oak Power Co., LLC (5/9/02)	680 MW	Pittsylvania County	PUE-2002-00305	4-Gas CT	sum 04	10/24/02	SCC app 8/1/03,**w/drawn**
	3,865 MW >>> 680 withdrawn **leaving 3,185 MW**						
New power plants that have applied for an SCC certificate							
Duke Energy Wythe, LLC (12/27/01)	620 MW	Wythe County	PUE010721	Gas CC	sum 04	6/25/02	**Dismissed 5/20/04**
CinCap-Martinsville	330 MW	Henry County	PUE010169	4-GasCT	sum 03	9/18/01	**Dismissed 4/29/03**
Kinder Morgan VA, LLC	560 MW	Cumberland County	PUE010722	Gas CC	sum 04	12/17/02	**Dismissed 1/14/03**
Kinder Morgan of Virginia, LLC	550 MW	Brunswick County	PUE010423	Gas CC	win 04	11/7/01	**Dismissed 11/1/02**
Henry County Power/Cogentrix (MB)	1,100 MW	Henry County	PUE010300	Gas CC	sum 04	10/17/01	**Dismissed 8/26/03**
Loudoun County Power/Tractebel (WS)	1,400 MW	Loudoun County	PUE010171	Gas CC/CT	04/05	12/6/01	**Dismissed 3/27/02**
Mirant Danville, LLC (KH)	870 MW	Pittsylvania County	PUE010430	Gas CT/CC	03/04	12/5/01	**Dismissed12/16/03**
Total	**5,430 MW** >>> withdrawn/dismissed **leaving 0 MW**						

*Commercial Operation Date

Company/Facility	***Size***	***Location***	***Docket***	***C.O.D.***	***Order***
Transmission lines					
APCo	765 kV-90 mi	Wymoing-Jackson's Ferry	PUE970766	6/06	5/31/01 approved, under construction
DVP	230 kV- 4 mi	Loudoun	PUE010154	5/06, 5/07	6/27/02 approved, under construction
DVP	500 kV-8 mi	Morrisville-Loudoun	PUE-2004-00062	5/07	7/15/05 approved
DVP	230kV – 11.8 mi	Trabue-Winterpock	PUE-2004-00041	11/06	9/28/04 approved, under construction
DVP	230kV – 8 mi	Loudoun	PUE-2002-00702	n/a	appealed to Supreme Court
DVP	230kV – 7 mi	Norfolk	PUE-2004-00139	5/07	pending
DVP	230kV- 16 mi	Pleasant View-Hamilton	PUE-2005-00018	6/08	pending
Natural gas pipelines					
DVP	20" – 14 mi	Prince William County	PUE000741	2003	SCC app 11/5/01, in-service 7/03
Duke Energy Patriot Extension	24"-95 mi	Wythe to Rockingham Cty	FERC	2004	FERC app 11/20/02, in service 2/04
Dominion Transmission Greenbrier	30"-279 mi	Charleston to Rockingham	FERC	2007	FERC app 4/9/03, extended 2 years
Saltville Gas Storage Co., LLC	24"-7 mi	Saltville / Chilhowie	PUE010585	2003	SCC approved 1/22/03, in-service 8/03
Tenaska VA II Partners, LP	20"-14 mi	Buckingham County	PUE010429(ref)	n/a	n/a
Cove Point East Pipeline capacity expansion	87 mi	Maryland to Loudoun	FERC	2008	pending FERC approval
Cove Point LNG terminal capacity expansion	9.6BCF storage	Cove Point, Maryland	FERC	2008	pending FERC approval

Regional Transmission Organization membership

AP (PJM West)	PUE-2000-00736	Order of 10/8/04 approving transfer of operation of transmission facilities to PJM West.
Conectiv (PJM East)	PUE-2001-00353	Order of 5/20/04 recognizes current membership in PJM since 3/97 satisfies RTE Rules.
KU (MISO)	PUE-2000-00569	EXEMPT 2003 via §56-580 G
AEP (PJM West)	PUE-2000-00550	Order of 8/30/04 approving transfer of operation of transmission facilities to PJM West.
DVP (PJM South)	PUE-2000-00551	Order of 11/10/04 approving transfer of operation of transmission facilities to PJM.

RTE Development

Section 56-579 of the Restructuring Act requires incumbent electric utilities to establish or join regional transmission entities ("RTEs")[22] as part of the transition to retail competition. This obligation is imposed on each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity. Section 56-579 also requires the State Corporation Commission to determine "whether to authorize transfer of ownership or control from an incumbent electric utility to a regional transmission entity." Behind this requirement was an expectation that RTEs would manage and control the transmission assets of Virginia's utilities with the objective of meeting the transmission needs of electric generation suppliers both within and outside Virginia.[23]

On April 2, 2003, HB 2453 was placed into law. HB 2453 amended §§56-577 and 56-579 of the code of Virginia to require utilities seeking to transfer control of their transmission facilities to an RTE to submit "a study of the comparative costs and benefits thereof, which study shall analyze the economic effects of the transfer on consumers, including the effects of transmission congestion costs." HB 2453 also prohibits the transfer of control prior to July 1, 2004, and requires the Commission to conduct a public hearing regarding any such request. The Restructuring Act previously required notice and an opportunity for a hearing. HB 2453 also states that "each incumbent electric utility shall file an application for approval pursuant to this section by July 1, 2003, and shall transfer management and control of its transmission assets to a regional

[22] RTE and RTO (Regional Transmission Organization) are essentially synonymous terms. The former is used in the Act; the latter is the Federal Energy Regulatory Commission's preferred acronym.
[23] § 56-579 A 2 d.

transmission entity by January 1, 2005, subject to Commission approval as provided in this section."

All of Virginia's investor-owned electric utilities have now shifted management of their transmission facilities to an RTE. APCo, Allegheny Power, Delmarva and Dominion are participating in PJM[24] and Kentucky Utilities is participating in the MISO.[25]

Appalachian Power

Appalachian Power filed a substitute application for approval to transfer functional control of its transmission facilities to PJM, Case No. PUE-2000-00550. On January 15, 2004, the Commission issued a procedural schedule in setting the matter for notice and hearing. APCo was directed to file testimony and exhibits by March 1, 2004; respondents were directed to file testimony and exhibits by May 24, 2004; and Staff was directed to file testimony and exhibits by June 22, 2004. The public hearing took place on July 27, 2004. During the hearing, APCo; the Commission's Staff; the Attorney General; the Old Dominion Committee for Fair Utility Rates; PJM; and Edison Mission Energy offered a stipulation recommending that the Commission approve APCo's participation in PJM subject to certain specified conditions. The conditions set-forth in the stipulation included agreements by APCo and the parties regarding future ratemaking proposals that may come before the Commission; modest bill credits for the period 2005-2010; a curtailment protocol specifying conditions under which service to Virginia consumers may be curtailed; and information reporting requirements for APCo and PJM.

