# 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 Regional Transmission Organizations ("RTO"), 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 a small portion of Dominion Virginia Power

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[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

("Virginia Power" or "DVP") customers in northern Virginia with a limited renewable resource and another supplier recently acquired four large Delmarva customers. Staff is not aware of any other electricity supply offers.

Despite modifications to the Commission approved pilot programs of Virginia Power 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.

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energy.

[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 electricity consumers on January 1, 2004. Allegheny Power ("AP" or "APS")[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. One CSP is fully registered with Delmarva and has just recently enrolled its first customer.

Virginia Power's service area was fully opened to retail choice on January 1, 2003. To date, six CSPs and five 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 1,339 customers as of August 11, 2006. 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.

**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-five electric and natural gas competitive service providers ("CSP") 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 local distribution company's ("LDC") 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.

Currently, six CSPs, Dominion Retail, Pepco Energy Services, Washington Gas Energy Services, Commerce Energy, ECONnergy Energy Company and WPS Energy Services are

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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

fully registered with DVP. Additionally, five aggregators are fully registered with DVP, American PowerNet Management, Independent Energy Consultants, Intel-Audits, WPS Energy Services, and the City of Fairfax.

One supplier, Washington Gas Energy Services ("WGES"), is fully registered with Delmarva. The other electric utilities do not have any registered suppliers at this time to serve customers in Virginia.

("VAEDT"). Further information may be found at http://www.vaedt.org .

## Licensed Competitive Service Provider/Aggregator
## as of August 11, 2006

| 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 |
| Hess Corporation | C, I | WG, SG | Electric, natural gas and aggregation (E&G) |
| 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 | R, C, I | WG, SG, CGV | Electric, natural gas and aggregation (E&G) |
| Utility Resource Solutions, LP | R, C, I | | Natural gas |
| Old Mill Power Company | R, C, I | | Electric, natural gas and aggregation (E&G) |
| Metromedia Energy, Inc. | C, I | WG | Natural gas |
| Stand Energy Corporation | C, I | WG | Natural gas |
| Intel-Audits, Inc. | C, I | DVP | Aggregation (E) |
| AOBA Alliance, Inc. | C | | Aggregation (E&G) |
| UGI Energy Services, Inc. | C, I | WG | Natural gas |
| Constellation NewEnergy, Inc. | C,I | WG, SG | Electric, natural gas and aggregation (E&G) |
| City of Fairfax | R | DVP | Aggregation (E) |
| American PowerNet Management, LP | C,I | DVP | Aggregation (E&G) |
| JP Communications Group | R,C | | Aggregation (E) |
| ECONnergy Energy Co., Inc. | R,C | DVP, WG | 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 and natural gas |
| Delta Energy LLC | C,I | | Natural gas and aggregation (G) |
| Renaissance Energy, LLC | C,I | | Electric and natural gas aggregation |
| New Era Energy, Inc. | R, C, I | | Aggregation (E) |

**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 1,339 residential and 19 commercial customers are enrolled with PES. No industrial customer has yet chosen a competitive electricity service provider.

Delmarva has recently experienced its first switching activity with WGES enrolling four large commercial customers in Virginia. This followed Delmarva's request to increase its fuel factor by almost 50% in 2006 for its Virginia customers on the Eastern Shore. However, the Commission Order of June 19, 2006 in Case PUE-2006-00033, permitted an increase of about 25%, still a significant increase to customers.

## Customer Participation

Pepco Energy Services began serving retail access customers in January 2002 and is currently the only CSP serving residential customers. Out of approximately 3.2 million customers in Virginia who currently have the right to choose an alternative supplier of electric energy, about 1,339 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 August 11, 2006.

| 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** | 1,937,804 | 231,383 | 1,339 | 19 |
| **AEP-VA** | 432,136 | 70,358 | 0 | 0 |
| **AP** | 80,910 | 14,641 | 0 | 0 |
| **DPL** | 18,654 | 3,233 | 0 | 4 |
| **NOVEC** | 119,506 | 8,169 | 0 | 0 |
| **REC** | 85,765 | 4,558 | 0 | 0 |
| **SVEC** | 28,359 | 4,902 | 0 | 0 |
| **CEC** | 8,506 | 1,620 | 0 | 0 |
| **A&N** | 10,257 | 787 | 0 | 0 |
| **BARC** | 11,480 | 585 | 0 | 0 |
| **CVEC** | 28,784 | 2,828 | 0 | 0 |
| **CBEC** | 5,710 | 588 | 0 | 0 |
| **MEC** | 28,802 | 1,731 | 0 | 0 |
| **NNEC** | 16,176 | 1,052 | 0 | 0 |
| **PGEC** | 9,104 | 1,036 | 0 | 0 |
| **SSEC** | 48,854 | 2,171 | 0 | 0 |
| **TOTAL** | 2,870,807 | 349,642 | 1,339 | 23 |

***** Customer numbers as of December 31, 2005

## 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 on an annual basis, but terminating on June 30, 2007.  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 original forward price method considered prices at two delivery or receipt points (Cinergy and PJM Western Hub) 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.

In 2005, the Commission further modified the forward price methodology by restricting consideration of forward prices to the PJM Western Hub delivery point.

Projected market prices for DVP during 2006 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 2006; therefore, wires charges are not applicable to any DVP customers that choose to take service from a CSP during 2006. On July 1, 2006, DVP submitted an application to potentially impose wires charges for the first half of 2007. 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.

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 2006, none of the Cooperatives are collecting wires charges.

**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.

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 or cooperatives imposed a wires charge component within its prices-to-compare during 2006.

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[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

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 2006 price-to-compare values for the subject investor-owned utilities are:

| Customer Class | DVP | APCo | PE | Delmarva |
|---|---|---|---|---|
| Residential | 6.078¢/kWh | 3.714¢/kWh | 3.87¢/kWh | 6.47¢/kWh |
| Small Commercial | 5.699¢/kWh | 3.535¢/kWh | 3.96¢/kWh | 7.00¢/kWh |
| Large Commercial | 5.435¢/kWh | 4.053¢/kWh | 3.90¢/kWh | Not applicable |
| Small Industrial | 4.629¢/kWh | 3.430¢/kWh | 3.55¢/kWh | 6.73¢/kWh |
| Large Industrial | 4.217¢/kWh | 3.249¢/kWh | 3.34¢/kWh | 6.00¢/kWh |
| Churches | 6.651¢/kWh | 3.452¢/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 2007. 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

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Cooperative.

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

No significant changes to the Virginia Energy Choice ("VEC") consumer education program were implemented in the past year. Three years ago, the scope of the program was limited to maintaining a toll-free information line and website that give consumers basic facts on the restructured energy market in Virginia. For those persons needing more detailed explanations, they may request a call from the SCC staff or send their questions to a special VEC email address. The program distributed over 2,329 VEC consumer guides and other publications in the fiscal year ending June 30, 2006.

The VEC toll-free information line (1-877-YES-2004) is supported by an automated system that gives callers the choice of listening to a brief recording on restructure, leaving address information to receive consumer education materials, or leave a message for SCC staff. The information line received 5,312 calls in the last fiscal year. In an average month, 17 callers leave messages for SCC staff to respond to general questions about the status of retail choice in Virginia and energy-related topics.

The VEC website (www.vaenergychoice.org) received between 7,700 and 8,500 individual visits per month in the last fiscal year. Web visitors may read extensive information on the changes to the energy market in Virginia, print information sheets, or request consumer guides be mailed to them.

Rising electricity and natural gas prices in the past year caused a number of consumers to turn to VEC for information on competitive service providers offering energy supply service at a lower price than the incumbent utilities. Staff noted an increased number of calls and emails with a negative tone when consumers learned of the lack of electric choice and limited natural gas choice.

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.

Following several meetings and submission of comments, the proposed rules appeared acceptable and issues regarding the "reasonable margin" and "administrative costs" components of market-based costs clearly became the most controversial. A work group discussion to attempt to resolve the wide range of opinions among the parties regarding the two large outstanding issues was held on July 19, 2005. As parties could not agree on how to

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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 .

resolve the outstanding issues, and the result of zero wires charges for 2006, requests were submitted to defer ruling on the contested issues. On January 4, 2006, the Commission issued its Order Adopting Rules and Regulations regarding the Rules Governing Exemptions to Minimum Stay Requirements and Wires Charges as set forth in the Staff's Report. The Order also deferred any finding regarding the contested issues until such time the marketplace became conducive to implement these exemption programs. The Commission also submitted the Rules to the Registrar's Office to be codified in Chapter 313 (20 VAC 5-313-10 et seq.) of Title 20 of the Virginia Administrative Code.

