REPORT OF THE
LEGISLATIVE TRANSITION TASK FORCE
ESTABLISHED UNDER

The Virginia Electric Utility Restructuring Act

TO THE GOVERNOR AND
THE GENERAL ASSEMBLY OF VIRGINIA

SENATE DOCUMENT NO. 17

COMMONWEALTH OF VIRGINIA
RICHMOND
2003

MEMBERS OF THE LEGISLATIVE TRANSITION TASK FORCE

Senator Thomas K. Norment, Jr., Chairman
Delegate Clifton A. Woodrum, Vice Chairman
Delegate Terry G. Kilgore
Delegate Brian J. Moran
Delegate Harry J. Parrish
Delegate Kenneth R. Plum
Senator Richard L. Saslaw
Senator Kenneth W. Stolle
Delegate Robert Tata
Senator John Watkins

STAFF

Division of Legislative Services

Franklin D. Munyan, Senior Attorney
C. Maureen Stinger, Staff Attorney
Brenda C. Dickerson, Operations Staff Assistant

Senate of Virginia - Clerk's Office

Thomas C. Gilman, Coordinator of Committee Operations

EXECUTIVE SUMMARY

The Virginia Electric Utility Restructuring Act establishes the statutory framework for Virginia's transition from traditional regulation of the generation component of electric service to a market-based system in which competitive market forces will be relied upon to determine its rates and ensure adequate capacity. Even under the deregulation model, however, the State Corporation Commission (SCC) and the Federal Energy Regulatory Commission (FERC) will continue to regulate the distribution and transmission components of electric service, respectively.

The Legislative Transition Task Force was established to work collaboratively with the SCC in conjunction with the phase-in of retail competition. The establishment of the Task Force is an acknowledgement that the General Assembly's responsibilities with respect to implementing retail choice did not end with the enactment of the Restructuring Act. The Task Force has actively monitored developments relating to the implementation of the Restructuring Act. When appropriate, the Task Force has not been reluctant to modify the provisions of the original Restructuring Act in order to address evolving circumstances and issues raised during the course of the transition to competition.

As Virginia delves further into issues relating to competition for electric utility service, the members of the Task Force endeavor to become educated in a variety of complicated engineering, economic and legal disciplines. As the Task Force has developed familiarity with these complex issues over the past several years, other members of the General Assembly have deferred to the body with respect to issues relating to electric utility deregulation. Consequently, the Task Force has been placed in the role of a gatekeeping forum before which any proposals for legislation affecting electric utilities are scrutinized.

The Task Force met six times during its fourth year of existence, during which it received testimony on numerous issues, including:

- **The status of competition in Virginia and across the nation.**

There has been a decline in retail market activity in Virginia and nearby states that are considered to be part of Virginia's regional market. Virginia has no residential competitive offers below the price-to-compare of any incumbent utility in the state. Since last year there has been a slight increase in residential offers nationwide, due to the advent of restructuring in Texas.

Barriers to the development of a workable retail electricity market include risks of the exercise of market power in wholesale markets and reductions in new power plant construction. Recent disclosures of wholesale market improprieties and the "credit crunch" have contributed to a reduction in efforts by energy marketers to market electricity nationally.

As of September 1, 2002, 2.2 million of the 3.1 million customers in Virginia had the right to pick their electricity provider. All customers of utilities subject to the Restructuring Act will have retail choice by January 1, 2004. However, the right to choose does not mean the

ability to choose. Only 2,375 residential customers and 23 commercial customers are buying electricity from an alternative supplier.

The SCC is concerned that FERC's proposed rules for a standard market design (SMD) create substantial risks that Virginia's electric utility industry may face increased retail prices and loss of jurisdiction over elements of electric system reliability. The SCC cautioned the Task Force that if Virginia allows the transfer of control of transmission assets to a FERC-regulated regional transmission entity (RTE) or allows components of electricity rates to remain unbundled, the FERC would gain jurisdiction over matters now within the SCC's purview, which shift may have a significant impact on retail electric rates and reliability. The SCC contended that in order to avoid the application of FERC's SMD rules, Virginia must rebundle components of electricity rates and defer the requirements that Virginia's electric utilities join an RTE and transfer control of their transmission systems to the RTE.

Several electric utilities countered that there is no need to rebundle the components of electric rates and urged the Task Force not to delay the RTE development process. Rebundling rates was characterized as a premature and drastic measure that would strike at the heart of the Restructuring Act. Rather, the Task Force was told that Virginia can safeguard reliable service to native load by maintaining control over utility membership in regional transmission entities. The Attorney General's Office observed that postponing the ability of utilities to join RTEs was an adequate step, and observed that while Virginia may need to rebundle the components of electric rates at some point, it is not necessary today. If Virginia can rebundle rates today, then it can do so in the future if the FERC's final SMD rules make such a step appropriate.

- **The Status of Regional Transmission Entities**

RTEs are intended to provide a more efficient and fairly priced means of transmitting wholesale electric energy. RTEs are entities created to operate transmission grids and ensure short-term system reliability, independent of control by incumbent utilities and other market participants. The Restructuring Act recognizes that the development of a competitive retail market for electric generation requires incumbent utilities to transfer ownership or control of their electric transmission assets to an RTE. The requirement of RTE independence is intended to ensure that incumbent utilities, which traditionally controlled the generation, distribution and transmission of electricity, do not use the control of transmission assets to favor their generation arms over competing suppliers. The ability to attract competitive suppliers to Virginia's market depends to a large extent on the development of a competitive regional wholesale market. The Restructuring Act requires incumbent electric utilities owning, operating, controlling or having an entitlement to transmission capacity shall join or establish a regional transmission entity by January 1, 2001.

Both AEP and DVP have announced their intent to follow Allegheny Power in joining PJM Interconnection, LLC, a Pennsylvania-based RTE. The Task Force heard several concerns regarding the implications of the utilities' memberships in PJM. The PJM structure, which complies with aspects of the SMD model being considered by FERC, is alleged to cede elements of control over generation facilities and some long-term resource adequacy planning to the RTE. PJM's locational marginal pricing provisions (LMP) were said to pose the risk of increased costs

and to expose market participants to price uncertainty for congestion cost charges and the possibility of market manipulation. Under LMP, the unit that provides the increment of electricity that meets the load sets the price that all of the providers will receive, even if the price they would otherwise have charged is less than the price bid by the supplier of the last increment. As a result, the price of power is based on prices that are bid, and not on the actual cost of the electricity.

- **Data on Energy Infrastructure and Reliability**

Pursuant to Senate Bill 684 of the 2002 Session, the SCC convened a work group to study the feasibility, effectiveness, and value of collecting data pertaining to Virginia's electric and natural gas infrastructure. The SCC concluded that while collecting the data identified in the legislation is feasible, the value and effectiveness of collecting the information is more difficult to ascertain. The restructuring of Virginia's natural gas and electricity industries means the Commonwealth will rely on the competitive market to meet consumer demand for electric and natural gas service. Electric utility industry restructuring may shift jurisdiction for overseeing generation and transmission service reliability from state regulators to the FERC. The FERC's SMD rules may place significant new federal regulation over the pricing and reliability of electricity. In addition, if Virginia's utilities join regional transmission organizations that operate a regional electricity market, state regulators may lose jurisdiction over generation and transmission reliability. These shifts in oversight jurisdiction cast doubt over the value of collecting data about Virginia's electrical infrastructure. In addition, stakeholders have split on the issue of whether state regulators will be able to require incumbent utilities to build generation facilities to meet the needs of Virginians. Once Virginia's electric utility industry is regionalized, the concept of monitoring the dedication of facilities to the service of Virginia's native load becomes problematic.

- **Implications of Capped Rates**

A study of capped rate savings commissioned by Dominion Virginia Power (DVP) compared the base rates charged its residential customers with the base rates that would likely have been in effect had the caps not been imposed. The report concludes that the Restructuring Act's cap on base rates will produce total savings for its residential customers of between $780 million and $871 million from 1998 through 2007. Average annual savings per residential customer ranged from $45 to $50. The study assumes that base residential rates would have risen between 7.9 and 9.2 percent between 2001 and 2007 had the rate cap not been imposed.

An SCC report on changes in residential electric rates in northern and southern states for investor-owned electric utilities during the period 1998 through 2002 concludes that northern states, many of which have deregulated their electricity markets, continue to have higher rates than southern states, most of which have not deregulated. The average residential cost of electricity is 10.463 cents/kWh in northern states and 7.110 cents/kWh in southern states. In Virginia, average rates declined over this period from 7.021 cents/kWh to 6.967 cents/kWh, while the average residential rate in all southern states increased from 6.967 cents/kWh to 7.11 cents/kWh, or about one-half of one percent per year. Northern states, on the other hand, experienced a decline of about one percent over this period, from 10.572 cents/kWh to 10.463

cents/kWh. Moreover, from 1998 through 2002, the base rate (which excludes fuel cost adjustments) in southern states declined at 10 of the electric utilities; increased at five; and did not change at two.

- **Stranded Costs Recovery**

The Restructuring Act provides that incumbent electric utilities will recover any stranded costs by July 1, 2007, through a portion of the capped rates (for customers who do not switch to a competitive supplier) or wires charges (assessed on customers who switch to a competitor). However, the Restructuring Act neither defines stranded costs nor provides any formula or statutory framework for their calculation. The Restructuring Act directs the Task Force, after the commencement of customer choice, to monitor whether the recovery of stranded costs has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

The Task Force has requested the SCC to convene a work group comprised of Commission staff and representatives of persons representing the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, to develop consensus recommendations on issues relating to stranded cost recovery. By July 1, 2003, the work group is to present its consensus recommendations regarding (i) definitions of "stranded costs" and "just and reasonable net stranded costs" and (ii) 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. By November 1, 2003, the work group is to present its recommendations on the amount of each incumbent electric utility's just and reasonable net stranded costs and the amount that it has received, and is expected to receive, to offset just and reasonable net stranded costs from capped rates and from wires charges.

- **Revenue From Taxes on Electric Utilities**

The electricity consumption tax rates were set in 1999 at levels expected to generate $66 million, which is the difference between the revenue-neutral goal of $87 million and the expected $21 million of corporate income tax receipts. For fiscal year 2002, the consumption tax is expected to generate an amount very near the $66 million that was expected. However, the distribution of tax collections among rate classes varies significantly from the anticipated distribution. For the 2001 taxable year, Virginia electric suppliers paid $3.8 million in corporate income taxes. The corporate income tax on electric utilities was expected to generate $21 million annually.

- **Other Issues Examined**

The Task Force received information during the past year addressing activities of the Consumer Advisory Board, the status of the SCC's consumer education program, DVP's plans for three aggregation pilot programs, the siting of electricity generating facilities, the propriety of

suspending application of the Restructuring Act to Kentucky Utilities, local taxation issues, and activities of the SCC in implementing the Act.

The Task Force endorsed eight proposals for legislation pertaining to the Restructuring Act that were enacted by the 2003 Session of the General Assembly:

- House Bill 2453 delays the date by which incumbent electric utilities with transmission capacity must join an RTE. This measure provides that utilities shall not join an RTE prior to July 1, 2004. Utilities are required to file an application to join an RTE by July 1, 2003, and to transfer management and control of transmission assets to the RTE by January 1, 2005, subject to SCC approval. Prior to approving a request to join an RTE, the Commission must determine that the action will (i) ensure that consumers' needs for economic and reliable transmission are met and (ii) meet the transmission needs of electric generation suppliers that do not own, operate, control or have an entitlement to transmission capacity.

- House Bill 2637 provides that application of the Restructuring Act shall be suspended effective July 1, 2003, for Kentucky Utilities, so long as such utility does not provide retail electric services in any other service territory in any jurisdiction to customers who have the right to receive retail electric energy from another supplier.

- House Bill 2319 authorizes the SCC to conduct pilot programs for aggregation efforts encompassing retail customer choice of electricity energy suppliers for certain incumbent electric utilities. Upon application of an incumbent electric utility, the Commission may establish opt-in and opt-out municipal aggregation pilot programs and any other pilot programs that the SCC deems to be in the public interest. The SCC shall report to the Task Force on the status of such pilots by November of each year through 2006.

- House Bill 2318 extends the term of the Task Force to July 1, 2008. The existence of the Task Force had been scheduled to cease on July 1, 2005.

The Task Force endorsed two additional legislative proposals that were not enacted by the 2003 Session of the General Assembly:

- House Bill 2317 would have required each distributor of electric energy to collect from each residential distribution account $.03 per month, or $.36 per year, to be credited to the Home Energy Assistance Fund. Up to three percent of moneys collected may be used to pay the distributor's costs of collecting and transmitting such funds. The measure was defeated in the House Committee on Commerce and Labor by a vote of 10-12.

- House Bill 2046 would have made it a violation of the Virginia Antitrust Act for the operator of an electric power generation facility who generates electricity for sale to manipulate electricity prices by withholding power that has been committed to satisfy

reserve requirements from the relevant market. The was stricken from the docket of the House Commerce and Labor Committee at the patron's request.

The Task Force endorsed a proposal that was not considered by the General Assembly. The measure, which was intended to have been added to the legislation introduced as House Bill 2453 rather than being introduced as a separate bill, would have amended § 56-579 to prohibit the SCC from approving an application to transfer control over transmission assets to an RTE if it would result in the direct or indirect transfer of jurisdiction over the reliability or price of generation serving current or future load in the Commonwealth from the Commonwealth to the FERC or any other entity, or if the transfer would negatively affect the reliability or pricing of such generation.

Finally, the Task Force did not endorse three proposals that were offered for its consideration:

- A proposal recommended by Old Mill Power Company to eliminate the existing provision that allows municipal electric utilities and utility consumer services cooperatives to prevent competitive energy services providers from billing willing customers directly, rather than having its billing information included in a consolidated bill. Direct invoicing was lauded as enabling suppliers to be responsible for their own invoicing and bill collection and to establish brand identities.

- A proposal that would allow a staged transition to competition by rate class. The proposal provided that if a large commercial or industrial customer is willing to commit to market-based pricing should it ever return to its local distribution company, that customer should be allowed to switch to a competitive service provider without paying a wires charge. Legislation that would have enacted this proposal was introduced as Senate Bill 891. Following Senator Watkins' statement that he would introduce the bill with the intention of asking that they be referred by the standing General Assembly committee to the Task Force for further consideration, the Task Force took no vote on the proposal. The measure was referred to the Task Force by the Senate Committee on Commerce and Labor.

- A proposal that would allow large commercial or industrial customers who return to the incumbent utility after switching to a competitive provider to have the option of paying market-based prices as an alternative to complying with the current 12-month minimum stay requirement. The measure was identified by the SCC as being worthwhile for Task Force consideration. Legislation that would have enacted this proposal was introduced as Senate Bill 892. Following Senator Watkins' statement that he would introduce the bill with the intention of asking that it be referred by the standing General Assembly committee to the Task Force for further consideration, the Task Force took no vote on the proposal. The measure was referred to the Task Force by the Senate Committee on Commerce and Labor.

The Task Force recognizes that the successful implementation of the Restructuring Act is of vital importance to all Virginians. Potential pitfalls to the transition to a vibrant competitive

market include elements of the FERC's proposed rules on standard market design, the threats to continued state jurisdiction over issues related to rates and reliability, the lack of unqualified success in implementing retail competition in other states that have deregulated their electric utilities, and a credit crunch that has affected the development of new generating facilities and the financial well-being of several electric utilities. However, the successful implementation of the Restructuring Act offers the prospect for greater efficiencies that will provide tangible benefits to all Virginians.

The Task Force remains committed to fine-tuning the Restructuring Act in order to provide a legislative framework for the effective deregulation of the electric utility industry. In its efforts, it will endeavor to ensure that all Virginia consumers have the opportunity to realize the greater efficiencies inherent in a market-based system, without subjecting them to unnecessary risks that may threaten the Commonwealth's long-standing status as a state with reliable and low-cost electric service.

The next year will be vital in the implementation of retail competition for electricity. Task Force members will attempt to identify ways to surmount barriers to the development of a vibrant market for the generation component of electric service. At the same time, the Task Force will continue to monitor federal and regional developments to ensure that Virginia does not cede its authority to protect electricity consumers in the Commonwealth.

TABLE OF CONTENTS

APPENDICES

REPORT OF THE
LEGISLATIVE TRANSITION TASK FORCE
ESTABLISHED PURSUANT TO THE
VIRGINA ELECTRIC UTILITY RESTRUCTURING ACT

To: The Honorable Mark Warner, Governor of Virginia
and
The General Assembly of Virginia

Richmond, Virginia
April, 2003

I. INTRODUCTION

The Virginia Electric Utility Restructuring Act, Chapter 23 (§ 56-576 et seq.) of Title 56 of the Code of Virginia, establishes the framework through which components of retail electric generation service will be deregulated. The General Assembly created the Legislative Transition Task Force for the purpose of working collaboratively with the Virginia State Corporation Commission (SCC) in conjunction with the phase-in of retail competition in electric services within the Commonwealth. The duties of the Task Force include:

- Monitoring the work of the SCC in implementing the Restructuring Act, receiving such reports as the SCC may be required to make, including reviews, analysis, and impact on consumers of electric utility restructuring programs of other states;
- Determining whether, and on what basis, incumbent electric utilities should be permitted to discount capped generation rates;
- After the commencement of customer choice, monitoring, with the assistance of the SCC, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, whether the recovery of stranded costs has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs;
- Examining utility worker protection during the transition to retail competition;
- Examining generation, transmission and distribution systems reliability concerns;
- Examining energy assistance programs for low-income households;
- Examining renewable energy programs;
- Examining energy efficiency programs;
- Reporting annually to the Governor and each session of the General Assembly during their tenure concerning the progress of each stage of the phase-in of retail competition, offering such recommendations as may be appropriate for legislative and administrative consideration in order to maintain the Commonwealth's position as a low-cost electricity market and ensuring that residential customers and small business customers benefit from competition;

- Receiving reports from the SCC pursuant to § 56-579 F on its assessment of the success of the regional transmission entity (RTE) in facilitating the orderly development of competition in the Commonwealth;
- Receiving reports from the SCC pursuant to § 56-581.1 on delays in any element of the provision of billing services and the underlying reasons therefor;
- Receiving reports from the SCC, not later than December 1, 2004, and annually thereafter, pursuant to § 56-585 E, regarding modification or termination of default service;
- Receiving reports from the SCC pursuant to § 56-592 with its findings and recommendations regarding the development of its consumer education program;
- Receiving periodic updates from the SCC pursuant to § 56-592.1 regarding the implementation and operation of its consumer education program; and
- Receiving the annual reports of the SCC pursuant to § 56-596 on the status of competition in the Commonwealth, the status of the development of regional competitive markets, and its recommendations to facilitate effective competition in the Commonwealth as soon as practical.

The Task Force consists of 10 members: Senator Norment of James City County, chairman; Delegate Woodrum of Roanoke, vice chairman; Senator Stolle of Virginia Beach; Senator Watkins of Chesterfield County; Senator Saslaw of Fairfax County; Delegate Brian J. Moran of Alexandria (appointed during the 2002 interim to replace former Delegate J.C. Jones of Norfolk); Delegate Kilgore of Scott County; Delegate Parrish of Manassas; Delegate Plum of Fairfax County; and Delegate Tata of Virginia Beach.

The first report of the Task Force, detailing its activities and the recommendations developed during the 1999 interim, was submitted as Senate Document 54 of 2000. The Task Force's second year of work is reported in Senate Document 39 of 2001. The Task Force's third year of work is reported in Senate Document 27 of 2002.

Printed copies are available through the General Assembly's bill room (telephone 804-786-6984). These reports may be viewed at the Task Force's Internet web site (http://dls.state.va.us/elecutil.htm). The website also provides access to many of the materials submitted at the Task Force's meetings, as well as links to the text of the Restructuring Act and the annual reports of the Joint Subcommittee Studying Restructuring of the Electric Utility Industry. The annual report of the joint subcommittee pursuant to Senate Joint Resolution 118 (1996) is Senate Document 28 (1997); the report pursuant to Senate Joint Resolution 259 (1997) is Senate Document 40 (1998); and the report pursuant to Senate Joint Resolution 91 (1998) is Senate Document 34 (1999).

Pursuant to the statutory directive that the Task Force annually report to the Governor and the General Assembly concerning the progress of each stage of the phase-in of retail competition, this report compiles relevant developments during the period from date of its previous report through the end of the 2003 legislative session.

II. ISSUES EXAMINED BY THE TASK FORCE

The Legislative Transition Task Force met on six occasions during its fourth year of existence: June 2, November 19, November 26, and December 12, 2002, and January 7 and January 27, 2003.

A. THE DEVELOPMENT OF COMPETITION IN VIRGINIA

The paramount goal of the Restructuring Act is to develop a competitive market-based system for the provision of the generation component of electric service. Such a system, wherein providers of generation services compete to provide consumers with their electricity, was envisioned by Restructuring Act advocates as superior to the traditional method used to regulate electric utilities that has served the Commonwealth for generations. The Act envisions that the ability of consumers, guided by prices and other market signals, to choose their electricity suppliers is better than the regulated system pursuant to which the electric utility providers are granted the exclusive franchise to provide service in designated territories in exchange for the right to charge just and reasonable rates that ensure recovery of prudently incurred expenses and a regulated profit.

The Restructuring Act acknowledges that a robust, competitive market for electric generation cannot be established by legislative fiat. Section 56-596 of the Act provides that in all relevant proceedings, the SCC shall take into consideration, among other things, the goals of advancement of competition and economic development in the Commonwealth. This section also requires the SCC to report to the Task Force and the Governor, by September 1 of each year, on the status of competition in the Commonwealth, the status of the development of regional competitive markets, and its recommendations to facilitate effective competition in the Commonwealth as soon as practical. The report is also to include any recommendations of actions to be taken by the General Assembly, the SCC, and other entities that the SCC considers to be in the public interest.

The SCC's two-volume report was issued on August 30, 2002. The Task Force received a briefing on the report at its November 26, 2002, meeting. The report concludes that Virginia is making slow progress toward allowing Virginians to competitively choose their supplier of electricity. Competitors are not yet vying for customers in Virginia's electric power market. Other states that have implemented retail choice are largely experiencing similar low levels of competitive activity. The full text of the report can be viewed on the SCC website at http://www.state.va.us/scc/division/restruct/main/staff/teirstaff.htm.

1. Status of Development of Competitive Regional Markets

Dr. Kenneth Rose, Senior Fellow at the Institute of Public Utilities at Michigan State University, presented the portion of the report addressing the status of the development of regional competitive markets. A copy of Dr. Rose's materials is available on the Task Force's website at http://www.state.va.us/scc/caseinfo/reports/rose_lttf_pres.pdf.

Dr. Rose observed that there has been a decline in retail market activity in Virginia and nearby states that are considered a part of Virginia's regional market. As of the date of the report, Virginia had no residential competitive offer below the price-to-compare of any incumbent utility in the State. Pennsylvania had three such offers; Maryland had two; and the District of Columbia had one.

Since 2001, there has been a slight nationwide increase in residential offers, with most of the increase being attributable to the start of competition in Texas. The number of competitive offers at or below the prices paid by nonshopping customers increased from nine to 44 nationwide during the year ending July 2002. Of the 44 offers below the price to compare, 29 were in Texas.

Dr. Rose expressed concern with evidence that significant market power, or the ability of sellers in a market to set prices for products, is being exercised in all wholesale power markets. The ability of wholesale sellers to exercise market power will prevent the development of a workable retail electricity market. Another area of concern is the reduction in new power plant construction, which is attributable in part to curtailment in available credit for new projects. Nationwide, almost 180,000 MW of planned new capacity was tabled or canceled between January and July 2002, and General Electric's power systems division has forecast an 80 percent decline in gas-fired turbine orders and shipments.

Dr. Rose also expressed reservations with plans announced by the Federal Energy Regulatory Commission (FERC) to increase efficiencies within and across regional transmission entity areas. On July 31, 2002, the FERC issued a notice of proposed rulemaking on a standard market design. The proposed rules are intended to address market design flaws and a lack of uniformity that cause a misallocation of transmission and generation resources. Elements of FERC's plan include independent transmission providers, transmission pricing reforms, congestion management through locational marginal pricing, and tradable congestion revenue rights. Anticipating that market incentives will not result in the construction of sufficient capacity, FERC's proposal also includes a resource adequacy requirement. The standard market design proposal includes the strongest assertions to date of the FERC's authority.

Dr. Rose cautioned that the net additional benefits from larger RTEs may be modest and are uncertain. Some inefficiencies in the current system are due to physical constrains, rather than market design flaws. In addition, the plan to manage congestion through locational marginal pricing may increase the potential for suppliers to exercise market power. He also cited a recent study prepared for the Southeastern Association of Regulatory Commissioners of the benefits and costs of establishing three RTEs in the southeast. The report concluded that there is considerable uncertainty as to whether benefits from the RTEs and the proposed standard market design would exceed their implementation costs.

2. Status of Competition in Virginia

Richard J. Williams, Director of the SCC's Division of Economics and Finance, addressed competitive activity in Virginia's electricity market. As of September 1, 2002, 2.2 million of the 3.1 million customers in Virginia have the right to pick their electricity provider.

All customers of utilities subject to the Restructuring Act will have retail choice by January 1, 2004. However, the right to choose does not mean the ability to choose. Only 2,375 residential customers and 23 commercial customers are buying electricity from an alternative supplier that offered "green" power at a higher cost than the incumbent utility's price-to-compare. This lone competitive supplier is no longer marketing its power to new customers.

The Commission's report outlines developments that may contribute toward competitive wholesale and retail markets. By January 1, 2004, all of Virginia's utilities should be members of operating RTEs, which are intended to provide a more efficient and fairly priced means of transmitting wholesale electric energy. However, the ability to attract competitive suppliers to Virginia's market depends to a large extent on the development of a competitive regional wholesale market. Recent disclosures of wholesale market improprieties and the "credit crunch" have contributed to a reduction in efforts by energy marketers to market electricity.

3. Recommendations to Facilitate the Development of a Competitive Market

The third part of the SCC's report outlines 20 proposals submitted by electric utilities, competitive suppliers, business groups, and consumer representatives to foster the development of competition. The SCC identified two of these proposals that the Task Force may wish to consider. The first calls for amending the Restructuring Act to allow a large industrial or commercial customer to switch to a competitive service provider (CSP) without paying a wires charge if it commits to accept market-based pricing if it returns to its incumbent utility. The second would allow large customers who switch to a CSP and later return to their incumbent utility to select market-based prices as a means of avoiding a minimum stay requirement. Though these proposals are directed at large customers, the SCC observed that fostering retail market activity for large customers may improve the chance of competitive offers will be made to residential customers.

B. THE STATUS OF REGIONAL TRANSMISSION ENTITIES

1. Developments under the Act

The Restructuring Act, as enacted in 1999, requires incumbent electric utilities owning, operating, controlling or having an entitlement to transmission capacity to join or establish a regional transmission entity by January 1, 2001, and to transfer the management and control of its transmission assets to the RTE. Conditions for joining or establishing an RTE include obtaining the prior approval of the SCC. The issue of which RTE is appropriate for Virginia's utilities is complicated by the fact that Virginia is located at the crossroads of three existing or proposed regional RTEs: PJM, Midwest ISO, and GridSouth.