[24] Delmarva has participated in PJM since PJM's inception decades prior to passage of the Restructuring Act. PJM accepted control of Allegheny's transmission facilities on April 1, 2002, AEP's on October 1, 2004, and Virginia Power's on May 1, 2005.
[25] "MISO" is the Midwest Independent System Operator. MISO began offering transmission service over

On August 30, 2004, the Commission issued an order modifying the curtailment protocol specified in the stipulation and approving the transfer of control of APCo's Virginia jurisdictional transmission facilities to PJM. PJM assumed control of AEP's transmission system on October 1, 2004.

Allegheny Power

Allegheny filed an application to transfer control of its transmission facilities to PJM under an arrangement known as PJM West, Case No. PUE-2000-00736.

On January 30, 2002, FERC issued an Order that, among other things, permitted Allegheny and PJM to form PJM West. Pursuant to that order, Allegheny turned over operational control of its transmission facilities to PJM on March 1, 2002 and currently operates under the LMP model.

The Commission held a public hearing on September 28, 2004 to consider Allegheny's request to join PJM. During the hearing, Allegheny; the Commission's Staff; the Attorney General; and PJM; offered a stipulation recommending that the Commission approve Allegheny's participation in PJM subject to certain specified conditions. The conditions set-forth in the stipulation included a curtailment protocol specifying conditions under which service to Virginia consumers may be curtailed and information reporting requirements for Allegheny and PJM. On October 8, 2004, the Commission issued an order approving the stipulation and Allegheny's request to transfer operation and functional control of its transmission facilities to PJM.

Delmarva

KU's transmission facilities on February 1, 2002.

On October 16, 2000, Delmarva filed a Motion with the SCC in Docket No. PUE-2000-0086[26], requesting the Commission to determine that Delmarva's membership in PJM constituted compliance with the requirements of the Restructuring Act and the SCC's Regulations Governing Transfer of Transmission Assets to Regional Transmission Entities, 20 VAC 5-320-10 *et seq.* ("RTE Rules").

After a number of procedural orders and responsive pleadings, the Commission issued an order dated March 4, 2004 requiring, among other things, Delmarva to file a legal memorandum regarding a question of whether the Commission had authority under § 56-579 of the Code of Virginia to grant "prior approval" of a transfer that occurred long before enactment of that statute. On March 26, 2004, Delmarva filed its response. Delmarva asserted that on July 1, 1999, the effective date of the Restructuring Act, it had already transferred "the management and control of its transmission system" in the Commonwealth to the PJM Interconnection, L.L.C., and that this transfer had occurred on March 31, 1997. Thus, Delmarva contended, that because it retained no management or control over its transmission system, there was nothing to which the Commission could give "prior approval" as envisioned by §56-579 of the Act. Delmarva further argued that Virginia law made clear that newly enacted statutes, such as the Act, could only be given prospective effect and could not be applied retroactively, unless the legislation clearly expressed the intent that it be applied retroactively, or if the legislation affected only procedural and not contractual or other substantive rights.

On April 14 and 16, 2004, respectively, the Staff and the Attorney General filed Responses to Delmarva's filing. All filing parties conclude that the Commission cannot

[26] Delmarva's RTE related requests were subsequently reassigned to Case No. PUE-2001-00353.

apply its new authority under code § 56-579 to Delmarva's membership in PJM, which occurred prior to the passage of the statute.

On May 20, 2004 the Commission found that Delmarva does not now possess, nor did possess as of July 1, 1999, management and control of its transmission facilities within the Commonwealth of Virginia; that the management and control of such facilities is now, and has since at least March 31, 1997, been possessed by PJM; that the Commission was without authority to give "prior approval" to the transfer of management and control that occurred over two years prior to the passage of the Act, which directs all jurisdictional utilities to make such transfers subject to the prior approval of the Commission; that, notwithstanding the Commission's lack of jurisdiction under the limited factual circumstances presented herein, Delmarva's membership in PJM appears to satisfy the requirements of our RTE Rules and is not contrary to the public interest; and that this matter should accordingly be dismissed.[27] The Commission rejected Delmarva's contention that its transmission facilities do not fall within the general jurisdiction of the Act, due to their geographical location on the Eastern Shore. To the contrary, we find that those facilities do comprise a part of "Commonwealth's interconnected grid and we retain jurisdiction over any subsequent transfer of operation and control of them by Delmarva or any other operator.

Dominion Virginia Power

On June 27, 2003, DVP filed an application seeking to join PJM. On September 26, 2003, the Commission entered its Order for Notice in this proceeding. The Order for Notice directed the Dominion, among other things, to file certain relevant information

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[27] See PUE-2001-00353 at: http://www.scc.virginia.gov/caseinfo.htm.

and supporting information by November 26, 2003. This date was subsequently amended by additional Orders of the Commission to March 15, 2004.

On December 22, 2003, the Commission issued a procedural schedule setting this matter for notice and hearing. Respondents were directed to file testimony and exhibits by July 15, 2004, and Staff was directed to file testimony and exhibits by August 16, 2004. A public hearing regarding DVP's request was held on October 12, 2004. During the hearing, DVP; the Commission's Staff; the Attorney General; Old Dominion Electric Cooperative; PJM; Chaparral (Virginia) Inc., the Municipal Electric Power Association of Virginia; Central Virginia Electric Cooperative; and Craig-Botetourt Electric Cooperative offered a partial stipulation recommending that the Commission approve DVP's participation in PJM subject to certain specified conditions. The conditions set-forth in the stipulation included a curtailment protocol specifying conditions under which service to Virginia consumers may be curtailed, and information reporting requirements for DVP and PJM. On November 10, 2004, the Commission issued an Order accepting the stipulation and approving the transfer of control of DVP's Virginia jurisdictional transmission facilities to PJM. PJM assumed control of DVP's transmission system on May 1, 2005.

Dominion also serves over 100,000 customers in northeastern North Carolina. On April 2, 2004, pursuant to North Carolina law, Dominion filed with the North Carolina Utilities Commission (NCUC) an application to transfer to PJM, operational control of its transmission facilities located in North Carolina.

The State of North Carolina has chosen not to restructure its retail electric industry. Regarding Dominion's filing, the NCUC concluded that, as originally proposed by Dominion and as subsequently modified in a Joint Offer of Settlement, approval of the application would not be justified by the public convenience and necessity.[28] However, the NCUC did conclude that approval of Dominion's application would be justified subject to the imposition of certain additional conditions intended to provide sufficient protections for Dominion's North Carolina retail ratepayers. The NCUC conditions, which were subsequently agreed to by Dominion and PJM, are as follows:

1. That Dominion's North Carolina retail ratepayers shall be held harmless from all direct and indirect effects and costs, either related to operations, quality of service, reliability, or rates, arising from its integration with PJM including, specifically, the following:

    a. As stated in the testimony of Dominion witnesses, Dominion's North Carolina retail customers shall continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law using the same ratemaking methodology as that employed by this [NCUC] Commission as of the time of Dominion's joining PJM notwithstanding Dominion's integration into PJM or decision to participate in any capacity or energy market administered by PJM; that is, under no circumstance(s) or event(s) shall the costs of generation and transmission, among other things, included in Dominion's N.C. retail rates be greater than the lesser of (1) such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or (2) the marginal costs of generation and transmission supplied into or purchased from PJM;