**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, seven additional aggregators have been licensed by the Commission, while four others chose not to renew their aggregator's license in 2006.

**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. 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. Recently the Institute for Electrical and Electronic Engineers (“IEEE”) has completed its work on establishing a national standard for distributed generation interconnections (“IEEE-1547”).

On August 8, 2005, the U.S. Congress enacted the Energy Policy Act of 2005, P.L. 109-58, 119 Stat. 594 (the "Energy Policy Act"), to develop, among other things, a new federal PURPA standard that would, if adopted, require each electric utility to make available, upon request, interconnection service to any customer that the utility serves. Section 1254(a) of the Energy Policy Act amends § 11l[19] (d) of PURPA, 16 U.S.C. § 2621(d), by adding the following standard for consideration:

> (15) INTERCONNECTION - (A) In this paragraph, the term 'interconnection service' means service to an electric consumer by which an on-site generating facility on the premises of the electric consumer is connected to the local distribution facilities.
> (B)(i) Each electric utility shall make available, on request, interconnection service to any electric consumer that the electric utility serves.

[19] Section 111 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601et seq. ("PURPA"), requires each state regulatory authority, with respect to each electric utility for which it has ratemaking authority, to consider certain federal standards established by PURPA for electric utilities within its jurisdiction. Each such state regulatory authority is required to determine whether or not it is appropriate, to the extent consistent with otherwise applicable state law, to implement these standards.

> (ii) Interconnection services shall be made available under clause (i) based on the standards developed by the Institute of Electrical and Electronics Engineers entitled 'IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems' (or successor standards).
> (C)(i) Electric utilities shall establish agreements and procedures providing that the interconnection services made available under subparagraph (B) promote current best practices of interconnection for distributed generation, including practices stipulated in model codes adopted by associations of State regulatory agencies.
> (ii) Any agreements and procedures established under clause (i) shall be just and reasonable and not unduly discriminatory or preferential.

Section 1254(b) of the Energy Policy Act requires each state regulatory authority to consider whether or not the interconnection standard would be appropriate for implementation However, a state regulatory authority is not required to consider and determine whether or not such standard is appropriate to be implemented if, prior to the August 8,2005, enactment of the statute: (1) the state implemented the standard or a comparable one; (2) the state regulatory authority conducted a proceeding to consider implementation of the standard or a comparable one; or (3) the state legislature voted on the implementation of the standard or a comparable one.

By Order dated May 10, 2006, entered in Case No. PUE-2006-00064, the Commission is seeking comments with regard to what action, if any, it needs to take with regard to interconnection standards. This proceeding is ongoing at the time of this report.

Chapter 470 of the 2006 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. As amended, eligible customer-generator means a customer that owns and operates, or contracts with other persons to own, operate, or both, an electrical generating facility that: (i) has a capacity of not more than 10 kilowatts for residential customers and 500 kilowatts for nonresidential customers; (ii) uses as its total source of fuel renewable energy, as defined in § 56-576; (iii) is located on the customer's premises and is connected to the customer's wiring on the customer's side of its interconnection with the distributor; (iv) is interconnected and operated in parallel with an electric company's transmission and distribution facilities; and (v) is intended primarily to offset all or part of the customer's own electricity requirements.

In response to this statutory change, by Order dated June 23, 2006, the Commission initiated Case No. PUE-2006-00073. In its June 23, 2006 Order, the Commission noted that the current Net Energy Metering Rules[20] must be revised first to reflect an expansion of the definition of eligible customer-generator such that it will include not only a customer who owns and operates an electrical generating facility, but also one who contracts with other persons to own, operate, or both, the electrical generating facility. In addition the Commission noted that the Net Energy Metering Rules must also be revised to reflect the expansion of the types of permissible fuels for the electrical generating facility. In addition to previously permitted solar, wind, and hydro, energy from waste, wave motion, tides, and geothermal power are now permissible fuels. It is also now required that not only must the generator be located on the customer's premises, but must also be connected to the customer's wiring on the customer's side of its interconnection with the distributor.

Comments on the Commission's proposed amended Net Metering Rules are due by August 21, 2006.

**Business Practices**

[20] 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 .

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.[21] NAESB is accredited as a standards-setting body from the American National Standards Institute, charged by the Federal Energy Regulatory Commission ("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 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.[22] Approval of six additional facilities was granted by this Commission with capacities totaling 3,865 MW. One of those facilities with a capacity of 680 MW withdrew its certificate. The remaining five projects have not yet been developed. Currently, one application for a 39 MW wind turbine facility is pending before this

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

[22] 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.

Commission. The table at the end of this section provides further detail regarding the applications.

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 likely include physical construction and enhancement as well as contractual and financial alternatives. Additional discussion of such issues will be addressed in the following sections of this report regarding RTO Development and FERC Dockets.

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 was completed and energized on June 25, 2006. Certificates for two shorter transmission lines were granted in 2005 and four certificate applications are currently pending before the Commission. Additionally, several new natural gas pipelines are now in service or have been approved.

Although applications have not been filed with the Commission, several major generation and transmission projects by Virginia utilities have been proposed or are currently being evaluated. As a result of its Regional Transmission Expansion Planning process focusing on 2011 needs, PJM has approved two proposed transmission projects as the best solutions for addressing regional transmission reliability concerns (including Northern Virginia) by improving west-to-east power flows. These include an APS 500kV transmission line project from Pruntytown, West Virginia to Mt. Storm and a joint APS/DVP 100-mile 500 kV transmission line from Mt. Storm to Loudoun County in Virginia. The cost of these lines will be allocated to beneficiaries in neighboring states (Maryland, Pennsylvania, and Washington, D.C.) as well as to Virginia. PJM has also approved two DVP proposed projects, a 56-mile 500 kV Carson to Suffolk line and a 26-mile 230 kV Suffolk to Fentress line, to address reliability concerns in Eastern Virginia.

It should be noted that AEP recently proposed a new 765 kV transmission line stretching from West Virginia to New Jersey. AEP states that the proposed line is designed to relieve transmission congestion and enhance west-to-east power flows and reliability. However, PJM has not evaluated this proposal or its potential impacts with respect to the approved APS and DVP transmission projects discussed above.

Dominion Resources is studying the possible construction of up to two more nuclear generating units at DVP's North Anna Power Station. In 2003, the Company filed an application with the Nuclear Regulatory Commission ("NRC") for an early site permit. An NRC decision on the application is expected during 2007.

DVP is the lead entity of a consortium (including APCo, ODEC, Blue Ridge Power Agency, and the Virginia Municipal Electric Association Number 1) that is currently evaluating the construction of a 500 to 600 MW Circulating Fluidized Bed Coal Plant in Wise County, Virginia pursuant to § 56-585 G of the Restructuring Act.

In the Petition of Virginia Electric and Power Company for Certain Initial Determinations with Regard to Virginia Code § 56-585 G, Case No. PUE-2006-00075, Dominion Virginia Power has requested that the Commission make certain legal determinations relating to that company's possible construction of a coal-fired generation facility in the coalfield region of Virginia.[23] Significantly, the Petition before the Commission is not an application to construct and operate any such facility. Instead, the Petition seeks *preliminary* determinations relating to the interpretation and application of § 56-585 G of the Code of Virginia.

Specifically, Dominion Virginia Power has requested that the Commission issue an order that (1) approves a particular calculation and implementation of an Allowance for Funds Used During Construction rate for the period during the planning and construction of a Plant pursuant to Virginia Code § 56-585 G, (2) approves a "risk premium" during the commercial operation of the facility, and (3) grants exemptions from certain portions of the electric utility bidding rules found at 20 VAC 5-301-10 *et seq*. The Commission issued an Order for Notice and Hearing on July 13, 2006; a hearing on these issues is slated for October 17, 2006.

AEP is proceeding with plans to construct at least two 600 MW Integrated Gasification Combined Cycle clean-coal plants outside of Virginia (most likely in Ohio and/or West Virginia) with targeted in-service dates of 2010 and 2013. AEP has signed an agreement with

[23] The Company states in its Petition that the preliminary site selected for the Coal Plant is in Virginia City, Virginia, just outside of St. Paul, Virginia, in Wise County. The Coal Plant's estimated output will be 500-600 MW, fuel supply for the Coal Plant will consist primarily of run-of-mine coal from various mines in the coalfield region of the Commonwealth, and the Plant, a described, will also allow the use of opportunity fuels such as coal waste and biomass (wood chips). The preliminary site is not within Dominion Virginia Power's service area

General Electric Energy and Bechtel Corporation to begin the front-end engineering and plant design process.

