PART II

STATUS OF RETAIL ACCESS AND COMPETITION

IN THE COMMONWEALTH

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Executive Summary

The first part of our fourth annual report to the Governor and the Commission on Electric Utility Restructuring ("EURC"), provided a review of recent performance of electricity power markets throughout the United States. The electricity supply industry continues to struggle following price run-ups, disclosures of accounting and data improprieties, creditworthiness issues, and volatile fuel prices, particularly natural gas. Most of the retail markets remain inactive, especially for smaller residential and commercial customers.

Part II of the Report focuses on activities in Virginia related to retail access and competition in the electricity market over the past year. It also reviews the SCC's efforts to develop a proper infrastructure to accommodate competition and to prepare Virginians for consumer choice for generation, as directed by the Restructuring Act.

At the present time, about 3.1 million electricity customers of Virginia's investor-owned utilities and electric cooperatives in Virginia have the right to choose an alternative supplier of electricity. The exception is the approximately 29,400 customers in the southwestern part of the Commonwealth exempted from the Act by legislation enacted by the General Assembly in 2003 and approximately 7,600 customers served by Powell Valley Electric Cooperative.

As we reported last year, the right to choose has not yet evolved into the ability to choose. While it is clear that the SCC, the utilities and the various stakeholders have effectively enabled almost universal retail access in Virginia, there is little competitive activity in the Commonwealth. We understand that many suppliers still perceive little economic incentive to enter the Virginia retail market. No competitive service provider is offering energy priced so that switching customers may save money. Currently, one supplier continues to serve just under 1,900 residential customers and 20 small commercial customers in Dominion Virginia Power's northern Virginia with an environmentally-friendly "green" power offer. This service is more expensive than Dominion Virginia Power's price-to-compare and the number of customers taking such service has declined from last year's report. Again, as detailed in Part I, this lack of activity is not unique to the Commonwealth; in other states currently offering retail access, few customers have the option to purchase power at a price lower than their incumbent's price-to-compare.

Over the past twelve months, the SCC, aided by the incumbent utilities and interested stakeholders, continued to make strides in preparing the Commonwealth for the arrival of competition for the generation component of electric service. Various work groups coordinated by the Staff have been assisting the SCC to provide the foundation for retail access by examining many issues, including competitive metering, supplier billing, default service and energy infrastructure. The SCC appreciates the time and effort of the respondents that have participated with these work groups.

The SCC has issued orders during the past year relating to issues such as competitive metering, market price/wires charge determination, market-based costs, regional transmission organizations ("RTO"), and pilot programs within Dominion Virginia Power's territory. Slow development of competitive activity and statewide budget constraints have caused the SCC to continue suspension of its consumer education efforts.

INTRODUCTION

In this part of the State Corporation Commission's ("Commission" or "SCC") report to the Governor and to the Commission on Electric Utility Restructuring ("EURC"), we provide an update regarding activities in Virginia related to competition in the electricity market. Since § 56-596 of the Virginia Electric Utility Restructuring Act ("Restructuring Act" or "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. At the present time, 3.1 million electricity customers in Virginia have the right to choose an alternative supplier of electricity. In compliance with the Act and this Commission's Order in Case PUE-2000-00740, all electricity customers of Virginia's investor-owned utilities and electric cooperatives are eligible to switch to a competitive supplier except for about 29,400 customers in the southwestern part of the Commonwealth[2] and approximately 7,600 customers served by Powell Valley Electric Cooperative.

As discussed later in this report, work began or continued during the past year to address restructuring issues such as those related to competitive metering, supplier billing, default service, energy infrastructure, stranded costs, and regional transmission organizations ("RTO"), to name a few.

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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 energy.

It remains disappointing, however, that more competitive service providers have not made offers of attractively priced energy options. As in many other states that offer retail access, competitive activity has stagnated in Virginia during the past twelve months. One supplier continues to serve a small portion of customers in northern Virginia with a limited renewable resource, but no other electricity supply offers have been made.

The Commission approved Dominion Virginia Power's ("DVP") revised proposal to implement three pilot programs as a means to encourage competitive activity. These programs are just underway and it is too early to draw any conclusions. Further details will be discussed later in this report.

The following pages provide an overview of the continued transition to full retail access; the process used to develop wires charges and a price-to-compare; the status of our consumer education program; and details on a diverse list of activities and investigations devoted to the development of a competitive market.

ACTIVITY RELATED TO ACCESS

This section provides a review of activity during the past 12 months of the transition to full 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.

Transition to Full Retail Access

Allegheny Power ("AP")[3], American Electric Power – Virginia ("AEP-VA") 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 AEP-VA to provide service within their respective Virginia service territories. Only one CSP is fully registered with Delmarva but has not pursued serving customers.

Dominion Virginia Power ("DVP") implemented customer choice for its customers in three phases beginning in September 2002. DVP's phase-in was complete on January 1, 2003 when the final third of its residential customers became eligible to switch suppliers.

To date, six CSPs and aggregators are registered with DVP to provide service within DVP's 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 1,888 customers. Although PES is not currently mass-marketing its service, it continues to enroll 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.

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

The Commission Order in PUE-2000-00740 permitted the electric cooperatives ("Cooperatives") to phase-in implementation of retail access at their own pace provided it was completed by January 1, 2004. Northern Virginia Electric Cooperative's ("NOVEC") implemented retail access in July 2002. Four additional distribution cooperatives implemented retail access in 2003: Rappahannock Electric Cooperative ("REC"), Shenandoah Valley Electric Cooperative ("SVEC"), Community Electric Cooperative ("CEC"), and Southside Electric Cooperative ("SSEC").

The phase-in of retail access was complete when customers of A&N, BARC, Central Virginia ("CVEC"), Craig-Botetourt ("CBEC"), Mecklenburg ("MEC"), Northern Neck ("NNEC") and Prince George ("PGEC") Electric Cooperatives became eligible to choose a CSP on January 1, 2004. Commission approval of the retail access applications was complete by the end of 2003 to comply with its Order and the Restructuring Act to offer electricity retail choice to all of Virginia's customers by January 1, 2004.

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.[4] 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-four electric and natural gas CSPs and aggregators are licensed

[4] Guidelines to become licensed as a competitive service provider or aggregator are available on the SCC's website at: http://www.state.va.us/scc/division/eaf/compete.htm.

by the Commission to participate in full retail access. A list of licensed suppliers can be found at the end of this section.

In order to participate in an LDC's retail choice program, a CSP must also complete a registration process with the utility. Electronic Data Interchange ("EDI")[5] 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, three CSPs, Dominion Retail, PES and Washington Gas Energy Services ("WGES") are fully registered with DVP. Additionally, three aggregators, New Era Energy, EnergyWindow, Inc. and Vivex, Inc. are fully registered with DVP.

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

[5] EDI standards and guidelines are established by the Virginia Electronic Data Transfer Working Group ("VAEDT"). The VAEDT is discussed later in this report.

Licensed Competitive Service Provider/Aggregator
as of August 10, 2004

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

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 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, landfill gas from a landfill 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 1,888 residential and 20 commercial customers are enrolled with PES. No industrial customer has yet chosen a competitive electricity service provider.

Customer Participation

Pepco Energy Services began serving retail access customers in January 2002 and is currently the only active CSP. Out of approximately 3.1 million customers in Virginia who currently have the right to choose an alternative supplier of electric energy, less than 1,900 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 23, 2004.

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	1,868,436	224,063	1,856	20
AEP-VA	423,423	69,235	0	0
AP	76,587	13,903	0	0
DPL	17,961	3,145	0	0
NOVEC	106,773	7,274	0	0
REC	79,324	5,036	0	0
SVEC	27,332	4,599	0	0
CEC	8,228	1,576	0	0
A&N	9,971	723	0	0
BARC	11,164	577	0	0
CVEC	26,881	2,575	0	0
CBEC	5,609	543	0	0
MEC	28,307	1,711	0	0
NNEC	15,387	942	0	0
PGEC	8,935	1,022	0	0
SSEC	46,656	2,077	0	0
TOTAL	2,760,974	339,001	1,856	20

***** Customer numbers as of December 31, 2003

FUNCTIONAL UNBUNDLING AND WIRES CHARGE

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.[6]

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 procedure 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.

<u>Functional Unbundling</u>

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.

[6] 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,[7] 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. This section will provide an update to the last report.

AEP-Virginia (PUE-2001-00011): By order dated June 18, 2002, the Commission approved the Company's April 30, 2002, motion requesting that the Commission hold all further proceedings on the corporate separation issues in abeyance until no earlier than July 1, 2003. On July 1, 2003, AEP-Virginia filed a Motion For Leave to Withdraw Request. The Company states that it is no longer actively pursuing legal separation at this time. AEP-Virginia requests leave to withdraw, without prejudice, its request for legal separation and further requests that this proceeding be closed. On December 24, 2003, the Commission issued an Order Granting Motion allowing AEP-Virginia to withdraw its request for legal separation and closing the case.

Wires Charge 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

[7] A bundled rate is a single rate for electricity comprised of all service elements: generation, transmission and distribution.

establish such wires charges the Commission must determine projected market prices for energy and subtract those projected market prices from each utility's embedded generation rate. According to the Act, these projected market prices and the resulting wires charges may be adjusted on no more than an annual basis. The embedded generation rate includes fuel costs as determined by the Commission pursuant to § 56-249.6.

Market price determination for full retail access began in 2001 with the market price and wires charges determinations for AEP-VA and DVP.[8] In 2002, the Commission established the market price determination methodology for the electric distribution cooperatives within the Commonwealth, and this past year, completed the determination of wires charges for all relevant electric cooperatives in the Commonwealth for 2004.