RTEs are entities created to operate transmission grids and ensure short-term system reliability, independent of control by incumbent utilities and other market participants. The Restructuring Act recognizes that the development of a competitive retail market for electric generation requires incumbent utilities to transfer ownership or control of their electric transmission assets to an RTE. The requirement of RTE independence is intended to ensure that

incumbent utilities, which traditionally controlled the generation, distribution and transmission of electricity, do not use the control of transmission assets to favor their power over power offered by competing suppliers.

In Case No. PUE990349, the SCC promulgated regulations governing the transfer of the ownership or control of transmission assets by incumbent electric utilities to RTEs. The SCC noted that incumbent electric utilities were required by FERC Order 2000 to file information with FERC concerning plans to join a regional transmission organization (which is substantively identical to the term "regional transmission entity" used in the Restructuring Act) by January 1, 2001 (or January 15, 2001, for utilities that are members of an RTE that complies with FERC Order 888's Independent System Operator principles). The SCC concluded that its actions pertaining to RTEs are not preempted by federal law.

The SCC's rules for RTE participation were finalized on July 19, 2000. The SCC's regulations establish elements of RTE structures to be applied in determining whether the SCC may authorize transfer of ownership or control of transmission assets to an RTE. Regulations address (i) planning and reliability practices, (ii) non-discriminatory pricing practices, (iii) governance independent of competitive interests, and (iv) fair compensation to the transferor. The SCC's order required Virginia's five investor-owned electric utility companies to submit applications by October 16, 2000, for transferring ownership or control of transmission assets to an independent operator.

In 1999, DVP AEP, and 14 other electric utilities in 11 states announced plans to create the Alliance Regional Transmission Organization. On June 3, 1999, the Alliance companies filed an application to FERC for approval of the Alliance RTE. This proposal would permit transmission asset owners to either divest their transmission assets to the RTE or to transfer control of such facilities to the RTE. This concept would enable transmission owners (and any transmission user) to individually own up to five percent of the voting stock of Alliance RTE. Such transmission owners could potentially control 25 percent of the voting stock. This voting block could be increased if other divesting utilities join the RTE. Additionally, divesting owners could obtain a non-voting ownership interest in the entity that would manage the day-to-day operations of the RTE.

The SCC, the Virginia Committee for Fair Utility Rates, the Attorney General's Office, and others intervened in this FERC filing in July 1999. The parties raised concerns that the proposed ownership interests of transmission owning utilities may prevent independent and non-discriminatory operation of the RTE. They questioned whether the Alliance's proposed pricing policies were consistent with the FERC's prohibition regarding the "pancaking" of transmission rates. They also questioned whether the geographic configuration of the RTE would serve as a detriment to effective competition, noting that the Alliance RTE had been described as a "toll-gate" between mid-western and eastern power markets.

On December 20, 1999, FERC issued an order conditionally approving the Alliance RTE and directing that certain proposals be modified. Specifically, FERC found that the Alliance did not meet Order No. 888's independence standard because members' ownership of stock in the RTE could give members effective control of the RTE. FERC also found that the proposed

pricing proposal violated a provision of its Order 2000. FERC also expressed concerns that its configuration would perpetuate a situation where the Alliance members separate the buyers and sellers that constitute the predominant west-east trading patterns.

On February 17, 2000, Alliance members made a partial compliance filing in response to the FERC's conditional approval order. In this filing, the Alliance members attempted to provide further support for its original proposal to allow divesting transmission owners to have voting interests in the RTE. They also modified a number of other proposals in response to FERC's directives.

On May 18, 2000, FERC issued an order finding that the Alliance members had not adequately addressed the independence issues. FERC specified that the aggregate voting interest of divesting transmission owners could not exceed 15 percent, and reserved judgement with regard to the configuration issue. In response, Alliance members developed a revised pricing proposal and made an additional compliance filing on September 15, 2000. Under this filing, the Alliance Companies proposed to create a for-profit transmission company, or transco. On January 24, 2001, FERC found that the Alliance filing basically met the four characteristics and most of the functions of an RTE discussed in FERC Order 2000, but directed further modifications.

On July 12, 2001, FERC issued another order conditionally approving the Alliance companies' RTE filing. The FERC expressed concerns that business decisions prior to implementation of the Alliance RTE were being made by Alliance companies rather than independently. Though the SCC had scheduled hearings for September 2001 on the Alliance applications, they were placed on hold pending the outcome of FERC proceedings. On December 20, 2001, FERC approved the terms of the Midwest ISO but -- notwithstanding its previous conditional approvals of the Alliance RTE -- ruled that the Alliance lacked sufficient scope to exist as a stand-alone RTE, as required by FERC Order 2000. FERC directed the Alliance companies to explore how their business plans can be accommodated with in the Midwest ISO. FERC also observed that the Midwest ISO may not be the ideal RTE for all Alliance companies and noted that DVP may prefer to join another RTE. The companies were given 60 days to announce their plans to join an RTE. In her dissenting opinion, Commissioner Breathitt observed that Alliance Companies had spent approximately $75 million in start-up costs and stated she "cannot participate in this sudden departure from the road map I believe we drew in our prior Alliance orders."

On February 19, 2002, the Alliance Companies reported that they were in discussions with the Midwest ISO. A supplemental report on the status of negotiations was filed with FERC in March 2002. On April 24, 2002, FERC directed some of the Alliance companies, within 30 days, to file a compliance filing detailing which RTE they planned to join and stating whether they planned to participate individually or grouped together as a for-profit independent transmission company. In May 2002, FERC announced that it would consider new electricity market rules to encourage U.S. utilities to balance reliability with profits as they decide how to sew together their patchwork power grids. FERC said it was disturbed by recent announcements by some utilities that they intend to join regional transmission organizations far removed from

their home territories. FERC did not set forth any specific actions it will take to encourage utilities to join RTEs that are close to their natural boundaries.

At the Task Force's meeting on June 21, 2002, Stuart Solomon, Vice President of Public Policy for AEP, reported that AEP and PJM Interconnection LLC, an RTE based in Pennsylvania, signed a memorandum of understanding on May 7, 2002. Mr. Solomon noted that the PJM RTE currently has an organized spot market and complies with FERC's template for standard market design. Under the terms of their agreement, which includes a 120-day development period, AEP can join PJM as either a stand-alone transmission owner or as part of an independent transmission company. AEP favors a for-profit independent transmission company that offers the ability to attract capital and squeeze out inefficiencies. AEP contemplated the transfer of functional control of its transmission system to PJM by December 2002, and the integration of AEP into the PJM energy market by May 2003. AEP stated that PJM membership offers the opportunity to secure the benefits of an RTE, thereby facilitating retail competition, sooner than do other options. Other former Alliance members, including Commonwealth Edison, Illinois Power, and Dayton Power & Light, intend to join PJM. Though FERC has expressed concerns that proposals by some Alliance companies to join PJM may not be consistent with natural markets, Mr. Solomon discounted the applicability of this concern to AEP, noting that FERC's concern is more likely directed at other former Alliance companies, with noncontiguous service territories in Illinois, that wish to join PJM. AEP expressed confidence that FERC will focus more on existing electrical ties and connections that on maps of the utilities' service territories. AEP filed an application with FERC to join the PJM RTE on December 11, 2002.

Allegheny Power spokesperson John Ahr recounted that his firm turned over functional control of its transmission system to PJM on April 1, 2001, thereby forming PJM West. Under the PJM regional market model, prices for power for the combined market area are calculated. Depending on system congestion, that price would apply over the whole region. The model also addresses the dispatch of generation units in merit order and coordinates transmission outages for the entire region. Other duties of the PJM RTE include conducting regional transmission system planning and operating a market monitoring unit, which has responsibility for monitoring members' compliance with market rules and ensuring that its policies are consistent with the operation of a competitive market. A copy of Mr. Ahr's presentation is attached as Appendix A.

Harold Adams told the Task Force at the same meeting that DVP recognizes its legislative and regulatory obligations to join an RTE, and vowed to notify the Task Force of its decision concurrently with the company's notification of federal and state regulators. A properly functioning RTE is viewed as meeting three goals: providing improved price signals to consumers and suppliers, encouraging efficient solutions to transmission congestion management, and exerting competitive pressures on energy costs. A copy of Mr. Adams' presentation materials is available on the Task Force's website at http://dls.state.va.us/groups/elecutil/06_21_02/DominionLTTFUpdate6-02/index.htm.

In response to FERC's order of December 19, 2001, that rejected the proposed Alliance RTE, Dominion worked to find an alternative that will be accepted by regulators and customers. In a summit with interested persons convened by DVP on June 13, 2002, stakeholders identified

relevant factors. However, there was no consensus as to which RTE was best. The two leading contenders were identified as PJM and the Midwest ISO. GridSouth, formed by Duke Power, Carolina Power & Light, and South Carolina Electric & Gas, had been under consideration but lost viability when it recently announced that its members were suspending most aspects of its development.

On June 25, 2002, DVP and PJM announced their execution of a memorandum of understanding to join PJM, subject to approval by FERC, the SCC, and the North Carolina Public Utility Commission. At the Task Force's subsequent meeting on November 19, 2002, DVP elaborated on its application to join PJM. The plan calls for DVP's control area to be operated as PJM South, which will be separate from the PJM and PJM West control areas. DVP would cede operational control of its transmission lines to PJM, but would continue to own these assets. DVP's Director of Electric Market Policy told the Task Force that PJM offers several advantages, including the approval by the FERC of its RTE structure and the fact that all major electric utilities serving Virginia will be members of the same RTE. DVP announced its intention to file its plan for joining PJM with FERC and state regulators in December 2002, to be followed by adopting a transmission tariff by February 2003. Under DVP's schedule, federal and state regulators were to issue their approvals by June 2003, and the integration of DVP into PJM's system would be competed by October 2003. DVP's presentation materials are available on the Task Force's web page at http://dls.state.va.us/groups/elecutil/11_19_02/RTO/sld001.htm.

The Task Force received comments from interested stakeholders regarding RTE membership issues at its June 21 meeting. August Wallmeyer of the Virginia Energy Providers Association claimed that the lack of a functioning, independent RTE is preventing wholesale competition in Virginia. VEPA advocates incumbent utilities joining the PJM RTE in part due to its governance structure and market design features. He suggested adoption of a goal calling for the issuance of all necessary approvals for PJM membership by the end of 2002.

Edward Petrini, representing the Virginia Committee for Fair Utility Rates, a group of large DVP customers, expressed concern that the delays by incumbent electric utilities in joining RTEs have effected the schedule contained in the Restructuring Act. While the Act contemplated a six and one-half year transition phase, delays in RTE development have reduced this period to less than five years.

Ralph L. Axselle, speaking on behalf of the Alliance for Lower Electric Today (ALERT), echoed concerns with the delays in transferring control of transmission assets to an approved RTE. Both the Act and the 1998 legislation that established a timeline for deregulation called for the establishments of RTEs by January 1, 2001, because the legislature recognized that RTEs are needed for the development of wholesale markets.

Judy Jagdmann of the Office of the Attorney General added that operating RTEs are critical. Functioning wholesale markets are needed for the development of retail markets, and RTEs are necessary for the existence of viable wholesale markets.

Greg White of Old Dominion Electric Cooperative explained that transmission system congestion is affecting the wholesale pricing of electricity under RTE rules. He suggested that

utilities should not join RTEs where the price of electricity is highest. For example, he stated that the price of electricity in PJM is about 40 percent higher than in MISO.

Cody Walker of the SCC staff outlined several FERC-related RTE developments. A copy of the SCC staff's presentation is attached as Appendix B. Concurrent with the appointment of Pat Wood as its new FERC chairmen, the FERC has been much more aggressive in its approach to RTE issues. In addition to rejecting the proposed Alliance RTE and directing its members to pursue membership on other RTEs, FERC has initiated mediation efforts to form larger RTEs, as evidence by its effort to merge PJM, ISO-New England and NYISO into a Northeast RTE. FERC has also started reaching out to state regulatory commissions through regional workshops and questionnaires, has initiated efforts to adopt a single market design, and has begun an effort to assess the costs and benefits of RTE formation.

The SCC has actively participated in FERC RTE proceedings in order to ensure that the essential elements of RTEs are in place and that RTE development will further the development of competition in Virginia. In DVP's recent RTE summit, the SCC staff noted that RTE practices and policies should promote reliability and appropriate pricing for transmission service, be consistent with FERC requirements, fairly compensate the transmission system owner, generally promote the public interest, and assure that the RTE is managed independently of market interests. In addition, they should provide for transmission planning and facilitate construction of needed facilities, provide for appropriate interconnection of new generating facilities, provide for effective relief of transmission congestion, and provide for effective market monitoring. The SCC staff also noted that ideally Virginia utilities should participate in operational RTEs at least one to two years prior to the end of the capped rate period.

2. Perspective of FERC

Addressing the Task Force at its June 26, 2002, meeting, FERC spokesperson Charles Whitmore observed that his agency has promoted the formation and development of voluntary, geographically sensible regional RTEs. He announced FERC's release of the "Big Ticket" list, which outlines FERC's timetable for major standard market design and RTE issues over the next 18 months (Appendix C). The Task Force was told that the resolution of two RTE-related issues will be important to Virginia. First, FERC is working to eliminate seams, which are regulatory, market and physical barriers to trade among regions. Second, FERC is seeking to ensure that RTEs create sensible geographic markets in the Eastern Interconnection. FERC has asked DVP, AEP, and other utilities to explain how their decision regarding RTE membership will effect seams issues and be consistent with natural markets. The issue of natural markets could be troubling in the Midwest and Mid-Atlantic region if utilities join an RTE for which there are no contiguous boundaries.

Mr. Whitmore also announced that FERC is drafting rules for standard market design (SMD) that will apply to all public utilities. SMD seeks to provide more choices and improved services to wholesale market participants, reducing delivered wholesale electricity prices through lower transaction costs and wider trade opportunities, improving system reliability, and increasing certainty about market rules and cost recovery. FERC contemplates that RTEs would be the primary entities to implement SMD.

FERC's efforts to have electric utilities voluntarily join RTEs was described as being more torturous than anticipated as the result of the problems with California's experiment with deregulation, the collapse of Enron and other energy trading firms, and public perceptions. In reaction to allegations of improper trading practices, the FERC has established an Office of Market Oversight and Investigation. A copy of his remarks is attached as Appendix D.

3. Implications of PJM Membership

By the fall of 2002, it became clear that the Commonwealth's three major investor-owned electric utilities all had joined, or were intending to join, the PJM RTE. PJM operates both a multistate transmission system and associated electricity trading markets. Commencing with the November 19, 2002, meeting, the Task Force received a great deal of testimony, pro and con, regarding the implications of the utilities' memberships in PJM. At that meeting, several Task Force members expressed concerns regarding the possible reduction in SCC oversight that may ensue if these incumbent utilities join PJM. The PJM structure, which complies with the SMD model being considered by FERC, is alleged to cede control over the dispatch of generation to the RTE. In addition, some long-term resource adequacy planning will be overseen by the RTE. One member commented that the Restructuring Act contemplated RTE oversight of transmission, but not generation, services.

Greg White of Old Dominion Electric Cooperative raised concerns with PJM's locational marginal pricing (LMP) rules. As he characterized LMP, when generation is dispatched in transmission-constrained areas, the price for all of the power will be the cost of the last-dispatched, highest-priced power. In contrast, under the current system as more expensive power is dispatched, its cost is blended with that of all of the power. Fixed transmission rights can in theory be purchased as a hedge against the congestion costs associated with the locational marginal pricing rules. However, in practice they have not always proven to be adequate. While the rules may theoretically provide an incentive for the construction of new low-cost generation and transmission assets to reduce congestion, the long periods needed for approval and construction of power lines and other facilities have forced customers to pay higher costs.

The discussion of the implications of PJM membership was continued at the Task Force's November 26 meeting. PJM responded to previous concerns regarding PJM's use of locational marginal pricing and the possible reduction in state regulators' oversight of electric generation dispatching and planning. PJM spokesperson Kenneth Laughlin defined locational marginal pricing as the cost to serve the next megawatt of load at a specific location, using the lowest production cost of all available generation, while observing all transmission limits. It includes the marginal cost of generation, the cost of transmission congestion, and the cost of marginal losses. Because it results in higher costs when a transmission system is congested, it is viewed as creating incentives for investing in transmission infrastructure. Mr. Laughlin's presentation materials are available on the Task Force's website at http://dls.state.va.us/groups/elecutil/11_26_02/pjm/sld001.htm

Locational marginal pricing poses two challenges. First, it exposes market participants to price uncertainty for congestion cost charges. Second, during constrained conditions, PJM

collects more revenue from loads than it pays to the power generators. PJM's solution is to allow the system's users to obtain fixed transmission rights (FTRs). FTRs are contracts that entitle their holder to revenues based on the hourly energy price differences across the path. The owner of an FTR over a route receives a credit back for the amount of the congestion charge assessed as a result of the locational marginal pricing.

At the December 12, 2002, meeting, the SCC responded to comments at the previous meeting regarding the implications of Virginia's utilities' membership in the PJM RTE. Cody Walker of the SCC's Division of Energy Regulation offered his perspective on the implications of using LMP to determine the cost of electricity in transmission-constrained areas. A copy of SCC staff's tables illustrating implications of the LMP model are attached as Appendix E. In areas where LMP applies, the price of the power charged by the last unit dispatched to serve a load becomes the price for all of the power dispatched to meet that load. Under LMP, the unit that provides the increment of electricity that meets the load sets the price that all of the providers will receive, even if the price the other generators would otherwise have charged is less than the price bid by the supplier of the last increment.

While FTRs are intended to address some of the concerns with LMP by allowing suppliers to obtain contractual rights to the transmission of power as a hedge against transmission congestion costs, the process of obtaining FTRs is complex. In theory, the owners of generation facilities can be protected from risks associated with LMP because, while they may pay more for power to meet load needs, their revenues will reflect the higher marginal prices. Market participants who do not have generation capacity can in theory protect themselves by entering into bilateral contracts. However, generators may have little incentive to enter into bilateral contracts where doing so means giving up the potential advantages of higher LMP-based revenue.

Mr. Walker noted that the possibility of market manipulation can exist with LMP. If a generator withholds low-cost power from the market in order to have more expensive electricity set the marginal price, the cost of the power can rise. As a result, the need exists for strong market power monitoring and mitigation. PJM has a market monitoring unit with responsibility for determining transmission congestion costs and the potential of market participants to exercise market power within the PJM area.

Other areas of concern identified by Mr. Walker with respect to PJM membership include:

- The effects of LMP on the development of retail access, as new entrants may face problems obtaining FTRs or generation capacity.
- The effects of higher power prices in transmission-constrained areas, such as the Eastern Shore, on economic development.
- Whether the high prices resulting from LMP will actually spur needed improvements, because suppliers who benefit from the higher prices may raise obstacles to upgrades that would abate the congestion.
- When the SCC establishes prices for default service, whether the market price will reflect prices resulting from LMP, and if so whether the price will be net of the effects of FTRs.

- Whether state regulators will have any role in determining the need for additional transmission capacity, or whether their role in acting on project applications will be limited to such issues as the facility's environmental impact.

The debate over the effects of PJM membership continued at the Task Force's January 7, 2003, meeting. Steve Herling of PJM stated that his organization is committed to avoid causing undue hardship in Virginia. He denied that PJM would force Virginians to reduce electricity consumption in order that power could be shipped to other states. With respect to concerns about LMP, Mr. Herling added that PJM has adopted tools for evaluating connection events that address the issues others have raised. Much of the concern with LMP in spot markets can be addressed by self-supply and bilateral contracts among utilities. Moreover, joining PJM will not affect the reliability of service for customers and transmission siting approval authority will remain with state regulators.

In response to questioning by Senator Watkins, Mr. Herling stated that while PJM's analysis of the DVP and AEP systems is ongoing, it has found no problems with load pockets that would require new investments. He responded to Delegate Woodrum's question about cost increases sustained at the A&N Electric Cooperative on the Eastern Shore by observing that PJM has instituted measures, including new tests with lower voltage transmission, to avoid the problems experienced in the past.

While AEP has continued to implement its plan to join PJM, DVP announced at the Task Force's January 7, 2003, meeting that it would delay action on its application to join the RTE until concerns have been addressed. However, its delay may not necessarily preclude its original plan to join PJM by the scheduled entry date of October 1, 2003.

A spokesman for PJM Interconnection continued the colloquy at the January 27, 2003, meeting by lauding the benefits produced by PJM's markets. These benefits include a 35 percent improvement in the performance of plants, lower prices of $10 million per day, and increases in generation capacity. In addition, demand response programs have alleviated system congestion. PJM committed to provide the Task Force with copies of relevant cost-benefit studies. In the case of Allegheny Power, PJM membership is estimated to achieve $40 million in value in 2002.

C. RISKS POSED BY FERC'S STANDARD MARKET DESIGN PROPOSAL

As noted by Dr. Rose in his overview of the development of competitive regional markets, FERC's proposed rules for a standard market design (SMD) create substantial uncertainty for Virginia's electric utility industry. The SCC's concerns with FERC's SMD notice of proposed rulemaking prompted the release of an addendum to the 2002 report on the status of competition. The full text of this supplemental report, dated December 30, 2002, may be viewed at the SCC's website at http://www.state.va.us/scc/caseinfo/reports/lttf_addendum_02.pdf.

The SCC's supplemental report asserts that the FERC's SMD plan, "if adopted as proposed, would have a profound impact on restructuring actions the SCC has already taken and may take in the future." Under the FERC SMD proposal, Virginia cannot ensure the same price

and reliability protection it can at present. Rates could unnecessarily increase and there could be service interruptions that would not occur today.

A major concern is the SMD's elimination of native load preferences, which give Virginia consumers first priority to be served by the generation and transmission facilities that they have bought and continue to pay for through existing rates. FERC believes that the favoring of native load customers is discriminatory and damages wholesale electric markets. The SCC fears that eliminating native load preferences means that Virginians could experience service interruptions to ensure that power is provided elsewhere in its multi-state region, notwithstanding the fact that there is adequate generation and transmission capacity in Virginia to meet the needs of Virginians.

Aspects of the SMD proposal that are cited by the SCC as being of particular concern include:

- Mitigation and Market Oversight: Despite assertions that competition may ultimately be an effective regulator of the reliability and price of electricity, the SMD rules provide for federal mitigation and market oversight responsibilities. The SMD rules envision a market monitoring function that will reside at the RTE and which will be responsible to the RTE and the FERC. The complexity of market monitoring and the questionable ability of FERC to oversee market monitoring efforts casts doubts on the proposal's ability to ensure good industry performance.

- Market Power: Addressing the potential exercise of market power in a regional market through competition would require the electric utility system to have enough generation and transmission capacity to allow many sellers to provide service to consumers. Absent sufficient extra capacity, a supplier that is asked to meet the last increment of demand may be able to charge rates for its power that exceed the rates that could be charged in market where no supplier is able to exercise market power. Until generation and transmission facilities are greatly expanded, congestion in load pockets may create opportunities to exercise market power. While there is sufficient generation and transmission capacity to serve Virginia's native load, extra capacity would be needed to avoid potential abuses of market power. The current generation and transmission infrastructure was not designed to provide this extra cushion of capacity needed to support a truly competitive market, and building the extra capacity would entail substantial costs.

- Locational Marginal Pricing: The SMD proposal relies on locational market pricing in spot markets as a mechanism to address transmission congestion. Under LMP, the spot price for electricity at any time will be determined using bids submitted by available generators in the regional market. If transmission is constrained, costs may be based on the cost of the last (and most expensive) generation unit from which electricity is dispatched to serve the load in the constrained area. In theory, allowing higher prices to be charged for power transmitted through congested areas will create incentives to build the infrastructure needed to alleviate the congestion. However, the SCC raises several concerns that implementation of LMP will be detrimental to

Virginia's consumers. In certain areas, the owner of generation capacity for an isolated pocket could exert market power and demand prices that may be unjust and unreasonable. Even if the highest bid price submitted to provide power in a load pocket is warranted, it could be higher than the average blended rate that Virginia's consumers currently pay.

- Regional Resource Adequacy Requirements: The SMD rules include a resource adequacy requirement that obligates the RTE to forecast resource adequacy on a regional basis. It is not clear whether the substantial costs of new transmission facilities needed to make the regional market competitive, and which exceeds what is needed for system reliability, will be socialized by requiring everyone to share the cost or whether only those benefiting from the new transmission facilities will pay. In either event, the SCC warns that ultimately consumers will be required to pay for the new transmission assets.

The SCC characterizes the costs of complying with the proposed SMD rules and the risks they pose as "tremendous." The Commission asserts that it is "highly likely" that the FERC's SMD rules would apply in Virginia, regardless of whether the Commonwealth has allowed the transfer of control of its utilities' transmission systems to federally-regulated regional transmission entities, because retail electricity rates have been unbundled into their generation, distribution, and transmission components. In New York v. FERC, 122 S. Ct. 1012, 1027-1028 (2002), the Supreme Court held that FERC has jurisdiction over the transmission component of unbundled retail rates. The issue of whether FERC also has jurisdiction to impose SMD rules on states that have not unbundled their rates or allowed utilities to transfer control of their transmission systems to an RTE is unresolved.

The SCC concludes that if Virginia allows the transfer of control of transmission assets to a FERC-regulated RTE or if the components of electric rates remain unbundled, the FERC will obtain jurisdiction, which in turn can have a significant impact on retail electric rates and reliability. Moreover, it will be extremely difficult, if not impossible, for the Commonwealth to retrieve such jurisdiction should it pass to FERC.

The addendum report contends that two things must occur for Virginia to avoid the application of FERC's SMD rules:

> First, as a result of court, congressional or FERC action, the states must have the opportunity to decide whether their utilities will comply with the requirements of the SMD notice of proposed rulemaking (NOPR), including the NOPR's requirement to have an independent entity operate their utilities' transmission facilities. Second, the Commonwealth must decide that Virginia utilities should not now be part of the proposed federal plan. This decision could be made by amending the Act to rebundle rates and service and defer, or eliminate for now, the requirements that Virginia's electric utilities join an RTE and seek to transfer control of their transmission systems to such RTE.

The first requirement is derived from the fact that the proposed SMD rules would apply to both bundled and unbundled states. The SCC contends that reversing the Restructuring Act's

requirements that retail rates be unbundled and deferring the requirement that utilities join an RTE would give Virginia the opportunity to wait until the FERC has finalized its rules. After the rules are finalized, Virginia could then make an informed decision on whether to proceed with retail competition. Delaying the decision of whether to be subject to the FERC's SMD rules is viewed by the SCC as having no significant impact on the Commonwealth.

The SCC presented its addendum to the competition report to the Task Force on January 27, 2003. Commission staff observed that the SMD rules are the source of much contention and may be revised prior to adoption by FERC. If Virginia's primary goal is to open retail markets to competition, no action should be taken. If the primary goal is to keep Virginia in control of its destiny to the maximum extent possible, it should both (i) defer approving transfers of control over transmission assets to RTEs and (ii) rebundle the components of retail rates.