**Summary of Construction Activity in Virginia**
**As of August 1, 2006**

| *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** | | | | | | |
| **Power plants granted SCC certificates** | | | | | | | |
| 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** | | | | | | |
| **New power plants that have applied for an SCC certificate** | | | | | | | |
| Highland New Wind Development | 39 MW | Highland County | PUE-2005-00101 | 19-wind | fall 07 | 11/8/05 | pending |

*Commercial Operation Date

| ***Company/Facility*** | ***Size*** | ***Location*** | ***Docket*** | ***C.O.D.*** | ***Order*** |
|---|---|---|---|---|---|
| **Transmission lines** | | | | | |
| APCo | 765 kV-90 mi | Wyoming-Jackson's Ferry | PUE970766 | 6/06 | Completed and energized 6/25/06 |
| DVP | 230 kV- 4 mi | Loudoun | PUE010154 | 5/06, 5/07 | 6/27/02 approved, under construction |
| DVP | 500 kV-8 mi | Fauquier | PUE-2004-00062 | 5/07 | 7/15/05 approved, under construction |
| DVP | 230kV – 11.8 mi | Chesterfield | PUE-2004-00041 | 11/06 | 9/28/04 approved, under construction |
| DVP | 230kV – 8 mi | Loudoun | PUE-2002-00702 | 12/08 | 10/8/04 approved, under construction |
| DVP | 230kV – 7 mi | Norfolk | PUE-2004-00139 | 5/07 | 8/29/05 approved, under construction |
| DVP | 230kV- 16 mi | Loudoun | PUE-2005-00018 | 6/08 | pending |
| DVP | 230kV – 6 mi | Virginia Beach | PUE-2006-00040 | 12/06 | pending |
| DVP | 230kV – 16 mi | Fauquier & Prince William | PUE-2006-00048 | 5/09 | pending |
| NNEC | 230kV – tap | King George | PUE-2006-00071 | 9/06 | 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, implemented 3/1/02. |
| 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, Withdrawal from MISO effective September 1, 2006. |
| AEP (PJM West) | PUE-2000-00550 | Order of 8/30/04 approving transfer of operation of transmission facilities to PJM West, implemented 10/1/04. |
| DVP (PJM South) | PUE-2000-00551 | Order of 11/10/04 approving transfer of operation of transmission facilities to PJM, implemented 5/1/05. |

## RTE Development and Competitive Conditions

Section 56-579 G of the Restructuring Act requires the Commission to report annually "its assessment of the success in the practices and policies of the RTE [regional transmission entities] facilitating the orderly development of competition in the Commonwealth." Earlier reports focused on the development of RTEs. In the 2005 report we noted that all of Virginia's investor-owned electric utilities had shifted management of their transmission facilities to an RTE. APCo, Allegheny Power, Delmarva and Dominion are participating in PJM[24] and Kentucky Utilities is currently participating in MISO.[25] This report will discuss further developments in RTE participation and the impacts of RTE operations on the development of competition.

Kentucky Utilities

Kentucky Utilities ("KU") doing business in Virginia as the Old Dominion Power Company transferred control of its transmission facilities to MISO on February 1, 2002. On October 7, 2005, KU filed an application with the FERC and the Kentucky Public Service Commission for approval of withdrawal from MISO. In its application, KU raised concerns regarding significant cost issues associated with its continued participation in MISO. Many of these concerns were associated with the design and operation of MISO's energy market. KU believed that participation in the MISO energy market had resulted in the suboptimal economic dispatch of its generating units, which had a detrimental impact on its fuel expenses. In short, KU argued that withdrawal from MISO would result in a significant net economic benefit for the company and its

[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

customers. On March 17, 2006, the FERC conditionally approved withdrawal of KU from MISO. The Kentucky Commission approved KU's withdrawal from MISO on May 31, 2006. Subject to a few ongoing non-controversial regulatory matters, KU is now scheduled to withdraw from MISO's energy market on September 1, 2006. At that same time, KU will contract with the Tennessee Valley Authority to act as its reliability coordinator and with the Southwest Power Pool to act as its open access transmission tariff administrator. It should be noted that §56-580 G relieves KU of any obligation to be in an RTO pursuant to Virginia law.

Competitive implications of PJM and the PJM markets

Virginia's largest electric utilities have now been integrated into PJM for at least one year. Consequently, the Commission Staff has now begun to gather and review data to facilitate a better understanding of the implications of PJM membership on the development of competition and to assess the competitiveness of the electric utility industry in the Commonwealth. This task is extremely difficult given the sheer volume of PJM's operating rules and the complexities associated with the transmission grid. In conjunction with this effort, the Staff collected certain information, reviewed post-RTE integration reports submitted by the utilities and PJM, and reviewed PJM's State of the Market Report. Additionally, the Staff is seeking Virginia specific information regarding certain indicators of market concentration and competitive conditions. The Staff has also sought additional information needed to assess the various bidding strategies of generators participating in the PJM energy markets. While the Staff has not yet obtained all the requested information it continues to pursue additional data from PJM.

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KU's transmission facilities on February 1, 2002.

In the absence of that information, the Staff has begun to review other available information in conjunction with its assessment of the effectiveness of the PJM markets in Virginia. The following discussion represents some of the Staff's preliminary observations derived from that assessment.

Prices associated with PJM's energy markets are based on a system of locational marginal prices ("LMP"), where the price for a given time increment is based on the bid submitted by the last unit needed to operate during that time period, as selected through a competitive auction. All units selected during this time interval receive the same payment based on the last selected bid, i.e. the market clearing price. Since the various components of the transmission system have differing levels of capacity, PJM has to control flows across its system so that no single transmission element becomes overloaded. PJM controls transmission flows by dispatching generating units based on the bids of the units and physical conditions. The results of this dispatch are the basis for LMPs throughout the PJM region. LMPs within PJM are typically not uniform for each time interval since the PJM grid cannot always reliably accommodate a free flow of power throughout the entire PJM footprint.

During these constrained periods, market clearing prices begin to separate throughout PJM to reflect the accessibility of load to generation or conversely of generation to load. In effect, the LMP system recognizes that PJM's electricity market segments into smaller markets as the ability of the transmission grid to reliably accommodate economic transfers of power decreases. Unfortunately, transmission flows are a function of an ever-changing set of conditions that include but are not limited to generating unit availability and output, transmission configuration, and load levels. As such, the size of a particular electrical market is never static.

Generally, electrical markets separate and become smaller as the electrical system becomes more constrained. As markets grow smaller they become less competitive since the available universe of buyers and sellers shrink. During unconstrained periods there are many buyers and sellers. At the other extreme, when the system is very constrained, a relevant electrical market may consist of a single buyer or seller. In other words, the competitive playing field is often not level or balanced. The field typically becomes less balanced as the transmission system becomes more constrained. As such, the degree of separation in LMPs throughout PJM can provide insights with regard to the competitiveness of the electrical system for a given area.

While the degree of LMP price separation within PJM can provide insights as to the competitiveness of the segmented electrical markets, it should be noted that factors other than transmission constraints can contribute to the degree of price separation and that the degree of price separation is not an absolute indicator of competitiveness. The greatest difference in price between regions may not correspond with the time when the system is the most constrained due to other factors that may impact LMPs. For example, LMP price differences may be greater when the spread between fuel prices, i.e. between coal and gas prices, is higher even if dispatch and transmission flows are identical.

LMP prices can also be used as indicators of what competitive prices would be in the absence of regulation or price caps. The LMP market is in effect a spot market where the spot price of electricity is clearly defined. Once again, however, LMP prices should not be viewed as an absolute indicator of the market price of electricity. Competitive prices may also be derived through bilateral contracts or auctions. While not absolute, LMP is a good indicator of potential market prices since they may also form the basis for longer term pricing arrangements. Such arrangements will likely reflect expectations of LMPs over the terms of those arrangements as well as the risk premiums or discounts that may be required as a result of risk aversion.

Given the insights that can be obtained from LMPs, the Staff has collected LMP information and analyzed that information in a number of ways. The following table shows the simple average day-ahead LMPs for various Virginia utility zones and the entire PJM footprint for the twelve month period ending April 30, 2006:

| | |
|---|---|
| AEP | $41.35 / MWh |
| APS | $59.97 / MWh |
| Delmarva Power | $67.97 / MWh |
| Dominion Power | $67.26 / MWh |
| PJM | $58.88 / MWh |

As can be seen, the Delmarva and Dominion zones are the more expensive zones within Virginia. AEP is a less expensive zone. This simple comparison is consistent with other LMP comparisons, which consistently indicate that Dominion and Delmarva LMPs are typically among the highest in PJM.