The Commission approved the basic methodology for AEP-VA 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 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

[8] Delmarva and Potomac Edison waived their right to wires charges throughout the transition period. AEP-VA waived its right to collect wires charges consecutively for calendar years 2002 though 2004, and recently waived its right to wires charges during calendar year 2005.

prices"[9] for electric power traded in the wholesale market. The Commission made this decision in the beliefs that forward prices are the most appropriate indicators of projected market prices and that forward markets were functioning reasonably well.

The forward price method considers prices at two delivery/receipt points (Cinergy and PJM West) for a calendar year of data. Although DVP has incorporated a value for capacity in the Company's 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.

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 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 additional "headroom" for CSP's entering the Virginia retail electricity market.

At the time that the Commission allowed the incorporation of the capacity adder into DVP's projected market prices, it declined to allow certain proposed changes to DVP's CSP Coordination Tariff that the company had proposed concomitantly with its capacity adder proposal. Although DVP maintained that the tariff changes were necessary to make the

[9] "Forward prices" generally refer to agreements made today for the future purchase and sale of a specified quantity of electric power at some specified location for a specified time period.

company whole in the event of a CSP default, the Commission was concerned that the proposed changes might have had a negative effect on CSP participation in the Virginia retail market. The Commission, however, did not preclude DVP from proposing risk mitigation measures in the future if they were found necessary.

In 2003, DVP again proposed changes to its CSP Coordination Tariff. As in the previous year, these changes were intended to minimize the financial risks of including the capacity adder in the company's projected market prices. The company modified its proposed changes somewhat from the previous year, and in particular, did not seek the ability to recover through a fuel proceeding any lost revenues due to non-compliance of a CSP with the tariff. In accepting the proposed revisions, the Commission specifically prohibited the use of a fuel proceeding to recover any lost revenue due to tariff non-compliance by a CSP and stated that the recovery of any such lost revenues must be accomplished through DVP's approved tariff provisions.

The projected market prices for DVP for 2004 remain below the company's capped generation rates. As such, wires charges are applicable to DVP customers that choose to take service from a CSP during 2004. On July 1, 2004, DVP submitted an application to impose a wires charge in 2005. This application is currently under review by Staff.

This year, AEP-VA 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.[10] AEP-VA's decision not to seek wires charges for 2005 implies that market prices for 2005 within its service territory will again be above its capped generation rate.

[10] Although this decision by AEP-VA leaves the issue of the company's calculation of its transmission cost adjustment to its projected market prices unresolved, the issue remains moot for 2005. To date, the Commission has not accepted AEP-VA's methodology for calculating this adjustment given that AEP-VA's proposed adjustments have been significantly higher than the Commission deems reasonable.

With respect to the electric distribution 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 AEP-VA should be utilized by the Virginia electric distribution cooperatives,[11] 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 AEP-VA. Whereas, the capped rate 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.

The approval process of projected market prices for the respective Cooperatives began in 2002 and was completed by early 2004. With the exception of Central Virginia Electric Cooperative, which did not seek to collect wires charges, the capped rates of the remaining Cooperatives are in excess of the projected market prices within the respective service territories of these Cooperatives; therefore, customers of those Cooperatives who switch to CSPs must pay a wires charge to the cooperative serving them.

<u>Price-to-Compare</u>

[11] 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.

Once rates have been unbundled and the appropriate wires charge has 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.

Among investor-owned utilities, only DVP imposed a wires charge component for 2004 to be included within its price-to-compare. Each of the cooperatives implementing retail access in 2004, with the exception of Central Virginia Electric Cooperative, also included a wires charge component within the respective price-to-compare.

The table below shows the prices-to-compare for the investor-owned utilities in Virginia required to implement retail competition. A similar table for the electric distribution cooperatives that have implemented retail competition 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 2004 price-to-compare values for the subject investor-owned utilities are:

Customer Class	Dominion Virginia Power	AEP Virginia	Allegheny Power	Conectiv
Residential	4.276¢/kWh	3.246¢/kWh	3.87¢/kWh	5.47¢/kWh
Small Commercial	4.320¢/kWh	3.067¢/kWh	3.96¢/kWh	5.94¢/kWh
Large Commercial	3.949¢/kWh	3.585¢/kWh	3.90¢/kWh	Not applicable
Small Industrial	3.812¢/kWh	2.962¢/kWh	3.55¢/kWh	5.58¢/kWh
Large Industrial	3.535¢/kWh	2.781¢/kWh	3.34¢/kWh	5.49¢/kWh
Churches	4.157¢/kWh	2.984¢/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 2005. 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 wires charges imposed pursuant to § 56-583 of the Act. The Commission initiated a proceeding with its Order of June 16, 2004 in Case No. PUE-2004-00068, to permit an exemption to the current payment of wires charges.

Such amended legislation provides an opportunity for large industrial and commercial customers, and aggregated customers in all rate classes subject to aggregated demand criteria as may be established by the Commission, to switch to a CSP without paying wires charges if those customers agree to pay market-based costs for electric energy upon return to an incumbent LDC or default provider. Customers are permitted to avoid wires charges and participate in this program on a first-come, first-served basis until the accumulative billing demand of transferred customers reaches 1000 MW or eight percent of such LDC's adjusted peak-load within 18 months after the program is implemented. Additionally, such customers may not return to the incumbent electric utility or default provider thereafter under capped rates.

The recent Commission Order charged the Staff to invite interested parties to participate in a work group to assist the development of the rules, as well as an appropriate methodology, necessary to implement this new statutory provision. Several questions were also included in the Commission Order for interested parties to provide responses to prompt discussion at the initial work group meeting held on August 19, 2004. Such discussions will continue over the next several weeks. The Staff is directed to submit its report within 30 days of the last work group meeting which is expected to be this fall.

CONSUMER EDUCATION

The "quiet" period for the Virginia Energy Choice ("VEC") consumer education program continued for the past year with limited resources focused on maintaining a website, a toll-free information line, responding to requests for printed materials, and completing the remaining consumer education grant projects. VEC suspended all market research, advertising, public relations, and major grassroots outreach activities on March 1, 2003.

The VEC website (www.vaenergychoice.org) has extensive information on the changes coming to the energy market in Virginia and is routinely updated. The site receives between 8,000 and 10,000 individual visits per month. Web visitors can print information sheets or request consumer guides be mailed to them. The SCC also responds to an average of 20 email inquiries per month from the site.

The VEC toll-free information line (1-877-YES-2004) is supported by an automated system that provides callers with the choice of listening to a brief recording on energy restructuring, leaving address information to receive consumer education materials, or requesting a call from SCC staff. The information line receives between 500 and 600 calls per month.

Two consumer education projects funded with VEC grants were completed in the past year. A total of 10 community-based organizations have participated in the grant program to disseminate information to consumer groups with special needs. Funds were used to print special brochures on energy choice topics, distribute consumer information, or conduct workshops. VEC shared these outreach ideas with organizations that have participated in the grassroots program through an electronic newsletter called "The Source." The periodic distribution of the newsletter is planned to continue through the "quiet" period in order to keep those who are interested informed about energy choice.

The SCC continues to receive the advice and input from the Virginia Energy Choice Education Advisory Committee. The committee members represent investor-owned utilities, electric cooperatives, consumer groups and competitive suppliers. With the likelihood of limited minimal retail energy market activity in the coming year, the SCC and the committee agreed to maintain the Virginia Energy Choice consumer education program at the existing modest level and provide for necessary updates to education materials. With the participation of the committee, the SCC will determine the size and scope of future energy choice outreach activities as market conditions warrant.

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.[12] The Rules Governing Retail Access to Competitive Energy Services ("Retail Access Rules" or "Rules"), adopted by Commission Order in Case No. PUE-2001-00013,[13] 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

[12] 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.
[13] The Rules Governing Retail Access to Competitive Energy Services are available on the Commission's website at: http://www/state/va/us/scc/division/restruct/main/rules/teirrules.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.[14]

Minimum Stay Provisions

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 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, to permit an exemption to the current minimum stay requirement.

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.[15] The statutory exemption permits such customers to elect to accept market-based costs for electric energy as an alternative to being subject to the 12-month minimum stay provision. The recent Commission Order charged the Staff to invite interested parties to participate in a work group to assist the development of the rules, as well as an appropriate methodology, necessary to implement this new statutory provision. Several questions were also included in the Commission Order for interested parties to provide responses to prompt discussion at the initial work group meeting held on August 19, 2004. Such discussions will continue over the next several weeks. The Staff is directed to submit its report within 30 days of the last work group meeting which is expected to be this fall.

[14]Dockets regarding restructuring issues may be found on the SCC's website at: http://www.state.va.us/scc/caseinfo.htm .
[15] 20 VAC 5-312-80 Q

Competitive Metering Provisions

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

In addition, the Commission directed the Staff and the competitive metering work group to continue to study the possibility of the utilities establishing voluntary time-of-use rate programs for residential and small commercial customers and to expand these efforts to consider new meter technology including examining the types of meters the utilities use, and for the Staff to file a report on or before May 1, 2004, providing the results of its investigation. The Staff filed its report on April 28, 2004,[16] advising that it is premature to implement additional elements of competitive metering and recommending that the Staff and the work group continue to monitor regulated and competitive market developments in metering. The Commission provided interested parties an opportunity to comment on the Staff's report by June 1, 2004.

Following comments to the Staff Report submitted by three parties, the Commission entered its Order on July 16, 2004, adopting the recommendations of the Staff Report.

Competitive Billing Provisions

On August 31, 2002, the Commission issued an Order in Case No. PUE-2001-00297, adopting rules for CSP consolidated billing.[17] The Commission also found that an EDI workaround approach for implementation of CSP consolidated billing was reasonable on an

[16] The report may be found at: http://docket.scc.state.va.us:8080/vaprod/main.asp .
[17] The adopted rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e010298b.pdf .

interim basis, recognizing that such approach will need to be replaced with standardized EDI protocols as the competitive market develops and the volume of competitive billing increases.