Susan N. Kelly, an attorney with the Washington, D.C., firm of Miller, Balis and O'Neil, advised the Task Force that Virginia cannot avoid FERC regulation of its electric utilities' transmission service simply by delaying RTE participation. The unbundling of retail transmission service, rather than membership in an RTE, was characterized as the critical factor in determining whether FERC has jurisdiction over the transmission element of retail electric rates. She cited FERC Order 888, in which FERC asserts that its jurisdiction arises as a result of a state retail program. Because Virginia's utilities have already unbundled their transmission rates, she believes that FERC now has jurisdiction over the terms, conditions and rates of retail transmission. A copy of Ms. Kelly's remarks is attached as Appendix F.

The Task Force chairman asked interested persons to address three questions: Whether FERC would have jurisdiction if Virginia's rates were unbundled; whether Virginia should postpone allowing utilities to join an RTE; and whether Virginia should rebundle its rates. Stakeholders were split in their reaction to the SCC's recommendation that steps be taken to forestall the application of the FERC's proposed SMD rules to Virginia's utilities.

AEP asserted that there is no need to rebundle rates, and observed that the Restructuring Act currently requires utilities to join RTEs after obtaining SCC approval. AEP urged the Task Force not to delay the RTE development process. Moreover, as it is unlikely that the SMD rules will be enacted in the form presently under review, drawing conclusions about their implications is premature.

Stewart E. Farrar, speaking on behalf of DVP, emphasized that it is not necessary or appropriate to rebundle rates in order to protect service to native load customers. Such a response would be a premature and drastic measure that would strike at the heart of the Restructuring Act. Rather, the proposal to delay electric utilities from joining RTEs was called "an appropriate response to any current concerns about FERC's proposed rulemaking." He asserted that Virginia is not prevented by any federal law from rebundling at some future date, if it finds that is the appropriate response to FERC's final rules.

The Task Force was also provided with a white paper prepared for Dominion Resources Services by Thomas L. Blackburn, an attorney with the firm of Bruder, Gentile & Marcoux, in which he argues that Virginia can safeguard reliable service to native load by maintaining control

over utility membership in regional transmission entities. As FERC's assertion of jurisdiction over retail transmission service does not affect the reliability of service to native load, rebundling rates in order to ensure reliability of service is unnecessary. A copy of Mr. Blackburn's paper is attached as Appendix G.

Other persons who advised the Task Force not to adopt either or both of the recommendations stated in the SCC's report include:

- Dr. Ransome Owan of Washington Gas Energy Services stated his company's opposition to both of the SCC's recommendations for rebundling electricity rates and delaying approval of applications to join an RTE.

- August Wallmeyer of VEPA contended that rebundling rates would hurt investments in generation facilities.

- Ray Bourland of Allegheny Energy said that FERC already has jurisdiction over unbundled transmission rates, and the proposal to postpone requests to join an RTE will invite additional jurisdictional battles with FERC.

- Reggie Jones stated that the Alliance for Lower Electricity Rates Today recognizes that unbundled rates are necessary to a competitive market. Until the benefits that will result from rebundling rates are certain, such a step is unwarranted. The Restructuring Act contemplated that Virginia would have the benefit of utilities' being members of RTEs for several years prior to the expiration of the capped rate period. Consequently, delaying membership in RTEs may necessitate postponing the end of capped rates.

Virginia's electric cooperatives voiced support for the proposal to delay allowing utilities to join an RTE. Rob Omberg asserted that allowing the transfer of control over transmission assets to an RTE that has a market clearing function (such as PJM) exceeds the authorization in the Restructuring Act.

The Virginia Citizens Consumer Council is concerned about FERC's jurisdiction over Virginia's utilities, and advocated rebundling rates. Dr. Irene Leech observed that the electric utility restructuring process is not working anywhere, and argued that slowing down its implementation in Virginia will not hurt anything.

Judy Jagdmann of the Office of the Attorney General noted that the Supreme Court, in New York v. FERC, agreed that the FERC has jurisdiction over unbundled transmission rates. Three justices said that FERC's authority extends to bundled transmission rates as well. She agreed with the contention that postponing the ability of utilities to join RTEs was an adequate step, and observed that while Virginia may need to rebundle the components of electric rates at some point, it is not necessary today. If Virginia can rebundle rates today, she noted, then it can do so in the future if the FERC's final SMD rules make such a step appropriate.

D. DATA ON ENERGY INFRASTRUCTURE AND RELIABILITY

Senate Bill 684 of the 2002 Session, patroned by Senator Watkins, requested the SCC to convene a work group to study the feasibility, effectiveness, and value of collecting data pertaining to Virginia's electric and natural gas infrastructure. The purpose of the data collection would be to monitor the adequacy of the energy infrastructure within the Commonwealth. Pursuant to the legislation, the SCC convened a work group consisting of representatives of electricity generators, incumbent electric utilities, interstate gas transmission companies, large industrial customers, and SCC staff.

SCC Energy Regulation Division Director Bill Stephens presented the report to the Task Force at its December 12, 2002, meeting. He reported that work group participants generally agreed that collecting the data identified in the legislation is feasible. However, the value and effectiveness of collecting the information is more difficult to ascertain. The restructuring of Virginia's natural gas and electricity industries means the Commonwealth will rely on the competitive market to meet consumer demand for electric and natural gas service. Electric utility industry restructuring may shift jurisdiction for overseeing reliability over generation and transmission services from state regulators to the FERC. FERC's recent notice of proposed rulemaking for the implementation of SMD, if implemented, will place significant new federal regulation over the pricing and reliability of electricity. In addition, if Virginia's utilities join RTEs that operate a regional electricity market, state regulators may lose jurisdiction over generation and transmission reliability.

A shift in oversight jurisdiction with respect to generation and transmission reliability casts doubt over the value of collecting data about Virginia's electrical infrastructure. In addition, stakeholders have split on the issue of whether state regulators will be able to require incumbent utilities to build generation facilities to meet the needs of Virginians. Once Virginia's electric utility industry is regionalized, the concept of monitoring the dedication of facilities to the service of Virginia's native load becomes problematic.

Mr. Stephens presented the Task Force with three options: collect the data and gauge its value at a future time; wait until the industry stabilizes and then request the data; or collect some basic data that could provide information as to infrastructure adequacy and forecast load and planned reserve margins until such time as it is determined that either more or less information is necessary. The third approach is described in the SCC's report as being more practical in the current environment and less burdensome on the entities providing the information. The report is available on the Internet at http://www.state.va.us/scc/caseinfo/reports/sb684_112002.pdf.

In response to Mr. Stephens' presentation, Senator Watkins asked the staffs of both the Task Force and the SCC to look into the issue of whether anything could be done to ensure that the Commonwealth does not cede monitoring responsibilities to FERC or to a regional transmission organization. While FERC may eventually exert jurisdiction over transmission and other aspects of electric service, a state may be giving up its oversight authority prematurely if its utilities join a regional transmission organization that operates a wholesale market. The proposal developed in response to this request is discussed in Part III B of this report.

E. IMPLICATIONS OF CAPPED RATES

1. Effect of Rate Cap on Customers of Dominion Virginia Power

Christine Chmura of Chmura Economics and Analytics (CEA) presented the Task Force with the results of a study of capped rate savings commissioned by Dominion Virginia Power (DVP). A copy of CEA's findings is available on the Task Force's website at http://dls.state.va.us/groups/elecutil/11_19_02/Dominion/index.htm. In August 1998, a rate case settlement froze DVP's retail rates through March 2002. With the enactment of the Virginia Electric Utility Restructuring Act in 1999, the cap on retail rates was extended from 2002 until July 2007. CEA's report concludes that the Act's cap on base rates, when compared to the base rates that would likely have been in effect had the caps not been imposed, has produced total savings for DVP's residential customers of between $780 million and $871 million over the period 1998 through 2007.

The estimated savings consist of three elements:

- $285.6 million for period 1998-2001 from SCC-imposed rate case cap settlement;
- $302.7 million to $393.7 million, depending on the revenue forecast used, predicted for the 2002-2007 capped rate period under the Restructuring Act; and
- $192 million from DVP's inability to obtain rate relief to cover extraordinary expenses, primarily environmental project expenditures, during 2002-2007.

Assuming the average residential consumer uses 1,000 kWh per month, average savings per residential customer ranged from $429 to $480 from 1998 through 2007, which equates to an average annual savings of $45 to $50 over the entire period. The report also states that, through the multiplier effect, savings from the rate caps will generate between $132 million and $148 million in additional economic activity in Virginia.

CEA's study assumes that base residential rates would have risen between 7.9 and 9.2 percent between 2001 and 2007 had the rate cap not been imposed. This assumption is based on a model developed by CEA that attempts to take into account the factors that the SCC confronts when approving rate changes.

2. Comparison of Residential Electricity Rates in Other States

During the questioning that followed Ms. Chmura's presentation, Senator Watkins asked the SCC staff to compile information on residential rate increases in other states during the same time frame. At the January 7, 2003, meeting, Ronald Gibson, director of the SCC's Division of Public Utility Accounting, presented a report on changes in residential electric rates in northern and southern states for investor-owned electric utilities during the period 1998 through 2002. The text of the Commission's report can be viewed on the SCC's web site at http://www.state.va.us/scc/caseinfo/reports/ratecomp_lttf_010703.pdf.

Mr. Gibson concluded that northern states, many of which have deregulated their electricity markets, continue to have higher rates than southern states, most of which have not

deregulated. The average residential cost of electricity in northern states is 10.463 cents/kWh, compared with 7.110 cents/kWh in southern states.

In Virginia during the period examined, average rates declined from 7.021 cents/kWh to 6.967 cents/kWh from 1998 to 2002. Exhibit 4, page 1 of the report shows the components of the statewide rate change as follows:

Company	% Change from 1998	% Change Base Rates	% Change Fuel Rates
Appalachian Power	-4.21%	-1.75%	-11.61%
Virginia Electric and Power Company	1.75 %	-5.96%	53.62%

The SCC's report reveals that during the period 1998 to 2002, the average residential rate in southern states increased from 6.967 cents/kWh to 7.11 cents/kWh. The increase of 0.143 cents/kWh over this period is about two percent, or one-half of one percent per year. Northern states, on the other hand, experienced a decline of about one percent over this period, from 10.572 cents/kWh to 10.463 cents/kWh.

A comparison of total rates, and tracking the rate of the change in the totals, can be misleading because the total rate includes both a base rate component and a fuel cost component, which tends to be more volatile. The Restructuring Act's capped rates are subject to adjustment to reflect changes in fuel costs, as provided in § 56-582 B. Consequently, the base rate arguably provides a better benchmark of how much rates would have changed in the absence of the Restructuring Act's capped rate provision. From 1998 through 2002, the base rate in southern states declined at 10 of the electric utilities; increased at five; and did not change at two.

F. STRANDED COSTS RECOVERY

If electricity generation is deregulated, then the revenue collected by an incumbent electric utility could decline, either as customers elect to buy power from a competitor or from declines in the market price for generation. Consequently, the utility's generation assets -- constructed and financed at a time when cost-of-service regulation was in place -- could lose substantial portions of their pre-restructuring book value. Similarly, the price of power purchased from nonutility generators prior to restructuring by investor-owned utilities may equal or exceed the market price for power in a deregulated market. These potential declines in the value of assets incurred while the utility was subject to traditional rate regulation illustrate the concept of stranded costs that a utility may face as a result of the advent of retail competition.

Arguments for allowing recovery of stranded costs are based on the "regulatory compact." Implicit in the relationship between regulated utilities and their regulators, which provides that in exchange for fulfilling their obligation to serve all customers within certificated service territories, costs prudently incurred by regulated utilities in furtherance of providing such service will be recovered in regulated rates. Under this argument, any departure from a

regulated, cost-of-service environment must allow a utility to recover prudent costs that were incurred while it was regulated and that that are rendered uneconomic because of restructuring.

Subsection C of § 56-595 of the Restructuring Act provides that members of the Legislative Transition Task Force shall:

> "[A]fter the commencement of customer choice, monitor, with the assistance of the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs . . . "

The Restructuring Act provides that shopping customers choosing to purchase generation from a nonincumbent must pay a nonbypassable wires charge. The wires charge is intended to serve as a surrogate for the stranded cost recovery that an incumbent would receive from non-shopping customers. The recovery mechanism will be in effect until mid-2007.

However, the Restructuring Act neither defines stranded costs nor provides any formula or statutory framework for their calculation. Stranded cost recovery was one of the most critical policy hurdles the joint subcommittee had to clear as it developed Virginia's restructuring bill. The Joint Subcommittee Studying Electric Utility Restructuring, which produced the Restructuring Act in 1999, convened a Stranded Costs Task Force to address issues pertaining to stranded costs recovery.

The report of the Stranded Costs Task Force, which is Appendix J to the 1999 report of the Joint Subcommittee Studying Restructuring of the Electric Utility Industry (Senate Document 34), illustrates the difficulty in agreeing upon a definition of "stranded costs." Members of this stranded costs task force distinguished stranded costs and its elements from "transition costs," or costs that utilities may incur in transitioning from a regulated to deregulated market for generation. Illustrative of transition costs are utilities' costs in (i) establishing or joining an independent system operator or regional power exchange and (ii) funding mandatory consumer education programs concerning restructuring. Primary sources of potential stranded costs were identified as (a) generation asset devaluation, (b) potential losses associated with above-market purchased power contracts (including cooperatives' wholesale power purchase contracts), and (c) regulatory assets.

Perspectives were provided during the 1999 study of this issue by:

> **DVP:** Stranded costs are losses in the economic value of an electric utility's investments and obligations related to the supply of electric generation that result from the implementation of competition in the purchase and sale of electric energy. Virginia Power proposed permitting utilities to recover net losses associated with the onset of retail competition, including the costs of increased consumer and employee benefits, mandated obligations (NUG contracts, nuclear decommissioning, and other governmental requirements imposed prior to competition), transition costs (including the formation of

an RTE), and the net losses in the economic value of generation investments (stranded costs).

SCC: Stranded costs will occur if there is a net loss in economic value of existing generation-related utility assets and contracts from a restructured industry. The change in economic value will be based upon the difference between embedded-cost electricity rates calculated under regulation and competitive market-based electricity prices.

AOBA: Stranded costs represent costs that are recoverable by a utility under existing regulatory policies that are not recoverable under competitive market pricing of services if current regulated rates are above competitive market prices. Stranded value represents profits in excess of a regulated fair rate of return that the owners of regulated generation resources would derive if they are permitted to price energy and capacity services on the basis of market values that are in excess of current cost-based ratemaking levels. The most consistent approach to measurement of the future value of a utility's generation assets is obtained when the utility sells its generation resources through an open competitive bidding process.

Virginia Citizens' Consumer Council: Stranded costs are the difference between the value of generation-related assets currently in rates that have a net book value equal to or above their market value and the value of generation-related assets that have a net book value below their market value, after mitigation efforts, and excluding costs that are avoidable in the future. Stranded costs should be recoverable only when management had no discretion over incurring the costs or when failure to recover these costs would drive the utility into bankruptcy.

Consumer Counsel, Office of Attorney General: Stranded costs in a competitive market are a utility's lost revenues associated with prudently incurred and unrecoverable costs related to utility investments in power production assets. Stranded benefits in a competitive market are a utility's net profits over and above earnings that would result under the continuation of traditional cost-based regulation.

The Division of Consumer Counsel's comments to the SJR 91 subcommittee on stranded costs illustrates the complexity of the issue. The Division notes that unless and until there is effective competition in the retail electric generation market and customers leave their current provider in favor of a competitor, no stranded costs or benefits can exist.

Senate Bill 1269 of 1999 as introduced was silent on the issue of who would determine stranded costs. Section 56-595 was amended in committee to direct the Task Force to monitor the issue. Prior to its introduction, the report of the SJR 91 stranded costs task force notes that stakeholders agreed that the SCC should play a significant role in addressing stranded costs and stranded benefits. Several proposals specifically enumerated factors that the SCC would use in calculating and determining stranded costs and stranded benefits.

Proposal 5 in Part III of the SCC's 2002 report on the status of competition states the recommendation of Washington Gas Energy Services, Energy Consultants, and the Virginia

Committee for Fair Utility rates that the SCC or General Assembly should calculate recoverable stranded costs for each utility and the pricing of standard offer service should reflect an amortization of those costs over a fixed period of time (August 30, 2002, report at page 17). In its response, the SCC notes that the Restructuring Act neither defines stranded costs nor provides any formula or statutory framework for their calculation. "Since there was no determination of reasonable net stranded costs going into the transition (nor any statutory structure for their calculation, thereafter), this may be a challenging task for the LTTF" (Id. at 18). The SCC's report further notes:

> [S]ince measuring the 'underrecovery' or 'overrecovery' of stranded costs under § 56-595 C requires their quantification, it will be necessary to adopt a formula or method for their calculation. Moreover, and with respect to monitoring their levels of recovery, it will also be necessary to determine what part of the utilities' capped rates (together with wires charges) should be allocated to stranded cost recovery. Simply put, two things must be done in order to monitor the progress Virginia's utilities are making toward recovery of their stranded costs. First, determine the amount of stranded costs; second, allocate wires charges and some part of capped rates to their recovery. Undertaking any of the foregoing presupposes, however, that authority exists within the Restructuring Act's current statutory framework for doing so (Id. at 18-19).

In October 2002, Senator Watkins requested staff to prepare a draft of a resolution pursuant to which the Task Force would request the SCC to convene a work group comprised of Commission staff and representatives of persons representing the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers. The work group's purpose would be to develop consensus recommendations on issues relating to stranded cost recovery. After circulating the draft among stakeholders for comment, DVP prepared an alternative version of a resolution.

The major substantive difference between the resolutions involved the work group's objectives. Senator Watkins' version called on the work group to calculate each incumbent electric utility's recoverable stranded costs and the amounts it collects from capped rates and wires charges to offset such costs. The DVP alternative proposal asked the work group to develop a process, methodology or formula for determining whether the stranded costs recovered by an incumbent electric utility have resulted in the overrecovery or underrecovery of just and reasonable net stranded costs.

Interested parties offered a variety of perspectives on the issue at the December 12 Task Force meeting:

- Mark Kumm of Pepco Energy Services recommended that the SCC should lead a quantification effort that would result in a stranded cost total for each utility. A formal proceeding before the Commission would be preferable because the issues are complex and a work group is unlikely to reach a consensus.

- R. Daniel Carson, Virginia President of AEP, supported a modified version of the DVP alternative under which a subcommittee of the Task Force would direct and

monitor stakeholder deliberations and make appropriate recommendations to the full Task Force. The group should first determine what is meant by the language directing the Task Force to monitor stranded cost recovery.

- August Wallmeyer of Virginia Independent Power Producers agreed with AEP that a subcommittee of the Task Force should be convened, as in the deliberations in 1998. He expressed concern that the party convening a working group can steer its work product. The only goal of the group should be to define stranded costs.

- William G. Thomas, representing DVP, contended that this issue was addressed on the floor of the House of Delegates in the 1999 Session when language was removed from Senate Bill 1269 that would have directed the SCC to conduct a proceeding to determine stranded costs. He urged the Task Force to start by adopting a process rather than by collecting numbers.

- Reggie Jones, representing ALERT, supported Senator Watkins' version. The pilot programs for retail electric choice were a failure for consumers, and Virginia's utilities are two years behind schedule in joining or forming regional transmission entities. The clock is ticking on the scheduled lifting of capped rates in 2007, and the DVP alternative will only slow the process.

- Spokesmen for Old Mill Power Company, the Virginia Citizens Consumer Counsel, the Virginia Committee for Fair Utility Rates and Old Dominion Committee for Fair Utility Rates endorsed Mr. Jones' comments in support of Senator Watkins' version of the resolution.

- Bill Lukhard, chairman of the Consumer Advisory Board, also opined that Senator Watkins' proposal is more appropriate.

After considering the two versions of the resolution, the Task Force directed staff to prepare a version that incorporates elements of both Senator Watkins' version and the DVP alternative. Two Task Force members will monitor the proceedings of the work group, and the Task Force's subcommittee on stranded costs will be reconvened. The resolution envisions a two-step process. By July 1, 2003, the work group is to present its consensus recommendations regarding (i) definitions of "stranded costs" and "just and reasonable net stranded costs" and (ii) 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. By November 1, 2003, the work group is to present its recommendations on the amount of each incumbent electric utility's just and reasonable net stranded costs and the amount that it has received, and is expected to receive, to offset just and reasonable net stranded costs from capped rates and from wires charges. Delegate Woodrum voted against the proposal.

G. REVENUE FROM TAXES ON ELECTRIC UTILITIES

In 1999, the General Assembly enacted Senate Bill 1286, which revamped the system of taxing electric utilities. The tax on utilities' gross receipts was eliminated, and in its place (i) utilities became subject to the corporate income tax, subject to certain adjustments, and (ii) electricity consumers became subject to a tax based on the amount of power consumed. At the December 12, 2002, meeting, Christian Tennant of the Department of Taxation presented the most current available data on receipts from Virginia's electricity consumption tax and the corporate income tax on electric utilities. A copy of his presentation is available on the Task Force's web site at http://dls.state.va.us/groups/elecutil/12_12_02/taxlttf/index.htm. The study of the tax implications of electric utility restructuring estimated that the gross receipts tax generated $100 million annually. Of this sum, $13 million represented contributions paid by governmental entities. The electricity tax legislation was intended to generate $87 million per year, which would make the new levies revenue neutral after deducting the amounts paid indirectly by governmental entities.

Prior to enactment of Senate Bill 1286 in 1999, the corporate income tax was expected to generate $21 million annually. This estimate was based on pro forma federal income tax returns from 1995 through 1997. Income earned in several states was apportioned among the states using a three-part test that gave equal weight to sales, payroll and property factors. The corporate income tax provisions enacted in 1999 included a tax credit of three dollars per ton of coal purchased to generate electricity, which continued a coal tax credit that could be claimed against gross receipts tax liability. It also allowed a deduction from net income for the amortization of the difference between the aggregate adjusted book basis and the aggregate adjusted tax basis of certain assets. This Federal Accounting Standards Board (FASB) 109 adjustment represents nearly $300 million in reduced tax liability over 30 years.

The rates of the consumption tax were set at levels expected to generate $66 million, which is the difference between the revenue-neutral goal of $87 million and the expected $21 million of corporate income tax receipts. Three declining block consumption tax rates were adopted to reflect the differences in gross receipts tax paid by residential, commercial and industrial customers resulting from the lower rates charged to consumers of large amounts of power.

For the 2001 taxable year, Virginia electric suppliers paid $3.8 million in corporate income taxes. The discrepancy between this sum and the estimate of $21 million was attributed to several causes, including the volatility of this tax, the coal tax credit, the filing of consolidated returns, the enactment of legislation that implements a double-weighting of the sales factor in multi-state income apportionment, and the general decline in the economy.

For fiscal year 2002, the consumption tax is expected to generate an amount very near the $66 million that was expected. However, the distribution of tax collections among rate classes varies significantly from the anticipated distribution. Revenue from the consumption of less than 2,500 kWh per month represents 62.9 percent of the total, compared to the expected 54.5 percent. Large consumers (more than 50,000 kWh per month) paid 23.4 percent, compared to the expected 14.9 percent. Consumers of between 2,500 and 50,000 kWh per month paid a

substantially smaller share (13.7 percent) of the consumption tax than was projected (30.6 percent).

H. CONSUMER ADVISORY BOARD RECOMMENDATIONS

The Restructuring Act established a Consumer Advisory Board to assist the Task Force in its work under § 56-595, and in other issues as may be directed by the Task Force. The 17-member Board is required to be appointed from all classes of consumers and with geographical representation. William Lukhard serves as chairman and Otis Brown as vice chairman. Delegate Plum continued to serve as the liaison between the Task Force and the Consumer Advisory Board.

Over the past four years, the Consumer Advisory Board has developed recommendations in areas of assisting low-income consumers in meeting their energy needs, energy efficiency, and renewable energy. The Board has worked to provide the Task Force with the perspective of a variety of interests that may otherwise have little opportunity to offer their perspective on issues pertaining to the Restructuring Act and its implementation. The Board is particularly interested in issues relating to the effect of electric utility restructuring on residential and small business consumers.

The Consumer Advisory Board held four meetings and two subcommittee meetings in 2002. The Board continued its examination of energy efficiency, aggregation, demand-side management, and the effect of deregulation on small business. Much of the Board's work in 2002 reflected its efforts to implement energy education programs and to ensure that the move to a competitive market for electric generation does not ignore the advantages inherent in demand-side management programs.

Chairman Lukhard presented the Consumer Advisory Board's recommendations at the November 19, 2002, meeting of the Task Force. The Board asked the Task Force to accept the following recommendations:

- Amend the Restructuring Act to allow shopping customers who return to the incumbent utility the option to select market-based pricing, in order to avoid minimum stay requirements.
- Direct the SCC to convene an Energy Management Work Group.
- Work with the Department of Mines, Minerals and Energy (DMME) to define a program of consumer education in energy management and energy efficiency that is designed to reduce the cost of electricity to Virginia consumers and reduce the risk of power shortages and extreme price swings at times of peak demand.
- Oppose any proposals to allow incumbent electric utilities to legally separate their generation business from their transmission and distribution business.
- Request DMME to prepare a report on building codes relating to energy management and energy efficiency, and addressing the authority to establish unique requirements for state-owned facilities.

- Amend the Restructuring Act and the natural gas deregulation statutes to have the SCC develop models, with both opt-in and opt-out provisions, for use in pilot programs for municipal aggregation, by January 1, 2004.
- Assess each residential account in the Commonwealth with a charge of three cents per month, to generate revenue for the Home Energy Assistance Fund.
- Amend the Restructuring Act to extend the term of the Task Force to at least July 1, 2008.

Members of the Task Force who have an interest in pursuing any of these proposals were asked to contact the Chair of the Consumer Advisory Board. Several of the recommendations generated legislative recommendations that are discussed in Part III of this report.

At the Task Force's January 7, 2003, meeting, the Consumer Advisory Board presented its annual report to the Task Force. The Board's report, without its appendices, is attached as Appendix H.

I. OTHER ACTIVITIES

1. Status of Consumer Education Program

Section 56-592.1 of the Restructuring Act directs the SCC to establish and implement a consumer education program, and to provide periodic updates to the Task Force concerning the program's implementation and operation. The program was established to educate Virginia's consumers about retail consumer choice for both electricity and natural gas. The program was initially scheduled to be implemented over five years at a total estimated cost of $30 million.

The annual report on the Virginia Energy Choice consumer education program is included in Part I of the SCC's August 30 report on the status of competition. Most of the activity over the past year has focused on the first phase of the program, which addresses building awareness of energy choice. As a result of the slow pace of competition's development, the SCC has significantly reduced its spending on paid advertisements.

SCC Division of Information Resources Director Kenneth Schrad reported to the Task Force on the status of the Virginia Energy Choice program. During his presentation, Delegate Parrish questioned Mr. Schrad about the use of consumer choice education program funds for print advertisements and thunder sticks distributed at recent college football games. Concerns regarding the extent to which such expenditures educate consumers about the retail electricity competition were shared. The SCC noted that the purpose of that portion of the education campaign was to raise public awareness of the advent of customer choice. Delegate Parrish's inquiry regarding Virginia Energy Choice's sports sponsorships prompted a discussion of the media objective of the consumer education campaign. Sports event sponsorships were defended as an effective and efficient means of building awareness in the program. In addition, such programs are directed at the target audience of adult homeowners and adding a community-focused element.