The following table presents the load-weighted monthly average day-ahead LMPs for AEP, APS, Dominion Power, and the entire PJM footprint for the twelve months ending April, 30, 2006[26]. The load weighted LMP price is a better indicator of market prices in that the actual costs incurred to serve load will vary with the respective load and price for the varying time intervals. LMPs paid by loads vary hourly.

[26] PJM does not post the hourly loads for the Delmarva zone and the Staff could not calculate the load weighted LMP for that zone.

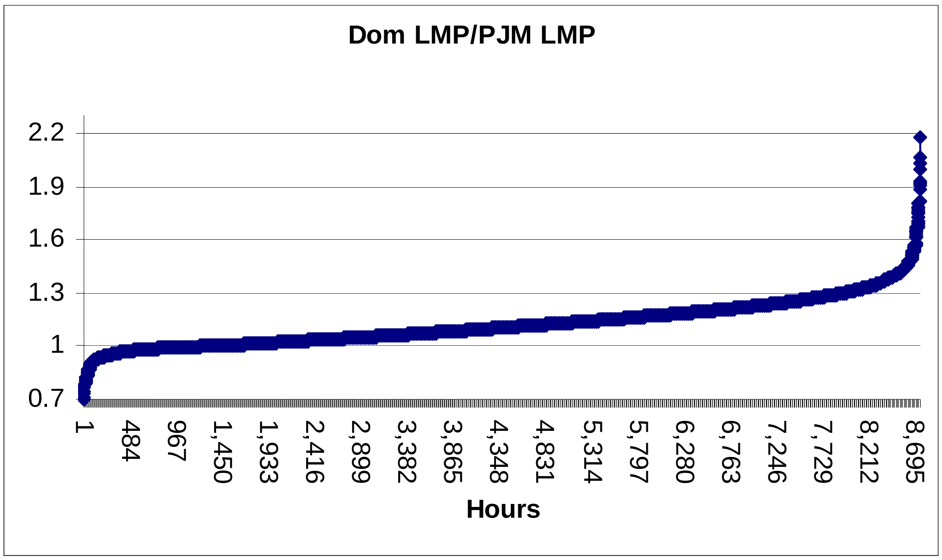
**Average Monthly Load Weighted LMP**

| | *AEP* | *APS* | *Dom* | *PJM* |
|---|---|---|---|---|
| | /MWh | /MWh | /MWh | /MWh |
| **May** | $ 35.35 | $ 40.75 | $ 43.53 | **$ 40.87** |
| **Jun** | $ 48.61 | $ 55.88 | $ 65.68 | **$ 59.16** |
| **Jul** | $ 58.04 | $ 69.89 | $ 82.02 | **$ 71.78** |
| **Aug** | $ 64.88 | $ 81.56 | $ 95.30 | **$ 82.97** |
| **Sep** | $ 60.98 | $ 78.51 | $ 92.57 | **$ 79.73** |
| **Oct** | $ 54.47 | $ 70.42 | $ 82.34 | **$ 71.89** |
| **Nov** | $ 46.59 | $ 59.68 | $ 61.47 | **$ 57.61** |
| **Dec** | $ 71.35 | $ 90.70 | $ 90.54 | **$ 83.89** |
| **Jan** | $ 42.55 | $ 50.14 | $ 59.05 | **$ 51.94** |
| **Feb** | $ 44.63 | $ 52.45 | $ 67.17 | **$ 54.57** |
| **Mar** | $ 46.37 | $ 55.99 | $ 65.55 | **$ 55.24** |
| **Apr** | $ 45.08 | $ 49.58 | $ 52.47 | **$ 48.62** |
| **12 Months** | **$ 52.10** | **$ 63.91** | **$ 73.01** | **$ 64.18** |

By way of comparison, anecdotal information indicates that the average total cost of AEP's and APS's generation is around $40 /MWh. These embedded costs are considerably below the weighted average LMPs for those zones. Additionally, those LMPs reflect only one component of generation costs required in conjunction with the PJM markets. It should be noted that the above figures do not reflect any offsets that may be associated with revenues received from transmission revenue rights that may have been received by load serving entities in the above zones. Revenue from such rights can be thought of as hedges against transmission congestion that may be contributing to higher LMPs. Such revenues would reduce the above figures. For example, the inclusion of these revenues for the Virginia portion of the Dominion zone would reduce the 12 month average LMP for the Dominion zone from $73.01 /MWh to $69.28 /MWH.

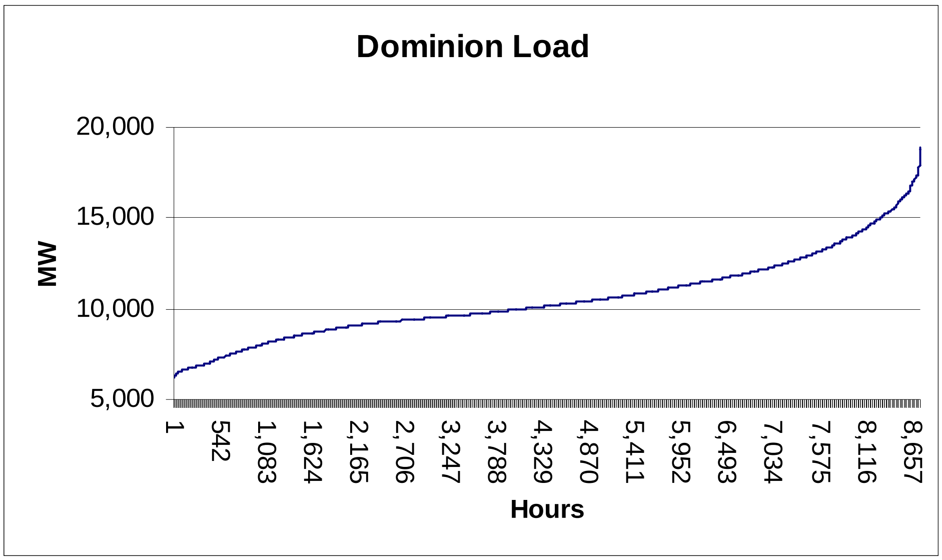
The Staff has also examined differences in hourly LMP prices for the Virginia Zones and PJM in attempt to gain insights as to the degree of market segmentation impacting competition in the Commonwealth. For the 12 month period ending April 30, 2006, prices were uniform throughout PJM during 58 hours, less than 1 percent of the time. In other words, PJM experienced transmission constraints to some degree or the other greater than 99 percent of the time. During these periods, prices will be higher or lower in the various zones depending on each zone's access to specific generating units. If a given zone has less access to low cost generation as a result of transmission congestion it will experienced higher LMPs. Conversely, zones that have lower cost generation that would otherwise be dispatched in the absence of transmission congestion would see lower LMPs when the system is congested. For example, the average hourly LMP for the AEP zone exceeded the PJM-wide LMP during 188 hours and was below the PJM-wide LMP during 8,513 hours during the twelve months ending April, 2006. On the other hand, LMPs in the Dominion zone were lower during only 1,304 hours and higher than the PJM-wide LMP during 7,396 hours for this same period. This indicates that the AEP zone generally has access to lower cost generation while the Dominion zone has far less access to cheaper generation.

The Staff has attempted to gain further insight as to the degree of market segmentation impacting the Dominion zone by dividing the hourly Dominion LMP by the corresponding PJM-wide LMP. While price difference is, as noted earlier, not an absolute indicator of the degree of market segmentation it does provide some limited insight. Dominion zone and PJM-wide prices are the same only where the blue line in the chart intersects the "1" line on the following graph. As the graph depicts, for thousands of hours the Dominion zonal price is higher, often much higher, than the PJM-wide price. Since a single entity (Dominion) owns or controls approximately 90 percent of the generation located within the Dominion zone, this appears to indicate that the Dominion Zone may be subject to uncompetitive conditions during many hours.




PJM's "2005 State of the Market Report" provides some further, albeit limited, insight into the degree of market segmentation within the Dominion zone. In the PJM report market concentration is expressed in terms of the HHI index. The PJM market monitor considers markets to be un-concentrated, moderately concentrated, and highly concentrated at HHIs below 1000, between 1000 and 1800, and above 1800 respectively. While the PJM report concludes that PJM's overall energy market was moderately concentrated in 2005, with HHIs varying from 855 to 1854, the report notes that the intermediate and peaking portions of supply are highly concentrated and the baseload portion is moderately concentrated. It is crucial to note that these concentration measures apply to the entire PJM footprint and that individual zones within PJM may have greater concentrations.