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.[18] By Order dated April 9, 2003, the Commission issued an Order adopting a change to Retail Access Rule 20 VAC 5-312-20 D and reaffirming our direction to Staff to file two reports on or before July 1, 2004. One report related to the impact on the development of a competitive market, of incumbent-affiliated competitive service providers and their activities in affiliated LDC's service territories. The second report related to the impact of aggregation contracts, particularly regarding exit fees, on the development of competitive retail markets in the Commonwealth

On June 28, 2004, Staff filed a report detailing both issues as required. Staff noted in its report that there has been no aggregation activity in the Commonwealth. Therefore Staff was unable to study the two issues as directed. However, Staff noted that the Commission recently approved three pilot programs offered by DVP and are expected to commence this fall, with one pilot specifically focused on municipal aggregation. Staff expressed belief that these pilots may result in aggregation activity that may permit the two issues mentioned above to be addressed. The Commission recognized the current lack of aggregator activity in its Order of

August 25, 2004, by concluding this matter and dismissing it from the docket of active cases. These issues may be revisited in the future if market conditions warrant further review.

Distributed Generation

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

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

Chapter 827 of the 2004 Acts of the General Assembly amended the net metering provisions of the Code of Virginia, Section 56-594 of the Restructuring Act to revise the definition of eligible customer generator. The definition now refers to a nonresidential customer that owns and operates an electric generation facility that, among other things, has a

[18] Available at http://www.state.va.us/scc/caseinfo/pue/e020174.htm .
[19] In May of 2000, the Commission issued rules governing net energy metering promulgated pursuant to § 56-594 of the Restructuring Act. The net metering rules establish interconnection guidelines and tariffs under which an electric customer may interconnect a small wind, hydro or solar generating facility to the grid. The rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e990788rul.pdf .

capacity of not more than 500 kW. The capacity limit for nonresidential customers previously was 25 kW.

In response to this statutory change, by Order dated June 3, 2004, the Commission established Case No. PUE-2004-00060. This proceeding to amend the current Regulations Governing Net Energy Metering adopted in 2000 permits interested parties to submit comments or a request for hearing by July 19, 2004 and Staff to file a report of its findings and recommendations by August 25, 2004. Several parties filed comments raising substantial issues. DVP filed a motion for leave to submit reply comments, to modify the procedural schedule and to permit the convening of a work group to assist Staff's consideration of the complex issues raised. Several parties support DVP's motion which is now pending before the Commission.

Business Practices

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

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

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

conference calls to update regulators and continues to serve on the Advisory Committee to NAESB.

Virginia Electronic Data Transfer Working Group

The Staff continues to serve as a facilitator for the Virginia Electronic Data Transfer ("VAEDT") Working Group to develop standards and guidelines for electronic data interchange ("EDI"). EDI is a means for a utility and a CSP to communicate electronically and involves the computer-to-computer exchange of business and customer information that is required to transact business between CSPs and LDCs. The current Virginia Plan, Implementation Guidelines, and EDI Test Plan[21] are on file with the Commission for informational purposes. Because of current inactivity, the VAEDT has not been as active and intends to meet this fall to discuss potential issues relating to membership within PJM.

The VAEDT continues to support efforts of the First Regional Electronic Data Interchange ("FREDI")[22] to establish and maintain uniform criteria across the Mid-Atlantic region[23] and more easily exchange electronic information between electric utilities operating in multiple jurisdictions. This effort served as the basis for NAESB's on-going 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.

Generation and Transmission Additions

Since 1998, ten generating plants have been built and placed into commercial operation within the Commonwealth, adding 3,682 megawatts ("MW") to existing generation physically located in Virginia.[24] Approval of seven additional facilities has been granted by this

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[21] Additional information available at: http://www.vaedt.org .
[22] Additional information available at: http://www.firstregionalEDI.org .
[23] Currently comprised of jurisdictions from DC, DE, MD, NJ, PA, OH, and VA.
[24] These new plants are comprised of three Dominion generating stations, one ODEC facility, and six independent

Commission summing to 4,333 MW, of which one facility is under construction and should be ready for operation by the fall of 2004. Another certificated facility of 680 MW has since been withdrawn. The remaining facilities, totaling 3,185 MW, are in various stages of development to move forward. In addition, seven independent power producers submitted applications for generating capacity of 5,430 MW, but withdrew their requests prior to receiving certificates. The table at the end of this section provides further detail regarding applications for new facilities.

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

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

Expansion of transmission facilities is also needed to accommodate expected customer demand and required energy supply. The SCC granted permission to AEP-VA to construct a 765-kV electric transmission line in southwestern Virginia. That line is under construction and

power plants, representing 1,500 MW, 472 MW, and 1,710 MW, respectively.

is expected to be operational in late 2006. Applications for a few smaller transmission lines have been approved or are currently pending before the SCC. Additionally, several new natural gas pipelines are now in service or have been approved.

By order dated August 21, 2002, the Commission adopted filing requirements for applications filed on or after September 1, 2002.[25] In the August 21st Order the Commission also concluded that, due to the passage of SB 554[26], filing requirements addressing cumulative environmental impacts are not necessary and therefore are excluded from the Commission's filing requirements.

The Restructuring Act as amended by the 2004 Session of the General Assembly as Senate Bill 651, extended by two years the expiration date of certain certificates granted by the Commission. Those certificates to construct and operate electrical generating facilities for which applications were filed with the Commission prior to July 1, 2002, will receive the two-year extension.

[25] The amended rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e010655a.pdf .

[26] The adopted rules may be found at: http://www.state.va.us/scc/caseinfo/pue/e010313.htm. Senate Bill No. 554 was signed by Governor Warner on April 4, 2002, and became effective on July 1, 2002. The bill modified the Commission's role in reviewing the environmental aspect of appliations to construct electric generating facilities in Virginia.

Summary of Construction Activity in Virginia
As of August 10, 2004

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 (1/16/01)	885 MW	Fluvanna County	PUE010039	Gas CC	May 04	3/13/02	4/19/02
INGENCO Wholesale Power, LLC (11/13/03)	16 MW	Chesterfield County	PUE-2003-00538	48-LFGas	Jun 04	none	4/12/04
	3,682 MW						
New power plants with SCC certificates currently under construction.							
Marsh Run Generation, LLC (12/28/01)	**468 MW**	Fauquier County	PUE020003	3-GasCT	Sep 04	5/21/02	SCC app 11/6/02
New power plants with SCC certificates, but not yet under construction.							
Competitive Power Ventures (8/31/01/2/02)	520 MW	Fluvanna County	PUE010477	Gas CC	spr 06	1/9/02	SCC app 10/7/02
Tenaska Virginia Partners II, LP (8/15/01)	900 MW	Buckingham County	PUE010429	Gas CC	n/a	5/28/02	SCC app 1/9/03
CPV Warren, LLC (2/14/02)	520 MW	Warren County	PUE020075	2-GasCC	spr 05	7/24/02	SCC app 3/13/03
Chickahominy Power, LLC (1/4/02)	665 MW	Charles City County	PUE010659	Gas CT	n/a	5/1/02	SCC app 3/12/04
James City Energy Park, LLC (3/8/02)	580 MW	James City County	PUE-2002-00150	2-GasCC	win 05	9/18/02	SCC app 3/12/04
White Oak Power Co., LLC (5/9/02)	680 MW	Pittsylvania County	PUE-2002-00305	4-Gas CT	sum 04	10/24/02	SCC app 8/1/03,w/drawn
	3,865 MW	>>> 680 withdrawn **leaving 3,185 MW**					
New power plants that have applied for an SCC certificate							
Duke Energy Wythe, LLC (12/27/01)	620 MW	Wythe County	PUE010721	Gas CC	sum 04	6/25/02	**Dismissed 5/20/04**
CinCap-Martinsville	330 MW	Henry County	PUE010169	4-GasCT	sum 03	9/18/01	**Dismissed 4/29/03**
Kinder Morgan VA, LLC	560 MW	Cumberland County	PUE010722	Gas CC	sum 04	12/17/02	**Dismissed 1/14/03**
Kinder Morgan of Virginia, LLC	550 MW	Brunswick County	PUE010423	Gas CC	win 04	11/7/01	**Dismissed 11/1/02**
Henry County Power/Cogentrix (MB)	1,100 MW	Henry County	PUE010300	Gas CC	sum 04	10/17/01	**Dismissed 8/26/03**
Loudoun County Power/Tractebel (WS)	1,400 MW	Loudoun County	PUE010171	Gas CC/CT	04/05	12/6/01	**Dismissed 3/27/02**
Mirant Danville, LLC (KH)	870 MW	Pittsylvania County	PUE010430	Gas CT/CC	03/04	12/5/01	**Dismissed12/16/03**
Total	**5,430 MW**	>>> withdrawn/dismissed **leaving 0 MW**					

*Commercial Operation Date

Company/Facility	***Size***	***Location***	***Docket***	***C.O.D.***	***Order***
Transmission lines					
AEP-VA	765 kV-90 mi	Wymoing-Jackson's Ferry	PUE970766	2006	5/31/01 approved, under construction
DVP	500 kV-101 mi	Joshua Falls-Ladysmith	PUE910043	n/a	revised 5/02 and continued
DVP	230 kV- 4 mi	Loudoun	PUE010154	n/a	6/27/02 approved conditionally
DVP	500 kV-8 mi	Morrisville-Loudon	PUE-2004-00062	5/07	pending
DVP	230kV – 11.8 mi	Trabue-Winterpock	PUE-2004-00041	11/06	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 Loudon	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 4/9/04 for AP to file cost/benefit analysis by 6/18/04, Staff report on 8/23/04 and hearing on 9/28/04.
Conectiv (PJM East)	PUE-2001-00353	Order of 5/20/04 recognizes current membership in PJM since 3/97 **SATISFIES** RTE Rules.
KU (MISO)	PUE-2000-00569	**EXEMPT** 2003 via §56-580 G
AEP (PJM West)	PUE-2000-00550	Order of 1/15/04 setting 6/22/04 for Staff Report & hearing on 7/27/04.
DVP (PJM South)	PUE-2000-00551	Order of 12/22/03 setting 8/16/04 for Staff Report & hearing on 10/12/04.