[28] See Orders of the North Carolina Utilities Commission, Docket No. E-22, Sub 418. March 30, 2005 and April 19, 2005.

b. Dominion shall continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales;

c. Dominion shall take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with the same (or higher) superior level of bundled electric service as that provided prior to Dominion's integration with PJM, including, for example, reliable generation, transmission, and distribution service; minimization of power outages, efficient restoration of service; and responsive customer service;

d. Dominion shall not include in base rates: (a) PJM administrative fees or any replacement mechanism for such fees approved by the FERC; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs) or auction revenue rights (ARRs) or any replacement mechanism for such cost and revenues approved by the FERC; (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service; (d) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement; or (e) any increase in transmission costs to the Company or any revenues resulting from the FERC's orders in Docket Nos. ER04-829 and ER05-6, et al. imposing the Seam Elimination Cost Adjustments (SECAs);

e. Dominion shall allocate sufficient FTRs, ARRs, or other revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from Dominion's North Carolina retail ratepayers through the operation of G.S. 62-133.2; and

f. Neither PJM, Dominion nor any affiliate shall assert in any proceeding in any forum that federal law, including, but not limited to, the Public Utility Holding Company Act of 1935 (PUHCA) or Federal Power Act (FPA), preempts the [NCUC] Commission from exercising such authority as it may otherwise have (or would have were Dominion not a member of PJM) under North Carolina law to set the rates, terms, and conditions of retail electric service to Dominion's North Carolina retail ratepayers and that Dominion shall bear the full risks of any such preemption;

2. That Dominion and PJM shall, consistent with, and to the extent not altered by, the above additional regulatory conditions and this Notice of Decision, comply with the terms of the Joint Offer of Settlement filed December 16, 2004;

3. That Dominion and PJM shall, consistent with the above additional regulatory conditions, comply with the terms of the Settlement Agreement with Progress filed December 16, 2004. Dominion and PJM shall, with regard to all of the signatories thereof, honor, and discharge Dominion's obligations pursuant to, the various VACAR and other regional agreements referenced in the Settlement Agreement, including but not limited to the VACAR Reserve Sharing Agreement, as Dominion would have been so obligated to do prior to Dominion's integration with PJM. In fulfilling this condition, Dominion and PJM shall continue to follow the practices and operating procedures around these agreements that have

been customarily observed by the participants but do not necessary exist in written form; and

4. That Dominion shall continue to comply with all regulatory conditions and codes of conduct previously imposed by the [NCUC] Commission.

<u>Kentucky Utilities</u>

On October 16, 2000, Kentucky Utilities ("KU") filed an application for Commission approval to transfer the operational control over its transmission assets to MISO. MISO assumed control of KU's transmission system on February 1, 2002. On June 28, 2005, KU filed a Motion to Dismiss its Application. In support of its motion, Kentucky Utilities stated that the Virginia General Assembly approved House Bill No. 2637 on March 19, 2003, which added subsection G to § 56-580 of the Code of Virginia and that § 56-580 G suspends the applicability of the Restructuring Act to KU. Accordingly, Kentucky Utilities requested that its application be dismissed without prejudice. On July 26, 2005, the Commission issued an order dismissing KU's request without prejudice.

<u>RTO Prices</u>

Since Virginia's largest electric utilities only recently integrated into PJM, there has not been enough time to gather and review data to understand the real implications on the utilities and respective customers. Although it is too soon to determine the affect on prices from joining PJM, the following table simply shows load-weighted average prices from the most recent information of the largest electric utilities in Virginia since joining PJM.

Dominion Virginia Power	5/05-7/05	$67.11 / MWh
Appalachian Power	10/04-7/05	$41.35 / MWh
Potomac Edison	8/04-7/05	$46.04 / MWh

Significant RTO-Related Dockets at FERC

Virginia's Restructuring Act directs the Commission to participate "to the fullest extent possible" in RTO-related dockets at the FERC (§ 56-579 C). The Commission is also directed by the Act to provide an annual report to the CEUR concerning the Commission's assessment of RTOs relative to the development of competitive markets in Virginia (§ 56-579 F).[29]

As recounted in previous versions of this annual report, the Commission has participated extensively in the RTO-related dockets at the FERC, committing considerable Staff and financial resources to such participation. Such participation began almost immediately after the General Assembly passed the Restructuring Act in 1999, when Dominion Virginia Power, the Appalachian Power Company, and a number of other transmission-owning utilities sought the FERC's approval for the creation of the Alliance Regional Transmission Organization ("Alliance RTO"). The FERC ultimately rejected the Alliance RTO on the basis that it did not conform to all of the requirements of FERC's Order 2000.

Subsequently, the Commission participated fully in a number of significant RTO-related dockets, culminating in the integration of AEP's operating companies (including

[29] The Commission is also charged by § 56-578 G of the Restructuring Act with ensuring that the rules and practices of RTOs are sufficiently mitigating market power in transmission-constrained areas associated with electric generation (capacity or energy) serving Virginia's retail customers. If these rules and practices are insufficient to curb any such market power, the Commission is directed to adjust retail rates for electric generating capacity or energy within these transmission-constrained areas to the extent necessary to protect retail customers from the effects of market power.

Appalachian Power) into the "PJM West" region of the PJM Interconnection, LLC, and the integration into PJM of Dominion as a single-utility PJM region named "PJM South."

The FERC's review of AEP and DVP's proposed integration into PJM ran roughly parallel to corresponding proceedings before the Commission, pursuant to § 56-579 of Virginia's Restructuring Act, requiring Commission approval of the transfer of management and control of these utilities' transmission facilities to PJM. Significantly, however, at the request of Chicago-based utility Exelon, Inc., and others, FERC initiated its first ever challenge to a state's authority to pass on the propriety of such proposed transfers in an extensive proceeding convened before the FERC pursuant to § 205 of the Public Utilities Regulatory Policy Act ("PURPA"). Prior to the commencement of these formal proceedings, FERC issued its preliminary opinion that provisions of Virginia law prevented AEP and PJM from consummating a voluntary agreement to coordinate their facilities and that AEP should be exempted from compliance with these unspecified provisions of Virginia's Restructuring Act. After this "verdict," a formal hearing was conducted before a FERC Administrative Law Judge who initially issued findings supporting FERC's preliminary conclusions. Unsurprisingly, the FERC issued an opinion (Opinion No. 472), upholding its ALJ's findings. Additional litigation ensued and the FERC's proceeding was effectively rendered moot when this Commission approved AEP's integration into PJM in 2004. Ultimately, FERC converted its Opinion No. 472 into a non-binding "policy statement," that could not be appealed into the federal courts.[30]

[30] FERC Docket No. ER03-262-009

With the integration of Virginia's transmission-owning utilities into FERC-regulated RTOs completed, the work of the Commission insofar as participation in FERC dockets continues. There are several significant dockets underway at the FERC as this report goes to publication. All of them have an impact on the price and reliability of electricity provided to Virginia's residential, commercial and industrial customers. These dockets and other significant Orders issued by the FERC are discussed below.