Given the highly concentrated nature of the intermediate and peaking portions of PJM's aggregate supply curve, the Staff developed the following load duration curve for the Dominion zone in an effort to further assess competitiveness of that zone.




The above curve is informative in that it can provide insights regarding the zone's reliance on intermediate and peaking units. There are approximately 9,600 of nuclear or coal fired capacity, i.e. baseload capacity, located within the Dominion zone. The load within the Dominion zone is less than or equal to the amount of baseload capacity during approximately 3,300 hours of the year. Conversely, the load exceeds the baseload capacity during approximately 5,460 hours or 62 percent of the time. During these hours, the Dominion zone's reliance on the highly concentrated portion of PJM's overall supply curve increases as total load increases. The concentrations associated with this supply segment become even greater as load grows and the PJM system becomes more constrained. Again, this would indicate that competitive conditions are less than optimal during a significant portion of the time.

**<u>Significant RTO-Related Dockets at FERC</u>**

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).

As reported in last year's report, the integration of Virginia's transmission-owning utilities into FERC-regulated RTOs is complete; nevertheless, the work of the Commission insofar as participation in FERC dockets continues. This segment of the report will furnish updates on dockets that were underway—and in which the Commission had intervened—as last year's report went to publication. Additionally, during this past year, the Commission has intervened in significant new FERC dockets that relate to the structure and operation of RTOs. These are discussed below, as well.

<u>*The Commission's Participation in New FERC Dockets*</u>:

<u>Joint State/Federal Board examines economic dispatch.</u>

Pursuant to the Energy Policy Act of 2005, FERC convened joint state/federal boards to study security constrained economic dispatch ("SCED") for various market regions of the country. The Commission nominated Howard M. Spinner, Director of its Division of Economics and Finance to serve a Virginia's official representative on the joint board studying SCED in the PJM/MISO region. All regional joint boards were convened in FERC Docket No. AD05-13-000 pursuant to initial order dated September 30, 2005.

Each joint board was authorized to:

- consider issues relevant to what constitutes "security constrained economic dispatch";
- consider how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned; and
- make recommendations to the Commission regarding such issues.

For purposes of this proceeding, FERC adopted the definition of economic dispatch provided in section 1234(b) of the Energy Policy Act of 2005 as the definition of security constrained economic dispatch, *i.e.*, "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

The Joint Board for the PJM/MISO region submitted its final report to FERC on May 24, 2006. The report is available on the FERC website at http://elibrary.ferc.gov/idmws/search/results.asp. The final report's first section includes a summary of 17 recommendations. Key recommendations include:

- An ongoing demonstration of benefits from PJM and MISO managed SCED is important for sustaining market participant and state regulator confidence in the RTOs. The RTOs should establish a clear benchmark to assess the degree to which the reliability and least cost objectives of optimal SCED, as described in EPAct's SCED definition, are being captured.

- Because adequate transmission infrastructure is important for the achievement of SCED's least-cost and reliability objectives, the RTOs should devote adequate resources and substantial management attention to the transmission expansion planning process.

- The RTOs are encouraged to bring to the attention of state regulators any situations in which transmission facilities found to be needed in the RTO expansion plan are not getting implemented in a timely manner.

- RTO independence is critical for the RTOs' ongoing credibility. Accordingly, PJM and MISO are encouraged to continue to strive for independence as a bedrock principle. Both state and federal regulators have a role in the oversight of RTO independence.

- Some state regulators believe that they do not currently have sufficient access to the data needed to evaluate and oversee the RTOs' operation of market-based SCED. The RTOs' policies for limited state regulator access to data should be revisited.

FERC submitted its final report to Congress on Monday July 31, 2006. In that report, the FERC noted that "None of the joint boards recommends fundamental changes in the way security constrained economic dispatch is conducted in their respective regions" and that there were no recommendations for Congressional action. [27]

<u>Electric Energy Market Competition Task Force.</u>

The Energy Policy Act of 2005 established an inter-agency task force, known as the Electric Energy Market Competition Task Force ("Task Force"). This task force was charged with conducting a study and analysis of competition within the wholesale markets and retail markets for electric energy in the United States. The Task Force consisted of 5 members:

- one employee of the Department of Justice, appointed by the Attorney General of the United States.
- one employee of the Federal Energy Regulatory Commission, appointed by the Chairperson of that Commission.

[27] The full report can be viewed at: http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf.

- one employee of the Federal Trade Commission, appointed by the Chairperson of that Commission .
- one employee of the Department of Energy, appointed by the Secretary of Energy, and
- one employee of the Rural Utilities Service, appointed by the Secretary of Agriculture.

In addition, as required by EPACT 2005, FERC opened a docket, No. AD05-17, by order of October 13, 2005. In that docket, FERC directed the Electric Energy Market Competition Task Force to study competition in wholesale and retail markets for electric energy in the United States. The Task Force is also charged with delivering a final report to Congress within one year of the effective date of the act. The purpose of this study was to analyze the critical elements for effective wholesale and retail competition, the status of each element, impediments to realizing each element, and suggestions for overcoming these impediments.

The Task Force was required to "consult with and solicit comments from any advisory entity of the task force, the States, representatives of the electric power industry, and the public." For both wholesale and retail competition for electric power, the Task Force was instructed to focus on the current state of competition and on factors that help support competition, or that otherwise may limit competition, among suppliers and buyers in regional wholesale markets and retail markets at the state level. In order to produce their report, the Task Force sought comments on a series of questions, some of which are set forth below:

- What are the critical elements or attributes of competition in wholesale electricity markets that the Task Force should examine?

- What are the critical elements or attributes of competition in retail electricity markets that the Task Force should examine?
- What benefits have occurred because of competition in wholesale and retail electricity markets? What additional benefits are expected? What benefits were forecasted and have not occurred? Why? What harms have occurred because of competition in wholesale and retail electricity markets?
- What are the major public policy concerns that the Task Force should examine in its review of competition in wholesale and retail electricity markets?
- In what significant ways do wholesale and retail electricity markets differ from other energy or commodity markets? What implications do their differences have for public policy?

The Virginia State Corporation Commission responded to the Task Force's request for comment on the state of competition for electric service by submitting the 2005 Report to the Commission on Electric Utility Restructuring of the Virginia General Assembly And the Governor of the Commonwealth of Virginia titled Status Report: The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia.

On June 5, 2006, the Task Force produced a draft report. Comments have been received on the draft and a Final Report is to be delivered to Congress in August, 2006.

PJM Files its proposed Reliability Pricing Model.

On August 31, 2005, PJM filed under sections 205 and 206 of the Federal Power Act ("FPA") a proposal for a reliability pricing model ("RPM") to replace its currently existing capacity obligation rules. RPM is a proposal to fundamentally change the manner and dollar amount that generating units are compensated for making generating capacity available to participate in the PJM markets. PJM proposed RPM in a section 206 filing at FERC. This maneuver had PJM filing a complaint against its own existing capacity market construct, claiming that its existing capacity market did not produce outcomes that were just and reasonable.

PJM's RPM proposal addresses a key concern that competitive markets will not ensure adequate generating capacity at reasonable cost to consumers. Proposed RPM is, in part, an administrative mechanism that will set generator payments at the intersection of an auction-based supply curve and an administratively determined demand curve. The annual auctions would solicit capacity offers for a year four years into the future. The intersection of those points will occur at a point that yields an administratively determined level of capacity necessary to provide adequate reliability. This process is done separately for different sub-regions within PJM to take into account regional deliverability issues. The proposal also includes a reliability backstop feature that has PJM enter into long-term contracts for capacity if the capacity auction fails to produce a sufficient level of capacity necessary to meet PJM reliability requirements.

FERC docketed the matter as Nos. EL05-148 and ER05-1410. On April 20, 2006, FERC issued an "initial" order in this matter that found PJM's existing capacity construct is unjust and unreasonable. No evidentiary hearing had been conducted.

The April 20 order made certain rulings and provided guidance as to various issues raised with respect to establishing the just and reasonable replacement for PJM's existing capacity construct. The order also established further procedures, including a paper hearing and staff technical conference, for resolving the remaining issues. In the order the FERC encouraged the parties to continue to seek a negotiated resolution, and offered the FERC's settlement judge procedures or dispute resolution service ("DRS") to facilitate these discussions.