Energy Infrastructure Study

Senate Bill 684, enacted by the 2002 Session of the General Assembly, requires 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 EURC 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 EURC's consideration. The EURC 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 EURC, on or before July 1, 2003, and to provide subsequent reports as the Commission deems necessary or as requested by the EURC.

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 is currently collecting updated data and will report to the EURC on this matter in the near future.

RTE Development

Section 56-579 of the Restructuring Act requires incumbent electric utilities to establish or join regional transmission entities ("RTEs")[27] as part of the transition to retail competition. This obligation is imposed on each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity. Section 56-579 also requires the State Corporation Commission to determine "whether to authorize transfer of ownership or control from an incumbent electric utility to a regional transmission entity." Behind this requirement was an expectation that RTEs would manage and control the transmission assets of Virginia's utilities with the objective of meeting the transmission needs of electric generation suppliers both within and outside Virginia.[28]

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

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[27] RTE and RTO (Regional Transmission Organization) are essentially synonymous terms. The former is used in the Act; the latter is the Federal Energy Regulatory Commission ("FERC") preferred acronym.
[28] § 56-579 A 2 d.

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

Three of Virginia's incumbent electric utilities, Kentucky Utilities, Allegheny Power and Delmarva, have shifted management of their transmission facilities to an RTE. Delmarva and AP are participating in PJM[29] and KU is participating in the MISO.[30]

Virginia Power and AEP, along with a number of other utilities, sought to form the Alliance RTO which was rejected by the FERC on December 20, 2001. On April 25, 2002, FERC issued an order directing the Alliance Companies to make compliance filings detailing which RTO(s) they plan to join, collectively or individually. On May 28, 2002, AEP made a compliance filing noting its intention to join PJM West. Virginia Power also made a filing on that date noting that it was soliciting input from its stakeholders. On July 15, 2002, Virginia Power filed an update to its earlier filing notifying that the Company had entered into a MOU to join PJM as "PJM South."

On July 31, 2002, FERC issued an order conditionally accepting AEP's and Dominion Virginia Power's filings. Both utilities have entered into implementation agreements with PJM. These agreements reflect financial commitments by both companies to fund certain PJM expansion related costs and set forth schedules for the proposed expansions. The following discussion will provide additional information regarding the status of individual RTE proceedings currently pending Commission approval.

[29] 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.

[30] "MISO" is the Midwest Independent System Operator. MISO began offering transmission service over KU's transmission facilities on February 1, 2002.

AEP-VA

AEP-Virginia filed a substitute application for approval to transfer functional control of its transmission facilities to PJM on December 19, 2002. The Commission issued a scheduling order, in Case No. PUE-2000-00550,[31] regarding that application on March 7, 2003. That order required AEP "to develop, as soon as practicable, but no later than 90 days, after a final SMD rule has been adopted, a study of the costs, benefits, and resulting cash flows that would arise from the transfer of AEP-VA's transmission assets to PJM. The Company shall submit a report detailing the methodology, key assumptions, and results of the cost/benefit analysis from the perspective of AEP, AEP-VA, other AEP corporate entities, AEP shareholders, AEP-VA's customers, and Virginia ratepayers as a whole." The order also noted that the Commission expected: "the cost/benefit analysis to include at a minimum an examination of (1) how participation in PJM would impact AEP-VA's fuel factor during the capped rate period; (2) market prices for generation as compared to current cost of service based generation pricing; (3) transmission rates for the recovery of embedded transmission costs; (4) transmission congestion costs incurred under the locational marginal pricing ("LMP") construct; and (5) the availability and effectiveness of transmission rights for "hedging" against transmission congestion charges. The study also should include a sensitivity analysis to evaluate and identify critical assumptions including, but not limited to, the following: (1) differing load forecasts; (2) differing levels of transmission congestion and associated transmission rights; (3) abnormal vs. normal weather; (4) differing unit outage assumptions; and (5) differing fuel cost projections (higher or lower gas costs vs. coal costs, for example). Finally, the study should include a discussion of how the completion of the planned Wyoming to Jackson's Ferry 765 kV line might impact study results."

On November 7, 2003, the Commission entered an Order pursuant to which the Commission amended the March 7, 2003 Order to require the Company to file additional relevant information quantifying the net costs of the Company's proposal with respect to various stakeholder groups under six scenarios.

On March 14, 2003, the public utilities commissions of Ohio, Michigan and Pennsylvania filed a motion requesting that the FERC direct that AEP transfer control of its transmission facilities to PJM, irrespective of pending state regulatory approvals. Exelon Corporation and Commonwealth Edison Company filed in support of the motion on March 17, 2003. This Commission filed a response to those motions on April 1, 2003. The Commission's response sought to preserve state authority and argued against federal preemption. On that same day, the FERC approved AEP's request to join PJM but did not direct that AEP join by a date certain thereby avoiding any ruling regarding state authority relative to RTO participation. Thereafter, the Commission filed a request for rehearing on May 1, 2003, questioning the FERC's decision to grant approval on the basis that the record was devoid of any factual basis for the FERC finding that AEP's transfers of control of its facilities to PJM would be consistent with the public interest. Significantly, and as emphasized in the Commission's request for rehearing, the application lacked, among other things, information identifying the actual facilities whose control was proposed to be transferred from AEP to PJM. AEP's application was similarly silent concerning the impact of the proposed transfers on customers' rates for power and energy. The Commission's request, as well as various other motions for reconsideration, is currently pending.

On June 26, 2003, the FERC Staff issued data requests to PJM and AEP seeking information regarding the possibility of transferring control of only a portion or portions of

[31] See http://www.state.va.us/scc/caseinfo/pue/e000550.htm

AEP's transmission system to PJM. PJM filed responses basically concluding that partial integration of the AEP system was feasible from a technical and operational perspective. By its own admission, PJM did not address any "federal or state legal or regulatory concerns or issues that might arise about dividing AEP-East's facilities ...." AEP filed responses with quite different conclusions. AEP noted that partial integration would result in a long list of quite serious negative consequences, including; (1) increasing the cost to serve AEP customers, (2) violating Commission requirements pertaining to single-tariff service over a single holding company system, (3) potentially creating a seam within AEP-East where none has existed previously, (4) decreasing planning and operational efficiencies, (5) contradicting Commission policies which favor the regionalization of tariff and reliability functions, (6) complicating the pending AEP applications in non-transferring states, and (7) creating intra-company operational barriers for the first time for those individual AEP operating companies that serve customers in more than one state. On July 16, 2003, the Commission filed comments supporting AEP's position and criticizing PJM's response with the FERC.

On July 17, 2003, the Kentucky Public Service Commission ("KPSC") denied AEP's application to transfer control of its major transmission lines in Kentucky to PJM. The KPSC determined that the proposed transfer would not be in the public interest because it would impose costs on Kentucky Power ratepayers without providing demonstrable benefits. The KPSC cited the following factors in denying Kentucky Power's application to join PJM:

- Kentucky Power would pay $3 million annually in membership fees, but could show no quantifiable benefits of membership in PJM.

- Kentucky Power has low costs and reliable transmission, so is unlikely to benefit from membership in PJM.

- PJM could in the future set a single wholesale electricity rate for its entire system, a move that would significantly raise rates for Kentucky Power customers.

- If Kentucky Power joins PJM, the RTO could decide which customers in the overall system get priority in the event of power shortages. That conflicts with Kentucky law that requires utilities in the state to give priority to the "native load" in their service territories. The PSC has no authority to override that law.

AEP filed a petition for rehearing of the Kentucky decision on August 6, 2003. The petition was granted and rehearing was scheduled for April 21, 2004.

On September 12, 2003, the FERC issued an "Order Announcing Commission Inquiry into Midwest ISO-PJM RTO Issues." The order directs AEP, among others, to have a senior company official present at an inquiry to be held on September 29 and 30, 2003. AEP must file prefiled testimony discussing impediments to its voluntary commitment to join an RTO by September 23. The order also invites state commission representatives to the inquiry. The Commission filed a motion for reconsideration of the September 12 order on September 24, 2003 and was represented at the FERC hearings held on September 29 and 30. The Commission also filed comments concerning AEP's partial integration proposal on October 9, 2003.

On November 25, 2003, in Docket No. ER03-262-009, FERC issued its "Order Making Preliminary Findings and Giving Public Notice and Setting Matter for Public Hearing under PURPA Section 205 (A)," in which it preliminarily found that AEP should be exempted from complying with either the orders of the Kentucky Public Service Commission or the provisions of the Virginia Electric Utility Restructuring Act because these "are preventing AEP from fulfilling both its voluntary commitment in 1999, as part of merger proceedings, to join an RTO, and its application to join an RTO pursuant to the Commission's Order No. 2000."

The FERC convened a public hearing on this matter on January 26, 2004. Briefs were filed on February 12, 2004, and oral argument in lieu of reply briefs was held on February 24, 2004. The Administrative Law Judge filed recommendations on March 15, 2004.