<u>FERC Abandons its controversial Standard Market Design rulemaking.</u>

Effective July 1, 2005, FERC Commissioner Joseph Kelliher replaced Pat Wood as Chairman of the FERC, the latter not having been reappointed to that commission. In a significant action following Commissioner Kelliher's appointment by President Bush to the Chairmanship, the FERC entered an Order in FERC Docket No. RM01-12-000 on July 19, 2005, terminating the controversial Standard Market Design ("SMD") rulemaking the FERC had established in 2002. So ends the saga of a FERC rulemaking so controversial that SMD was, at one time, the subject of special provisions within some versions of the federal energy bill prohibiting or delaying its implementation. The SMD, among other things, made RTO or ISO participation (and FERC oversight thereof) mandatory for all interstate transmission facilities, and (in its original form) asserted jurisdiction over transmission used to provide retail service to native load customers. The FERC offered as a rationale for this "Order Terminating Proceeding," the continuing development of voluntary RTOs and ISOs, and the FERC's announced plans to revisit Order 888, and possibly revise it. In sum, the FERC stated that "the SMD NOPR has been overtaken by events."

<u>Transmission rate increase sought by AEP</u>.

In FERC Docket ER05-751-000, the American Electric Power Company seeks to substantially increase its FERC-regulated transmission rates. These proposed increases, if approved, would be paid by the transmission customers of AEP, including AEP's operating companies such as APCo, which provides service in western and southwestern Virginia. AEP's operating companies, particularly APCo, would likely seek to pass along these transmission rate increases to their retail customers, the timing of which depends on whether and when APCo decides to file a comprehensive rate case with the Commission.

Increased AEP transmission rates would also increase the costs of competitive suppliers seeking to transmit power across the AEP transmission system in order to sell competitive generation supply to retail customers within the Commonwealth, including APCo's Virginia service territory, although there are no such suppliers now operating in Virginia. Furthermore, these rate increases would also be paid by electric cooperatives and municipal power supply systems in Virginia who utilize AEP's transmission system to bring power to their retail customers. The FERC Administrative Law Judge assigned to this case has scheduled a January 24, 2006, hearing date.

<u>FERC looks at PJM's methods for mitigating market power in load pockets.</u>

In FERC Docket EL04-121-000, the FERC is reviewing PJM's current methods for preventing generation owners from hiking up generation prices above reasonable levels for the output of their generation units that must run ("must-run units") in certain areas during periods when demand is high and transmission capacity in these areas is in short supply, or "constrained." A good example of a frequently constrained area within PJM is Virginia's Eastern Shore. Under PJM's current procedures (spelled out in its tariffs on file at the FERC), the wholesale price of must-run units can be capped or limited through the actions of PJM's Market Monitoring Unit ("MMU") during periods when transmission is constrained. One of the questions FERC has raised in this investigation is whether PJM's current price caps (and the actions of PJM's MMU in triggering them) might work to discourage the construction of new generation needed in these so-called load pockets. The FERC's Order initiating this current investigation suggests that "scarcity pricing" may actually be needed in some instances to induce new generation construction. The Commission has intervened in this proceeding.

<u>FERC's investigation of the justness and reasonableness of PJM's current rate design.</u>

This FERC docket (EL05-121-000) was established in May 2005 for the express purpose of determining whether transmission rates within PJM are just and reasonable vis-à-vis cost allocations among PJM members. The catalyst for this proceeding is AEP's assertion that the benefits of its extra high voltage system ("EHV") system (500 kV and above) are shared by all PJM members, but that under PJM's current zonal rate tariffs, the cost of AEP's EHV system is recovered principally from load within AEP's transmission zone.

In an Order issued May 31, 2005, the FERC found (as a consequence of AEP's assertions) that PJM's current modified rate design may not be just and reasonable. Consequently, the FERC opened a new docket for the express purpose of conducting a hearing on this issue. Following the filing of pre-filed testimony in this proceeding, a hearing in this docket will be convened in April 2006. The Commission has intervened in this docket. Modification of PJM's rate design could ultimately result in a shifting of costs between PJM regions. For example, a uniform, system-wide PJM rate could decrease costs to customers located in the AEP region and increase costs to customers located in the Dominion region. However, the ultimate impact of a revised PJM rate design on Virginia customers is far from clear given jurisdictional questions regarding state versus federal authority and the existence of capped rates.

<u>Appeal to federal appeals court concerning future rate treatment of DVP's RTO integration and ongoing administrative costs.</u>

The Office of the Attorney General of Virginia and the Commission have taken appeals to the United States Court of Appeals for the District of Columbia from an Order entered by the FERC in FERC Docket ER04-829-000. At issue in this appeal is whether DVP will be positioned to seek recovery from Virginia ratepayers after 2010 when DVP's capped rates expire, of approximately $280 million in RTO-related costs (plus carrying costs) incurred *during* the capped rate period.

In FERC Docket ER04-829-000 (DVP's RTO integration docket), the FERC approved DVP's entry into PJM South by FERC Order dated October 5, 2004. In that docket, DVP specifically requested that the FERC authorize DVP to carry forward on its books of account for future rate treatment purposes, DVP's costs associated with joining an RTO and the annual administrative costs associated with its membership in PJM—all of which occurred or are occurring during DVP's retail capped rate period slated to end at the end of 2010. Costs given this type of accounting treatment by a regulatory body are called "regulatory assets." DVP asserted in its pleadings in this docket that its RTO-related costs are not currently recovered in its capped rates, nor were they intended to be.

Under the FERC's own accounting rules and the FERC's precedent applying them, before the FERC can give a utility the green light for regulatory asset treatment, the

FERC must first determine that (i) such costs are not currently recovered in rates, and (ii) that these costs can be recovered in future rates. DVP explicitly asked the FERC for such a determination as part of its RTO integration petition. However, the FERC declined to make these determinations required under its own rules, but instead authorized DVP to decide for itself whether to book these costs as regulatory assets.

The Commission and the Attorney General first sought rehearing from the FERC on the basis, *inter alia*, that the FERC had violated its own rules and precedent by not making these two specific findings described above. The FERC's March 5, 2005, Order on Rehearing rejected that contention. The Commission and the Attorney General then filed their appeals with the D.C. Circuit, where the matter is pending. The FERC has filed a motion with the Court seeking dismissal of the appeal, which has not yet been heard as of this writing.

Energy Infrastructure

Senate Bill 684, enacted by the 2002 Session of the General Assembly, required the SCC to convene a work group to "… study the feasibility, effectiveness, and value…" of collecting information relative to the location and operation of specified electric generating facilities, electric transmission facilities, natural gas transmission facilities, and natural gas storage facilities serving the Commonwealth. This information encompasses data relative to the electricity and natural gas loads imposed by Virginia consumers and the dedication of facilities to the service of those loads.

The Commission filed its report on November 20, 2002, and presented the results of its work to the CEUR during its December 12, 2002, meeting. The Commission report concluded that the collection of extensive data related to Virginia's energy infrastructure is, in fact, feasible. With regard to the effectiveness and value of such a data collection effort, the report noted that ". . . the electric utility industry is in a state of extreme uncertainty and will likely remain so for the foreseeable future." The report ultimately recommended three options for the CEUR's consideration. The CEUR concluded that the Commonwealth must continue to maintain oversight over the reliability of the electric infrastructure and adopted a resolution on January 27, 2003 ("Resolution"), requesting, in part, that the Commission collect the data necessary to monitor the dedication of generating facilities to the provision of electric bulk power supply in the Commonwealth. The Resolution also requested the Commission to report the results of its work to the CEUR, on or before July 1, 2003, and to provide subsequent reports as the Commission deems necessary or as requested by the CEUR.