Additional information regarding the marketing program was provided at the December 12 meeting. Mr. Schrad cited polling evidence that the education program has had success in raising awareness of electric utility restructuring. Specific objectives of the program's first stage have included directing Virginians to the program's website and toll-free number where they can learn more about retail competition for generation services. A copy of the SCC's summary is attached as Appendix I.

At the January 7, 2003, meeting, Mr. Schrad advised the Task Force that the Governor's proposed budget provides for the transfer of $8.5 million from the special regulatory revenue tax revenues available for the Energy Choice program to the general fund. A copy of the SCC's January 7 update is attached as Appendix J.

2. Aggregation Pilot Programs

Stewart Farrar, representing DVP, advised the Task Force at the January 7, 2003, meeting that the utility has developed three innovative pilot programs for the purpose of jump-starting retail competition through consumer aggregation. The three pilot programs would have an aggregate maximum load of 500 mW. DVP announced that it will apply to the SCC for approval of the pilot programs. A summary of the retail competition pilots is attached as Appendix K. Each of the aggregation programs would have a two-year duration, be developed during 2003, be implemented at the beginning of 2004, and remain in effect through 2005. Pilot program participants would be able to leave the pilot and return to DVP's capped rate service at any time.

The key element of the pilot programs is DVP's agreement to waive one-half of its wires charges for all participating customers. The 50 percent reduction in DVP's wires charge is intended to give competitors significantly greater opportunity to compete profitably with the incumbent utility. Mr. Farrar gave an example of residential customers, for whom DVP's current wires charge is 1.8 cents/kWh and the "price to compare" is about 4 cents/kWh. Therefore, a competitor must offer to sell power for less than 4 cents/kWh in order to sell electricity for less than DVP's capped rate of 5.8 cents/kWh. However, reducing the wires charge by half will effectively increase the "price to compare" to 4.9 cents/kWh, which increases the chances that a competitor will be willing to sell power profitably at a price that is less than DVP's price. This cost is exclusive of DVP's costs of distribution and transmission, which for residential customers are approximately 2.74 cents/kWh.

The municipal aggregation pilot would consist of about 100 MW of load of residential and small business customers. Two municipalities with about 30,000 customers each would participate. One locality would use an "opt-in" model under which customers affirmatively select the municipality as their aggregator, and the other would use an "opt-out" model under which the municipality would be their aggregator unless they affirmatively opted not to participate in the program. Because § 56-589 authorizes localities to only use opt-in aggregation, Mr. Farrar urged support of a portion of a recommendation of the Consumer Advisory Board that would amend the Restructuring Act to allow opt-out aggregation. This pilot program seeks to provide information on the best methods of bringing competition to aggregated groups of residential and small business customers, to simplify comparisons between opt-in and opt-out

aggregation, and to give participating localities experience with the costs and requirements of municipal aggregation.

The competitive default service pilot would consist of about 200 MW of load and involve up to 50,000 residential and small business customers.

The SCC would use its authority under the Restructuring Act to seek competitive bids to supply the electricity to serve these customers with default service. In effect, these volunteers would be receiving default service from a provider other than their incumbent utility.

The commercial and industrial pilot would consist of about 200 MW of load to customers with greater than 500 kW of demand. The pilot could accommodate up to 150 customers. Customers would arrange to buy power from an alternative supplier, as they are allowed to do today. The pilot is intended to measure the extent to which the 50 percent reduction in DVP's wires charge will increase competition.

3. Siting of Electricity Generating Facilities-- Senate Joint Resolution 116

In 2001, the General Assembly, at the Task Force's recommendation, adopted Senate Joint Resolution 467, which directed the Task Force to study the Commonwealth's generation facility siting process. Specific duties include examining procedures applicable to the construction of new electricity generation facilities in the Commonwealth and recommending any amendments to the Commonwealth's administrative and regulatory procedures as may be appropriate to facilitate the approval of construction of sufficient electricity generation capacity to provide a competitive market for electricity in the Commonwealth as soon as practical, without lessening necessary environmental considerations including siting and air quality impacts. The results of the Task Force's study of these issues is included in the 2002 Report of the Task Force's activities.

As noted in last year's report, the Task Force's study of the siting process for electric generating facilities was not completed prior to the start of the 2002 Session. One factor complicating the Task Force's review of the siting process was the SCC's decision, announced in June 2001, to establish new requirements for entities seeking to construct and operate new electric generating facilities. The SCC's order adopting these new requirements was issued on December 14, 2001, at which time the Commission also adopted a new proceeding (Case No. PUE010665) to consider additional rules addressing the cumulative impacts of new electric generating facilities, filing requirements related to market power, and expedited permitting processes for small (less than 50 megawatts) generating facilities. The Task Force received testimony on the ability of operators of generating facilities to acquire air pollution emission credits from facility operators in other states, and thereby to risk exceeding the statewide cap on NOx emissions. The Task Force acknowledged that changes to the SCC's environmental review procedures contemplated by Senate Bill 554 will further complicate its review of the siting process.

The Task Force unanimously endorsed a resolution to continue its study of siting procedures, which was introduced in the 2002 Session as Senate Joint Resolution 116. The

resolution was unanimously approved by the General Assembly. A copy is attached as Appendix L.

The SCC's December 14, 2001, order opening a case dealing with the cumulative impact of new plants on air quality, water quality and on existing utility infrastructure and the new competitive electric generating market called for staff to make recommendations by April 19, 2002. However, on April 4, 2002, the Commission entered an order vacating the date for the staff's report as it related to the cumulative impact on air quality and water resources. The vacating of that part of the order was the result of the enactment of SB 554, which limits the SCC's powers to negate siting-related decisions of other governmental agencies.

By order dated August 21, 2002, the SCC adopted filing requirements for power plant applications filed after September 1, 2002. The order concludes that the enactment of Senate Bill 554 in the 2002 Session of the General Assembly makes it unnecessary to include information addressing cumulative environmental impacts. Accordingly, such provisions are absent from the final rules.

During the June 21 Task Force meeting, the SCC's John Dudley advised the Task Force that the SCC issued an order on June 11, 2002, inviting comment on a draft memorandum of agreement between the Commission and the Department of Environmental Quality regarding the coordination of reviews of environmental impact of electric generating plants and associated facilities. Development of the memorandum of agreement was required by Senate Bill 554. The initial draft of the memorandum generated concerns among several groups of stakeholders.

On August 14, 2002, the Commission entered an order in Case No. PUE-2002-00315 distributing the final version of the memorandum of agreement with the Department of Environmental Quality. The final version of the memorandum was revised from the June draft to more closely follow the provisions of § 10.1-1186.2:1. A copy of the memorandum of agreement is attached as Appendix M.

Senate Joint Resolution 116 raises the issue of the ability of operators of electric generation facilities within the Commonwealth to exceed the statewide cap on nitrous oxide emissions air emissions credits from operators of facilities located in other states. According to materials provided by August Wallmeyer of VEPA, such state-to-state trading is not currently allowed, and Virginia's generators are this not permitted to use allowances from other states. State-to-state trading will not be permitted to occur until 2004 at the earliest, and will be contingent upon the federal Environmental Protection Agency's final approval of Virginia's state implementation plan (SIP). Virginia has submitted its SIP for nitrous oxide control to the EPA. On November 12, 2002, EPA published in the Federal Register its intention to approve Virginia's SIP, with exceptions relating to banking and flow control issues.

A table summarizing the status of power plant construction activity in Virginia as of July 31, 2002, is included in the SCC's August 30, 2002, report on the status of competition at pages 52 and 53.

4. Application of Restructuring Act to Kentucky Utilities

At the November 26, 2002, Task Force meeting, Kentucky Utilities (KU), doing business in Virginia as Old Dominion Power Company, asked the Task Force to endorse a proposal that would suspend the application of most of the Restructuring Act to KU. The exemption would continue until the SCC determines that competition for residential customers exists in KU's service territory in another state. Under the proposal, KU, which serves approximately 29,500 customers in Wise, Lee, Russell, Scott and Dickinson Counties, would be exempt from provisions involving wire charges, stranded costs, default service, competitive metering and billing, and the loss of exclusive service territory until Kentucky enacts electric utility restructuring legislation. The Act's capped rate feature, under which rates are fixed until July 1, 2007, would still apply to KU. After that date, the capped rates would continue until its rates are changed pursuant to a traditional rate case.

KU's service in Virginia is provided through electric lines from Kentucky without connection to any other electric utility in Virginia except Powell Valley Electric Cooperative, which is not connected with any other Virginia electric utility. Nearly 86 percent of KU's Virginia customers are small residential customers whose rates are much lower than comparable rates of the other electric utility companies in Virginia.

KU requested the exemption on grounds that its initial cost to comply with the Act's consolidated billing provisions is $1,500,000, and the recurring annual cost will be $1,200,000. These costs would raise residential customers' bills by between eight and 15 percent. As only about five percent of its revenue is from Virginia customers, expenses of complying with Virginia's Restructuring Act would not benefit 95 percent of its customers.

In addition, KU asserted that electric utility restructuring would not benefit KU's Virginia customers because the utility's rates are so low that it would be virtually impossible for a competitive service provider to offer lower rates. The "price-to-compare" for 1000 kWh per month used by residential customers of DVP, AEP, and Potomac Edison Company is approximately 3.7¢, 3.3¢ and 3.9¢, respectively, compared to 2.9¢ for KU customers. The Restructuring Act's only effect, according the exception's proponents, would be a substantial unnecessary increase in customers' electric bills. Members initially expressed skepticism about exempting any utility from the Restructuring Act. KU was invited to revisit this policy issue when the Task Force meets prior to the 2003 Session. The Task Force's action on this proposal is discussed at Part III C of this report.

5. Recent SCC Activities

Section 56-595 of the Restructuring Act directs the Task Force to monitor the work of the SCC in implementing the Act, receiving such reports as the SCC may be required to make pursuant to the Act. The Task Force received reports on the status of implementation of the Act from the SCC at several of its meetings.

In addition to the activities discussed elsewhere in this report, Commission activities during the 2002-2003 interim include:

- Opening a case to investigate aggregation issues.
- Developing proposed interconnection standards for distributed generation.
- Initiating a process to discern the extent of interest of non-incumbents pursuant in providing elements of default service.
- Establishing a methodology for calculating market prices for purposes of determining incumbents' wires charges.
- Reconvening the Retail Access Rules work group to assist in the development of rules for minimum stay periods.
- Continuing the work of developing rules for competitive metering and competitive billing.
- Preparing comments to the FERC's proposed rules on standard market design.

An overview of SCC staff restructuring activities, presented at the June 21, 2002, meeting, is attached as Appendix N. These and other SCC activities are addressed in Part I of the Commission's August 30 report on the status of competition.

6. Centralized Assessments of Electric Generation Facilities

James P. Downey, an Arlington attorney, told the Task Force on January 7, 2003, that several local governments have doubled or tripled their local property taxes assessed on power plant facilities. He asserted that these increases are an unintended consequence of Senate Bill 1286, which was enacted in 1999. This legislation amended provisions in Chapter 26 of Title 58.1 to require central assessment of electric utility property by the SCC. Power generation property had been assessed at the machinery and tools tax rate. While the legislation authorized localities to charge a lower real property tax rate for these facilities in order to achieve revenue neutrality, Mr. Downey asserted that not all have done so. While he did not advocate any legislative changes at the current time, Mr. Downey alerted the Task Force that he may ask the body to revisit this issue if efforts to "debug" the process are unsuccessful over the coming year.

7. Effect of Local Consumption Tax Rate

Raymond Lee Richards, Commissioner of Revenue for the City of Charlottesville, provided the Task Force with materials supporting his concern that the local consumption tax rate is generating less revenue for localities in certain areas of the state than had been collected under the pre-1999 methodology based on gross receipts. In 2001, the local consumption tax generated 41 percent less tax revenue in Charlottesville than would have been collected under the previous methodology. Mr. Richards has requested the Virginia Municipal League to conduct a survey of other localities to determine whether they are experiencing similar decreases in revenues and whether any such decline is attributable to a flaw in the calculation of the local consumption tax rate. The SCC has indicated the decline in tax revenue is due to basing the local portion of the consumption tax on a statewide average of electric utility revenues and consumption. Using the statewide average results in a shift in relative tax burdens toward the average. As a result, DVP's customers are paying slightly less in local consumption taxes, thereby reducing the revenue for localities in such territories, compared to revenues under the previous method for determining tax collections.

8. State Jurisdiction to Penalize Wholesale Market Misconduct

In the course of the presentation by the SCC staff on December 12, 2003, concerns were raised that power generators may in some circumstances be able to manipulate the market price for their electricity by intentionally withholding generation and capacity. Staff was directed to identify potential barriers to state enforcement of measures aimed at curbing such misconduct by participants in the wholesale electricity market.

The issue of the Commonwealth's jurisdiction to enforce such measures involves complex issues of Commerce Clause and Federal Power Act jurisprudence. In Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927), the Supreme Court held that the Commerce Clause barred state regulation of interstate wholesale sales of electricity due to the burden such regulation would impose on interstate commerce. The Federal Power Act of 1935 places under federal regulation the aspects of electricity service that were held under Attleboro and other cases to be beyond the scope of state jurisdictional authority. Section 201(b)(1) grants FERC jurisdiction over all facilities for transmission or sale of electric energy at wholesale in interstate commerce. Section 201 (c) provides that "electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States."

FERC has been held not to have jurisdiction over facilities used in local distribution, used only for transmission of electric energy in intrastate commerce, or for the transmission of electric energy consumed wholly by the transmitter. Under section 201(d), "The term 'sale of electric energy at wholesale' when used in this subchapter, means a sale of electric energy to any person for resale." Pursuant to the Supreme Court's holding in Federal Power Commission v. Florida Power & Light, 404 U.S. 453 (1972), in every state except Alaska, Hawaii, or Texas, wholesale sales are held to be sales in interstate commerce.

FERC Order 2000, promulgated in 1999, requires all public utilities that own, operate or control interstate electric transmission to take steps to create or join a regional transmission organization or explain why they had not done so. RTEs will have exclusive authority to maintain short-term reliability, including the right to order redispatch of any generator connected to transmission facilities it operates, if necessary for reliability. The order addresses control over the redispatch of generation. RTEs would also have authority to override owner's scheduled outages. If an RTE operates within a region whose reliability standards are controlled by another entity (such as a reliability council), the RTE must report to the Commission if these standards hinder the RTE.

The limits on a state's jurisdiction over wholesale market activities is illustrated by developments in California's calamitous experience with electric utility deregulation. California's Public Utility Commission, in an Order Instituting Investigation, R.98-12-013 (December 8, 1998), claimed that it had the authority to impose sanctions on a utility for a transmission outage. The California independent system operator's federal tariff contained provisions on all aspects of system operations, including investigation and corrective measures related to unplanned outages. These FERC-approved tariff provisions were found to completely

displace the Public Utility Commission 's authority to take actions with respect to these aspects of the system's operation.

Antitrust laws have been identified as an area where a state may argue that it retains jurisdiction over anticompetitive behavior of power suppliers. In Otter Tail Power v. U.S., 410 U.S. 366 (1973), the Supreme Court held, "There is nothing in the legislative history which reveals a purpose to insulate electric power companies from the operation of the antitrust laws. To the contrary, the history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest." 410 U.S. at 373-4.

The filed rate doctrine protects a party from civil claims (including antitrust claims) based on its implementation of tariffed rates (and ancillary tariffed matters) that are directly regulated by federal agencies like FERC. This doctrine was announced in Keogh v. Chicago & Northwestern Railway, 260 U.S. 156 (1922), where the Supreme Court held that once a carrier's rate had been submitted to and approved by the responsible regulatory agency, a private shipper could not recover treble damages on a claim that the rate violated antitrust laws. The Supreme Court reaffirmed the filed rate doctrine in holding that it applies to antitrust claims generally in Square D Co. v. Niagara Frontier Tariff Bureau, 476 U.S. 409 (1986) (antitrust damage claim barred; rates filed with ICC). However, the Court noted that "exemptions from the antitrust laws are strictly construed and strongly disfavored" and reiterated that the filed rate doctrine does not bar criminal or injunctive antitrust actions. 476 U.S. at 421.

The argument has been made that the filed rate doctrine may not apply where rates are not in issue in the case. In Columbia Steel Casting Co. v. Portland General Elec. Co., 111 F.3d 1427 (9th Cir. 1996), the court held that the filed rate doctrine did not apply because the anticompetitive conduct at issue involved the utilities' division of territories through a non-competition agreement, and did not involve the establishment of a rate.

In Duke Energy Trading and Marketing, L.L.C., 267 F.3d 1042 (9th Cir. 2001) the filed rate doctrine was invoked by the Ninth Circuit Court of Appeals to bar California from commandeering contracts to deliver wholesale electric power to utilities within the state during the state's deregulation crisis. However, these proceedings involved the Governor's emergency powers, and did not arise in the context of an antitrust proceeding.

Part III I of this report discusses a proposal to make the intentional withholding of power from the market in order to manipulate prices a violation of the Virginia Antitrust Act.

III. DELIBERATIONS AND RECOMMENDATIONS

At its January 7, 2003, meeting the Task Force considered numerous proposals to amend the Restructuring Act or otherwise further the introduction of competition for electric generation. This section of the report traces the development of each proposal and recounts their disposition during the 2003 Session of the General Assembly.

A. APPLICATIONS TO JOIN REGIONAL TRANSMISSION ENTITIES

In response to concerns that the planned actions of Virginia's electric utilities to join the PJM RTE should be subject to increased SCC scrutiny, Virginia Delegate Parrish sponsored a proposal to delay the Restructuring Act's timetable for RTE action. The proposal was considered by the Task Force at its January 7 meeting. A copy is attached as Appendix O. Major provisions include:

- Eliminating the existing requirement that utilities join or create an RTE by January 1, 2001;
- Amending the terms and conditions under which the SCC may consider utilities' applications to join an RTE by (i) removing the condition that the RTE membership will ensure the successful development of interstate regional transmission entities and (ii) adding a condition that the RTE membership will ensure that consumers' needs for economic and reliable transmission are met;
- Requiring that consideration of whether RTE membership is consistent with meeting the transmission needs of electric generation suppliers that do not own, operate, control or have an entitlement to transmission capacity;
- Providing that the SCC's approval of any transfer of ownership or control of transmission assets must follow notice and a hearing;
- Requiring that any application for SCC approval of a requested transfer of ownership or control of transmission assets shall include 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;
- Authorizing the SCC to require that the transmission system be upgraded prior to approving such a transfer if a proposed transfer does not satisfy a condition for approval of the application; and
- Requiring the SCC's annual report on the status of RTE membership to set forth actions taken by the SCC regarding requests for the approval of any transfer of ownership or control of transmission facilities to an RTE, including a description of the economic effects of such proposed transfers on consumers.

Following Senator Watkins' motion that the proposal be reported, the Task Force agreed to endorse it. Delegate Parrish introduced the proposal as House Bill 2453. The bill was amended in the House Committee on Commerce and Labor to prohibit any transfer of ownership or control of transmission assets prior to July 1, 2004, with the exception that any incumbent electric utility that has filed an application for approval by July 1, 2003, shall have transferred

management and control of its transmission assets to an RTE, following Commission approval, not later than January 1, 2005. Another amendment provides that if the SCC finds that a proposed transfer of transmission assets does not satisfy a condition for approval, the SCC may require, as a condition of approval, that, following the transfer of the transmission system, the transmission system be upgraded or, if appropriate, the constraint be mitigated, provided that any such condition of approval (i) is the least cost solution for retail customers of all electric utilities in the Commonwealth and (ii) ensures full and timely retail rate recovery of all reasonable and not otherwise recovered costs for such required transmission upgrading or constraint mitigation. The SCC would also be required to determine, as a requirement for its approval, that the impact of any transmission congestion costs attributable to existing constraints can be reasonably mitigated by the actions of load serving entities. Finally, at the insistence of Allegheny Power, a second enactment clause was added that exempted from its provisions an incumbent electric utility that, on or before January 1, 2003, had transferred functional control of its transmission facilities to an RTE pursuant to FERC authorization. As rewritten, the bill passed the House of Delegates with one negative vote.

House Bill 2453 was amended in the Senate Committee on Commerce and Labor to:

- Remove the second enactment clause, which exempted incumbent electric utilities that, on or before January 1, 2003, had transferred functional control of transmission facilities to an RTE pursuant to FERC authorization.
- Require incumbent electric utilities to file an application for approval of proposed transfers of ownership or control of transmission assets by July 1, 2003, and to implement such transfer to an RTE by January 1, 2005, subject to Commission approval.
- Remove the provision authorizing the SCC, as a condition on approving an application, to require that the transmission system be upgraded or, if appropriate, that a transmission system constraint be mitigated.

The Senate unanimously approved the amended version of House Bill 2453, and the House unanimously approved the Senate's amendments. The Governor proposed an amendment to the bill that would add an emergency clause.

B. PRESERVATION OF STATE JURISDICTION REGARDING RELIABILITY ISSUES

In response to Bill Stephens' presentation at the December 12 meeting, Senator Watkins asked the staffs of both the Task Force and the SCC to look into the issue of whether anything could be done to ensure that the Commonwealth does not cede monitoring responsibilities to FERC or to a regional transmission organization. While FERC may eventually exert jurisdiction over transmission and other aspects of electric service, it is feared that a state may be giving up its oversight authority prematurely if its utilities join a regional transmission organization that operates a wholesale market.

In compliance with this request, a proposal was prepared and offered for discussion at the January 7, 2003, meeting (Appendix P). The proposal would amend § 56-579 to provide that a transfer of control over transmission assets to an RTE shall not be approved if it would result in

the direct or indirect transfer of jurisdiction over the reliability or price of generation serving current or future load in the Commonwealth from Virginia to the FERC or any other entity, or if the transfer would negatively affect the reliability or pricing of such generation.

Senator Watkins described the proposal as a stop-gap measure to protect ratepayers in Virginia. As it amended the same section of the Restructuring Act that is amended by Delegate Parrish's proposal regarding RTE approvals, he observed that he may add it to that bill during the legislative session rather than introducing it as a separate item of legislation. The Task Force unanimously endorsed the proposal.

During the 2003 Session, this proposal was neither added to Delegate Parrish's House Bill 2453 nor introduced as a separate bill.

C. SUSPENSION OF APPLICATION OF ACT TO KENTUCKY UTILITIES

Delegate Kilgore proposed an amendment to the Restructuring Act that would suspend the Act's application to any investor-owned incumbent electric utility whose portion of total energy sales subject to the jurisdiction of the SCC does not exceed 10 percent. A copy is attached as Appendix Q.

The rationale for the proposal is discussed in Part II, section H 4 of this report, above. An amendment was offered to specify the six counties in which the exempt utility operates. The Task Force unanimously agreed to the amendment, and agreed to endorse the revised proposal on a 5-2 vote.

Delegate Kilgore and Senator Wampler introduced identical versions of the proposal as House Bill 2637 and Senate Bill 876. The bill was amended to incorporate the amendment endorsed at the Task Force's January 7 meeting. As passed, the bill provides that application of the Restructuring Act shall be suspended effective July 1, 2003, for an incumbent electric utility supplying electric service to retail customers on January 1, 2003, whose service territory assigned to it by the Commission is located entirely within Dickinson, Lee, Russell, Scott, and Wise Counties, so long as such utility does not provide retail electric services in any other service territory in any jurisdiction to customers who have the right to receive retail electric energy from another supplier. House Bill 2637 unanimously passed the House of Delegates and the Senate and was signed into law by the Governor as Chapter 719 of the 2003 Acts of Assembly. Following the House of Delegate's passage of House Bill 2637, Senator Wampler allowed his Senate Bill 879 to remain in the Senate without action.

D. PILOT PROGRAMS FOR AGGREGATION

The Consumer Advisory Board unanimously endorsed a recommendation offered by chairman William Lukhard that the appropriate sections of the Virginia Electric Utility Restructuring Act and the Natural Gas Deregulation Act be amended to require the SCC develop models to be used in pilot programs for municipal aggregation. The models, to be available no

later than January 1, 2004, should include both "opt-in" and "opt-out" concepts and any other concepts the SCC may develop. A copy is attached as Appendix R.

Delegate Plum moved that the Task Force endorse the recommendation with the understanding that it may be amended during the legislative process. The Task Force endorsed the proposal with this caveat. Delegate Plum introduced the measure as House Bill 2319. As introduced, the bill requires the SCC to develop models for conducting pilot programs for municipal aggregation, including opt-in, opt-out, and any other model the Commission deems to be in the public interest. The bill also provides that nothing in subsection A of § 56-589 shall prohibit the SCC's development and implementation of pilot programs for opt-in, opt-out or any other type of municipal aggregation. An enactment clause required the SCC to develop models for conducting pilot programs for municipal aggregation of natural gas customers, including opt-in, opt-out, and any other model the SCC deems to be in the public interest. The Commission shall report such models to the Task Force no later than November 1, 2003.

House Bill 2319 was amended in the Hose of Delegates to remove the clause directing the development of models for municipal aggregation of natural gas customers. In the Senate Committee on Commerce and Labor, the portion of the bill directing the SCC to develop models for municipal aggregation programs was rewritten to incorporate the approach requested by DVP at the Task Force's January 27 meeting.

As revised, the proposal authorizes the SCC to 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 the public interest, and the Commission shall report to the Task Force on the status of such pilots by November of each year through 2006. The measure passed both houses of the General Assembly and was signed into law by the Governor as Chapter 795 of the 2003 Acts of Assembly.

E. TERM OF LEGISLATIVE TRANSITION TASK FORCE

The Consumer Advisory Board's recommendations for legislative action, presented to the Task Force on November 19, 2002, included a proposal to extend the term of the Task Force. Board chairman William Lukhard expressed concerns that the existence of the Task Force is scheduled to cease on July 1, 2005, which precedes the end of the Act's phase-in period. Given the consumer concerns, the current lack of a retail competitive market, concerns over a volatile wholesale market, and other issues, the Board recommended that the Task Force should propose legislation to the General Assembly that would extend the life of the Task Force to at least July 1, 2008. This extension would provide legislative oversight over electric utility restructuring and development of a competitive market after capped rates and wires charges are currently scheduled to expire. A copy of the proposal is attached as Appendix S. The Task Force agreed to endorse this recommendation.

Delegate Plum introduced the proposal as House Bill 2318. The measure passed the House of Delegates and the Senate without amendment. Though it was signed into law by the Governor, its provisions extending the term of the Task Force to 2008 are incorporated into § 30-209, which is added by Senate Bill 1315, as discussed in Part N of this section of this report.

F. HOME ENERGY ASSISTANCE FUND ASSESSMENT

The Consumer Advisory Board's third recommendation necessitating legislation sought to generate revenue for the Home Energy Assistance Fund through a Residential Meters/Account Assessment Charge in the amount of three cents per month. The assessment would be incorporated into the existing base customer service charge. The assessment was suggested to the Board by the Association of Energy Conservation Professionals (AECP). AECP spokesperson Billy Weitzenfeld told the Board that if the number of residential accounts is 2,890,609 for 12 months, the charge of $0.36 per account per year would yield $1,040,619 for the Home Energy Assistance Fund each year. The monthly meter/account assessment charge would be collected on a monthly basis by the local distribution company and then deposited into the Treasury of the Commonwealth of Virginia for allocation to the Home Energy Assistance Fund. The Board voted eight to four to recommend this proposal.