On April 20, 2004, the parties to the Kentucky Power RTE proceeding presented the KPSC with a proposed stipulation, which would settle the matter by allowing AEP to transfer its Kentucky Power transmission facilities to PJM control, subject to certain conditions. On May 19, 2004, the KPSC approved the stipulation and allowed Kentucky Power to transfer control of its major transmission lines to PJM subject to certain conditions. The stipulation affirms the KPSC's authority over Kentucky Power's retail rates, the KPSC noted in its order. "This affirmation of this Commission's authority, coupled with the voluntary nature of PJM's energy market for meeting Kentucky Power's native load energy requirements, provides adequate assurances that Kentucky Power's retail energy costs will continue to be fair, reasonable, and relatively stable over time, and not subject to market price variations," the KPSC said. The KPSC also sought to be dismissed from the FERC in Docket No. ER03-262-009 proceeding on the grounds that its May 19 order renders the question moot.

On June 17, 2004, the FERC issued an "Opinion on Initial Decision and Order on Rehearing" Docket No. ER03-262-009 that:

- Affirmed the FERC's initial finding that it could act under section 205(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA)[32] and permit AEP to integrate into PJM over the objection of the Commonwealth of Virginia.

- Recognized that the Virginia Commission is considering whether AEP-VA should join PJM and noted that while the FERC would prefer that Virginia complete its state proceeding prior to its decision in No. ER03-262-009 that the current schedule does not provide for the Virginia Commission's hearing to begin until July 27, 2004.

- The FERC further noted that it was concerned that such a schedule will not provide adequate notice to the market participants to permit AEP to join PJM as of October 1, 2004, the date set forth in our November 25, 2003 Order. The FERC stated that AEP, PJM, and their customers need greater certainty for the integration to be able to proceed on that date, and therefore invoked its authority under PURPA section 205.

[32] 16 U.S.C. § 824a-1(a) (2000).

- Finally the FERC noted, to the extent that the Virginia Commission is able to complete its proceedings prior to the date of integration and reaches agreement as to reasonable conditions relating to integration that do not prevent or prohibit integration, that it would be open to considering such provisions.

In a separate order issued on June 17, 2004, the FERC approved the Kentucky settlement.

On June 29, 2004, the Commission filed an Emergency Motion with the FERC in Docket No. ER03-262-009. The motion requested that the FERC issue an order staying the effectiveness of its June 17 opinion and order by no later than July 15, 2004. The FERC denied that motion for stay on July 15, 2004. On July 29, 2004, the Commission filed a Motion for Expedited Reconsideration of the FERC's July 15 Order. In that motion, the Commission noted that parties to the Virginia proceeding regarding the transfer of control of AEP's transmission facilities to PJM's had entered into a Stipulation that would enable the Commission to approve the proposed transfer and that approval of the Stipulation by the Commission would moot the issues addressed in Opinion No. 472 concerning the laws, rules and regulations of the Commonwealth of Virginia. On August 3, 2004, the FERC issued an order staying its opinion and order until September 2, 2004. It should also be noted that on July 16, 2004, the Commission filed with the FERC a motion requesting rehearing of the FERC's June 17, 2004, decision in this matter.

In a related filing, the Commission filed a Petition for Writ of Mandamus to the Federal Energy Regulatory Commission in the United States Court of Appeals for the District of Columbia Circuit on July 21, 2004. In that petition, the Commission requested that the Circuit Court stay the effectiveness of the FERC opinion and order until the FERC's order on rehearing is issued, and the matter can then be fully considered on appeal by the Circuit Court.

The Commission issued a procedural schedule in PUE-2000-00550 setting the matter for notice and hearing on January 15, 2004. AEP was directed to file testimony and exhibits by

March 1, 2004; respondents were directed to file testimony and exhibits by May 24, 2004; and Staff was directed to file testimony and exhibits by June 22, 2004. The public hearing took place on July 27, 2004. During the hearing, AEP-VA; the Commission's Staff; the Division of Consumer Counsel of the Office of the Attorney General; the Old Dominion Committee for Fair Utility Rates; PJM; and Edison Mission Energy offered a stipulation recommending that the Commission approve AEP-VA's participation in PJM subject to certain specified conditions. The conditions set-forth in the stipulation included agreements by AEP-VA and the parties regarding future ratemaking proposals that may come before the Commission; modest bill credits for the period 2005-2010; a curtailment protocol specifying conditions under which service to Virginia consumers may be curtailed; and information reporting requirements for AEP-VA and PJM. On August 2, 2004, the Commission issued an Order Requesting Comments on a proposed modification to the curtailment protocol specified in the stipulation. This matter is now pending a Commission decision.

Allegheny

Allegheny filed an application to transfer control of its transmission facilities to PJM under an arrangement known as PJM West. On August 16, 2001, the Commission issued an Order Prescribing Notice and Inviting Comments and/or Requests for Hearing that established a procedural schedule for this matter, Case No. PUE-2000-00736.[33] On October 26, 2001, Staff filed a report supporting Allegheny's application and its membership in PJM West. However, the Staff noted that it was unknown what would occur as a result of the FERC-ordered mediation involving PJM, Allegheny, the New York Independent System Operator, and IS0 New England. The Staff, therefore, recommended that the Commission either delay

[33] See http://www.state.va.us/scc/caseinfo/pue/e00736.htm

acting on, or grant only conditional approval of, Allegheny's request to transfer management and control of its transmission facilities in order to permit Staff to review any FERC order in the Northeast RTO proceeding.

On January 30, 2002, FERC issued an Order that, among other things, permitted Allegheny and PJM to form PJM West, effective March 1, 2002. On May 9, 2002, the Commission issued an order noting that much had occurred regarding the development and implementation of PJM West and that those developments may have affected the accuracy and completeness of the information included in Allegheny's application. Accordingly, the Commission required Allegheny to update its application.

On July 12, 2002, the Staff filed a Supplemental Report recommending that the Commission delay approval of Allegheny's application until more information was known about the ITC proposal for PJM West, Dominion's PJM South proposal, and the outcome of PJM and MIS0 discussions to form a single energy market across the PJM and Midwest regions.

On May 30, 2003, the Commission issued an order requiring Allegheny to develop and file a study of the costs, benefits, and resulting cash flows that would rise from the transfer of Allegheny's transmission assets to PJM within 90 days of FERC's adoption of a final rule pertaining to SMD.

Potomac Edison has turned over operational control of its transmission facilities to PJM and currently operates under the LMP model. A procedural schedule setting this matter for notice and hearing was issued on April 9, 2004. Potomac Edison was directed to submit an analysis of the comparative costs and benefits of its participation in PJM by June 18, 2004. Respondents were directed to file testimony and exhibits by July 26, 2004, and Staff was directed to file testimony and exhibits by August 23, 2004. The public hearing is scheduled for September 28, 2004.

Delmarva

On October 16, 2000, Delmarva filed a Motion with the SCC in Docket No. PUE-2000-00086[34], requesting the Commission to determine that Delmarva's membership in PJM constituted compliance with the requirements of the Restructuring Act and the SCC's Regulations Governing Transfer of Transmission Assets to Regional Transmission Entities, 20 VAC 5-320-10 *et seq.* ("RTE Rules").

On June 1, 2001, the SCC issued a procedural order prescribing notice and inviting comments on Delmarva's request. By Order dated June 22, 2001, the SCC created a separate docket, Case No. PUE-2001-00353, to receive comments and requests for hearing on Delmarva's request. On August 17, 2001, the Staff filed a response to Delmarva's request. In its response, the Staff noted that the FERC had issued an order on July 12, 2001, provisionally granting RTO status to PJM. The Staff commented that the FERC had strongly encouraged the formation of one Northeast RTO encompassing PJM, the New York Independent System Operator, and ISO New England.[35] The SCC Staff observed that the FERC's Order raised the possibility that PJM's configuration could change if a larger Northeastern RTO developed as a result of the involuntary mediation process the Commission had initiated. The Staff, therefore, recommended that the SCC either delay acting on, or grant only interim approval of,

[34] See http://www.state.va.us/scc/caseinfo/pue/e00286.htm

[35] PJM Interconnection, L.L.C., Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas & Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric & Gas Company, UGI Utilities, Inc., Order Provisionally Granting RTO Status, Docket No. RT01-2-000, 96 F.E.R.C. ¶ 61,061 at 61,231-61,232 (July 12, 2001).

Delmarva's request until more was known about the mediation process and about any Northeastern RTO that might be formed.

The Commission entered a second order on May 9, 2002, establishing a procedural schedule and requiring the filing of supplemental documents in this docket. The May 9, 2002 Order observed that a number of developments could have affected the accuracy and completeness of the information accompanying Delmarva's original request. It therefore required Delmarva to file on or before June 18, 2002, complete information about further developments relevant to Delmarva's October 16, 2000 request. Additionally, the Commission directed its Staff to file a supplemental report detailing the further results of Staff's investigation, and invited Delmarva and any interested person to file on or before August 2, 2002, comments responsive to the Staff's supplemental report.

On June 18, 2002, Delmarva filed its response to the SCC's May 9, 2002 Order. In its response, Delmarva reported that there had been no changes in Delmarva's status as a member of PJM, and that none of the features of PJM essential to Delmarva's compliance with Virginia's requirements had changed since August 31, 2001, or since Delmarva filed its Request on October 16, 2000.

On July 12, 2002, the Staff filed a supplemental report and recommended that the SCC delay or grant only conditional approval of Delmarva's request until more was known about the proposal for potential expansion of PJM West, Dominion's PJM South proposal, and the outcome of PJM's and MISO's discussions regarding formation of a single energy market across the PJM and Midwest regions.

On May 30, 2003, the Commission issued an order requiring Delmarva to develop and file a study of the costs, benefits, and resulting cash flows that would rise from the transfer of

Delmarva's transmission assets to PJM within 90 days of FERC's adoption of a final rule pertaining to SMD.

In light of the uncertain prospects for any final SMD rule, the Commission in an Order on March 4, 2004, directed Delmarva to first supplement its filing with a legal memorandum responding to the initial question whether, given Delmarva's long-standing membership in PJM, the Commission has authority under § 56-579 of the Act to grant "prior approval" to a transfer that appears to have occurred well before the enactment of this statute.