The Commission's Report of July 1, 2003, indicated that with the advent of restructuring, electric utilties providing service in the Commonwealth have reduced planned reserve margins and expect to rely largely on the market for the provision of capacity to serve load growth and to provide adequate reserves. The Commission Staff collected and provided updated infrastructure information at the September 8, 2004, CEUR meeting that support these same conclusions. At the present time, the Staff is not aware of significant changes with respect to planned construction of new infrastructure in Virginia.

AEP and Dominion Virgina Power, subsequent to Commission approval, joined PJM on October 1, 2004, and May 1, 2005, respectively. Accordingly, PJM is now the primary driver of generation and transmission reliability planning in most of Virginia. In addition to determining the need for transmission system expansion and upgrade to ensure grid reliability across its system, PJM effectively dictates to each load serving member its required generation reserve margin and certifies generation resources that contribute to reliable PJM capacity reserves. By directly considering the diversity in the timing of the peak demands of its load serving members and the vastness of PJM generation resources, lower generation reserve margins are required to maintain reliable service than if each member company were to perform such planning functions as an independent entity.

Due to concerns that PJM's generation capacity market, as currently structured with its relatively short-term horizon, may not provide sufficient financial incentive to ensure the timely construction of new generation facilities in the future, PJM is currently developing and evaluating a new Reliability Pricing Model proposal to potentially file with the FERC. An additional issue that may receive increasing attention in the future is whether new transmission facities should be constructed to meet economic needs in addition to those facilities constructed for reliability reasons. The Staff has noted significant divergence in wholesale power prices during certain peak load hours between different PJM zones within Virginia, indicative of transmission constraints within the system and raising the issue of the importance of accessibility to lower cost wholesale power.

The Staff continues to monitor PJM committee and subcommittee activities directed at reliability planning.

<u>Access to PJM Market Information</u>

Virginia statutes that govern the regulation of public utilities in general, and the Virginia Electric Utility Restructuring Act in particular, provide the SCC with both the obligation and authority to monitor the workings of wholesale electricity markets that will impact Virginia retail electric consumers. The integration of Virginia's electric utilities into PJM provides the SCC with a unique challenge in obtaining information from PJM and Virginia utilities required to monitor wholesale markets. At this time, it is too early in our evolving relationship with PJM to determine if the SCC will be able to carry out the market monitoring that was envisioned by the General Assembly when the Act was first passed in 1999. To date, the Staff's efforts to work with PJM have met with mixed results.

As an example, note that in order to assess the functioning of wholesale electric markets, it is reasonable for those inquiring to observe the manner and price levels that comprise offers to sell electricity by suppliers into PJM electricity markets. Unfortunately, PJM and many market participants consider such offer data to be "competitively sensitive," rendering that information generally unavailable to public scrutiny. To the extent that such data is available, it can be obtained on the PJM website after a 6-month waiting period. Further, the information is "coded" so that specific behavior of certain plants or certain generating companies are hidden from public view. This general procedure for the release of this crucial data has been approved by the FERC.

In addition, in the general course of business, the SCC is asked by PJM to comment on or otherwise evaluate certain policy initiatives that may be proposed by PJM for inclusion in its electric system or market operations. Other stakeholders may also make proposals, the evaluation of which requires information possessed by PJM. Moreover, SCC participation in various FERC proceedings could benefit from access to information held by PJM. Up to this point, it has been difficult to obtain from PJM at least some of the information that the SCC deems necessary for the SCC to meet its statutory obligations to monitor wholesale electricity markets.

PJM currently has in place a FERC sanctioned process by which state regulatory commissions may obtain confidential information from PJM. As of this writing, the PJM website indicates that only two state commissions (Pennsylvania and Kentucky) have taken the steps necessary to obtain information under this FERC sanctioned process. Several state commissions, including the SCC, are studying the implications of participating in this process. Some state commissions appear reluctant to sign the FERC protocol for obtaining such confidential information.

The SCC has concerns with the FERC approved protocol and how it relates to the SCC's authority to obtain data and information under existing state law. We are also concerned about what data is deemed confidential, who deems it confidential, whether certain data and information will be provided under the FERC approved policy should we participate, and access to data and information that we believe should not be deemed confidential. Data access and general market monitoring issues will likely be important issues to be tackled as our working relationship with PJM evolves over the coming months and years.

OTHER ACTIVITIES AND ISSUES

Default Service Investigation

On July 24, 2003, the Commission issued an Order (Case No. PUE-2002-00645) establishing the provision of default service to retail customers effective January 1, 2004, pursuant to § 56-585 of the Restructuring Act. Until modified by future order of the Commission, the Commission determined that the components of default service include all elements of electricity supply service and directed the incumbent electric utilities to provide default service at capped rates. The Commission noted that such an approach is consistent with the early stage of competitive retail and wholesale market development in Virginia, yet permits the flexibility to accommodate the evolutionary development of a default service model to parallel future market changes.

Section 56-585 E of the Restructuring Act requires that on or before July 1, 2004, and annually thereafter, the Commission determine, after notice and opportunity for hearing, whether there is a sufficient degree of competition such that the elimination of default service for particular customers, particular classes of customers, or particular geographical areas of the Commonwealth will not be contrary to the public interest. The Commission is directed to report its findings and recommendations to the General Assembly and Commission on Electric Utility Restructuring by December 1 of each year.

In both the 2004 and 2005 proceedings (Case No. PUE-2004-00001 and Case No. PUE-2005-00002, respectively) pursuant to this statutory provision, the Commission issued a Final Order finding that there is not a sufficient degree of competition such that the elimination of default service for particular customers, particular classes of customers or particular geographic areas of the Commonwealth will not be contrary to the public interest. Additionally, the Commission found that default service should not be eliminated or otherwise modified at the current time. The Commission determined that these findings would be reported to the General Assembly and the CEUR in the annual report on the status of competition in Virginia.

Earnings of Virginia Investor-Owned Electric Utilities

Each investor-owned utility operating in Virginia with annual revenues in excess of $1,000,000, is required to make an Annual Informational Filing ("AIF") with the Commission. The purpose of these filings is to allow the Commission to, among other things, monitor the earnings generated by currently approved tariff rates. One section of the AIF, referred to as the Earning Test Analysis, assesses current earnings on a regulatory basis by making limited adjustments to the utility's financial records. Staff conducts a review of each filing and prepares a report to the Commission stating its findings. The following chart shows the calendar year 2001, 2002 and 2003 earnings of each investor-owned electric utility based on Staff's review (unless otherwise noted) of the earnings test analysis included in each company's AIF. The earnings reflect the bundled (generation, transmission and distribution) per books Virginia jurisdictional return on common equity earned on a regulatory basis.