The Virginia State Corporation Commission's position can best be summarized by its June 1, 2006 comments in this matter. The commission stated that, like FERC, it is "well aware that there must be an adequate supply of generation for the near- and long-term future." The Commission expressed concern with PJM's proposed RPM since that, to date, there has been no showing that PJM's proposed capacity market redesign will, or can, provide additional generation at just and reasonable rates. The Commission advised FERC that RPM, as proposed, would increase the cost of generation to customers today and that proponents of RPM have not established that customers will receive more than an empty promise for their increased payments.

The Commission's position is that PJM has not established that a capacity construct based on proposed RPM will result in just and reasonable rates nor has PJM demonstrated that its proposal will resolve resource adequacy problems. In addition, the Commission's position is that PJM has not established that the proposed RPM will move its market closer towards transparency and competitiveness and that, in fact, RPM may make these goals more elusive. The Commission closed its June 1, 2006 comments by re-stating its position that FERC should reject PJM's RPM filing. This matter is currently in the FERC settlement process.

PJM files tariff changes regarding its market monitoring function.

On April 3, 2006, PJM filed under section 205 of the FPA to amend Attachment M of its tariff, which governs its market monitoring function. FERC opened Docket Nos. ER06-826-000 and ER06-826-001 to hear this matter. In an order dated July 14, 2006, FERC found that PJM's proposed changes generally conform with the general principles established by FERC's Policy on Market Monitoring ("Policy Statement"),[28] and that application of that policy to PJM is just and reasonable.

In its filing, PJM sought to revise the enforcement powers of its Market Monitoring Unit ("MMU") and to conform to FERC's Policy Statement. In supporting pleadings, PJM held that its proposals reflect the appropriate allocation of policing and enforcement authority between the market monitor and FERC. PJM proposed to eliminate the MMU's authority to issue demand letters or make requests that market participants "discontinue actions." PJM also held that its proposals authorized additional action by the MMU to respond to market design or market rule issues. These actions include filing tariff changes, reports or complaints with the approval of the PJM Board. PJM proposed that should PJM not agree with any MMU recommendation for market rule or market design changes, the MMU may make its views known to FERC staff and PJM members.

This docket saw heavy participation by state commissions, consumer advocates and transmission dependant utilities (municipals and cooperatives). Other stakeholders also intervened. A joint protest was filed by Old Dominion Electric Cooperative, the Borough of Chambersburg, Pennsylvania, Delaware Municipal Electric Corporations, Inc., and ElectriCities of North Carolina (Joint Protestors), and the City and Towns of Hagerstown, Thurmont and Williamsport, Maryland (Maryland Municipalities). Protests were also filed by the Joint Consumer Advocates (representing Pennsylvania, Maryland, Ohio, the District of Columbia, Illinois and Indiana), Mirant Energy Trading, LLC,

[28] Market Monitoring in Regional Transmission Organizations and Independent System Operators, Policy Statement on Market Monitoring Units, 111 FERC ¶ 61,267 (2005).

Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC and Mirant Potomac River, LLC, (collectively, the Mirant Parties), the Organization of PJM States, Inc. ("OPSI"), the PJM Industrial Consumer Coalition ("PJM ICC"), the Public Service Commission of Maryland (Maryland Commission), jointly by the Public Utilities Commission of Ohio, the Virginia State Corporation Commission and the Delaware Public Service Commission (collectively, the Joint State Commissions) and by the Commonwealth of Pennsylvania (Pennsylvania Commission).

Motions to intervene were filed by the Public Utilities Commission of Ohio, the Maryland Commission, OPSI, Joint Protesters, American Municipal Power-Ohio, Inc., PJM ICC, Exelon Corporation, Blue Ridge Power Agency, North Carolina Electric Membership Corporation, Maryland Municipalities, Williams Power Company, Inc., NRG Companies (NRG Power Marketing Inc., Conemaugh Power LLC, Indian River Power LLC, Keystone Power LLC, NRG Energy Center Dover LLC, NRG Rockford LLC, NRG Rockford II LLC, and Vienna Power LLC), Dominion Resources Services, Inc., Constellation Energy Group Companies (Constellation Energy Commodities Group, Inc., Constellation Generation Group, LLC, Baltimore Gas & Electric Company, Constellation NewEnergy, Inc), PHI Companies (Potomac Electric Power Company, Delmarva Power & Light Company, Atlantic City Electric Company, and Conectiv Energy Supply, Inc.), North Carolina Utilities Commission, Illinois Commerce Commission, Virginia State Corporation Commission, Pennsylvania Public Utility Commission, and Delaware Public Service Commission. Motions to intervene out of time were filed by Coral Power LLC, American Electric Power Service Corporation, and PPL Companies (PPL Electric Utilities Corporation, PPL EnergyPlus, LLC, PPL Brunner

Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, PPL University Park, LLC, and Lower Mount Bethel Energy, LLC). On June 23, 2006, a joint response to OPSI's comments was filed by PHI Companies, PPL Companies, The Dayton Power and Light Company, The Williams Companies, Inc., and NRG Companies (hereinafter, the Pepco/PPL/NRG Parties).

The main issue for state commissions, including OPSI, as well as consumer representatives and transmission dependent utilities was the independence of PJM's market monitoring unit. Specifically, these parties --- including this Commission --- sought to use this docket to make important changes in the relationship between PJM management and the PJM MMU. The Virginia State Corporation Commission, along with these other numerous interveners, advocated greater structural separation between PJM management and the PJM MMU. Alternatives means to achieve this result were advanced by the parties. PJM did not propose any tariff revisions regarding the independence of the MMU and opposed any changes its current structure as it relates to market monitoring.

The Joint Protestors argued that the MMU must be independent of the PJM Board and management. They also contended that the MMU is only able to provide consistent and impartial evaluations of existing RTO rules and tariff provisions if the MMU is independent from the PJM Board, management and market participants. The Joint Consumer Advocates disputed the requirement that the MMU have permission from the PJM Board prior to making regulatory filings to address design flaws, structural problems, compliance, market power and to seek remedial measures or make recommendations. The Joint Consumer Advocates and OPSI argued that to maintain independence, the MMU must be able to bring its concerns directly to the FERC and the FERC staff, and must be able to file comments and testimony in proceedings without the prior approval of PJM management

OPSI protested this filing by offering a series of changes intended to provide the MMU with increased independence. OPSI's protest was supported by the Pennsylvania Commission and the Joint State Commissions. The Maryland Commission also endorsed greater independence for the MMU. To promote greater independence OPSI argued that the MMU's budget should be developed by the MMU subject to FERC approval. It also argued that the MMU staff should report exclusively to the Market Monitor. Further, OPSI contended that the Market Monitor should have substantial job security and should only be removed for "just cause." OPSI and the Maryland Commission requested that PJM's filing be modified to require the MMU to notify state commissions when the MMU identifies a market problem that may require state commission action. Similarly, the Maryland Commission would like a time frame established for the MMU to provide information to state commissions.

PJM and the Pepco/PPL/NRG Parties responded to these pleadings by contending that many protestors are seeking to greatly expand the role of the MMU beyond what is contemplated by PJM's tariff revisions or FERC's Policy Statement. PJM also argued that many protestors seek to bring about changes to PJM's internal structure that are outside the authority of the FERC.

FERC decided that Protestors who seek changes regarding the independence of the MMU and its reporting obligations are making recommendations that are not raised in this filing and are therefore beyond the scope of this proceeding. FERC stated that it saw "no reason to institute a section 206 proceeding to address matters that are more global than the issues properly before us." As such, absent reconsideration by FERC or any subsequent judicial intervention, the independence of the PJM market monitor from PJM management will not be enhanced as a result of this proceeding.

*Updates on Dockets discussed in the 2005 Report*

Transmission rate increase sought by AEP.

In last year's report, the Commission discussed FERC Docket ER05-751-000, in which the American Electric Power Company sought to substantially increase its FERC-regulated transmission rates.

The FERC entered an Order on December 7, 2005, approving a settlement stipulation, intended to resolve all of the issues set for hearing in that docket.[29] Specifically, the settlement agreement approved by the FERC authorizes a three-phase rate increase for AEP's East Zone. The approved settlement sets forth a stated unit rate of $1,081.06/MW-month for Firm Point-to-Point and Network Integration Transmission Service during Phase I (11/05 through 03/06); $1,621.40/MW-month during Phase II (04/06 through the commencement of Phase III); and $1,757.40/MW-month in Phase III. The third phase becomes effective on the later of August 1, 2006, or the first day of the month in which AEP's new Wyoming-Jackson's Ferry line becomes operational. The Phase III rate provides AEP an 11 percent return on equity with respect to this transmission line. Additionally, the approved settlement provides for the recovery (from ratepayers) of AEP's RTO start-up costs at the rate of approximately $2.3 million per year through May 2020.