On March 26, 2004, Delmarva filed its Response. Delmarva asserted that on July 1, 1999, the effective date of the Act, it had already transferred "the management and control of its transmission system" in the Commonwealth to the PJM Interconnection, L.L.C., and that this transfer had occurred on March 31, 1997. Thus, the Company contended, that because it retained no management or control over its transmission system, there was nothing to which the Commission could give "prior approval" as envisioned by §56-579 of the Act. The Company further argued that Virginia law made clear that newly enacted statutes, such as the Act, could only be given prospective effect and could not be applied retroactively, unless the legislation clearly expressed the intent that it be applied retroactively, or if the legislation affected only procedural and not contractual or other substantive rights.

On April 14 and 16, 2004, respectively, the Staff and the Office of the Attorney General's Division of Consumer Counsel ("Attorney General") filed Responses to Delmarva's filing. All filing parties conclude that the Commission cannot apply its new authority under code § 56-579 to Delmarva's membership in PJM, which occurred prior to the passage of the statute.

The Commission found that Delmarva does not now possess, nor did possess as of July 1, 1999, management and control of its transmission facilities within the Commonwealth of

Virginia; that the management and control of such facilities is now, and has since at least March 31, 1997, been possessed by PJM; that the Commission was without authority to give "prior approval" to the transfer of management and control that occurred over two years prior to the passage of the Act, which directs all jurisdictional utilities to make such transfers subject to the prior approval of the Commission; that, notwithstanding the Commission's lack of jurisdiction under the limited factual circumstances presented herein, Delmarva's membership in PJM appears to satisfy the requirements of our RTE Rules and is not contrary to the public interest; and that this matter should accordingly be dismissed. The Commission rejected Delmarva's contention that its transmission facilities do not fall within the general jurisdiction of the Act, due to their geographical location on the Eastern Shore. To the contrary, we find that those facilities do comprise a part of "Commonwealth's interconnected grid and we retain jurisdiction over any subsequent transfer of operation and control of them by Delmarva or any other operator.

Dominion Virginia Power

On June 27, 2003, DVP filed an application seeking to join PJM. On September 26, 2003, the Commission entered its Order for Notice in this proceeding.[36] The Order for Notice directed the Company, among other things, to file certain relevant information and supporting information by November 26, 2003. This date was subsequently amended by additional Orders of the Commission to March 15, 2004.

The Commission issued a procedural schedule setting this matter for notice and hearing on (date). Respondents were directed to file testimony and exhibits by July, 15, and Staff was directed to file testimony and exhibits by August 16, 2004. The public hearing is scheduled for October 12, 2004

Kentucky Utilities

Kentucky Utilities' application to transfer control of its transmission facilities to the MISO is pending. HB 2637 suspended the applicability of the Restructuring Act to Old Dominion. The implication of this exemption coupled with the fact that the Company has joined MISO must be explored in terms of required Commission approval. More specifically, the issue HB 2637 places before the Commission is whether the Commission has authority to continue its review (post July 1, 2003) of Old Dominion's RTE application.

FERC Fact Finding Investigation

On May 12, 2003, the FERC established a fact finding proceeding (to be facilitated by an Administrative Law Judge) concerning congestion on the Delmarva Peninsula. The purpose of this proceeding is to evaluate the "extent and costs of transmission congestion" and to help identify potential solutions. The FERC fact finding was unusually structured as a "non-adversarial" proceeding with limited discovery and a hearing where only predetermined questions were asked with no opportunity for follow-up. The Virginia, Delaware, and Maryland Commissions were invited to join other interested parties and to send expert staff members and an ALJ to work with FERC's ALJ. The Commission filed a notice of intervention on May 19, 2003. The Commission Staff actively participated in this matter. Additionally, the Commission was represented at the "non-adversarial" hearing held on July 30-31, and on August 1 and 4, 2003.

The Commission filed a report to be appended to the FERC ALJ's report on August 11, 2003. The Commission's report expressed concern that the limited nature of the FERC's "non-

[36] See http://www.state.va.us/scc/caseinfo/pue/e00551.htm

adversarial" proceeding did not allow a sufficient exploration of certain issues and recommended that the entire matter should now be referred to the FERC's Office of Market Oversight and Investigations for a full enforcement investigation. The Delaware Public Service Commission also filed a report stating similar concerns and recommending that the FERC conduct a distinct proceeding to solve the Delmarva Peninsula's problems. The ALJ issued her report on August 12, 2003, finding that the record in the proceeding was sufficient to provide the FERC "with relevant and material information necessary to address the facts and determine possible solutions regarding congestion on the Delmarva Peninsula."

On September 9, 2003, the FERC issued an order in Docket No. PA03-12 directing the ALJ to make findings of fact and recommendations, primarily regarding solutions to congestion and lessons to be learned from the Delmarva experience. On September 11, 2003, the ALJ issued an order offering parties an opportunity to submit proposed findings of fact and recommendations, based on the record already developed in the proceeding by September 25, 2003. On September 24, 2003, the Commission filed a motion for rehearing arguing that the record in the proceeding was not sufficient for the development of findings of fact. No ruling was made on this motion.

The ALJ issued her Findings of Fact and Recommendations on October 10, 2003. She found that adoption of LMP and inclusion of the 69 kV facilities in the LMP scheme did not cause or increase congestion. Additionally, she found that the record does not support a finding that the exercise of market power has caused or increased congestion on the Delmarva Peninsula. She does, however, recommend that FERC's Office of Market Oversight and Investigations ("OMOI") make an independent review of the subject record to determine whether a further investigation into the existence and extent of market power should be undertaken.

On October 27, 2003, the Commission filed comments on the ALJ's report recommending that the FERC not adopt the proposed findings. Instead, the Commission urged the FERC to direct its OMOI to investigate the possible exercise of market power on the Delmarva Peninsula, and in so doing to: (a) interview all participants in the Peninsula wholesale power markets; (b) obtain all data OMOI deems relevant, under confidentiality provisions, if necessary; (c) involve the staffs of the three affected state commissions (Delaware, Maryland and Virginia) in its investigation and, in particular, to share data, analysis and preliminary conclusions with the staff of those commissions, and (d) file a written public report with the Commission within 120 days. At its December 17, 2003, open meeting the FERC decided to take no action on this matter; consequently no order will be issued.

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. Accordingly, on January 15, 2004, the Commission issued an Order initiating an investigation of this matter (Case No. PUE-2004-00001), directing public notice, providing interested parties with an opportunity to submit comments and request a hearing, and directing the Staff to investigate and file a report with its findings and recommendations on this matter. Nine parties submitted comments; however, no party requested a hearing. None of the parties asserted that a sufficient level of competition exists such that the elimination of default service will not be contrary to the public interest; and, with one exception, all of the parties, as well as the Staff Report, advised against the elimination of or changes to default service at the current time.

On April 23, 2004, the Commission issued a Final Order in this proceeding 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 EURC in this 2004 annual report on the status of competition in Virginia.

<u>Earnings of Virginia Investor-Owned Electric Utilities</u>

Each 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 and 2002 earnings of each investor-owned electric utility based on Staff's review of the earnings test analysis included in each company's AIF. The earnings reflect bundled (generation, transmission and distribution) per books Virginia jurisdictional return on common equity earned on a regulatory basis.

	2001	2002
Dominion Virginia Power	9.80%	22.36%
AEP-Virginia	9.52%	12.79%
Potomac Edison	13.80%	15.12%
Delmarva	6.47%	*
Kentucky Utilities	10.76%	14.19%

* Staff report has not been completed.

Each of the above companies filed financial data for calendar year 2003 during the first half of 2004. Staff has not yet completed its review of the 2003 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.

	2003
Dominion Virginia Power	13.26%
AEP-Virginia	12.10%
Potomac Edison	10.03%
Delmarva	4.28%
Kentucky Utilities	11.81%

Stranded Costs

On January 27, 2003, the EURC 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 underrecovery of just and reasonable net stranded costs. On March 3, 2003, the Commission entered an Order Establishing Proceeding, docketing Case No. PUE-2003-00062[37] 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 EURC.

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 Virginia Power, and the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (the "Committees"), each presented one methodology. Staff's primary methodology proposed to calculate just and reasonable net stranded costs based on an asset valuation methodology and to calculate stranded recoveries from capped rates and wires charges. The Staff offered a second, alternative proposal, referred to as the Accounting Approach, that (1) measures recoveries of stranded costs from capped rates and wires charges, (2) measures potential stranded costs on an annual historic basis[38], and (3) after July 1, 2007 could be used to calculate actual stranded costs or benefits on an annual historic basis. Dominion Virginia Power's proposal provided for the monitoring of just and reasonable net stranded costs which included reporting to the EURC, (1) the over- or under-recovery of stranded costs collected through the wires charges from switching customers, (2) actual "above-market" or "potential" stranded costs exposure under

[37] See http://www.state.va.us/scc/caseinfo/pue/e030062.htm

[38] Potential stranded costs are defined as annual stranded cost exposure during the capped rate period, assuming all customers are paying market rates for generation service. This amount is a recalculation of capped rates based on the current embedded cost of generation by customer class compared to the actual market rate for the same period. The difference would be multiplied by the total kWh sales to determine the potential stranded costs. In its report, Staff proposed making this calculation annually on a historic basis during the transition period.

capped rates, (3) the amounts expended from funds available under capped rates to mitigate potential stranded costs, and (4) additional expenditures that negatively impact (increase) such costs during the transition period. The Committees' proposal was based on an asset valuation methodology for measuring stranded costs and incorporated stranded cost recoveries from both wires charges and capped rates.

The EURC'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 EURC because no consensus methodology was reached by the work group.