	2001	2002	2003
Dominion Virginia Power	9.80%	22.36%	13.26%*
Appalachian Power	9.52%	12.79%	13.96%
Potomac Edison	13.80%	15.12%	10.35%
Delmarva	6.47%	1.96%	4.33%*
Kentucky Utilities	10.76%	14.19%	11.81%*

* Per Company filing; Staff report has not been completed.

Each of the above companies filed financial data for calendar year 2004 during the first half of 2005. Staff has not yet completed its review of the 2004 data. The following chart reflects bundled per books Virginia jurisdictional return on common equity on a regulatory basis as included in each company's AIF.

	2004
Dominion Virginia Power	13.52%
Appalachian Power	6.27%
Potomac Edison	7.46%
Delmarva	7.02%
Kentucky Utilities	10.34%

Appalachian Power Rate Application

On July 1, 2005, APCo filed an application with the Commission for (i) an adjustment to its capped rates and (ii) approval of a methodology for making future such rate adjustments. The application requests approval of a rate surcharge, the "E&R Factor," to recover post-July 1, 2004 incremental costs for environmental compliance and transmission and distribution reliability ("environmental and reliability costs") pursuant to § 56-582 B (vi) of the Code. APCo requested that its proposed surcharges be made effective August 1, 2005, on an interim basis subject to refund. The proposed 9.18% surcharge will collect approximately $62.1 million annually.

The Commission entered an Order for Notice and Hearing on July 14, 2005, docketing the matter as Case No. PUE-2005-00056, setting a procedural schedule, and requiring public notice of the application. The Order denied until further order of the Commission the implementation of interim rates. The Commission requested legal memoranda on the question of whether and under what circumstances the Commission has authority to make any portion of APCo's proposed rates, filed pursuant to § 56-582 B (vi) of the Code, interim and subject to refund. On July 18, 2005, the Old Dominion

Committee for Fair Utility Rates filed its Notice of Participation as a Respondent in the proceeding.

Craig Botetourt Electric Cooperative Rate Application

On February 1, 2005, Craig Botetourt Electric Cooperative ("CBEC") filed an application with the Commission for an increase in base rates. The proposed annual revenue increase of $954,603 represents an increase over current revenues of 23.44%. The proposed increase is due in large part to a new market-based power supply agreement with AEP which increased purchased power expenses by $579,079 annually. On July 22, 2005, CBEC filed a Joint Motion to Approve Stipulation on behalf of the Cooperative, Staff and the OAG (collectively, the "Stipulating Participants"). The Stipulating Participants agreed to, among other things, an annual increase in revenues of $842,754. A hearing was held on July 26, 2005, where several public witnesses made statements and introduced a petition in opposition to the proposed increase with approximately 450 signatures. The final resolution of this case was still pending at the time this report was presented to the CEUR.

Stranded Costs

On January 27, 2003, the CEUR adopted a resolution (the "2003 Resolution") requiring that the State Corporation Commission:

> *By July 1, 2003, present to the Legislative Transition Task Force the work group's consensus recommendations regarding:*
>
> *(a) Definitions of "stranded costs" and "just and reasonable net stranded costs."*

> *(b) A methodology to be applied in calculating each incumbent electric utility's just and reasonable net stranded costs, amounts recovered, or to be recovered, to offset such costs, and whether such recovery has resulted in or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.*

The 2003 Resolution also included Requested Action No. 8, requiring Commission Staff analysis of differing recommendations in the event consensus recommendations were not reached and Requested Action No. 9, recommendations for legislative or administrative action that the Commission, work group, or both, determine appropriate to address any over- or under-recovery of just and reasonable net stranded costs. On March 3, 2003, the Commission entered an Order Establishing Proceeding, docketing Case No. PUE-2003-00062[31] establishing the work group and schedule. The work group held four sessions; however, members were unable to reach consensus on the issues before it. On July 1, 2003, the Commission submitted a Stranded Cost Report, prepared by its Staff, to the CEUR.

Because no agreement was reached during the work group sessions, the report summarized the various party recommendations and provided Staff's analysis of those recommendations. The Staff presented two methodologies to calculate just and reasonable net stranded costs, and Dominion, the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (the "Committees"), each

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[31] See http://www.scc.virginia.gov/caseinfo/pue/e030062.htm.

presented one methodology. Each of these methodologies was summarized in the Commissions September 2004 Report to the CEUR.

The CEUR's 2003 Resolution, in Requested Action No. 3, directed the work group to calculate each incumbent electric utility's just and reasonable net stranded costs as well as recoveries from wires charges and capped rates based on the consensus methodology and file a report by November 1, 2003. However, as pointed out in the Stranded Cost Report, the work group was unable to conduct such analyses without further direction from the CEUR because no consensus methodology was reached by the work group.

After several stakeholder meetings, the CEUR, on January 15, 2004, adopted a draft resolution (the "2004 Resolution") presented by the Attorney General. The 2004 Resolution requests that the OAG report on September 1, 2004, and annually thereafter until capped rates expire or are terminated, certain data related to stranded costs. A portion of the data to be included in the annual September reports is obtained from information filed with the Commission. Staff assisted the OAG by providing technical advise and information necessary to make its report to the CEUR. Specifically, Staff quantifies earnings available for stranded costs recoveries, at various target returns defined by the OAG, for each investor-owned electric utility based on calendar year data. Staff also calculates generation revenues based on each utility's embedded cost of providing generation service at various target returns. The OAG requests calendar year market price and customer usage data from each utility to determine generation revenues that would have been derived from a competitive market. The calculated market-based revenues are compared to the cost-based generation revenues calculated by Staff to determine potential stranded costs. The OAG made its first report to the CEUR on September 1, 2004.

Financial Profile of Virginia's Electric Utilities

Since the electric industry is capital intensive, it is very important that electric utilities be able to raise capital on reasonable terms and at favorable rates. When raising debt capital, a company's credit ratings are a major factor influencing the terms and rates it is able to obtain. The two major rating agencies are Moody's Investors Service ("Moody's") and Standard & Poor's Ratings Services ("S&P"). S&P assigns bond ratings ranging from "AAA" to "D", with a plus (+) or minus (-) added to show relative standing within the major categories. Moody's assigns ratings ranging from "Aaa" to "C", with a modifier of 1, 2 or 3 in each ratings category from "Aa" through "Caa" to show relative standings within the major categories. A bond rated below "BBB-" by S&P or "Baa3" by Moody's is considered non-investment grade or a "junk bond".