[29] The SCC was an intervenor in this docket, but not a signatory to the settlement.

These FERC-approved transmission rate increases will be paid by transmission customers of AEP, including AEP's operating companies such as APCo, which provides service in western and southwestern Virginia. These operating companies, in turn, may seek to pass along these transmission rate increases to their retail customers.[30]

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

As noted in last year's report, in FERC Docket EL04-121-000, the FERC was reviewing PJM's then current methods for preventing generation owners from exercising "market power." Market power in this context means hiking up generation prices above reasonable levels for the output of 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 had raised in this investigation was 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 suggested that "scarcity pricing" may actually be needed in some instances to induce new generation construction. The SCC intervened in this proceeding.

[30] As also noted in last year's report, increased AEP transmission rates will, at a minimum, 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.

The FERC approved a stipulation of settlement reached in this docket by letter order dated January 27, 2006. In summary, the settlement modified PJM's tariffs concerning wholesale price capping of units in constrained areas. A significant provision of this FERC-approved settlement establishes within the PJM market, five "Scarcity Pricing Regions" that have the potential to develop limitations in imports due to constraints on Extra High Voltage ("EHV") transmission facilities. EHV transmission facilities are rated at 500 kV or higher.

According to the settlement stipulation, scarcity pricing would triggered within these regions when certain actions are taken by PJM operators to address emergencies, such as dispatching on-line generators into emergency output levels and dispatching off-line generators that have been designated to run only in emergencies. Other triggering conditions include emergency voltage reductions, emergency energy purchases, and manual load dump actions. Scarcity conditions will be terminated when demand and reserves can be fully satisfied with generation that is not designated Maximum Emergency. When an action triggers scarcity pricing, PJM will set the price on its entire system or in a Scarcity Pricing Region, as applicable, equal to the highest market-based offer price of all generating units operating under its direction to supply energy or reserves on a real-time dispatch basis. PJM will not cap offers from any generation in the region while scarcity pricing is in effect, although such generation will remain subject to PJM's overall cap of $1,000 per megawatt-hour.

Additional provisions of this FERC-approved settlement establish generally higher offer caps for frequently mitigated (or capped) generation units. The settlement further requires PJM and the PJM Market Monitoring Unit to review and evaluate the eligibility of generating units dispatched out of economic merit order for reliability to set locational marginal prices. Finally, an important provision of the settlement retains the "three pivotal supplier" market test for capping offer prices,[31] subject to certain modifications, including (i) the application of offer caps to generation suppliers rather than generating units, and (ii) the inclusion of price sensitive demand and virtual bids and offers in the day-ahead energy market. The SCC was not a party to this stipulation.

FERC's investigation of the justness and reasonableness of PJM's current rate design.

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. The Commission intervened in this docket.

Modification of PJM's rate design could ultimately result in a shifting of costs between PJM zones, or control areas. For example, a uniform, system-wide PJM rate

[31] As discussed in the Initial Comments of the Commission [FERC] Trial Staff in Support of the Offer of Settlement in this docket dated December 6, 2005, "[T]he test suspends offer caps in any hour in which PJM has more than three jointly pivotal generator suppliers available for redispatch to relieve a transmission contraint. The FERC considers a supplier "pivotal " in a market if its capacity is required to meet peak market demand. Thus, PJM's test considers a market competitive, with no need to cap offer prices, when there are at least four generators available, each on a stand alone basis, to meet demand in a transmission-constrained area." Trial Staff Comments at 2.

could decrease costs to customers located in the AEP zone and increase costs to customers located in the Dominion zone. 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.

On July 13, 2006, FERC Administrative Law Judge ("ALJ") William Cowan, assigned to this docket issued an Initial Decision—an administrative determination on the merits of the case that awaits review and ultimate disposition by the members of the FERC. In sum, the ALJ's Initial Decision concluded that PJM's existing zonal "license plate" rate is unjust and unreasonable, and should be replaced with a "postage stamp" or regional rate design to be made effective April 1, 2006. The postage stamp rate design effectively allocates all of the revenue requirements throughout an RTO's footprint. Transmission customers then pay a fixed uniform charge for energy transmitted *within the region* regardless of distance. As indicated in the Initial Decision, advocates of the postage stamp approach (including the FERC's Trial Staff) contend that such a rate "reflects the widespread benefits provided by an integrated system like PJM's and allocates costs on a socialized basis to all beneficiaries." Initial Decision at 88. The ALJ's determinations, at this writing, await further action by the FERC. While the SCC has intervened in this docket, it has taken no position regarding proposed changes to PJM transmission rate design in this docket.

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

The Commission also discussed in last year's report appeals taken 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, by the Office of the Attorney General of Virginia and the Commission. At issue in this appeal is whether DVP will be authorized to recover from Virginia ratepayers after 2010 (when DVP's capped rates expire), 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. DVP has intervened in the appeal, filing a brief in support of the FERC's decision. The appeal is scheduled for oral argument before the Circuit Court on October 10, 2006.

**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.

AEP and DVP, 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.

There are 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 developed and filed with the FERC a new Reliability Pricing Model proposal that, if approved, is expected to increase wholesale capacity prices. 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.

**Access to PJM Market Information**

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 that the SCC requires to monitor wholesale markets. Over the past year, the SCC and its staff sought to obtain data and information necessary to carry out the market monitoring that was envisioned by the General Assembly when the Act was first passed in 1999. To date, our staff's efforts to work with PJM have met with mixed results. While PJM has made efforts to meet with the Commission and staff regarding this issue and appears to have instituted internal procedures to better track data requests made by the SCC staff, there remains significant difficulty obtaining key data and information necessary to independently assess the functioning of the competitive wholesale markets administered by PJM. This difficulty leaves the Virginia State Corporation Commission unable to independently warrant that PJM's competitive wholesale electricity markets are effectively competitive. Our staff continues to work with PJM to attempt to obtain the data and information necessary to answer this important and complex question.

As noted in last year's report, 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 bidding behavior associated with certain plants or generating companies is hidden from public view. Over the past year our staff and other industry observers have noted questionable bidding patterns by certain generators. The inability to identify entities' and generating units' particular bids as well as the six-month lag in bid reporting make it very difficult for independent investigators to use this most readily available data to conclusively determine that PJM's markets are reasonably competitive. It should be noted that PJM's general procedure for the release of this crucial data has been approved by the FERC and any changes in reporting procedures must be approved by that federal agency as well.

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. Yet, it continues to be 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 three state commissions (Pennsylvania, Kentucky and Maryland) have taken the steps necessary to obtain information under this FERC sanctioned process. Several state commissions, including the SCC, have studied the implications of participating in this process and appear reluctant to sign the FERC protocol for obtaining such confidential information. Importantly, up until this point, our information and belief is that no data has been requested by or provided to the three states currently participating under the terms of the FERC approved protocol for the provision of confidential information. It should also be noted that the FERC has approved this protocol only as a supplement to, and not a replacement for, existing state judicial processes through which state regulators might gain access to such information. PJM has recognized this fact, yet its interpretation is that formal legal proceedings must be undertaken before it will comply with a state information request. This represents a marked departure from the regular, ongoing exchange of information, formal and informal, which most state regulatory agencies have enjoyed with their jurisdictional utilities over the years.

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 currently working with PJM on alternatives to the FERC approved protocol that may allow PJM to provide confidential information to this Commission subject applicable Virginia law, without resort to initiation of formal legal proceedings.

## 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 the 2004, 2005, and 2006 proceedings (Case No. PUE-2004-00001, Case No. PUE-2005-00002, and Case No. PUE-2006-00001, 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, 2003 and 2004 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) Virginia jurisdictional return on common equity adjusted to a regulatory basis.

| | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|
| Dominion Virginia Power | 9.80% | 23.31% | 14.40% | 15.52% |
| Appalachian Power | 9.52% | 12.79% | 13.96% | 6.53% |
| Potomac Edison | 13.80% | 15.12% | 10.35% | 14.09% |
| Delmarva | 6.47% | 1.96% | 4.33% | 7.02% |
| Kentucky Utilities | 10.76% | 14.19% | 13.43% | 10.34%[32] |

[32] Staff did not review and adjust Kentucky Utilities reported Earnings Test results because the Company has no regulatory assets and the applicability of the Restructuring Act to Kentucky Utilities was suspended effective July 1, 2003.