After several stakeholder meetings the EURC, on January 15, 2004, adopted a draft resolution (the "2004 Resolution") presented by the Division of Consumer Counsel of the Office of the Attorney General (the "OAG"). 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 similar to that provided for in the Accounting Approach outlined above. A portion of the data to be included in the annual September reports will be obtained from information filed with the Commission. Staff has met with the OAG several times and is currently working to provide the OAG with the necessary information to make its report to the EURC. Specifically, Staff will quantify earnings available for stranded costs recoveries for each electric utility for calendar years 2001, 2002, and 2003, at various target returns defined by the OAG. Staff will also calculate generation revenues based on each utility's embedded cost of providing generation service at various target returns for calendar year 2003. The OAG has requested calendar year 2003 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 will be compared to the cost-based generation revenues calculated by Staff to determine potential stranded costs for calendar year 2003.

Financial Profile of Virginia's Electric Utilities

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

The key trend in 2004 has been the dramatic slowdown of credit rating downgrades relative to the past quarter and the past two years[39]. From the quarter a year earlier, the number of downgrades dropped from 50 downgrades to 17, a dramatic 66 percent slowdown. The overall ratings distribution has remained close to the profile of the past two years with the number of negative outlooks dominating over positive ones. Debt financed expansion into non-regulated businesses such as merchant generation and energy marketing and trading continues to damage the consolidated financial profiles of utility holding companies. Other contributors

[39] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 30, 2004.

to the high number of negative outlooks have been weak competitive positionings, refinancing risks, investments in unregulated activities, volatility in wholesale power markets, and acquisitions of financially weaker companies.[40]

Similar to last year when two investor-owned utilities operating in Virginia were downgraded, Virginia has again been affected by the turmoil facing the energy markets. This year, another two Virginia utilities have had their ratings downgraded to BBB ratings from S&P (see Senior Secured Debt Credit Ratings and Outlooks table below). In one instance the lower ratings can be partly attributed to S&P's consolidated ratings methodology that rates legal subsidiaries on par with their corporate parents. The idea is that cash is fungible and therefore can be used anywhere within the corporate family to meet debt service obligations. As a result, a strong utility owned by a weaker parent generally is rated no higher than the parent or the consolidated corporate credit quality.

In response to the balance sheet damage and liquidity crisis over the last several years in the electric industry, a theme of "back-to-basics" is becoming increasingly prevalent. The industry's repair job involves disposing of non-regulated assets, cutting capital expenditures, de-leveraging balance sheets, negotiating interim re-financings and "state regulatory commissions asserting themselves more vigorously regarding the operations and finances of U.S. electric utilities in the years to come." The fact that, "so few downgrades occurred because of weakened credit profiles of utilities themselves is attributable in no small measure to the support provided by state commissions in recent years."[41]

The outlook for the competitive segments of the industry will continue to be bleak as a result of natural gas prices remaining high and capacity overbuild.[42] S&P states that after years

[40] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 30, 2004.
[41] Standard and Poor's Research: Regulated Operations Back in Fashion for U.S. Electric Utilities; June 19, 2003.
[42] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 30, 2004.

of rate freezes imposed by deregulation, the influence of state regulators will play a substantial role in the credit quality of regulated utilities. Standard & Poor's will follow rate case proceedings in Pennsylvania and Ohio paying particular attention upon levels of ROE allowed.[43]

Financial flexibility has always been important to electric utilities and an industry that is restructuring needs the regulatory and political stability to attract capital from both lenders and investors. Adequate capital structures are becoming not only more costly and difficult to build but more important to maintain. Credit downgrades force companies into making hard decisions about capital structures and operations.[44]

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

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

[43] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 30, 2004.
[44] Standard and Poor's Project Finance and Infrastructure Finance; October 2002.

Appalachian Power (AEP-VA) – The rating of BBB for AEP-VA has remained unchanged from the last report. S&P cites liquidity and balance sheet improvements such as $2 billion in refinancing and AEP's issuing over $1 billion in equity, although the enhancements were insufficient to support a BBB+ rating. Consistency in AEP's regulated strategy could lead to ratings improvement over time.

Delmarva Power - S&P rates Delmarva based on the consolidated credit quality of its corporate parents, Conectiv and PEPCO Holdings, Incorporated (PHI). S&P listed Delmarva on Credit Watch on July 15, 2003. This listing resulted from a bankruptcy filing made by Mirant Corporation and the uncertain effects upon shared power purchase contracts between Mirant, and Delmarva's parent company, PHI. On March 4, 2004, S&P revised Delmarva's outlook to negative from stable. This outlook downgrade was issued to reflect declining free cash flow estimates in other PHI affiliated companies and the belief that estimated cash returns from unregulated operations would not occur as forecasted. According to S&P, Delmarva's strengths include its low-risk distribution business, a high percentage of residential customers and a strong service territory economy. S&P considers transmission and distribution to have lower technical and operational risk than generation, and residential customers to be a very stable revenue source.

Kentucky Utilities - Kentucky Utilities' (KU) rating is based partly on its direct parent, LG&E Energy Corp., and its ultimate parent E.ON AG, a German utility conglomerate. On August 4, 2003, S&P revised the corporate credit ratings on LG&E and its subsidiaries to BBB+ from A-. This rating downgrade was made to reflect LG&E's weaker consolidated financial projections relative to prior expectations held by Standard & Poor's, and to a lesser extent, moderate credit deterioration at LG&E Energy's parent, E.ON AG. According to S&P, KU's current stable outlook is based on E.ON's commitment to support LG&E Energy and its affiliates. Future concerns are potential environmental expenditures related to KU's coal-fired facilities and KU's large industrial customer base, according to S&P.

ODEC - 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. Recently, S&P lowered ODEC's rating from A+ to A with a stable outlook. According to S&P, the ratings downgrade on ODEC does not result from any one development, but rather reflects an amalgam of risks raised individually in the past and a re-assessment of those risks in the context of ODEC's business profile. The stable outlook reflects S&P's expectation that ODEC will maintain its strong business position by averting meaningful customer losses, successfully completing the construction of the remaining peaking facility, and preserving wholesale costs at about current levels.

Potomac Edison – S&P rates Potomac Edison based on the consolidated credit quality of its parent company, Allegheny Energy, Inc. The ratings of Allegheny Energy, Inc. were lowered several times in the past three years, mirroring its debt-financed growth in the merchant and trading business, according to S&P. However, recent signs of improved financial performance prompted S&P to raise Allegheny Energy's credit rating to 'B+' from 'B'. The weak profile for Potomac Edison is due to its parent company's heavy debt burden and non-performing assets belonging to another subsidiary. Although Potomac Edison's stand-alone credit profile is stronger than that of its parent, Allegheny, it is also negatively affected by several of its own factors. These factors include a considerable concentration in industrial demand (40%), a reliance on a financially distressed affiliate to serve its provider-of-last-resort load, and a limited ability to recover unexpected cost increases due to a retail rate freeze in Maryland. On August 20, 2004, Standard & Poor's improved the outlook for Allegheny and its subsidiaries to positive from stable. The revised outlook was a result of S&P's expectation that

Allegheny will continue to pay down $1.5 billion or more of debt before the end of 2005. Further ratings upgrades could result from improved asset management, further debt reductions, or positive rate filing outcomes.

Dominion Virginia Power - DVP is the only investor-owned electric utility in Virginia whose ratings are not equalized with its corporate parent by S&P. DVP's rating is assigned on a stand-alone basis a corporate credit rating of A-. DVP's parent, Dominion Resources, Inc. is currently rated the lower score of BBB+ by S&P. According to S&P, DVP's higher rating is supported by adequate credit protection measures along with statutory insulation that restrains Virginia Power from subsidizing holding-company expansion into non-regulated activities.[45] S&P further states, "State statutes also empower Virginia's utility regulatory body, the State Corporation Commission, to proactively prevent the utility from paying dividends to the parent if that action would impair the utility or the parent would profit to the detriment of the utility's bondholders."[46] The rating agency added that DVP's rating also reflects its "relatively strong" economic service territory.[47]

Moody's favorably views the "go slow" approach of Virginia to energy deregulation and the three major effects from recently passed legislation, Senate Bill 651. These effects included extending the base rate freeze an additional 3.5 years until December, 2010, maintaining the July 2007 expiration of the "wires charges," and the removal of the fuel factor from a regulatory environment to a semi-competitive environment.[48]

Property Value Assessment

[45] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; May 26, 2004.
[46] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; May 26, 2004.
[47] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; May 26, 2004.
[48] Moody's Investors Service, Global Credit Research; Analysis: Dominion Resources Inc., June 2004.

For many years, the State Corporation Commission has assessed the value of the property of public service corporations providing light and power by means of electricity. As provided by Chapter 26 (§ 58.1-2600 et seq.) of Title 58.1 of the Code of Virginia, the Commission assesses the value of the property subject to local taxation and reports these values to the counties and cities for application of the appropriate tax rates, billing the corporations, and collecting taxes. With minor exceptions, the localities have been required by statute since 1966 to apply the real estate rate to all property assessed by the Commission. The Restructuring Act extended central assessment of the value of property to "electric suppliers" which includes independent power producers, merchant plants, and qualifying facilities. The Commission began assessing the electric supplier's property for the 2002 tax year.

The Commission assesses all real and tangible personal property at fair market value as prescribed in Article X, § 2 of the Constitution of Virginia. The same assessment methodology has been applied uniformly to electric suppliers and the public service corporations (the investor-owned utilities and electric cooperatives). The Commission interpreted the 1999 legislation as an expression of the legislative intent that the property of all generators of electricity be assessed using the same methodology.