The key national trend in 2005 has been a rather modest level of rating activity with numbers of upgrades and downgrades being relatively balanced.[32] Ratings outlooks are an indicator of expected future rating trends. Stable ratings outlooks outnumber negative outlooks by 2 to 1, and only about 8% of outlooks are positive. So the future trend should remain stable but with a negative bias. Standard & Poor's remains skeptical of utilities' forays into non-regulated business pursuits outside of the companies' core competencies. Such activities include merchant generation and energy marketing and trading. Since the beginning of 2005, rating changes have been primarily influenced by

[32] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; May 3, 2005.

regulatory actions and operating performance. For example, regulatory actions supporting credit quality were influential in upgrading the electrical utilities in California.[33]

In the previous two years, four investor-owned utilities operating in Virginia were downgraded, and yet again, another Virginia utility has been affected. This year, Virginia Electric & Power Co. had its ratings downgraded from “A-” to “BBB+” by S&P, as shown in the following Senior Secured Debt Credit Ratings and Outlooks table. This downgrading resulted after a S&P review of regulatory insulation found that the State Corporation Commission has no mandated capital structure for Virginia Power which would require maintenance of a high, minimum equity level.[34] The rating agency regards a mandated capital structure indicative of a pro-active regulatory approach and a necessary control for financial insulation. According to S&P, while there exists a Virginia statute affording some protection for a utility from subsidizing the unregulated activities of a parent, it is only an “after-the-fact” approach unlike a capital-structure control. The one notch lowering of Virginia Power can be attributed to S&P’s consolidated ratings methodology that rates legal subsidiaries on par with their corporate parents, in this case Dominion Resources. The idea is that cash is fungible and therefore can be used anywhere within the corporate family to meet debt service obligations. As a result, a financially strong utility, owned by a weaker parent, generally is rated no higher than the parent or the consolidated corporate credit quality.

A continued “back-to-basics” theme has predominated in the U.S. electric industry in response to past balance sheet damage and liquidity crises. The industry’s

[33] Ibid.
[34] Standard and Poor’s Ratings Direct Research; Research Update: Virginia Power Downgraded; Dominion

repair job has involved disposing of non-regulated assets, cutting capital expenditures, de-leveraging balance sheets, negotiating interim re-financings and more vigorous assertion by state regulatory commissions regarding the operations and finances of electric utilities.

The merchant energy segment of the electric industry has been relatively stable in 2005. A few credit improvements have occurred but have been the result of mostly successful refinancing and strategic asset sales rather from improvements in operating fundamentals. Utilities with merchant exposure are experiencing unsettled cash flows and regulatory uncertainties.[35]

The need for considerable capital expenditures such as to satisfy environmental requirements, construct new generation facilities, and other unanticipated costs are driving the need for regulatory approvals.[36] Rate filings in Florida, Hawaii, Illinois, Kansas, Maryland, Massachusetts, Missouri and Wisconsin could, in the near future, have rating implications. Regulatory actions on issues such as the restructuring of regional transmission systems and incorporation of certain merchant plants of affiliated companies into the rate base will continue to be argued.

Financial flexibility has always been important to electric utilities and an industry that is restructuring needs the regulatory and political stability to attract capital from both lenders and investors. Credit downgrades force companies into making difficult decisions about capital structures and operations.[37]

Resources Rating Affirmed; December 22, 2004.

[35] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; May 3, 2005.

[36] Ibid.

[37] Standard and Poor's Project Finance and Infrastructure Finance; October 2002.

The current ratings for ODEC and each investor-owned electric utility operating in Virginia are listed below. Following the matrix is a brief discussion of the rating agency's rationale for the rating assigned.

Company	Senior Secured Debt / Credit Ratings and Outlooks
	Standard & Poor's Rating/Outlook
Appalachian Power	BBB/Stable
Delmarva Power	BBB+/Negative
Kentucky Utilities	BBB+/Stable
ODEC	A/Stable
Potomac Edison	BB-/Positive
Virginia Power	BBB+/Negative

Appalachian Power – The rating of "BBB" for APCo has remained unchanged from the last report. S&P rates Appalachian Power based on the consolidated credit quality of its corporate parent, American Electric Power Co. Inc. AEP has undergone restructuring in two of its main jurisdictions, Ohio and Texas, and also exited some unregulated operations. It will face a constant cycle of regulatory proceedings among the eleven states in which it operates. Being a mostly coal-based company, AEP will especially face rising costs from environment requirements.

Delmarva Power - S&P rates Delmarva based on the consolidated credit quality of its corporate parent, PEPCO Holdings, Incorporated (PHI). PHI's metrics for funds from operations to total debt and ratio of debt to total capital remain fairly weak but are tempered by an expectation of improvement in 2006 and 2007. PHI began a debt reduction plan in 2003. On a stand-alone basis, DPL has a strong business profile but remains under pressure to lower costs through 2007 while a rate freeze remains in effect in Delaware and Maryland. According to S&P, Delmarva's strengths include its lack of competition, low operational risk, and supportive regulatory environment. S&P considers transmission and distribution to have lower technical and operational risk than generation, and residential customers to be a very stable revenue source.

Kentucky Utilities - Kentucky Utilities' rating is based partly on its direct parent, LG&E Energy Corp., and on its ultimate parent E.ON AG, a German utility conglomerate. According to S&P, KU's current stable outlook is based on low costs, a reasonable regulatory environment, and on E.ON's implicit support to LG&E Energy and its affiliates. Short-term concerns are potential environmental expenditures related to KU's coal-fired facilities and KU's large industrial customer base.

ODEC - The rating of "A" for ODEC has remained unchanged from the last report. Although ODEC is not subject to SCC rate regulation, its 10 members in Virginia that cover about a third of the state's landmass are subject to capped rates until 2010. For the last five years, the service territory for ODEC has had favorable customer growth characteristics and proactive management by ODEC members has successfully addressed increasing demands. Balancing these strengths are a higher percentage (relative to other cooperatives) of debt obligations in balloon maturities and a high percentage (50%) of total energy needs filled under short-term contracts.

Potomac Edison – S&P rates Potomac Edison based on the consolidated credit quality of its parent company, Allegheny Energy, Inc. On May 9, 2005, S&P raised its credit ratings on Allegheny Energy Inc. and its subsidiaries to "BB-" from "B+". The upgrading was a result of Allegheny Energy Inc. lowering its debt profile by proceeds on asset sales, cash flow, and debt to equity conversion. In addition to its lowering of debt, also factoring into the upgrading were cost reductions and management's active involvement in seeking regulatory relief. Taken on its own, the credit profile for Potomac Edison is substantially stronger than that of its parent, Allegheny.

Dominion Virginia Power – In last year's report, DVP was the only investor-owned electric utility in Virginia whose ratings were not equalized with its corporate parent by S&P. However, on December 22, 2004, S&P downgraded DVP's issuer credit rating to "BBB+" from "A-" to match that of its parent, Dominion Resources, Inc. ("DRI"). As mentioned earlier, the downgrading was the result of a review by S&P of regulatory insulation. That review determined the protection afforded DVP from its parent's weaker financial profile was insufficient for its separate rating. Irrespective of the downgrading, reasons cited by S&P for the relatively strong rating of "BBB+" for Virginia Power include its cash flow stability and a reasonably favorable regulatory environment. Countering these positives are DRI's riskier exploration and production ("E&P") operations, commodity price risk exposure, high liquidity requirements for its E&P hedging program, and weak financial profile.[38]

The negative outlook for DRI reflects its negative, though improving, financials. Dominion's decision to leave its proprietary trading program could improve its cash requirements and reduce business risks. Management's decision to focus on its core

[38] Standard and Poor's Ratings Direct Research; Research Update: Virginia Power Downgraded; Dominion Resources Rating Affirmed; December 22, 2004.

business is a positive development. These developments should improve the company's risk profile and S&P might revise the outlook upward in 2005.[39]

Retail Access Pilot Programs

On March 19, 2003, DVP filed an application requesting approval of three retail access pilot programs to begin in 2004. Combined, the three Pilots make about 500 MW of load available to Competitive Service Providers, with up to 65,000 customers from all rate classes eligible to participate. To encourage participation by CSPs, DVP proposed to reduce the wires charge for the length of the Pilots by 50% of the amount approved by the Commission for 2003.