Mr. Lukhard presented the proposal, a copy of which is attached as Appendix T, to the Task Force. Members of the Task Force, concerned by possible reductions in federal funding for energy assistance programs and the relatively small amount of the proposed assessment, agreed to endorse the proposal by a vote of 5-1.

Delegate Plum introduced the proposal as House Bill 2317. A motion to report the measure was defeated in the House Committee on Commerce and Labor by a vote of 10-12.

G. WIRES CHARGE EXEMPTION FOR SWITCHING CUSTOMERS

Part III of the SCC's August 30 report on the status of competition lists 20 proposals to facilitate effective competition in the Commonwealth. Proposal 4 includes recommendations submitted by AES NewEnergy and Delmarva Power advocating a staged transition to competition by rate class. The SCC commented that it believes that it may be worthwhile for the Task Force to consider amending the Restructuring Act to provide more incentives and opportunities for large customers to switch suppliers. Specifically, the SCC stated that a proposal the Task Force should consider is:

> If a large commercial or industrial customer is willing to commit to market-based pricing should it ever return to its [local distribution company], that customer should be allowed to switch to a [competitive service provider] without paying a wires charge.

The SCC adds that this proposal would enhance the ability of large energy users to shop for competitive power because the absence of a wires charge would escalate the consumer's potential savings. The benefit to the incumbent utility is that the customer could not return to

capped rate service. The SCC's report recognized that the proposal may have an effect on the utility's ability to recover fully its stranded costs.

Following the presentation of this option at the November 26 meeting, Senator Watkins requested the preparation of draft language that would address this issue and the following recommendation (minimum-stay requirements). At the December 12, 2002, meeting, Arlen Bolstad of the SCC's Office of General Counsel presented proposals for the Task Force's consideration that would implement the options identified in the SCC's report as steps that might encourage the development of competition in the Commonwealth. A copy of the draft proposal, which incorporates several options, is attached as Appendix U. The Task Force did take any further action on this proposal at that meeting. However, in preparing the language for legislation that could be considered by the Task Force, the proposal was rewritten. A copy of the revised proposal is attached as Appendix V.

The revised proposal was offered for Task Force consideration at the January 7, 2003, meeting. DVP spokesperson Stewart Farrar stated that this proposal and the following proposal dealing with minimum stay requirements, both of which the SCC had presented for Task Force's consideration, were not the SCC's proposals, and that the SCC was neither sponsoring nor promoting them. Mr. Farrar noted that this legislation could have a devastating financial effect on incumbent utilities, since they could completely eliminate wires charges, as well as minimum stay requirements, for many customers. He also contended that this proposal would run counter to the Task Force's request that the SCC convene a work group to monitor the recovery of stranded costs.

Senator Watkins acknowledged that he had asked that the language for implementation of the proposal be drafted, and stated his intention to introduce the two proposals with the understanding that he would ask that they be referred by the standing General Assembly committee to the Task Force for further consideration. He observed that the goal is to entice competition to enter the marketplace, and that the current pricing structure, including wires charges, has been identified as a source of consternation. Delegate Parrish asked that these issues be given priority consideration by the Task Force, and that their fiscal impact as well as policy matters be addressed during the next year. Following this discussion, the Task Force did not take a vote on this proposal.

The proposal was introduced in the 2003 Session by Senator Watkins as Senate Bill 891. As introduced, it provides that if a commercial or industrial customer is willing to commit to market-based pricing should it ever return to its incumbent electric utility, that customer can switch to a competitive service provider without paying a wires charge. Customers who make this commitment and thereafter obtain power from suppliers without paying wires charges to their incumbent electric utilities may not be entitled to obtain power from their incumbent electric utility at its capped rates.

The bill was referred by the Senate Committee on Commerce and Labor to the Task Force on February 4, 2003.

H. MINIMUM STAY REQUIREMENTS

The other proposal identified in Part III of its August 30 report on the status of competition as one that the Task Force may wish to consider provides that shopping customers that return to the incumbent utility should have a market-based price as an option of avoiding minimum stay requirements. This proposal applies only to large commercial and industrial customers, because the SCC's rules only apply to customers with a demand of more than 500 kw. The SCC's rules impose a twelve-month minimum stay requirement on customers who had left their local distribution company and then returned to their local distribution company during high demand periods. The proposal is based on recommendations submitted to the SCC by Delmarva Power, and agreed to by Allegheny Power, Pepco Energy Services, Washington Gas Energy Services, and the Virginia Committee for Fair Utility Rates.

The Commission's report states that this proposal "has merit." It would enable large customers that agree to accept this option to shop again immediately upon returning to their local distribution company, rather than waiting twelve months. The Commission observed that the Task Force may wish to consider the effect of the proposal on the right to return to capped rates currently afforded shopping customers under § 56-582 D of the Restructuring Act.

Following the presentation of this proposal at the November 26 meeting, Senator Watkins requested the preparation of draft language that would address this issue and the preceding recommendation (wires charge exemption for switching customers). At the December 12, 2002, meeting, Arlen Bolstad of the SCC's Office of General Counsel presented proposals for the Task Force's consideration that would implement these options. A copy of the draft proposal, which incorporates several options, is attached as Appendix W. The Task Force did not take any further action on this proposal at that meeting.

A revised version of the proposal was presented to the Task Force for its consideration at the January 7, 2003, meeting (see Appendix X). Stewart Farrar, representing DVP, stated that this proposal was neither sponsored nor promoted by the SCC. Mr. Farrar questioned the need for this legislation because the SCC already has the authority under the Restructuring Act to ease or eliminate its current minimum stay rules if they are found to be a barrier to the development of a competitive market.

As with the preceding recommendation, Senator Watkins acknowledged that he had asked that the language for implementation of the proposal be drafted, and stated his intention to introduce it with the understanding that he would ask that it be referred to the Task Force for further consideration. As a result of Senator Watkins' commitment, the Task Force took no vote on this proposal.

The proposal provides that retail customers of electric energy who are subject to minimum stay periods prescribed by the Commission shall be exempt from such minimum stay obligations by agreeing to purchase electric energy at market-based rates from incumbent electric utilities or default providers concurrent with seeking to purchase electric energy from such utilities or providers after a period of obtaining electric energy from another supplier. The market-based rates shall be determined and approved by the Commission using a methodology

that is consistent with the goals of promoting the development of effective competition and economic development within the Commonwealth and ensuring that neither incumbent utilities nor retail customers who do not choose to obtain electric energy from alternate suppliers are adversely affected. However, any customers exempted from any applicable minimum stay periods shall not be entitled to purchase retail electric energy from their incumbent electric utilities thereafter at the capped rates unless such customers agree to satisfy any minimum stay period then applicable while obtaining retail electric energy at capped rates.

The proposal was introduced in the 2003 Session by Senator Watkins as Senate Bill 892. The bill was referred by the Senate Committee on Commerce and Labor to the Task Force on February 4, 2003.

I. PROHIBITING POWER GENERATORS FROM WITHHOLDING GENERATION

In reaction to the SCC staff's concerns that suppliers could engage in market manipulation by withholding generation and capacity in order to drive up the price of electricity, Delegate Woodrum requested the preparation of legislation that would penalize power generators who engage in this form of market manipulation. In recognition of the limits on a state's jurisdiction over activities in the wholesale electricity market that are established by the Commerce Clause, the Federal Power Act, and the filed rate doctrine, a proposal was drafted that provides that an operator of an electric power generation facility that generates electricity for sale to manipulate electricity prices by withholding power that has been committed to satisfy reserve requirements from the relevant market is in violation of the Virginia Antitrust Act. A copy of the proposal is attached as Appendix Y. The proposal was endorsed by the Task Force without objection. The proposal was introduced in the 2003 Session by Delegate Woodrum as House Bill 2046. It was stricken from the docket of the House Commerce and Labor Committee on January 30, 2003, at the request of the patron.

J. CONSOLIDATED BILLING BY COOPERATIVES AND MUNICIPAL UTILITIES

Old Mill Power Company asked the Task Force to endorse a proposal to amend subsection J of § 56-581.1 regarding competitive retail electric billing and metering (Appendix Z). The amendment would eliminate the existing provision that allows municipal electric utilities and utility consumer services cooperatives to prevent competitive energy services providers from billing willing customers directly, rather than having its billing information included in a consolidated bill from a cooperative or municipal utility that provides regulated distribution and other services. Direct invoicing was lauded by Old Mill Power Company president Mich King as enabling suppliers to be responsible for their own invoicing and bill collection and to establish brand identities.

Rob Omberg, speaking on behalf of Virginia's electric cooperatives, spoke against the proposal. He observed that this issue was debated only two years ago, and that cooperatives have not received complaints from customers. Following the testimony, no Task Force member moved to endorse the proposal.

K. STRANDED COSTS WORK GROUP RESOLUTION

As noted in Part II F of this report, the Task Force agreed to request the SCC to convene a work group for the purpose of developing consensus recommendations on issues relating to stranded cost recovery. Several amendments offered by DVP were incorporated into the draft resolution following the December 12, 2002, meeting. The amendments provide for two Task Force members to participate in the meetings of the work group, the reconvening of the Task Force's subcommittee on stranded costs, and the presentation by July 1, 2003, of recommendations regarding definitions of "stranded costs" and "just and reasonable net stranded costs" and 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. By November 1, 2003, the work group is to present its recommendations on the amount of each incumbent electric utility's just and reasonable net stranded costs and the amount that it has received, and is expected to receive, to offset just and reasonable net stranded costs from capped rates and from wires charges.

The revised resolution was presented for Task Force consideration at the January 7, 2003, meeting. At DVP's recommendation, two amendments to the draft resolution were adopted in concept. First, language was added to iterate that the recommendations of the work group are to be consistent with the provisions of the Restructuring Act. Second, amendments to the provision directing the work group to report to the Task Force's subcommittee on stranded costs provide that separate reports on the work group's two major objectives shall be made prior to the submission of the reports to the Task Force that are due by July 1 and November 1, 2003.

The resolution as revised to incorporate changes endorsed at the previous meeting was presented to the Task Force for approval at the January 27 meeting. The Task Force unanimously adopted the resolution. A copy of the resolution is attached as Appendix AA. On March 3, 2003, the SCC entered an order, in Case No. PUE-2003-00062, establishing a proceeding to convene the requested work group.

L. INFRASTRUCTURE DATA COLLECTION RESOLUTION

At the presentation of the SCC's report on the feasibility of collecting data on energy infrastructure and reliability pursuant to Senate Bill 684 (2002), Bill Stephens told the Task Force that it could pursue several options: (i) collect the data and gauge its value at a future time; (ii) wait until the industry stabilizes and then request the data; or (iii) collect some basic data that could provide information as to infrastructure adequacy and forecast load and planned reserve margins until such time as it is determined that either more or less information is necessary.

At the Task Force's January 7, 2003, meeting, the Task Force was presented with a draft of a resolution requesting the SCC , to the extent it is not currently doing so, to collect the data necessary to monitor the dedication of facilities to the provision of electricity service in the Commonwealth. At a minimum, such an effort should review the dedication or allocation of specific generation to the Commonwealth for the five-year period ending December 31, 2002.

Historical reserve margins should be calculated and basic operating indices for the units dedicated to the provision of service should be documented. A copy of the resolution is attached as Appendix BB. The Task Force adopted the resolution without debate. The resolution was brought back before the Task Force for reconsideration at its January 27 meeting, when it was again approved.

M. ENERGY MANAGEMENT WORK GROUP RESOLUTION

The Consumer Advisory Board recommended that the Task Force request the SCC to organize an Energy Management Work Group. The purpose of this work group would be to identify approaches to encourage the emergence of cost-effective energy management options, including real-time pricing, time-of-use pricing, real-time peak signaling and dynamic load response applications. The recommendation envisions that SCC staff will (i) invite energy industry entities to participate, (ii) provide a forum and location for stakeholders to meet periodically, and (iii) provide an electronic means of posting and exchanging information. Specific objectives include:

- Investigating short-term and long-term approaches to encourage voluntary and cost-effective energy management options to consumers within the Commonwealth;
- Monitoring and evaluating the results of similar investigations and pilot programs occurring in other states for potential applicability to Virginia;
- Identifying obstacles to the emergence of cost-effective energy management in Virginia; and
- Identifying tools and information currently available from local distribution companies to assist such investigation.

At the Consumer Advisory Board's presentation of its annual report to the Task Force on January 7, 2003, board chairman William Lukhard asked the Task Force to act on its recommendation that the Task Force request the SCC to organize an energy management work group. The Task Force deferred action to the January 27 meeting, at which time Mr. Lukhard offered the resolution for the Task Force's consideration. A copy is attached as Appendix CC.

After initially concurring with Mr. Lukhard's request that it adopt the resolution, the Task Force reconsidered its action. In response to concerns that the need to study other issues during 2003 are of greater priority than this issue, the Task Force agreed that action on this recommendation can be deferred until 2004. Accordingly, the recommendation was tabled.

N. AUTHORIZATION FOR STRANDED COST ACTIVITIES

The Task Force's decision to reconvene the stranded costs task force and to have two Task Force members monitor the activities of the SCC's stranded costs work group prompted consideration of issues of compensation. Staff advised the Task Force at the January 7 meeting that in order to ensure that Task Force members attending these meetings are entitled to receive per diems and expenses, § 56-595 of the Restructuring Act should be amended to expressly authorize such activities.

Staff presented language that authorizes the Task Force to establish one or more subcommittees of its membership, to meet at the direction of the chairman of the Task Force, for any purpose within the scope of the duties of the Task Force, including but not limited to assisting in the monitoring stranded costs. The measure further authorizes the chairman of the Task Force to designate one or more members of the Task Force to observe or participate in the discussions of any work group convened in furtherance of the Task Force's duties under the Restructuring Act, and provides that members of the Task Force shall receive such compensation and shall be reimbursed for reasonable and necessary expenses incurred in the performance of their duties. A copy of the proposal is attached as Appendix DD. The Task Force concurred that the amendment to § 56-595 would be appropriate.

Rather than being introduced as a separate item of legislation, this recommendation was offered with the understanding that its provisions were being incorporated into legislation being prepared at the direction of the Joint Rules Committees. The bill's primary purpose is to conform certain collegial bodies on which legislative members serve in order to meet the legislative guidelines adopted by the Joint Rules Committees. The legislation was introduced as Senate Bill 1315. As enacted, Senate Bill 1315 renames the Task Force as the Commission on Electric Utility Restructuring, repeals § 56-595, and relocates its provisions to new Chapter 31 (§ 30-201 et seq.) of Title 30. Section 30-205 authorizes the body to establish one or more subcommittees of its membership, to meet at the direction of the chairman, for any purpose within the scope of its prescribed duties.

IV. CONCLUSION

The Legislative Transition Task Force recognizes that the successful implementation of the Restructuring Act is of vital importance to all consumers of electricity in Virginia. Recent developments across the nation, including the potential effect of the FERC's proposed rules on standard market design, the threats to continued state jurisdiction over issues related to rates and reliability, the lack of unqualified success in implementing retail competition in other states that have attempted to deregulate the generation component of electric service, and credit crunch that has affected the development of new generating facilities and the financial well-being of several electric utilities, all underscore the need to proceed with caution and diligence. Nonetheless, the members of the Task Force believe that confident that the successful implementation of the Restructuring Act offers the prospect for greater efficiencies that will provide tangible benefits to all residents of the Commonwealth.

In its fourth year, the Task Force has continued to attempt to address issues that could not have been foreseen when the Restructuring Act was drafted during the late 1990s. In addition, the Task Force stands committed to acting positively on issues, such as the recovery of stranded costs, that the Restructuring Act did not address in sufficient detail. The ability to refine the provisions of the Restructuring Act as competition is phased in throughout Virginia remains an important safeguard for Virginia's consumers. The Task Force remains committed to laboring to restructure the electric utility industry in a manner that allows all Virginia consumers to realize the greater efficiencies inherent in a market-based system without subjecting them to unnecessary risks that may threaten the Commonwealth's long-standing status as a state with reliable and low-cost electricity.

The Task Force recognizes that the next year will be vital in the implementation of retail competition for electricity. Commencing July 1, 2003, the Legislative Transition Task Force will be renamed the Commission on Electric Utility Restructuring as provided in new § 30-201 of the Virginia Code. Its membership and duties will be unchanged. Work will continue on promulgation of the FERC's standard market design rules, and the results of the efforts, whether at the FERC, in Congress, or in the courts, will have a major effect on the legal landscape applicable to the provision of electric service. The Task Force recognizes that the debate over the FERC's SMD rules and the proposals of Virginia's major investor-owned electric utilities to join the PJM RTE, which currently utilizes many of features in the proposed SMD rules, are intertwined.

The ability to successfully implement the Restructuring Act requires resolving a troubling paradox: While a competitive wholesale market for electricity is a prerequisite for successful retail competition in Virginia, there are aspects of the FERC's proposed rules market design rules that may result in higher costs for electricity while and the transfer of jurisdiction over reliability from the Commonwealth's regulators to regional bodies that report to the FERC. In other words, the Task Force recognizes that wholesale markets offer both the promise of nondiscriminatory access to transmission assets by competing power generators and the threat that Virginia will lose some authority to ensure that its consumers are adequately protected. The Task Force's efforts over the next year will attempt to address this dilemma.

The members of the Task Force appreciate the diligent efforts of the members of the Consumer Advisory Board in as they continue to address issues of low-income energy assistance, renewable energy, and energy efficiency. In addition, the Task Force wishes to express their appreciation to all persons who have provided testimony, either in person or in writing, attempted to educate its members on the complex issues presented to us.

Respectfully submitted,

Senator Thomas K. Norment, Jr., Chairman
Delegate Terry G. Kilgore
Delegate Brian J. Moran
Delegate Harry J. Parrish
Delegate Kenneth R. Plum
Senator Richard L. Saslaw
Senator Kenneth W. Stolle
Delegate Robert Tata
Senator John Watkins

Delegate Clifton A. Woodrum, Vice Chairman of the Task Force, approves of the report generally, with reservations that are set forth in his attached concurring statement.

Concurring statement of Clifton A. Woodrum

I concur generally in the Report of the Legislative Transition Task Force in spite of my continuing concerns regarding the advisability of electric utility deregulation and its pace in Virginia.

In this report, I wish to indicate that while I agree with the intent of House Bill 2453 to effectively delay the transfer of transmission control to a regional transmission entity by Virginia's incumbent electrical utilities, I would have gone further. The underlying purpose of the bill was to avoid the assertion of jurisdiction over the transmission facilities by FERC and the imposition of the FERC's Standard Market Design which could cause serious pricing and availability problems for Virginia's consumers.

Unfortunately, HB 2453 may not accomplish its purpose. Numerous sources, including the State Corporation Commission, have warned that Virginia cannot avoid FERC regulation simply by delaying participation in a RTE. The unbundling (or functional separation) of retail electric transmission service is the critical factor in determining whether FERC has jurisdiction. This has already been accomplished in Virginia (in spite of my objection and previous

effort to delay the unbundling). A better course would have been to require the "rebundling" of functions by Virginia's electric utilities.

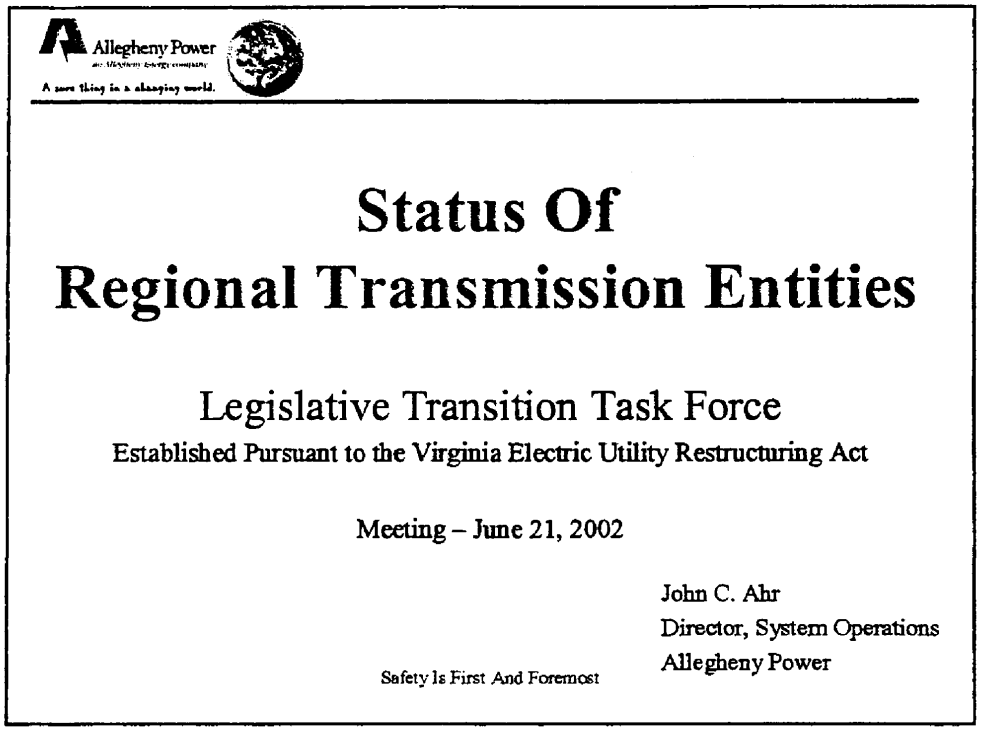
In addition, I note that in an effort to revise the tax imposed on electric utilities, the 1999 General Assembly enacted measures designed to restructure the scheme of taxation of those entities in "a revenue neutral manner." Unfortunately, "the best laid plans went astray"...again. The corporate income tax imposed on Virginia electric suppliers was to have generated $21 million in corporate income taxes. However, the tax generated only $3.8 million, a discrepancy that cannot be laid entirely to a weakened economy. Additional discrepancies are also present in the apportionment within classes of the "consumption tax" with the smaller consumers (less than 2500kWh per month--mostly residential and small business) paying 62.9 percent of the total versus a target of 54.5 percent.

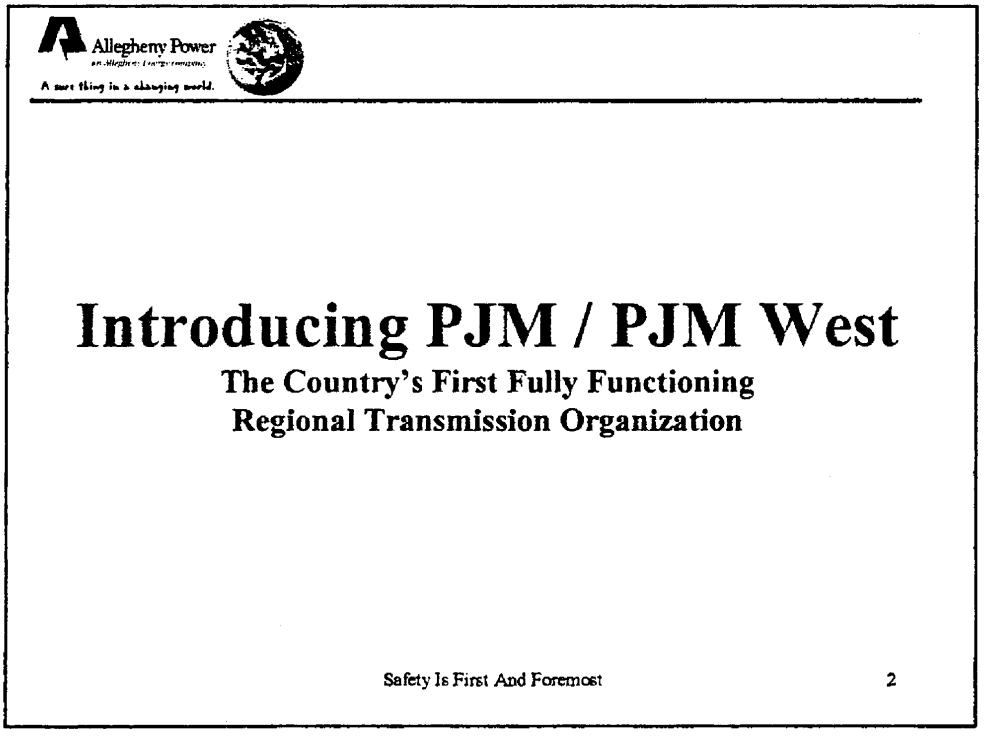
This does not criticize the hard work of the members of the LTTF but it does emphasize the perils of venturing into the unknown.

Once again, I hope that I am wrong.

Respectfully submitted,

Clifton A. Woodrum


Allegheny Power
A new thing in a changing world.
Status Of
Regional Transmission Entities
Legislative Transition Task Force
Established Pursuant to the Virginia Electric Utility Restructuring Act
Meeting – June 21, 2002
John C. Ahr
Director, System Operations
Allegheny Power
Safety Is First And Foremost


Allegheny Power
A new thing in a changing world.
Introducing PJM / PJM West
The Country's First Fully Functioning
Regional Transmission Organization
Safety Is First And Foremost
2

Allegheny Power

A new thing in a changing world.

What Is An RTO?

- An RTO Is
  - A Regional Transmission Organization (RTO) is an entity that is independent from all generation and power marketing interests and has responsibility for grid operations, short-term reliability, and transmission service within a region.

RTO Characteristics

- Independence from market participants
- Appropriate scope and regional configuration
- Possession of operational authority
- Exclusive authority to maintain short-term reliability

RTO Functions

- Administer tariff
- Manage congestion on the transmission system
- Develop and implement procedures to address parallel path flow
- Supply ancillary services
- Operate OASIS
- Monitor market
- Plan and coordinate transmission additions and upgrades
- Coordinate inter-regionally with other RTOs

Allegheny Power

A new thing in a changing world.

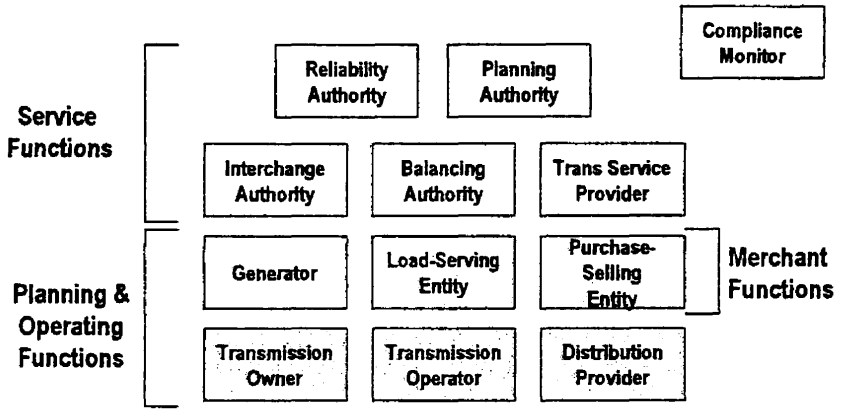
Allegheny and PJM West

- April 1, 2002
  - Allegheny turned functional control of our transmission system over to PJM.
- What Does That Mean?

Allegheny Power

A new thing in a changing world.