According to testimony and exhibits presented in several Commission proceedings and information provided informally by electric suppliers, the property taxes paid by many of the independent power producers, merchant plants, and qualifying facilities (usually cogeneration facilities) have increased. In some instances, the increase in taxes has been significant. Testimony and exhibits presented in several Commission proceedings and information provided informally by electric suppliers indicate that some increases in tax bills can be attributed to the loss of special treatment given facilities to entice them to the locality.

In some cases, the value of these facilities was assessed at a fraction of original cost which resulted in lower taxes.

When the legislation providing for central assessment by the Commission was drafted, the General Assembly anticipated that taxes could increase due to a change in the assessment methodology. As a result, language was added to § 58.1-2606C of the Code which gives the localities flexibility to adopt a tax rate for electric generation equipment that is less than the real estate rate. The Commission staff understood this option was offered in an attempt to make the transition to central assessment for all electric generation as revenue neutral as possible.

In testimony in Commission proceedings and in informal discussions, electric suppliers have stated that the localities have been unwilling to adjust the real estate rate downward. According to their applications, testimony, and exhibits, the increase in taxes and the absence of tax relief in the form of a lower rate on generation property as prescribed in § 58.1-2606 C has led electric suppliers to apply to the Commission for review and correction of its assessments of the value of property. As of January 1, 2004, seven applications for review and correction were filed by six electric suppliers. Four suppliers have moved for leave to withdraw their applications, and those requests are pending before the Commission or a hearing examiner. Two applications are in pre-hearing stages. One application has been heard, and the presiding hearing examiner has filed his report. On June 11, 2004, Hearing Examiner Howard P. Anderson filed his Report on the application of Gordonsville Energy, L.P, in Commission Case No. PST-2002-00046. Examiner Anderson concluded that Gordonsville Energy had not established that the assessment of the value of its property for tax year 2002 was in excess of fair market value. The Commission has not taken final action on the report.

Retail Access Pilot Programs

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

The three Pilots consist of: (i) a Municipal Aggregation Pilot, in which one or more localities may aggregate its residential and small commercial customers utilizing an opt-in method[49] and one or more localities may aggregate its residential and small commercial customers utilizing an opt-out[50] method for the purpose of soliciting bids from CSPs for electricity supply service; (ii) a Competitive Bid Supply Service Pilot,[51] 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 demand equal to or greater than 500 kW.

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

> The Commission may conduct pilot programs encompassing retail customer choice of electricity energy suppliers for each incumbent electric utility that has not transferred functional control of its transmission facilities to a regional transmission entity prior to January 1, 2003. Upon application of an incumbent electric utility, the Commission may establish opt-in and opt-out municipal aggregation pilots and any other pilot programs the Commission deems to be in

[49] The opt-in method requires that a consumer affirmatively choose to participate.
[50] The opt-out method requires that a consumer affirmatively choose not to participate; absent such a decision the consumer will be included.
[51] 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.

> the public interest, and the Commission shall report to the Commission on Electric Utility Restructuring on the status of such pilots by November of each year through 2006.

On September 10, 2003, the Commission issued its Final Order approving the Pilots stating that, "the Pilots are in the public interest and further the goal of advancing competition in the Commonwealth." In its Final Order, the Commission approved DVP's application with certain revisions including: (i) an opportunity for mid-sized commercial customers to participate in either the CBS Pilot or the Commercial and Industrial Pilot; (ii) a requirement that the Company initiate notification to customers randomly selected to participate in the CBS Pilot; and (iii) a "hold harmless" provision in the CBS Pilot that states participants randomly selected shall pay no more than they otherwise would have under capped rate service.

On October 27, 2003, DVP issued a Request for Qualifications to CSPs that may be interested in participating in the CBS Pilot. Only those CSPs that respond to the Request for Qualification are then eligible to bid on blocks of customers in the CBS Pilot. On November 14, 2003, three CSPs, Washington Gas Energy Services, Pepco Energy Services, and DVP's affiliate Dominion Retail, responded indicating that they were interested in participating. Simultaneously, the Company began soliciting municipalities to participate in the Municipal Aggregation Pilot. Several indicated some level of interest and agreed to allow the Company to fund a feasibility study to be conducted by a third party.

On December 11, 2003, DVP filed a request for three revisions to the Pilots. Specifically, DVP requested to: (i) delay the issuance of the Request for Bids in the CBS Pilot until ten days after the acceptance of the Company's market price/wires charge compliance filing for 2004; (ii) apply the 50 percent wires charge reduction to each competitive wires charge component rather than to the total wires charge; and (iii) reduce the time period for the Commission Staff to select the winning CSP in the CBS Pilot from ten days to two days.

On January 9, 2004, the Commission issued an Order Approving Pilot Revisions. In the Order the Commission granted approval for the first two revisions as no one opposed them. With respect to the third proposed revision, the Commission agreed with the Division of Consumer Counsel, Office of the Attorney General and the Commission Staff that reducing the time period for the Commission Staff to select the winning CSP may not allow the Staff to perform a thorough evaluation. However, the Commission recognized that a shorter selection period may be desirable for CSPs and as a result revised the CBS Pilot terms and conditions to state the Commission Staff must select the winning CSP within ten days, or sooner if practicable.

On January 12, 2004, DVP issued the Request for Bids to the three prequalified CSP. Bids were due by noon on February 3, 2004. No CSPs submitted a bid. While CSPs were not required to indicate why they did not submit a bid, Pepco Energy Services sent a letter to DVP with a copy to the Commission Staff stating, "PES has carefully reviewed the cost to serve participating customers in the Pilot Program and it has determined that it is not feasible for PES to submit a proposal whereby resulting in savings."

As a result of the failure of the Pilots to attract CSP participation, on January 30, 2004, DVP filed a request to delay the start date of the Pilots for two months while it considered modifications. On February 23, 2004, the Commission granted the extension and required the Company to notify all Pilot volunteers of the delay and to file its proposed modification by April 2, 2004.

The Company filed its proposed modifications, as ordered, on April 2, 2004. The Company proposed numerous modifications with the key component of the modifications a 100% wires charge reduction for 2004. For years after 2004, the wires charge reduction would be an amount up to but not exceeding the reduction for 2004. Pilot customers therefore would only pay, in later years, the increment that the later years' wires charges exceed the 2004 wires charges. Other proposed modifications included: (i) dividing the ten-day period for the Commission Staff to select the winning CSP into two components with the first a two-day period to select the winner based on price and the second an eight-day period to perform due diligence on the qualifications of the CSP; (ii) allowing the Commission Staff to select one CSP to serve all three geographic blocks in the CBS Pilot (originally one CSP could serve no more than two blocks) if selection of another CSP would result in an offer price of at least 1.5 percent higher than the lowest offer price; and (iii) specifying that the first bid supply period would extend through January 2006 and the second bid supply period would extend to July 2007.

The Commission received comments from Constellation NewEnergy, Inc., Direct Energy Marketing, Inc., Dominion Retail, Inc., Pepco Energy Services, Inc., Strategic Energy, LLC, Washington Gas Energy Services, Inc., Urchie B. Ellis, the Division of Consumer Counsel, Office of the Attorney General and the Commission Staff. Most of the comments were generally supportive of the Company's modifications although some additional revisions were suggested. Several of the comments, including those of the Consumer Counsel, indicated that the Company should eliminate the wires charge for the duration of the Pilots. The Commission Staff indicated that it encouraged the Company to eliminate the wires charge reduction for the length of the Pilot, but did not believe the Commission could require the Company to forgo its statutorily allowed right to the wires charge. The Company asserted in its response to the comments that it would not agree to eliminate the wires charge for the duration of the Pilots, and further stated that it believed its proposal was sufficient to attract CSPs to participate.

On May 25, 2004, the Commission issued an Order Approving Revisions. The approved revisions included the followings: (i) the wires charge reduction will be calculated as proposed by the Company; (ii) the Commission Staff will select the winning CSP in the CBS Pilot within two days; however, in the event that the Commission Staff cannot select the winning CSP within two days, then the winning CSP will be given the opportunity to withdraw its bid (this was a compromise to accommodate the CSPs' request for a shorter selection period); and (iii) the Commission Staff may select one CSP to serve all blocks in the CBS Pilot.

With the Commissions May 25, 2004, Order Approving Revisions, the three Pilots have now been re-initiated. On June 22, 2004, DVP issued a new Request for Qualifications in the CBS Pilot with Responses due by August 23, 2004. On August 24, 2004, the Company will issue a Request for Bids to those CSPs that respond, and bids will be due by noon on September 14, 2004. With respect to the other two Pilots, no CSPs have enrolled any C & I customers and no municipality has indicated definitive interest in participating in the Municipal Aggregation Pilot.

Future SCC Activity

As described in this Report, the basic rules, systems, and procedures are in place to accommodate retail choice. 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:

- Analyze the technical and operational implications of the RTO filings and act upon pending applications.
- Continue to explore the potential for designating alternative default service providers.
- Re-evaluate the method for determination of the market price and resulting wires charge for incumbent electric utilities, then re-set those numbers.

- Develop the methodology to determine market-based costs for use in exemption of wires charges and minimum stay provisions.
- Continue the development of a proper foundation for competition including the on-going work involving competitive metering, consolidated billing, development of business practices, distributed generation interconnection standards, and aggregation.
- Continue 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.
- Evaluate the merits of proposed pilot 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 July 1, 2004, WGL's program has twelve CSPs serving 7,155 non-residential customers and four active CSPs serving approximately 65,840 residential customers. Cumulatively, these accounts represent approximately 17.6 percent of the 416,001 natural gas customers in WGL's service territory. It is important to note, however, that WGL's unregulated affiliate, WGES, is serving approximately 79 percent of the non-residential shoppers and approximately 76 percent of residential shoppers. .

CGV's Retail Access Program

As of July 1, 2004, there are four CSPs providing service to 1,212 non-residential customers and 8,818 residential customers. Cumulatively, these accounts represent approximately 4.7 percent of the 212,746 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.