The three Pilots consist of: (i) a Municipal Aggregation Pilot, in which one or more localities may aggregate residential and small commercial customers utilizing an opt-in method[40] and one or more localities may aggregate residential and small commercial customers utilizing an opt-out[41] method for the purpose of soliciting bids from CSPs for electricity supply service; (ii) a Competitive Bid Supply Service Pilot,[42] in which CSPs bid to serve blocks of residential and small commercial customers; and (iii) a Commercial and Industrial Pilot, in which CSPs make offers to individual large Commercial and Industrial customers with demands equal to or greater than 500 kW.

As amended in the 2003 session of the General Assembly, § 56-577 C of the Code of Virginia states:

> The Commission may conduct pilot programs encompassing retail customer choice of electricity energy suppliers for each incumbent electric utility that

[39] Ibid.
[40] The opt-in method requires that a consumer affirmatively choose to participate.
[41] The opt-out method requires that a consumer affirmatively choose not to participate; absent such a decision the consumer will be included.
[42] Originally named the Default Service Pilot. Following discussion with interested parties, the Company revised the name in an effort to minimize the potential for customer confusion.

> has not transferred functional control of its transmission facilities to a regional transmission entity prior to January 1, 2003. Upon application of an incumbent electric utility, the Commission may establish opt-in and opt-out municipal aggregation pilots and any other pilot programs the Commission deems to be in the public interest, and the Commission shall report to the Commission on Electric Utility Restructuring on the status of such pilots by November of each year through 2006.

On September 10, 2003, the Commission issued its Final Order approving the Pilots stating that, "the Pilots are in the public interest and further the goal of advancing competition in the Commonwealth." However, as a result of the failure of the Pilots to attract CSP participation, on January 30, 2004, DVP filed a request to delay the start date of the Pilots for two months while it considered modifications. On February 23, 2004, the Commission granted the extension and required DVP to notify all Pilot volunteers of the delay and to file its proposed modification by April 2, 2004.

DVP filed its proposed modifications, as ordered, on April 2, 2004. Among the proposed numerous modifications, the key component was the 100% wires charges reduction for 2004. For years after 2004, the wires charge reduction would be an amount up to but not exceeding the reduction for 2004. Pilot customers therefore would only pay, in later years, the increment that the later years' wires charges exceed the 2004 wires charges. On May 25, 2004, the Commission issued an Order Approving Revisions.

On August 24, 2004, DVP issued a Request for Bids with the bids due by noon on September 14, 2004. No bids were received. Subsequently, no bids were received on the October, November, and December of 2004 or January and February of 2005 due dates.

As a result of the continued failure of the Pilots to attract CSPs, DVP again filed a request with the Commission to revise the Competitive Bid Supply Service Pilot. Specifically, DVP proposed to permit any pre-qualified CSP to submit bids on any business day, rather than on a specific due date. DVP would then notify other pre-qualified CSPs and permit them to submit a competing bid the next business day. Additionally, DVP proposed to modify the bidding period. Rather than two separate periods as originally approved, DVP proposed one bidding period that would extend through the October 2007 meter reading for participating consumers.

On January 28, 2005, the OAG and Direct Energy filed comments with the Commission generally supporting the revisions. On February 4, 2005, the Commission Staff filed comments stating that, as an attempt to encourage CSP participation in the Pilot, it did not object to the proposed revision relating to the elimination of the established monthly due date for bids. However, the Commission Staff expressed concern that such a revision may be at the expense of conducting a bidding process that will resemble one used for the procurement of default service in the future. The Commission Staff stated that the bidding process for default service will likely utilize a fixed bid date.

On March 3, 2005, the Commission approved the revisions as requested by DVP. Since that time no bids have been received in the Competitive Bid Supply Service Pilot. With respect to the other two Pilots, no CSPs have enrolled any C & I customers and no municipality has indicated definitive interest in participating in the Municipal Aggregation Pilot.

Future SCC Activity

As described in this Report, the basic rules, systems, and procedures are in place to accommodate retail choice. Virginia's electric utilities are now members of PJM, a fully functional RTO. Unless otherwise directed by the General Assembly, the SCC will take the following actions during the next year as part of the effort to facilitate retail access:

- Monitor and analyze the activities and events occurring within the PJM market.
- Continue to explore the potential for designating alternative default service providers.
- Monitor and analyze market prices and the implications for resulting wires charges for incumbent electric utilities, and re-set those values as needed.
- Develop the methodology to determine market-based costs for use in exemption of wires charges and minimum stay provisions.
- Monitor PJM activities regarding reliability planning and relationship to the study related to SB 684 regarding the reliability of our energy infrastructure.
- Continue working with the Office of Attorney General to review stranded costs and associated over or under recovery.
- Continue to solicit ideas from stakeholders about methods to attract CSPs to the Commonwealth.
- Continue to monitor approaches being used in other states to attempt to stimulate competitive activity.
- Reactivate the education of consumers about choice when it appears appropriate, although at a pace that conserves resources.
- Monitor activities within the framework of pilot programs and exemption programs to test our infrastructure for a competitive retail marketplace.

APPENDIX II-A

SUMMARY OF NATURAL GAS RETAIL ACCESS PROGRAMS IN VIRGINIA

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This appendix updates last year's report regarding natural gas retail access programs in the Commonwealth of Virginia. Large natural gas customers in the Commonwealth have been allowed to arrange for their own supply and transportation of gas for more than ten years. Natural gas retail access is now available through two programs, one in the service territory of Washington Gas Light ("WGL"), including customers within the service area of Shenandoah Gas, and the other in the territory of Columbia Gas of Virginia ("CGV").

WGL's Retail Access Program

As of July 1, 2005, WGL's program has twelve CSPs serving 6,997 non-residential customers and four active CSPs serving approximately 56,000 residential customers. Cumulatively, these accounts represent approximately 14.6 percent of the 432,708 natural gas customers in WGL's service territory. It is important to note, however, that WGL's unregulated affiliate, WGES, is serving approximately 82 percent of the non-residential shoppers and approximately 83 percent of residential shoppers. .

CGV's Retail Access Program

As of July 1, 2005, there are four CSPs providing service to 1,988 non-residential customers and 7,370 residential customers. Cumulatively, these accounts represent approximately 4.2 percent of the 221,956 natural gas customers in CGV's service territory. It is noteworthy that the two CSPs serving the greatest number of CGV's customers are non-regulated affiliates.

CSP Activity

The two natural gas retail access programs have provided useful information to utilities, CSPs, consumers, and the Commission Staff. The level of CSP activity has been considerably better in the natural gas programs than has been experienced in the electric programs, although a high level of affiliate market concentration may have distorted the actual level of competitive activity.

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