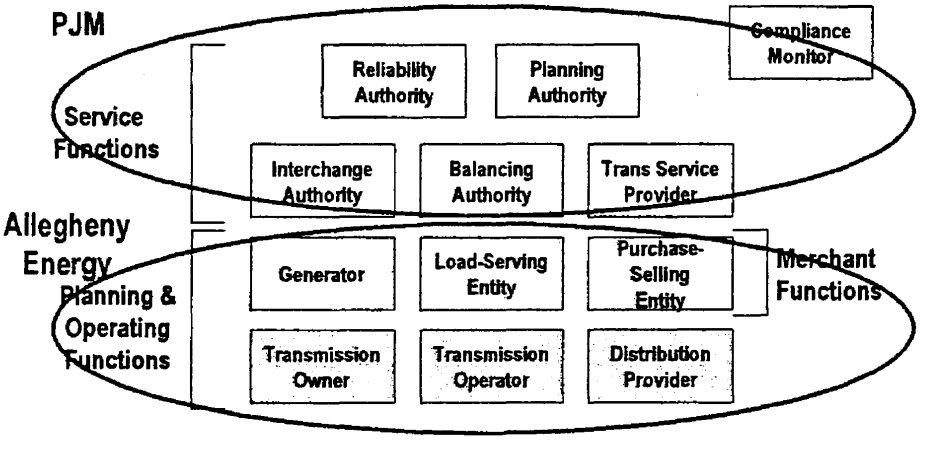
NERC's Functional Model



Allegheny Power

A new thing in a changing world.

NERC's Functional Model

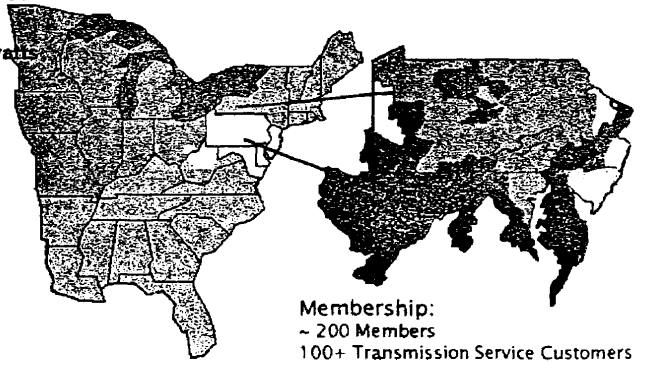


Allegheny Power

A new thing in a changing world.

PJM / PJM West Today

- Generating Units
  - –614 generation sources
- Generating Capacity
  - –Over 67,000 megawatts
- Peak Load
  - –62,445 megawatts
- Annual Energy
  - –298,011 gigawatts
- Transmission Lines
  - –13,100 miles
- Customers
  - –11,000,000
- Population Served
  - –25,100,000



Membership:
~ 200 Members
100+ Transmission Service Customers

Allegheny Power

A new thing in a changing world.

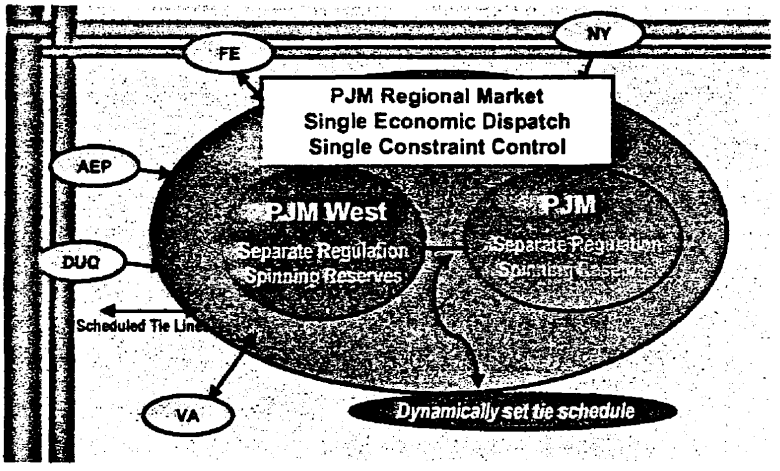
The Benefits

- Larger regional energy market
  - Better unit, fuel, weather diversity
  - Expanded assistance in emergency situations
  - Internalized loop flows across a larger region
- Seams issues eliminated
  - Common tariff, market, business practices, tools
- Greater resources to preserve short- and long- term reliability
  - Promotes efficiency

Allegheny Power

A new thing in a changing world.

PJM Regional Market



Allegheny Power

A new thing in a changing world.

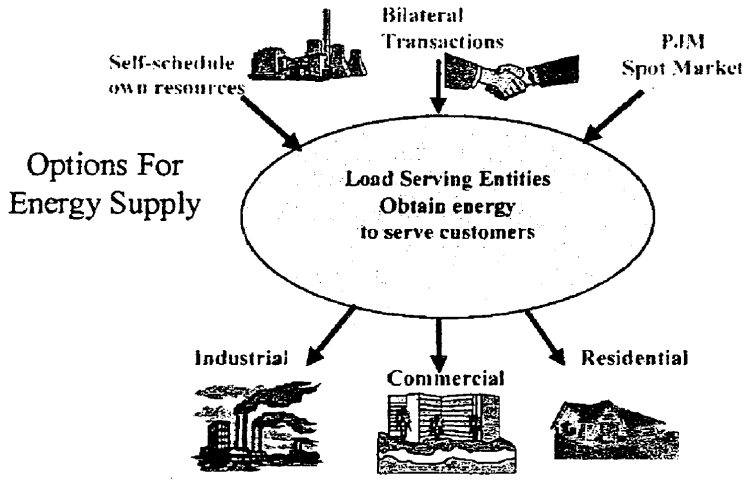
PJM Regional Market Model

- Application of existing rules and market constructs
  - LMPs are calculated for the combined area
  - Units dispatched in merit order
  - Transmission constraints operated based on entire region
- Resources scheduled and operated as required
  - Separate reserve requirements by control area
  - Separate regulation markets
- Transmission outages coordinated for entire region

Allegheny Power

A new thing in a changing world.

Energy Market



Allegheny Power

A new thing in a changing world.

Operations Model

- Two Control Areas
- PJM: Control Center in Valley Forge
  - Schedules resources to meet load plus reserves for entire region
  - Tracks instantaneous interchange
  - Ensures security of PJM transmission system
  - Maintains system control in PJM control area
- PJM West: Control Center in Greensburg
  - Ensures security of PJM West transmission system
  - Maintains system control on PJM West control area

Allegheny Power

A new thing in a changing world.

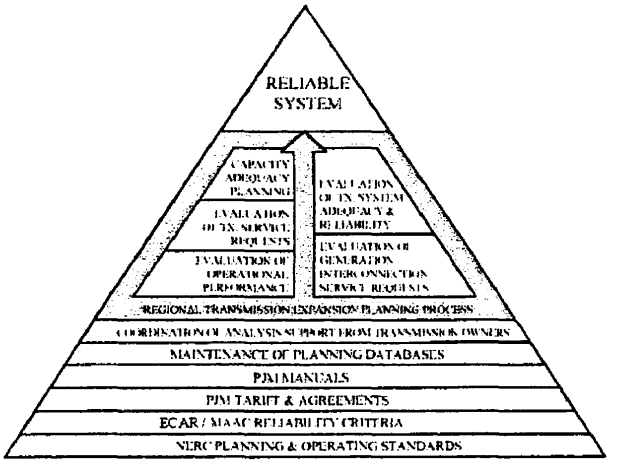
Regional Planning Process

- Allows for open process with input from all interested parties.
- Coordinates expansion plans across multiple transmission owner systems.
- Coordinates expansion plan based on all needs identified through the regional planning process.
- Identifies the most effective and efficient expansion plan for the region.

Allegheny Power

A new thing in a changing world.

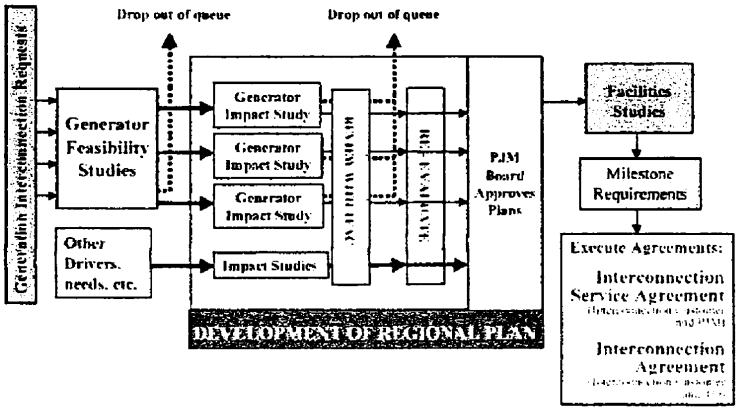
Regional Planning Process



Allegheny Power

A new thing in a changing world.

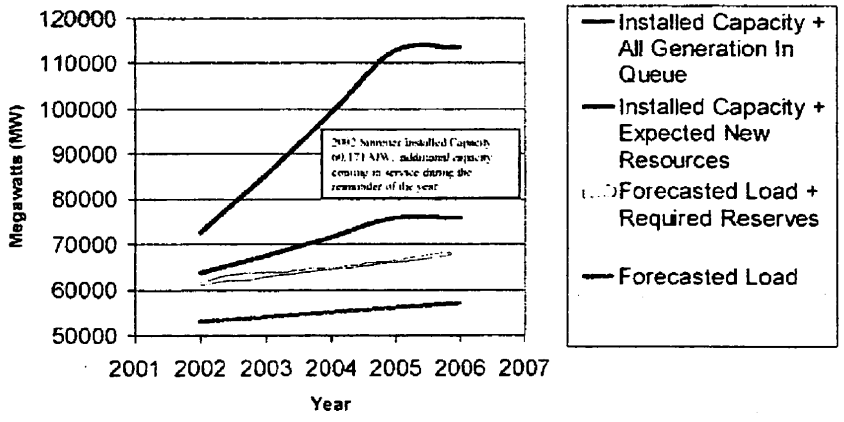
Generation Interconnection Process



Allegheny Power

A new thing in a changing world.

Planned New Generation In PJM



Allegheny Power

A new thing in a changing world.

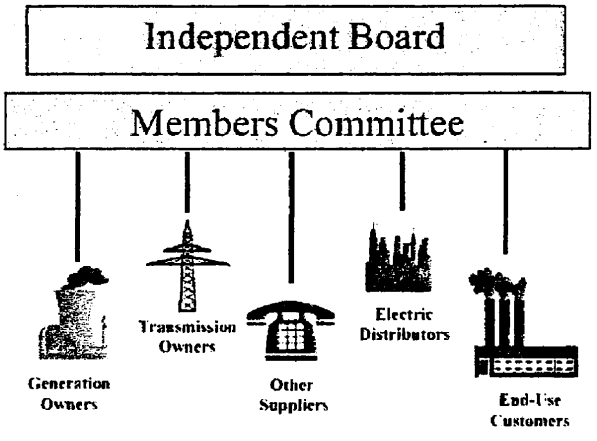
PJM's Board Approval

- First plan approved by PJM Board August, 2000
  - Currently includes $300 million in transmission infrastructure improvements.
  - Accommodates 39 generation projects (14,000 MW).
  - Plan is very fluid due to changes in generation projects.
- Second plan approved by PJM Board June 2001
  - Includes an additional $430 million in transmission infrastructure improvements.
  - Accommodates 43 additional generation projects (12,600 MW).

Allegheny Power

A new thing in a changing world.

PJM Governance



Allegheny Power

A sure thing in a changing world.

Market Monitoring Unit

- An independent internal entity responsible for keeping PJM's markets competitive.
- Responsible for
  - Monitoring the compliance of members with PJM's market rules
  - Monitoring PJM's policies to ensure those rules remain consistent with the operation of a competitive market.
- 2001 State of the Market Report

Allegheny Power

A sure thing in a changing world.

Questions...

RTE/RTO UPDATE

SCC Staff

FERC Related RTE/RTO Developments

- New FERC leadership- Hébert out, Woods & Brownell in
- FERC much more aggressive
- Initiates mediation efforts to form larger RTOs including effort to merge PJM, ISO-New England, and NYISO into a Northeast RTO
- Reaches out to state commissions through regional telecommunication workshops and questionnaires

FERC Related RTE/RTO Developments (continued)

- Rejects the Alliance RTO and directs Alliance Companies to pursue membership in other RTOs
- Initiates effort to adopt a Single Market Design (SMD) for RTOs
- Begins effort to assess the Costs and Benefits of RTO formation

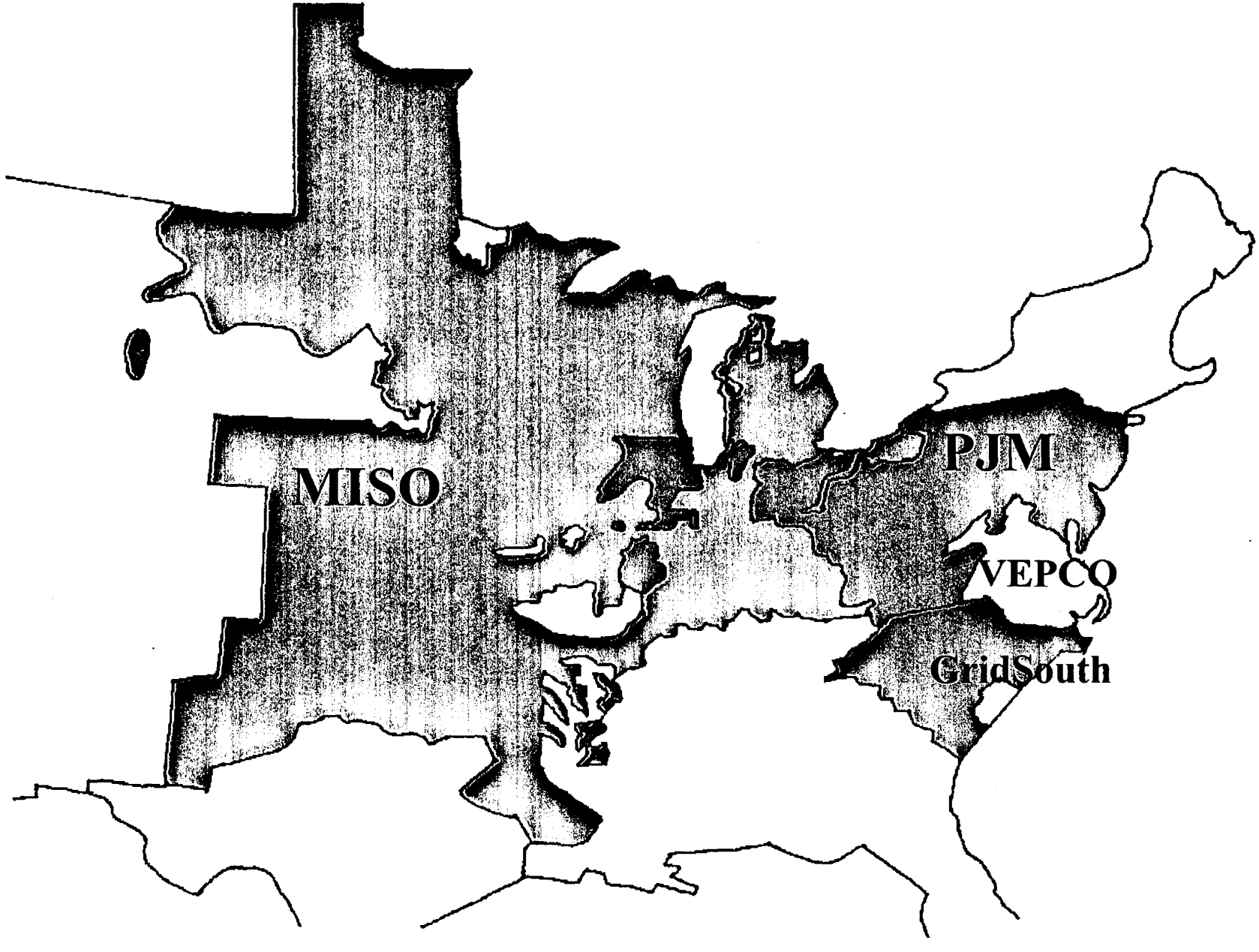
FERC Related RTE/RTO Developments (continued)

- The FERC rejected a request filed by certain Alliance Companies to direct MISO to accept Alliance RTO membership under specific terms and directed Alliance Companies to make compliance filings indicating their selection of an RTO by May 29, 2002 (AEP selected PJM. Dominion Virginia Power indicated that it had not selected an RTO and that it was soliciting input from its stakeholders.)

FERC Related RTE/RTO Developments (continued)

- Last week, FERC expressed concern regarding selections made by certain Alliance Companies and "invited" decision makers from each company to attend its next public meeting on June 26 to explain their RTO selections. Chairman Woods seems to be questioning the "voluntary" approach and threatening a more mandatory approach

RTOs in Transition



Other RTE/RTO Developments

- A number of Southeast state commissions filed comments regarding the FERC's cost benefit analysis and raised questions regarding whether the cost of RTO formation in the Southeast will outweigh the benefits. Generally, states in the Southeast are less than enthusiastic about RTO development. This could impact whether a southern RTO would be consistent with the timetable set forth in the Restructuring Act.

Other RTE/RTO Developments (continued)

- On June 18, 2002, Duke Energy, CP&L Energy and South Carolina Electric & Gas (SCANA), the sponsors of GridSouth announced that they will delay filing applications with their state commissions and will suspend the GridSouth Implementation project. They note that the postponement will provide time to review the effects of regulatory initiatives that are beginning now and due for completion later this year. The postponement will also allow additional time for the sponsors to receive and consider input from stakeholders and regulators.

SCC Participation in FERC Proceedings

- Pursuant to §56-579 C, the Commission has participated extensively in a number of FERC proceedings (A list of the specific proceedings is attached to your copy of this presentation)
- The Commission's participation in these proceedings has sought to assure that the essential elements of RTOs are in place and that RTO development will further the development of competition in the Commonwealth

SCC Participation in FERC Proceedings (continued)

- The Commission responded to the FERC's RTO questionnaires for the Midwest, Northeast, and Southeast regions. The Commission also participated in some of the regional RTO workshops and filed comments on the FERC RTO Cost/Benefit study
- In the Standard Market Design proceeding, the Commission noted that it supports the concept of a standard market design and believes that such an approach is needed to assure that generation markets are efficient.

Other Commission RTE/RTO Activity

- The Commission Staff participated in Dominion Virginia Power's "RTO Summit" that was held last week.
- During the Summit we distributed a document "RTO Requirements" that seeks to identify needed features of an RTO consistent with the Restructuring Act, the Commission's Rules governing RTO participation and other practical considerations. (A copy of that document is also attached to your copy of this presentation).

Other Commission RTE/RTO Activity (continued)

Briefly, the Commission Staff noted that RTO practices and policies should:

-promote reliability and appropriate pricing for transmission service

-be consistent with FERC requirements

-fairly compensate the transmission system owner

-generally promote the public interest

-assure that the RTO is managed independently of market interests

Other Commission RTE/RTO Activity (continued)

- provide for proper transmission planning and facilitate construction of needed facilities

-provide for appropriate interconnection of new generating facilities

-provide for efficiently priced transmission access to competing generating resources over as broad a region as possible

-provide for effective relief of transmission congestion

Other Commission RTE/RTO Activity (continued)

-provide for effective market monitoring

Finally, we (the Commission Staff) noted that it would be ideal if Virginia utilities were participating in operational RTOs at least one to two years prior to the end of the capped rate period.

Status of RTE Proceeding Before the Commission

- FERC rulings and ongoing FERC activity have added uncertainty to proceedings before the Commission and have caused delays in procedural schedules and in some instances suspension of pending proceedings.
- The procedural schedule for Old Dominion Power Company's request to join the MISO has been reestablished after being delayed as a result of efforts to merge MISO and the Alliance RTO. Staff's report in this matter is due July 24, 2002. MISO has received FERC approval as an RTO.

Status of RTE Proceeding Before the Commission (continued)

- The procedural schedules for Delmarva Power's proposal to join PJM and Potomac Edison's proposal to join PJM West have been reestablished after being delayed due to uncertainties associated with the Northeast RTO mediation. Staff reports in these proceedings are due on July 12, 2002. This proceeding could potentially be impacted by recent announcements that several of the "Alliance Companies" now intend to join the PJM system

Status of RTE Proceeding Before the Commission (continued)

- The schedules for AEP-Va and Dominion Va. Power's RTO proceedings have been suspended as a result of the FERC's rejection of the Alliance RTO and other uncertainties. AEP-Va has entered into a memorandum of agreement to join PJM West. Dominion Va. Power has not yet selected an RTO. Neither of these companies have updated their applications.

Virginia Commission Participation in FERC Proceedings

Docket No. EL02-65-000- Alliance Companies, et al and National Grid USA

Docket No. RM01-12-000- Electricity Market Design and Structure

Docket No. RT01-98-000- PJM Interconnection, L.L.C. and Allegheny Power

Docket No. ER02-485-000- Midwest Independent Transmission System Operator, Inc.

Docket No. RT01-99-000, -001 Northeast RTO Mediation

Docket No. RT01-2-001; PJM

Docket Nos. RT01-67-000, RT01-67-001, RT01-67-002, RT01-74-003, RT01-74-004, RT01-74-005, RT01-75-000, RT01-75-001, RT01-77-002, and RT01-100-000- Southeast RTO Mediation

Docket Nos. RT01-88-000, -001, -002, -003, -004, -005, -006, -007, -008, -009, 010, -011, -012; ER99-3144-000, -001, -002, -003, -004, -005, -006, -007, -008, -009, -010, -011, -012, -013, -014; EC99-80-000, -001, -002, -003, -004, -005, -006, -007, -008, -009, -010, -011, -012, -013, -014, Alliance Companies

ER01-2995-000; AEP

ER01-2993-000; Virginia Electric and Power Company

ER01-3000-000; RT01-101-000; EC01-146-000; ER00-3295-000, -001, -002; EC01-137-000; EL01-116-000; RT01-87-000, -001, -002, ER01-3142-000, -001, -002, 003, -004, ER02-108, ER02-106-000; Midwest Independent Transmission System Operator, Inc.

EL01-80-000; National Grid USA

RTO Requirements

Introduction

The Staff of the Virginia State Corporation Commission prepared this document in preparation for Dominion Virginia Power's (DVP) "RTO Summit" to be held on June 13, 2002. The purpose of this document is to provide a quick reference to the legislative, regulatory, and practical considerations that need to be addressed by DVP in selecting an RTO.

Legislative Requirements

Virginia Code § 56-577 provides that "[O]n or before January 1, 2001, each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity shall join or establish a regional transmission entity, which entity may be an independent system operator, to which such utility shall transfer the management and control of its transmission system, subject to the provisions of § 56-579."

Section 56-579 reiterates the requirements of § 56-577, and also requires that RTO participation be subject to terms and conditions that will:

a. Promote:(1) practices for the reliable planning, operating, maintaining, and upgrading of the transmission systems and any necessary additions thereto; and (2) policies for the pricing and access for service over such systems, which are safe, reliable, efficient, not unduly discriminatory and consistent with the orderly development of competition in the Commonwealth;

b. Be consistent with lawful requirements of the Federal Energy Regulatory Commission;

c. Be effectuated on terms that fairly compensate the transferor;

d. Generally promote the public interest, and are consistent with (i) ensuring the successful development of interstate regional transmission entities and (ii) meeting the transmission needs of electric generation suppliers both within and without this Commonwealth.

Dominion Virginia Power, and Virginia's other incumbents must also bear in mind the provisions of § 56-578—effectively a companion statute to § 56-579 that authorizes the Commission to take certain, prescribed actions if it determines that increases in the capacity of the transmission systems in the Commonwealth, or modifications in how such systems are planned, operated, maintained, used, financed or priced, will promote the efficient development of competition in the sale of electric energy, to the extent that such action is not preempted by federal law. Upon making any such determinations, the Commission may require one or more persons having any

ownership or control of, or responsibility to operate, all or part of such transmission systems to:

1. Expand the capacity of transmission systems;

2. File applications and tariffs with the Federal Energy Regulatory Commission (FERC) which (i) make transmission systems capacity available to retail sellers or buyers of electric energy under terms and conditions described by the Commission and (ii) require owners of generation capacity located in the Commonwealth to bear an appropriate share of the cost of transmission facilities, to the extent such cost is attributable to such generation capacity;

3. Enter into a contract with, or provide information to, a regional transmission entity; or

4. Take such other actions as the Commission determines to be necessary to carry out the purposes of this chapter.

Virginia's transmission-owning incumbents must also be mindful of § 56-596 of the Restructuring Act, as well. That section (added by the 2001 Session of the General Assembly) requires in subsection A thereof, that the Commission shall take into consideration, among other things, the goals of advancing competition and economic development in the Commonwealth in all relevant proceedings conducted pursuant to the restructuring Act. Consequently, DVP's RTO participation must be consistent with the goals of advancing competition and promoting economic development.

Regulatory Requirements

In addition to setting forth specific requirements for RTO participation, § 56-579 directed the Commission to "adopt rules and regulations, with appropriate public input, establishing elements of regional transmission entity structures essential to the public interest, which elements shall be applied by the Commission in determining whether to authorize transfer of ownership or control from an incumbent electric utility to a regional transmission entity." The Commission adopted such rules in Case No. PUE990349. In that case, the Commission established requirements in the following five essential categories. These requirements must be satisfied before any such transfer will be approved, and fall into the following categories: (i) reliability practices, (ii) pricing and access policies, (iii) independent governance, (iv) consistency with FERC policy, and (v) fair compensation to the transferor.

With respect to reliability practices, the Commission's rules require that the RTO's policy and practices, at a minimum:

1. Maintain short-term system reliability on an ongoing basis;
2. Identify and facilitate the addition of system enhancements needed to maintain reliability over the long term to promote efficient use of the grid, and to

promote the efficient development of competition in the sale of electric energy;

3. Provide assurance that needed transmission facilities are constructed in a timely fashion, including facilities for the interconnection of generating facilities, subject to required regulatory approvals;
4. Provide assurance that connected generation facilities will provide ancillary services necessary for reliable service as a condition of transmission service from the RTE;
5. Serve as an information resource to reliability councils or committees, potential market entrants, consumers, the FERC, and state regulatory commissions;
6. Promote the construction of properly located generation facilities when such facilities represent optimal solutions for maintaining reliability and enhancing competitive markets; and
7. Provide for appropriate interconnection of new or expanded generating facilities, including the timely performance of necessary interconnection or facilities studies in cooperation with utilities.

With respect to interconnection and pricing, the Commission's rules note that "RTEs shall promote policies and practices for the interconnection of generating facilities and for the pricing and access for transmission service that are safe, reliable, efficient, not unduly discriminatory, and consistent with the orderly development of competition in the Commonwealth, as required in § 56-579 of the Code of Virginia." Accordingly, the Commission required that interconnection, pricing, and access policies:

1. Provide for efficiently priced transmission access to competing generating resources over as broad a region as possible;
2. Use transmission rates that do not discourage economic transactions, and do not encourage uneconomic transactions;
3. Be adaptable for purchasers of electricity at wholesale or at retail;
4. Provide for the efficient relief of transmission congestion through the redispatch, by direct orders or by coordination with customers and generators, of competitively priced generation on an economically efficient basis;
5. Provide for the efficient pricing of transmission transactions between different regional transmission organizations;
6. Ensure that (i) transmission-related decisions, including interconnection, pricing, access, and planning are made, and (ii) operational procedures are developed, openly with appropriate stakeholder input, and will not harm the development of competitive markets;
7. Provide for effective market monitoring, including serving as a resource to assist the FERC and state regulatory commissions in the identification of existing market power and resolution of market power abuses;
8. Promote an environment that facilitates the development of an efficient generation market; and
9. Promote the construction of transmission facilities to enhance competitive markets within the boundaries of the RTE.