Each of the above companies filed financial data for calendar year 2005 during the first half of 2006. Staff has not yet completed its review of the 2005 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.

| | 2005 |
|---|---|
| Dominion Virginia Power | 6.61% |
| Appalachian Power | 5.04% |
| Potomac Edison | 2.38% |
| Delmarva | 11.07% |
| Kentucky Utilities | 8.08% |

Base Rate Case Activity

Appalachian Power Rate Applications

General Rate Case

On May 4, 2006, APCo filed an application for a general rate increase pursuant to Chapter 10 of Title 56 and § 56-582 of the Code, and the Commission's Rules Governing Rate Increase Applications and Annual Informational Filings. APCo requested an annual base revenue increase of $198.5 million to be effective June 3, 2006. Such proposed increase is based on a return on equity of 11.50%.

The Commission issued its Order for Notice and Hearing and Suspending Rates on May 30, 2006, which, among other things, assigned the application Case No. PUE-2006-00065, suspended the proposed rates through October 1, 2006, at which time they may go into effect on an interim basis subject to refund, assigned the case to a Hearing Examiner, prescribed notice, and established a procedural schedule. Such procedural schedule was subsequently modified by the Hearing Examiner. The original public hearing date of November 7, 2006 has been retained to receive testimony from public witnesses. The evidentiary haring will begin December 6, 2006 at the Commission's offices.

The Commission has received Notices of Participation from The Kroger Co., the Old Dominion Committee for Fair Utility Rates, the VML/VACo APCo Steering Committee, the Office of Attorney General's Division of Consumer Counsel, and Wal-Mart Stores East, LP. The Commission has also received public comments in opposition of the proposed increase.

<u>Adjustment to Capped Rates for Environmental and Reliability Costs</u>

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. This case is still pending before the Commission. The evidentiary hearing was held February 27 through March 1, 2006. Participants to the case filed briefs on April 11, 2006. The Hearing Examiner Report has not yet been issued.

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 Commission entered its Final Order which adopted the proposed stipulation on September 23, 2005.

Prince George Electric Cooperative

In April 2006, Prince George Electric Cooperative notified the Commission of its intent to file for a general rate increase to its base rates. The Cooperative expects to file its application on or before October 1, 2006.

**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[33] 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.

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

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 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 assists the OAG by providing technical advice 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.

**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".

2006 has proven to be a very positive year in rating trends for the U.S. utility sector. Standard & Poor's upgraded six companies and downgraded only three.[34] On the other hand, outlook changes went in the opposite direction with outlook revisions to

[34] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 21, 2006.

negative far outnumbering outlook revisions to positive. Ratings outlooks are an indicator of expected future rating trends. Stable ratings outlooks outnumber negative outlooks by 2 to 1, and only about 11% of outlooks are positive. Standard & Poor's remains skeptical of utilities' forays into nonregulated business pursuits outside of the companies' core competencies. Such activities include merchant generation and energy marketing and trading. Much of the industry continues to re-emphasize core competencies, where risks are certainly more familiar, but still daunting. These include major pending regulatory decisions, the need for substantial infrastructure expenditures, fuel cost recovery in a high-fuel-price environment, and still low, but gradually rising, interest rates.

This year, the ratings for Virginia's Old Dominion Electric Cooperative ("ODEC") and five investor-owned electric utilities remained unchanged. The current Senior Secured Debt Credit Ratings and Outlooks are listed below. Following the matrix is a brief discussion of the Standard & Poor'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 | A-/Negative |
| Kentucky Utilities | A/Stable |
| ODEC | A/Stable |
| Potomac Edison | BBB-/Positive |
| Virginia Power | A-/Stable |

Appalachian Power – The rating of BBB for Appalachian Power 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"). AEP has completed its transition to focus on its core utility operations rather than its former unregulated operations. AEP has improved its liquidity and balance sheet by refinancing billions in utility debt, extending the terms of bank credit facilities, and issuing significant amounts of common equity. 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. A large and complex environmental-compliance program looms as AEP's greatest credit-related issue. The company projects an environmental capital-expenditure program totaling $4.1 billion through 2010 to meet stricter air-quality standards.

Delmarva Power - The rating of A- for Delmarva Power ("DPL") has remained unchanged from the last report. S&P rates DPL 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 - The rating of A for Kentucky Utilities (KU) has remained unchanged from the last report. KU's rating is based partly on its direct parent, E.ON U.S. LLC (formerly, 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 its parent's implicit support to E.ON U.S. LLC and its affiliates and on a corporate strategy that maintains a primarily low-risk, utility-based business profile. 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 six 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 – The rating of BBB- for Potomac Edison has remained unchanged from the last report. S&P rates Potomac Edison based on the consolidated credit quality of its parent company, Allegheny Energy, Inc. Taken on its own, the credit profile for Potomac Edison is substantially stronger than that of its parent, Allegheny. The company's funds from operations ("FFO") interest coverage of over 5x, FFO to total debt of about 30%, and debt to total capital of about 52% are strong. On the downside, with recent legislative and regulatory hurdles faced by Baltimore Gas & Electric Co. in

Maryland, the potential for a rate shock in 2009 exposes the company to similar legislative and regulatory risks. The parent, Allegheny Energy, Inc., has heavy, albeit improving credit matrics, capped tariff rates, and exposure to coal and emission credits. The positive outlook reflects the expectation that Allegheny will continue to execute its plan to improve its operations and reduce interest expense.

Virginia Electric & Power – The rating of A- for Virginia Electric & Power ("Virginia Power") has remained unchanged from the last report. S&P rates Virginia Power based on the consolidated credit quality of its parent company, Dominion Resources, Inc. ("Dominion"). Reasons cited by S&P for the rating of A- for Virginia Power include Dominion's cash flow stability and a reasonably favorable regulatory environment. Countering these positives are Dominion's riskier exploration and production ("E&P") operations, growing portfolio of unregulated power generation, commodity price risk exposure, and weak financial profile. Despite Dominion's current weak financial measures, the stable outlook for Dominion reflects an expectation for improvement in 2007 and beyond.

Virginia Power has an average business risk profile relative to its integrated electric utility peers. Base rate price caps through 2010 provide cash flow stability, and more time to buy down its out of market, nonutility generator contracts. However, in exchange the company has agreed to freeze the fuel factor portion of rates, which is fixed through June, 2007. In 2004, fuel costs were frozen at what management believed to be prices at which fuel risk could be managed, but coal and gas prices since climbed to historically high levels. Subsidiary of Dominion, Consolidated Natural Gas Co., could only partially offset the utility's higher fuel costs in 2005 with its unhedged E&P

volumes. Recent lower-than-expected natural gas prices have mitigated fuel costs at Virginia Power and fuel related losses in 2006 will likely be lower than estimated.

## Retail Access Pilot Programs

On September 10, 2003 the Commission approved three retail access pilot programs proposed by DVP, making approximately 500 MW of load and up to 65,000 customers available to Competitive Service Providers. 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[35] and one or more localities may aggregate residential and small commercial customers utilizing an opt-out[36] method for the purpose of soliciting bids from CSPs for electricity supply service; (ii) a Competitive Bid Supply Service Pilot,[37] 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 originally approved, DVP agreed to provide a 50 percent reduction in the wires charge to encourage CSP and customer participation. As a result of the failure of the pilots to attract CSP participation, DVP requested, and the Commission approved, numerous modifications to the pilots in an attempt to encourage participation. The most

[35] The opt-in method requires that a consumer affirmatively choose to participate.
[36] The opt-out method requires that a consumer affirmatively choose not to participate; absent such a decision the consumer will be included.
[37] 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.

significant revision was increasing the wires charge reduction to 100 percent. Despite the modifications, no CSPs have enrolled customers.

**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.
- 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

# SUMMARY OF NATURAL GAS RETAIL ACCESS PROGRAMS IN VIRGINIA

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 August 1, 2006, WGL's program had twelve CSPs serving 7,598 non-residential customers, and four active CSPs were serving 50,882 residential customers. Cumulatively, these accounts represent approximately 13.1 percent of the 447,508 natural gas customers in WGL's service territory. It is important to note, however, that WGL's unregulated affiliate, WGES, serves approximately 85 percent of the switched customers.

## CGV's Retail Access Program

As of August 1, 2006, there were three CSPs providing service to 2,257 non-residential customers, and two CSPs were serving 6,837 residential customers. Cumulatively, these accounts represent approximately 4.0 percent of the 229,934 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.