With respect to independent governance, the Commission's rules require that RTOs:

1. Be governed independent of competitive interests;
2. Allow their decision-makers full discretion and appropriate incentives to achieve all the policies of this chapter; and
3. Provide for advisory boards with equitable stakeholder representation.

With respect to consistency with FERC policy and fair compensation to transferor, the Commission's rules basically restate the comparable provisions of § 56-579.

Practical Considerations

The Restructuring Act provides for a transition period for the development of electric competition in Virginia that will end on July 1, 2007, or sooner, if effectively competitive markets develop in the service territories of incumbents petitioning to end capped rates prior to that date. During this transition period, ratepayers are provided rate stability through rate caps, and incumbent utilities are afforded an opportunity to recover stranded costs through these same capped rates (for nonshopping customers), and the collection of wires charges from shopping customers who choose alternate generation suppliers during the transition period. The development of RTOs is a priority element in this restructuring process and in the development of effective competition in Virginia. While RTOs cannot, in and of themselves, deliver a competitive wholesale market, they can make a significant contribution to ensuring the efficient, and potentially cost-effective delivery of wholesale power.

Given this importance and the numerous complex issues that must be addressed in developing an RTO, DVP should move with dispatch to select an RTO and to obtain all necessary state and federal regulatory approvals. In the Commission's Staff's view, incumbent membership in operational RTOs (that satisfy the requirements of Virginia statutes and regulations outlined above) at least one to two years in advance of the end of Virginia's transition period to retail choice would be ideal. This would help CSPs, incumbent utilities, and other stakeholders gain familiarity with individual RTO policies and requirements. It would also provide a helpful "shakedown" period for refining these RTOs' policies and practices. However, the FERC is currently, undertaking a comprehensive reexamination of RTOs generally, and such complex RTO issues as standard market design and interconnection, specifically. We recognize that the FERC's reexamination could impact the time required for RTO development.

Finally, efforts by the FERC and others to assess the costs and benefits of various RTO configurations seek to identify what will best promote the public interest. Such reviews will help to ensure that Virginians have access to optimal generation markets from both cost and reliability perspectives, while maintaining reasonably priced and reliable transmission service.

FERC "Big Ticket" List

Revised 6-20-02

ID	Complete	Tasks & Milestones	Start	Finish
1		STANDARD MARKET DESIGN FOR ELEC WHOLESALE MKTS (RM01-12)		
2	X	**Comments Due on SMD Options Paper**		May 2002
3		**Informal Communications/Outreach on SMD Tariff**	May 2002	June 2002
4		**Conference on SMD Data and Software Needs**		July 18, 2002
5		**Issue NOPR on Proposed SMD Tariff**		July 2002
6		**Comments Due on SMD Tariff NOPR**		August 2002
7		**Reply Comments Due on SMD Tariff NOPR**		September 2002
8		**Assess Environmental Impact of SMD**	January 2002	October 2002
9		**Issue Final Rule on SMD Tariff**		November 2002
10		GENERATOR INTERCONNECTIONS-TERMS, CONDITIONS, PRICING (RM02-1)		
11		**Comments Due on Interconnection NOPR**		June 2002
12		**Issue Final Rule on Generator Interconnections**		October 2002
13		RT DOCKETS		
14		**Northeast**		
15		State Outreach (On-Going)	December 2001	On-Going
16	X	FERC-New England & New York Regional Panel		May 28, 2002
17	X	FERC-New England Agenda Building Session (Stowe, VT)		June 19, 2002
18	X	NE RTO Applicants' (NYISO/ISO-NE) Cost-Benefit Study Completed		May 2002
19	X	Discuss Northeast RTO Scope at Open Meeting		May 30, 2002
20		Northeast RTO Filing by NYISO/ISO-NE/Canadians Due		June 2002
21		Northeast Order		TBD
22		**Southeast**		
23		SE Trans RTO Petition for Declaratory Order Filing Due		Summer 2002
24		SE Trans RTO Declaratory Order		Summer 2002
25		SE Trans Selects IMA and Makes 203/205 Filings w/ FERC	Summer 2002	Winter 2002
26		N. and S. Carolina Commissions Issue Orders on GridSouth RTO		Winter 2002
27		State Outreach (On-Going)	January 2002	On-Going
28	X	Florida Commission Requests Tutorial from FERC		June 11, 2002
29		**Midwest**		
30	X	MISO/SPP Merger Order	March 2002	May 2002
31		State Outreach (On-Going)	November 2001	On-Going
32		FERC-Midwest Regional Workshop		June 24, 2002
33		**West**		
34		Transconnect Order		Summer 2002
35		West Connect Order		Summer 2002
36		RTO West Order	April 2002	Summer 2002
37		State Outreach (On-Going)	February 2002	On-Going
38		Data Requests		TBD
39	X	FERC-State Western Regional Panel		April 30, 2002
40	X	FERC-Western Agenda Building Session (Scottsdale, AZ)		June 12, 2002
41		WESTERN ISSUES		
42		**Presentation to the Commission on West-wide Issues**		TBD
43		**CAISO Market Design Order**	May 2002	Summer 2002
44	X	Second Technical Conference	May 2002	May 2002

TBD=Date to be Determined

FERC "Big Ticket" List

Revised 6-20-02

ID	Complete	Tasks & Milestones	Start	Finish
45		Order		Summer 2002
46		**CAISO Price Mitigation Order**		Summer 2002
47		**Calif ISO Audit**	January 2002	Summer 2002
48		Order on Audit Report (Governance and Independence)		Summer 2002
49		**PG&E Bankruptcy Order**		
50		Judges' Final Ruling on PG&E Bankruptcy		TBD
51		Hearing Order		TBD
52		Initial Decision		August 2002
53		PG&E Bankruptcy Order		TBD
54		**Refunds**		
55		Hearing		August 2002
56		Certification of Record by ALJ		TBD
57		Opinion		TBD
58		**Other Significant California Items**		
59		Path 15 Upgrades		June 2002
60		Order		June 2002
61		CA Regulatory Must Run (RMR) Opinion (ER98-495)	June 2001	TBD
62		Issue Final Order		TBD
63		**NW Refund Case**		TBD
64		ORDER NO. 637 COMPLETION		
65		**Price Cap on Short-term Capacity Release Transactions**		TBD
66		Presentation on Capacity Release Price Cap Report		May 2002
67	X	Issue Notice (or Staff Paper) Requesting Comments		May 2002
68		Comments Due on Notice		July 2002
69		Next Steps		TBD
70		**Order 637 Filings** ***(30 Cases pending)***	January 2002	December 2002
71		EL PASO - CAPACITY ALLOCATION		
72	X	**Order**		May 2002
73		AFFILIATE STANDARDS OF CONDUCT (RM01-10)		
74	X	**Public Conference**		May 2002
75		**Completion of Final Rule**		Fall 2002
76		INFORMATION INITIATIVES		
77		**Market Transparency Initiative**	January 2002	TBD
78		Outreach	April 2002	TBD
79		Technical Conference		TBD
80		Issue NOPR		TBD
81	X	**Form 1 (Instant Final Rule) (Delete 11 Schedules)**		May 2002
82		MARKET BASED RATES		
83		**Process Pending MBR Filings & Triennial Reviews (On-Going)**	January 2002	December 2002
84		**SMA Technical Conference**		Fall 2002
85		**SMA Rehearing**		TBD
86		**206 Refund Condition Rehearing**		TBD
87		Issue Rehearing Order		TBD

TBD=Date to be Determined

FERC "Big Ticket" List

Revised 6-20-02

ID	Complete	Tasks & Milestones	Start	Finish
88		INFRASTRUCTURE CONFERENCES (AD02-6)		
89	X	SE Infrastructure Conference		May 2002
90		SW Infrastructure Conference		Fall 2002
91		Midwest Infrastructure Conference		Fall 2002

TBD=Date to be Determined

Testimony of
Charles Whitmore
Federal Energy Regulatory Commission
Before the
Virginia State Legislative Transition Task Force
June 21, 2002

Mr. Chairman and Members of the Legislative Transition Task Force:

Thank you for inviting the Federal Energy Regulatory Commission to discuss with you today where we are in creating Regional Transmission Organizations – RTOs - for the wholesale electricity market. I know this is of particular concern to Virginians, who stand at the very crossroads of the electric highway system connecting different regions of the country.

As you probably know, our Commission has been promoting the formation and development of geographically sensible RTOs across the United States. Once formed, RTOs will assure reliable minute-by-minute grid operations, optimize fair use of the "electric highway" by all users, plan for the future transmission needs of the region and help long-term supply stay ahead of long-term demand. Electric markets are essentially regional and need regional institutions to work as well as they must.

Two years ago, we decided to move forward with the formation of voluntary RTOs. Although that has proven to be a more tortuous path than we originally imagined, we saw it as a way to prevent years of litigation. That, in turn, would speed up the delivery of the billions of dollars in savings to consumers that we expect from harnessing the power of competition in the industry.

Last year, the Commission clarified its plans for wholesale electric markets by announcing that it would move forward on two parallel tracks. The first track finalizes issues of scope and governance for RTOs; the second track is a rulemaking to standardize

market design for all public utilities. RTOs are the natural entities to implement standard market design – SMD – and we anticipate that they will be the primary ones to do so.

We recognize that electric market restructuring will work best when State and Federal authorities understand and cooperate with each other. To help this happen we have initiated state-federal regional panels as a structured forum for constructive dialogue with state commissions on RTO and SMD development.

I have brought with me today a handout that outlines the major activities that FERC is engaged in, along with general timetables for action. The "Big Ticket List" before you today will be made public to all on our website, and lets everyone know what we are planning to do and when.

As you can see, the whole list is ambitious, and much of it is not directly relevant to us here. The key thing for today is that SMD and RTOs are at the very top of the list. That rightly reflects the fact that they are at the center of our efforts.

Let me start with SMD. What is Standard Market Design?

SMD will standardize market practices around the country both to make sure that everyone can use the best current practices in market design and to eliminate many of the arbitrary differences that now make it costly and hard for many people to do business in today's electric industry. This is an urgent priority for us because the experience of the last two years has shown all too dramatically that costs that can arise from poor market design. SMD has four main goals:

- To provide more choices and improved services to all wholesale market participants,
- To reduce delivered wholesale electricity prices through lower transaction costs and wider trade opportunities,
- To improve reliability through better grid operations and speeding up expedited infrastructure improvements, and
- To increase certainty about market rules and cost recovery. This certainty will inspire greater investor confidence to facilitate needed investments in the crucial energy industry.

As the handout indicates, FERC is sponsoring a conference on SMD data and software needs on July 18, and intends to issue a Notice of Proposed Rulemaking on SMD by the end of next month. We look for a Final Rule by the end of the year.

Turning to RTOs. The handout shows our proposed schedule for addressing the RTO cases now before us. We are looking forward to a busy year.

I'd like to highlight two further issues here. The first is our effort to alleviate what the industry calls seams – that is, the regulatory, market or physical barriers to trade among regions, especially for now in the Northeast. The second is to make sure that eastern RTOs create sensible geographic markets in the Eastern Interconnection. Both of these issues may be important for Virginia.

On the seams issue: Some time back, we asked the three Northeast independent system operators – PJM, New York and New England - to present a list of seams issues across their boundaries, along with a timeline for resolving the problems. We have now asked state commissions and industry stakeholders to comment on that list to ensure its accuracy. A full report of those responses will be presented at our next ~~Open~~ Meeting. To the extent that Virginia utilities decide to join PJM, the resolution of seams issues in the Northeast will be important.

We have questions about the issue of "natural markets" for electricity. This could be particularly troubling in the Midwest and Mid-Atlantic region, where utility choices may create a "swiss cheese" or "salad bowl" configuration within a multi-state region, because some utilities choose to join an RTO for which there are no contiguous boundaries. This is particularly true of the Alliance companies, including Virginia utilites, who must now consider which of the remaining RTOs they wish to join.

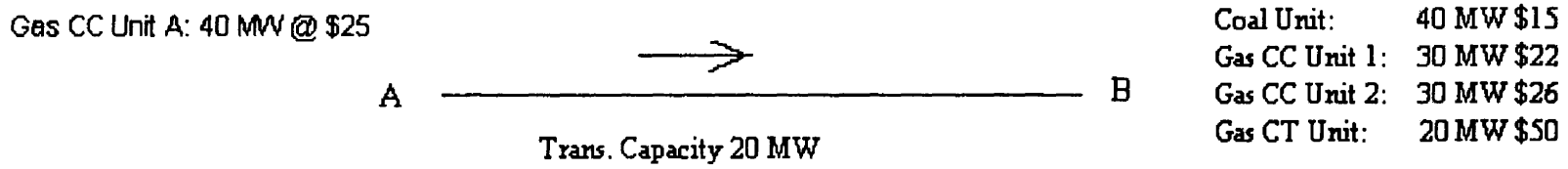
To help resolve this problem, we have asked the Alliance companies, along with National Grid, to make a joint presentation at our June 26 open meeting to explain where they intend to go, and justify why they are making those particular choices. We have asked them to explain the impact their choices will have on reliability, on seams issues, and how these choices are consistent with natural markets. Representatives of the Midwest ISO and PJM Interconnection will also attend the meeting to answer questions. We look forward to their response next week.

These decisions will be important for the Commonwealth of Virginia, which lies at the crossroads between PJM, the Midwest ISO and GridSouth. We at the Commission welcome your ideas about how best to configure the regional markets of which you will be part.

Finally, today, I would like to commend the Virginia Corporation Commission for its untiring work in making competition work for the citizens of Virginia. To make Virginia's retail access program work, there will need to be a vibrant and competitive wholesale market for electric power. We are committed to creating that market sooner rather than later. And we are very pleased at how well our ideas and those of the Virginia Commission are supporting each other.

Thank you.

Implications of LMP Model



Coal Unit: 40 MW $15
Gas CC Unit 1: 30 MW $22
Gas CC Unit 2: 30 MW $26
Gas CT Unit: 20 MW $50

Load at B is 100 MW

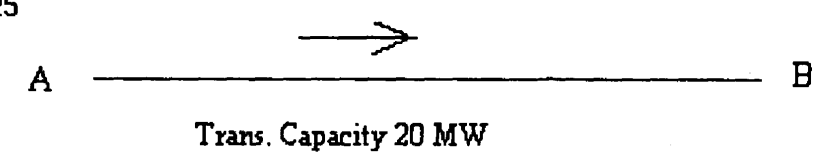
Dispatch:

Coal Unit	40 MW	$600
Gas CC Unit 1	30 MW	$660
Gas CC Unit A	20 MW	$500
Gas CC Unit 2	10 MW	$260
Gas CT Unit	0 MW	$-
	100	$2,020

LMP @ B:
Gas CC Unit 2 sets price, so load at B pays
100 MW @ $26/MWh or $2600

Implications of LMP Model
With Transmission Rights

Gas CC Unit A: 40 MW @ $25



Coal Unit: 40 MW $15
Gas CC Unit 1: 30 MW $22
Gas CC Unit 2: 30 MW $26
Gas CT Unit: 20 MW $50

Load at B is 100 MW

Dispatch:

Coal Unit	40 MW	$600
Gas CC Unit 1	30 MW	$660
Gas CC Unit A	20 MW	$500
Gas CC Unit 2	10 MW	$260
Gas CT Unit	0 MW	$-
	100	$2,020

LMP @ B:
Gas CC Unit 2 sets price, so load at B pays 100 MW @ $26/MWh or $2600

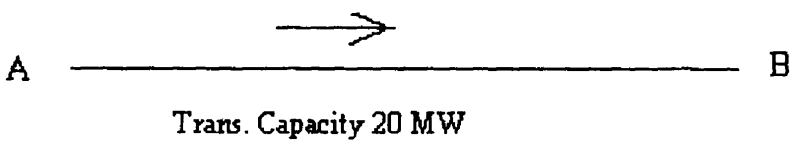
If load has transmission rights of 20 MW from A to B, load would receive a credit of ($26-$25) times 20 or $20.

Net paid by Load- $2580

Implications of LMP Model

With Transmission and Generation Protection

Gas CC Unit A: 40 MW @ $25



Coal Unit: 40 MW $15
Gas CC Unit 1: 30 MW $22
Gas CC Unit 2: 30 MW $26
Gas CT Unit: 20 MW $50

Load at B is 100 MW

Dispatch:

Coal Unit	40 MW	$600
Gas CC Unit 1	30 MW	$660
Gas CC Unit A	20 MW	$500
Gas CC Unit 2	10 MW	$260
Gas CT Unit	0 MW	$-
	100	$2,020

LMP @ B:
Gas CC Unit 2 sets price, so load at B pays 100 MW @ $26/MWh or $2600

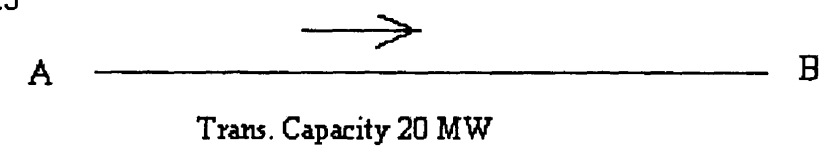
If load has transmission rights of 20 MW from A to B, load would receive a credit of ($26-$25) times 20 or $20.

If load owns all generation at B, it pays itself more for generation than it costs to produce. The coal unit has excess revenue of $440 (($26-$15) *40) Gas Unit 1 has excess revenue of $120 (($26-$22)*30).

Net paid by load B is $2600-$20-$440-$120 or $2020.

Implications of LMP Model
Unit withheld or unavailable

Gas CC Unit A: 40 MW @ $25



Coal Unit:	40 MW $15
Gas CC Unit 1:	30 MW $22
Gas CC Unit 2:	30 MW $26
Gas CT Unit:	20 MW $50

Load at B is 100 MW

Dispatch:

Coal Unit	40 MW	$600
Gas CC Unit 1	30 MW	$660
Gas CC Unit A	20 MW	$500
Gas CC Unit 2	0 MW	$-
Gas CT Unit	10 MW	$500
	100	$2,260

LMP @ B:
Gas CT Unit sets price, so load at B pays
100 MW @ $50/MWh or $5000.

LAW OFFICES

MILLER, BALIS & O'NEIL

A PROFESSIONAL CORPORATION

1140 NINETEENTH STREET, N.W.
SUITE 700
WASHINGTON, D.C. 20036-6600
(202) 296-2960
FAX (202) 296-0166
www.mbolaw.com

WILLIAM T. MILLER
STANLEY W. BALIS
ROBERT A. O'NEIL
JAMES R. CHOUKAS-BRADLEY
JOHN MICHAEL ADRAGNA
JAMES H. BYRD
JOHN P. GREGG
SEAN T. BEENY
SUSAN N. KELLY
RANDOLPH LEE ELLIOTT
JOSHUA L. MENTER
BENJAMIN L. WILLEY

PHYLLIS G. KIMMEL
BRIAN M. MELOY
REBECCA C. RAMAN
CRAIG W. SILVERSTEIN

*LINDA K. BROWNING
*BARRY COHEN
MILTON J. GROSSMAN
MARY A. HEKMAN
COUNSEL

*ADMITTED IN OTHER THAN THE DISTRICT OF COLUMBIA

January 24, 2003

WHY VIRGINIA CANNOT AVOID FERC REGULATION OF VIRGINIA ELECTRIC UTILITIES' TRANSMISSION SERVICE SIMPLY BY DELAYING RTE PARTICIPATION

- In Determining FERC's *Current* Jurisdiction Over the Transmission Element Of Virginia's Retail Electric Rates, The Critical Factor Is Whether Retail Transmission Service Is Bundled Or Unbundled, Not Whether Virginia's Electric Utilities Have Joined An RTE. FERC in its Order No. 888 found that when a retail electric service transaction is "broken into two products that are sold separately" (electric energy and transmission), "the resulting transmission transaction falls within the Federal sphere of regulation." Order No. 888, FERC Stats. and Regs. ¶ 31, 036 at p. 31,781.

  In FERC's own words, "[o]ur assertion of jurisdiction arises. . .only if the retail transmission in interstate commerce by a public utility occurs voluntarily *or as a result of a state retail program.*" Order No. 888-A, FERC Stats. and Regs. ¶ 31,048 at p. 30,226 (emphasis supplied). FERC's assertion of jurisdiction over unbundled retail transmission was affirmed in *New York v. FERC*, 535 U.S. 1 (2002). Moreover, the Supreme Court in that case implied that FERC could also assert jurisdiction over *bundled* retail transmission, if required to remedy undue discrimination in the provision of transmission service. FERC is now proposing to assert such jurisdiction in its pending rulemaking on Standard Market Design (SMD), discussed further below.

- Virginia's Retail Access Program Makes Virginia's Utilities' Retail Transmission Service FERC-Jurisdictional. Because Virginia has a retail access program, and Virginia's participating utilities therefore have unbundled transmission rates, FERC *now* has jurisdiction over their retail transmission terms, conditions, and rates. In fact, as a result of rate unbundling precipitated by Virginia's Restructuring Act, Virginia's retail electric customers are currently paying FERC-established retail transmission rates—regardless of whether these customers are taking generation service from an incumbent utility or a competitive supplier. Thus, whether VEPCO and AEP do or do not join an RTE makes no jurisdictional difference from FERC's perspective: FERC already has jurisdiction over the retail transmission service of these utilities, and the Supreme Court has affirmed that

jurisdiction.

- FERC's Proposed SMD Would Require Virginia's Utilities To Join "Independent Transmission Providers." FERC, in its July 31, 2002 Notice of Proposed Rulemaking (NOPR) on SMD in Docket No. RM01-12-000 (67 Fed. Reg. 55452), is proposing to require all "public utilities" it regulates (including AEP and VEPCO), to turn control of their transmission facilities over to "Independent Transmission Providers." FERC wants public utilities to meet this requirement by joining Regional Transmission Organizations (RTOs), which are essentially RTEs. FERC is relying upon its statutory power to remedy undue discrimination in the wholesale and retail provision of transmission service under Sections 205 and 206 of the Federal Power Act (FPA) to justify this requirement. Note that FERC, relying on the Supreme Court's *New York v. FERC* decision, would require *all* public utilities to do this, whether their retail transmission service is bundled or unbundled. Thus, FERC's proposal would apply to public utilities in states that have *no* retail access programs, *e.g.*, North Carolina. This has provoked a firestorm of opposition from bundled states, many of whom claim that in seeking to apply SMD to states without retail access programs, FERC has exceeded its FPA authority. If FERC issues an SMD Final Rule, the pendency of court appeals challenging the Rule, standing alone, will not delay the Rule's implementation and enforcement. Rather, those seeking judicial review would have to obtain a "stay" of the Rule, from either FERC or a United States Court of Appeals.

- The SMD NOPR Requires the Use of Locational Marginal Pricing, Centralized Power Markets, And Regional Resource Adequacy Requirements. The SMD NOPR would require all ITPs/RTOs to run centralized, bid (not cost)-based energy markets, use locational marginal prices (LMPs) set in those markets to price transmission congestion, and set regionally (not state) determined resource adequacy requirements. Generators would have to sign "Participating Generator Agreements" with their ITPs/RTOs and offer "available capacity" into their energy markets. Hence, SMD as FERC visualizes it has definite adverse impacts on continued state authority over generation and reliability.

- Bundled States' Opposition To The SMD NOPR Could Result In Different Regulatory Outcomes For Bundled And Unbundled States. In response to bundled states' intense opposition to the SMD NOPR, FERC has already ruled in three RTO-related cases that it will permit some regional variations from SMD. Opposition to SMD has also already surfaced in Congress, resulting in a further slowdown of FERC's timetable for issuing a final SMD rule. Consequently, and in response to the volume and intensity of this opposition, SMD's jurisdictional application could be curtailed as a result of: (1) voluntary action by the FERC; (2) Congressional action requesting or requiring it; or (3) judicial action directing it. One logical outcome of such action might be that utilities in those states with *unbundled* retail transmission service (over which FERC already has jurisdiction,

as made clear in *New York v. FERC*) would be subject to SMD, while utilities in those states with *bundled* retail transmission service would not.

- Simply Delaying The Joining Of An RTE Would Not Be Enough To Avoid FERC's SMD Rule. Some parties have said that Virginia can avoid any loss of jurisdiction over its utilities by simply delaying its utilities' joining of RTEs. As explained above, FERC's SMD initiative might well take this decision out of Virginia's hands. Nor is it true that "the FERC does not have jurisdiction over whether a utility joins an RTE." FERC is asserting its FPA Section 205/206 authority to essentially require this in the SMD NOPR. While some taking this position cite the decision of the United States Court of Appeals for the District of Columbia Circuit in *Atlantic City Electric Co. v. FERC*, 295 F.3d 1 (2002), that case is inapposite, for two reasons. First, it merely states that public utilities turning over their facilities to an RTO to operate (or withdrawing from such an RTO) need not first get FERC's authorization under *FPA Section 203*. FERC in its SMD NOPR is relying on its Section 205/206 mandate to remedy undue discrimination, not its Section 203 authority to approve dispositions of property. FERC could require its prior approval of any utility withdrawal from an RTO under FPA Section 205, due to the associated RTO tariff filings and rate schedules.

  Second, FERC on remand of that case has once again ruled that public utilities seeking to hand over operation of their transmission facilities to an RTO must first obtain FPA Section 203 authorization. *PJM Interconnection*, 101 FERC ¶ 61,318 (December 19, 2002). Hence, FERC has now officially refused to accede to the Court's decision, even assuming the issue of Section 203 authority is relevant to this issue.

VIRGINIA CAN SAFEGUARD RELIABLE SERVICE TO NATIVE LOAD BY MAINTAINING CONTROL OVER UTILITY MEMBERSHIP IN REGIONAL TRANSMISSION ENTITIES

Dominion Resources Services, Inc.
120 Tredegar Street
Richmond, Virginia 23219

Thomas L. Blackburn
Bruder, Gentile & Marcoux, L.L.P.
1100 New York Ave. N.W.

VIRGINIA CAN SAFEGUARD RELIABLE SERVICE TO NATIVE LOAD BY MAINTAINING CONTROL OVER UTILITY MEMBERSHIP IN REGIONAL TRANSMISSION ENTITIES

SUMMARY

The Federal Energy Regulatory Commission's ("FERC") assertion of jurisdiction over retail transmission service does not affect the reliability of service to native load. Therefore, it is not necessary to suspend retail choice programs or to rebundle rates in Virginia to ensure the reliability of service. In addition, the FERC does not have jurisdiction over the key aspects of service to native load. Consequently, whether a utility joins a Regional Transmission Entity ("RTE") has far more impact on the reliability of service to native load than does the unbundling of retail transmission service.

Any concerns that Virginia has with respect to the reliability of service to native load can be addressed by maintaining control over when utilities in Virginia join RTEs. The FERC cannot force utilities to join RTEs in the near term, and it will not implement Locational Marginal Pricing ("LMP") on a single-utility basis. Therefore, the Parrish legislation, which delays the requirement that utilities in Virginia must join RTEs, gives Virginia additional time to evaluate how the FERC's proposed Standard Market Design ("SMD") initiative will be finalized before deciding whether to approve the transfer of control of transmission assets to RTEs. In any event, if the FERC decides to move forward with SMD or LMP, it will first have to obtain jurisdiction over bundled retail transmission service, as explained below. If that occurs, rebundling retail transmission service will not provide any additional protection to Virginia native load.

THE FERC'S JURISDICTION OVER UNBUNDLED RETAIL TRANSMISSION SERVICE DOES NOT AFFECT THE RELIABILITY OF SERVICE TO NATIVE LOAD.

The FERC has jurisdiction over transmission service to unbundled retail load. In *New York v. FERC,* the United States Supreme Court held that under the Federal Power Act, the FERC has jurisdiction over all transmission service in interstate commerce. It concluded that the FERC's decision in Order No. 888 to require open access transmission service for all wholesale customers and unbundled retail customers was within the scope of the FERC's authority.

The FERC's exercise of jurisdiction over transmission service has not adversely affected the reliability of service to native load in the Commonwealth. The FERC has required utilities to provide transmission service to wholesale customers and unbundled retail customers under Open Access Transmission Tariffs ("OATTs"), which give those customers the same quality of transmission service that utilities provide to their bundled native load, since 1996. That requirement has not resulted in any deterioration in the reliability of transmission service to native load in Virginia. Retail transmission service was unbundled in Virginia in 2001, and that action also has not had any negative impact on native load in Virginia.

THE FERC CANNOT CONTROL KEY ASPECTS OF THE RELIABILITY OF SERVICE TO NATIVE LOAD CUSTOMERS.

The Federal Power Act provides that the FERC does not have jurisdiction over sales of electric energy to retail customers, and the FERC has acknowledged the limited nature of its jurisdiction. In its order establishing open access transmission service requirements for public utilities, the FERC noted that it does not have jurisdiction over

the following matters: generation and transmission siting, reliability of local service, administration of integrated resource planning, buy-side and demand-side decisions and generation and resource portfolios. In recognition of the limits of FERC jurisdiction, in *New York v. FERC* the Supreme Court confirmed that the FERC does not have jurisdiction over the generation and distribution aspects of service to retail customers. The Supreme Court also noted with approval the FERC's statements concerning the limited nature of its jurisdiction. Consequently, Dominion Virginia Power remains subject to the SCC's existing requirement that the Company's generation assets in Virginia must serve its customers in Virginia, and that only capacity and energy that is not needed for those customers may be sold in other markets.

QUICK FERC ACTION ON SMD IS EXTREMELY UNLIKELY.

Transmission-owning utilities today are under pressure from the FERC to join RTEs as quickly as possible. However, in and of itself the FERC's SMD proposal will not result in utilities being forced to join RTEs in the near term. (The FERC's initial SMD proposal would have required utilities to join RTEs by September 2004.) It is now clear that substantial opposition to SMD from utilities, states and the United States Congress has caused the FERC to delay the implementation of SMD and to modify the scope of its proposal. Therefore, even if the FERC's SMD proposal is not contested in the courts, it will not result in a requirement that utilities join RTEs before at least 2005, and perhaps significantly later than that.

The United States Court of Appeals has held that the FERC does not have the authority to require utilities to join RTEs under Section 203 of the Federal Power Act. In 1997, the FERC issued an order requiring the Pennsylvania-New Jersey-Maryland Interconnection ("PJM") to modify its Independent System Operator ("ISO") Agreement to prohibit any transmission owner from withdrawing from the ISO without FERC approval under Section 203 of the Federal Power Act. Last summer, the United States Court of Appeals reversed the FERC. The Court held that Section 203 gives the FERC jurisdiction only over sales, leases and other similar transfers of transmission facilities, and not over the transfer of operational control of transmission facilities. The Court also noted that the Federal Power Act leaves coordination and interconnection arrangements between utilities to the voluntary actions of utilities.

Since the Court of Appeals has held that the FERC does not have the authority to require utilities to join RTEs under Section 203 of the Federal Power Act, the only way in which the FERC could attempt to require utilities to join RTEs would be to conclude that utilities' continued operation of their own transmission facilities is unduly discriminatory under Section 205 of the Federal Power Act. The FERC's attempt to take such a step in the SMD NOPR has been extremely controversial and, as noted above, has caused the FERC to delay and modify its proposal. If the FERC were to persist in its attempt to force utilities to join RTEs pursuant to Section 205, it would undoubtedly result in even more controversy, Congressional opposition and extended litigation.

THE FERC WILL NOT IMPOSE LOCATIONAL MARGINAL PRICING ON UTILITIES THAT DO NOT J

OIN RTEs.

If a utility does not join an RTE, the FERC will not impose LMP on unbundled retail loads within that utility's service territory. This is because LMP is integrally related to the requirement to join RTEs. A fundamental principle of LMP is that control over the operation of transmission facilities and control over operation of the energy markets must be placed in the hands of entities that are independent of all market participants in order to ensure that LMP is administered fairly. In addition, imposing LMP on a utility-by-utility basis would not create the broad regional power markets that the FERC believes are necessary to give consumers access to less expensive generation.

If the FERC were to attempt to force utilities that are not members of an RTE to adopt LMP, it would be extremely time consuming and contentious. The FERC could impose such a requirement only through the SMD rulemaking or a new rulemaking proceeding. Either alternative would take from six months to more than a year to complete. The FERC also would have to allow utilities sufficient time to implement LMP after it adopts the requirement. Even more important, based on the widespread opposition to SMD, it is likely that both utilities and states would challenge the FERC's jurisdiction to impose LMP on bundled and unbundled retail loads, resulting in substantial and lengthy litigation that would take years to resolve. Finally, it also is likely that an attempt to impose LMP on unbundled retail loads would create the same Congressional opposition that resulted from the FERC's SMD proposal, and could result

in federal legislation restricting the FERC's authority.

IF THE FERC IMPLEMENTS SMD OR LMP, REBUNDLING TRANSMISSION SERVICE WILL NOT PROVIDE VIRGINIA NATIVE LOAD ANY ADDITIONAL PROTECTION UNLESS THE FERC IS FOUND NOT TO HAVE JURISDICTION OVER BUNDLED RETAIL TRANSMISSION.

It is extremely unlikely that the FERC will override the opposition from states, utilities and the Congress and impose SMD or LMP on unwilling states and utilities. However, if the FERC were to do so, the rebundling of transmission service would not provide any additional protection to native load in Virginia. The FERC's assertion of jurisdiction over transmission service to both unbundled and bundled retail load is fundamental to the implementation of SMD because SMD fundamentally affects service to those loads. LMP also will not be implemented unless it applies to bundled retail load because LMP is effective only if it applies to all loads in a region. Therefore, it is very unlikely that the FERC would implement SMD unless the FERC's attempt to assert jurisdiction over transmission service to bundled retail load is successful. If that occurs, it will make no difference whether transmission service to retail customers in Virginia is bundled, unbundled or "rebundled" since all transmission service will be FERC-jurisdictional. In the unlikely event that the FERC decides to implement SMD even if it does not obtain jurisdiction over bundled retail transmission, rebundling of transmission service could provide some benefit to Virginia native load. However, it would not be necessary or appropriate for Virginia to take that step at this time since the critical issues of the scope of the FERC's jurisdiction and the nature and timing of SMD

will not be resolved for some time. There will be ample opportunity to consider this action in the future.

VIRGINIA CAN PROVIDE THE BEST PROTECTION TO NATIVE LOAD BY DELAYING THE DATE BY W HICH UTILITIES MUST JOIN RTEs.

Under existing law, no Virginia utility may fully integrate into an RTE without the approval of the State Corporation Commission ("SCC"). Existing RTEs generally have adopted many of the aspects of the FERC's SMD initiative, including LMP. If Virginia is concerned that implementing SMD may adversely affect the reliability of service to retail native load, it can best protect native load by delaying the date by which utilities must join RTEs. The Parrish bill, HB 2453, which would delay the requirement that utilities must join RTEs, would allow Virginia to evaluate both the FERC's final SMD rules and the impact of SMD and LMP on native load in other states before making its final decision on whether utilities should join RTEs.

REPORT OF THE CONSUMER ADVISORY BOARD TO THE LEGISLATIVE TRANSITION TASK FORCE OF THE VIRGINIA ELECTRIC UTILITY RESTRUCTURING ACT

December 2002

I. INTRODUCTION

The Consumer Advisory Board, established under § 56-595 of the Restructuring Act, is directed to assist the Legislative Transition Task Force in its work of monitoring the transition to retail competition for electric energy. The seventeen-member Board is appointed from all classes of consumers and with geographical representation throughout the Commonwealth. Since its inception in 1999, William Lukhard has chaired the Board and Otis Brown has served as vice-chairman. Delegate Kenneth Plum continues to serve as liaison between the Task Force and the Consumer Advisory Board.

The Consumer Advisory Board held four meetings and two subcommittee meetings in 2002 to address a number of issues. The Board continued its examination of energy efficiency, aggregation, demand-side management, and the effect of deregulation on small business. Much of the Board's work this year has continued its attempts to enhance knowledge among residential and small business consumers and to develop options for improving the demand side of a competitive market.

II. ISSUES STUDIED BY THE BOARD

A. SCC REPORT ON THE STATUS OF COMPETITION

Dick Williams presented the SCC's second annual report on the status of competition. As of the date of the report, two-thirds of residential and nonresidential Dominion customers had the ability to choose their supplier. By January 1, 2003, all Dominion customers will be eligible to choose their supplier. Currently, Virginia has only one offer from a Competitive Service Provider: Dominion's Northern Virginia customers may purchase green power from PEPCO Energy Services. Approximately 2,500 residential customers and 24 small commercial customers have taken this offer.

Part I of the report is a history of what has happened in Virginia since last year. The SCC's order regarding minimum stay provisions has had little impact on residential users. The SCC issued an order to investigate aggregation, and a discussion of that investigation is Part C of this report. Part II was prepared once again by Dr. Ken Rose, and examines competitive activity across the country. Rose's report finds that a very large amount of switching activity nationwide is nonresidential. The slow development of a competitive wholesale market has caused transmission costs to be much higher than costs would be with perfect competition. Part III of the report contains a discussion of 20 recommendations received by the SCC from various stakeholders. The recommendations are not endorsed by the SCC. Rate caps and wires charges were the most popular topics of discussion. However, the SCC feels that before these can be eliminated, Virginia needs an effective competitive market.

The SCC did have two recommendations designed to help stimulate competition. The first would allow a large industrial customer to avoid paying a wires charge upon switching to a CSP, if the customer agrees to market-based pricing upon return to the incumbent. The second SCC proposal would allow a large commercial customer to avoid minimum stay requirements if the customer agrees to market-based pricing upon a return to the incumbent. Large customers are more attractive to CSPs and are more market savvy, so implementation of these recommendations may stimulate some competitive activity in Virginia.

Bill Lukhard appointed a subcommittee to examine the SCC's report and recommendations. The recommendations of the subcommittee are enumerated in Part III of this report.

B. ENERGY EFFICIENCY

1. Demand-Side Management Pilot Programs and Study of Signaling Technology.

In 2001, the Board asked the SCC to study demand-side management (DSM) programs and the availability of signaling technology in the Commonwealth. David Eichenlaub presented the results of the SCC's examination. Under traditional regulation, DSM was not mandated. Following the oil embargo in the mid-1970s, utilities sponsored voluntary, experimental programs, and conducted an extensive cost-benefit analysis of each. Virginia has not mandated any type of systems benefit charge to fund these programs.

Virginia Power currently has day-ahead price forecasting, and a standby generator program for existing customers. Those who produce electric energy receive a credit extension. Central Virginia Electric Cooperative has a water heater control program in place. None of these programs are very cost-effective or popular. Pure conservation programs take a long time to develop. There are some common sense things consumers can do to reduce their energy burden, such as turning off appliances when not in use, resetting thermostats, increasing insulation, and purchasing more energy-efficient appliances.

In the past, load control programs were determined by utilities and offered few options to customers. With new demand response programs, the customer has control. The SCC order regarding competitive metering allows flexibility for market participants to decide how to use their electricity. These programs require changes in infrastructure. SCC staff and the competitive metering work group considered programs that provide flexibility in the marketplace. An effective energy market should allow customers to make decisions about consumption, but a mechanism for communication between customers and suppliers is needed.

The SCC's competitive metering work group reached consensus that the most critical aspect is interval meter data. The SCC rules for competitive metering focus on the availability of interval metering, but staff is considering additional methods. Three fronts are needed for a competitive market to succeed: 1) a measurable hourly load, 2) price transparency, and 3) a viable Regional Transmission Organization. There are costs to establishing all of these, but the question of who pays these costs remains unanswered.

Eichenlaub gave the Board an update on these studies at its October 10 meeting. He reported that the competitive metering work group may not be the appropriate vehicle for the study of signaling technologies. California and New York have discussed conducting studies, but they have not recommended who should conduct them or when. The work group members are having trouble justifying the cost of such studies in an environment with little competition.

2. Energy Efficiency Education for Small Businesses.

Steve Walz of the Department of Mines, Minerals, and Energy (DMME) presented the Board with the results of DMME's study on energy efficiency education for small businesses. A copy of the presentation is attached as Appendix A. DMME completed the residential phase of the study and presented the results to the Board in 2001. For the small business phase of the study, DMME looked at characteristics of small businesses, reviewed their existing activities, examined real-time pricing education, and developed options for small business education. For purposes of the study, a small business had less than 100 employees or $5 million in gross receipts.

The study found that small business managers' and owners' attention tends to focus on more direct business matters. An education message must be compelling, and must focus on small, simple items in small doses. There are few direct energy education programs for small businesses. Often, energy efficiency education programs are part of broader activities, such as environmental education, energy audits, design assistance, installation services, and discounts, rebates, and financing. Little real-time pricing information is included in these programs.

The Environmental Protection Agency's EnergyStar program has a component designed to educate small businesses. The program provides a guidebook, electronic updates, a savings calculator, and a resource room for small business owners to obtain more information. The Department of Energy also has a business information component, including best practices information, emerging technologies, commuting alternatives, and information about alternative fueled vehicles and solar energy. The Alliance to Save Energy and the American Council for an Energy Efficient Economy also have programs targeted toward businesses.

In Virginia, the Department of Environmental Quality administers the Virginia Small Business Assistance Program and Virginia Innovations in Pollution Prevention program. The SCC includes energy efficiency information as part of Virginia Energy Choice, and the Virginia Tech Energy Management Institute includes Fundamentals of Energy Management and Corporate Energy Management seminars. The Virginia Center for Stewardship, the Virginia Housing and Environmental Network, and the AOBA of Metro Washington Speakers series all provide energy efficiency education in some form to small businesses.

DMME identified three types of programs that could be initiated, with expected results. A high-level program would target all 131,000 small businesses in Virginia, with a cost of $2.1 to $6.0 million, expecting 25 percent of businesses to take action to improve knowledge and six percent to implement at least one measure. A medium-level program would target 60,000 businesses, cost $1.1 to $2.5 million, with 12 percent of businesses taking action to improve

knowledge and three percent to implement at least one measure. A low-level program would target 30,000 businesses, cost $220,000 to $670,000, expecting six percent of businesses to take action to improve knowledge and 1.5 percent of businesses to implement at least one measure.

The chairman appointed a subcommittee to examine the issue of consumer education on energy efficiency. The subcommittee's recommendations are listed in Part III of this report.

C. AGGREGATION

1. SCC Study of Aggregation.

In March 2002, the Commission established its investigation regarding aggregation for the purpose of developing and refining policies, rules, and regulations for the provision of aggregation service. It identified three main areas of inquiry: licensing of aggregators, contractual relationships between aggregators and their customers, and the impact of incumbent utilities' relationships with the aggregator affiliates on the development of competition here in Virginia.

In its order establishing the investigation, the Commission directed its staff to conduct the investigation with input from a working group. On August 1, 2002, the Commission staff issued a report summarizing the issues examined in its investigation. The report reviewed the discussions that occurred in our May 1 work group meeting and also summarized comments received subsequent to the meeting. Of the three areas originally identified by the Commission's order, only the questions surrounding licensing needed to be addressed. Regarding contractual issues, the majority of the work group believed that there should be no stronger requirements for aggregators than there are for suppliers. Regarding incumbent electric utilities' affiliates providing aggregation services, most participants seemed to believe that the existing codes of conduct were adequate.

On the issue of licensing, the Staff report focused on the definition and applicability of licensing. Staff concluded that no change to the definition was warranted at this time. Staff discussed the need for marketing entities. Staff believes that, if a marketing entity stays out of the transactional arrangements between suppliers or aggregators and customers, then those marketers do not need to be licensed. However, staff believes that the behavior of the marketer is the responsibility of the supplier or aggregator using those marketing services. For purposes of ensuring protection of the public, Staff recommended that an existing rule be modified so that each supplier or aggregator with marketer relationships be required to maintain information identifying these marketing entities.

On September 20, the Commission issued an Order requesting comments on the Staff Report. Those comments were due October 8. Three parties have provided comments, all generally agreeing with the Staff's recommendation. The next step will likely be another order from the Commission addressing comments to the Staff report and making a finding with respect to the Staff's recommended rule change.

The Board notes that the Staff Report addresses a potential issue of market power of aggregators and competitive service providers that are affiliates of existing regulated companies and the intent of the SCC to closely monitor this.

2. Aggregation Practices in Ohio.

Jeff Murphy of Dominion East Ohio presented the Board with information about Ohio's aggregation successes. In Ohio, there are two types of governmental aggregation, opt-in and opt-out. Opt-in aggregators serve as a middle man in purchasing energy, and require an affirmative election on the part of the consumer. Opt-out is the process where customers must affirmatively say they do not want to be a part of the aggregation plan.

The aggregator is not a supplier. The aggregator selects the supplier based on a request for proposals, and the supplier enrolls and serves customers. The supplier can provide one of three kinds of offers: 1) a percentage savings over the utility's prices, 2) a fixed price for a fixed term, or 3) a variable price. The third option has the greatest uncertainty.

In the electricity market, 84.4 percent of customers who have switched have done so through governmental aggregators. Whether or not a governmental entity becomes an aggregator is determined by the voters. Governmental aggregators have a governance plan, setting out the rules of conduct as an aggregator. In opt-out aggregation in Ohio, up to 10 percent of customers choose not to participate in governmental aggregation.

E. WIRES CHARGES

Frank Munyan of the Division of Legislative Services and Howard Spinner of the SCC gave Board members an overview of wires charges. Section 56-584 of the Code of Virginia provides that "each incumbent electric utility shall only recover its just and reasonable net stranded costs through either capped rates as provided in § 56-582 or wires charges as provided in § 56-583." "Stranded costs" generally is used to refer to the value of assets, such as power plants and purchase contracts, that were prudently incurred by incumbent utilities while fully regulated (and with the expectation that such costs would be recovered through regulated rates) and that have been devalued because of restructuring. Wires charges are intended to cover shopping customers' pro rata share of incumbent utilities' potential losses, if any, resulting from market-based generation prices that are lower than the capped generation rates, and to cover the shopping customers' pro rata share of any costs incurred by these customers' former electric utilities as part of their transition to a competitive market for generation services.

Section 56-583 defines wires charges as "the excess, if any, of the incumbent electric utility's capped unbundled rates for generation over the projected market prices for generation, as determined by the Commission." Wires charge cannot be less than zero.

Customers who (i) switch to a competitive electricity supplier or (ii) are subject to and receiving default service, may be required to pay wires charges. Wires charges are payable during periods that a customer (a) chooses a supplier of electric energy other than the incumbent electric utility or (b) is subject to and receives default service. Any obligation to pay wires

charges will expire when capped rates expire or are terminated, as provided in § 56-582 (July 1, 2007, unless the Commission finds upon petition by a utility filed any time after January 1, 2004, that an effectively competitive market for generation services exists within the service territory of that utility).

The Commission shall seek to coordinate adjustments of wires charges with any adjustments of capped rates pursuant to § 56-582 (which are allowed for such things as recovery of fuel costs, changes in the taxation, and financial distress of the utility beyond its control). By order, the Commission will require utilities to file information regarding changes in capped rates and market price proposals by July 1 of each year, so that market prices and wires charges can be determined by October 1 for the following calendar year. The SCC shall permit any customer, at its option, to pay the wires charges on an accelerated or deferred basis. A supplier of retail electric energy may pay any or all of the wires charge owed by any customer to an incumbent electric utility, or contract with any customer to finance such payments.

F. LOW-INCOME ENERGY ASSISTANCE PROGRAMS (LIHEAP)

Duke Storen of the Department of Social Services presented the Board with an update on LIHEAP and the Home Energy Assistance Program at its October meeting. In 2002, Virginia received approximately $32 million in federal funds, a 20 percent increase from last year. However, contingency funds decreased from approximately $14 million to more than $3 million. Total funds decreased from $41 million last year to $35 million this year. The Department of Housing and Community Development received $4.9 million for the Weatherization Assistance Program. In FY 2002, applications increased by nine percent. Historically, 88 percent of applications are approved. While 250,000 Virginians live below the federal poverty line, and 600,000 Virginians would be eligible for LIHEAP, only 125,000 Virginians received services from the program in 2001. Storen presented a chart showing the average energy burden of a household eligible for LIHEAP, based on that household's income, which is attached as Appendix B.

The Department is still developing regulations to implement the Home Energy Assistance Program. Emergency regulations are effective September 1, 2002, through August 31, 2003. Proposed permanent regulations were presented at the October 16 Social Services Board meeting. The annual report to the General Assembly addressing the Home Energy Assistance Program and unmet need in the Commonwealth has been submitted as House Document 6 (2003).

Rita Randolph informed the Board that Dominion's EnergyShare raised just more than one million dollars for the 2001-2002 season, assisting 5,008 households with an average utility bill payment of $203. Garry Simmons of AEP presented Neighbor-to-Neighbor figures, which raised $114,767 for the 2001-2002 season, assisting 2,556 households with an average utility bill payment of $45.

G. VIRGINIA ENERGY CHOICE

The Board received a series of updates on Virginia Energy Choice throughout the year. Ken Schrad, Director of Information Resources at the SCC, explained that the SCC has been working with its Education Advisory Committee, communications and research consultants, and surveys of Virginia consumers to evaluate what Virginia's consumers know about deregulation and to determine the education program needs to emphasize to ensure Virginia's customers make informed decisions about their electric service providers. The objectives of the program are to provide clear, accurate, objective information to educate and inform consumers about restructuring. Interest in choice remains high, with 72 percent wanting to learn more. By January, 2002, awareness of choice had increased to 40 percent, from 28 percent the previous June. Business leader awareness had increased to 52 percent, from 38 percent. Virginia Energy Choice cut back on its advertising budget due to minimal competitive activity in the Commonwealth.

A survey of customers found that, while most consumers understand that choice takes time and have few concerns about choice, some consumers are frustrated with limited competition in Virginia and are concerned about prices increasing while reliability decreases. Awareness has increased, but there is still room to grow in this area.

More than 674 grassroots organizations were contacted by Virginia Energy Choice, including consumer groups, African-American organizations, non-English speaking organizations, low-income organizations and senior citizens organizations. The organizations committed to distributing consumer guides, including Spanish language materials, including choice in newsletter articles, and providing 106 website links. Presentations about choice were attended by 3,790 persons.

Virginia Energy Choice has enhanced its education for small businesses. The website has a business education toolbox, and links to other resources for business consumers. The outreach division contacted 14 statewide business organizations and 104 smaller organizations, and has partnered with the Small Business Development Centers (SBDC) to educate small businesses about choice. Virginia Energy Choice held a workshop for SBDC local directors, provided materials to SBDC, and the SBDC newsletter included an article about Virginia Energy Choice.

The Board commended the SCC on the educational material that is now available through the Virginia Choice Website. The SCC confirmed their plans to specifically add educational material on the saving potential from time-of-use and load management options available to customers that already have appropriate existing rates.

Virginia Energy Choice will continue to monitor the progress of the program and the development of a competitive market, and make adjustments where necessary.

H. TERMINATION POLICIES

In the 2001 interim, Irene Leech of the VCCC expressed to the Board her concern regarding utility termination policies in a restructured market. Leech reiterated those concerns at the Board's September meeting, and suggested consideration of a state policy on service

termination. Leech indicated that some states require a standardized rate for low-income consumers, and some states prohibit termination of service during periods of hot or cold weather.

David Holt of Dominion indicated that the utility's termination policies were on record with the SCC. Dominion is very careful about disconnecting service, and takes weather conditions into consideration, as well as any medical alerts a customer may have, before terminating service. Termination rules have not been set for after the end of the capped rate period. Under current SCC rules for retail access, a customer's service cannot be terminated for failure to pay the generation supplier. Rob Omberg, representing cooperatives, indicated the co-ops' satisfaction with the SCC's retail access rules. Omberg also explained the rule regarding a customer's partial payments: if a customer does not designate where the payment should go, the regulated portion of the bill is paid first, to avoid unnecessary disconnections.

III. DELIBERATIONS AND RECOMMENDATIONS

A. SUBCOMMITTEE ACTIVITY

Chairman Lukhard appointed two subcommittees at the September 11 meeting. The first subcommittee was charged with reviewing the SCC's report on the status of competition. The second subcommittee was charged with examining the DMME report on energy efficiency education. The subcommittees met on October 10, in the morning, before the full Board meeting. Each subcommittee presented a report to the Board with recommendations for the Board's consideration.

1. Subcommittee on the Status of Competition.

Steve Walker chaired the subcommittee on the status of competition, and Otis Brown, Brad Wike, Fletcher Lowe, and Quentin Wilhelmi served as members. The subcommittee discussed each of the 20 recommendations that had been presented to the SCC, and that are enumerated in Part III of the SCC's report on the status of competition. While the subcommittee did not vote to endorse any particular recommendation, members did agree that the full Board should consider and take action on five of the recommendations given to the SCC:

a. Staged transition to competition by rate class (SCC #4).
b. Calculation of recoverable stranded costs and amortization of those costs (SCC #5).
c. Permitting market-based pricing to avoid minimum stay requirements (SCC #8).
d. Placing a 5-year moratorium on restructuring (SCC #9).
e. Legal separation of a utility's generation business (SCC #19).

2. Subcommittee on Energy Efficiency Education.

The chairman also appointed a subcommittee to review issues of energy efficiency education for small businesses. Jack Greenhalgh chaired the subcommittee, and Oswald Gasser, Jim Copp, Don Sullivan, and Jimmie Trent were members. This subcommittee also examined the SCC report on the Status of Competition, and recommended the creation of an Energy Management Work Group to address six of the recommendations outlined in the SCC Report:

a. Provide customers with the tools necessary to monitor electricity prices (SCC #11).

b. Use regulation to stimulate DSM measures (SCC #12).

c. Require Local Distribution Companies to make time-based pricing available (SCC #13).

d. Quantify the effectiveness of demand controller on reducing demand (SCC #14).

e. Encourage distributed generation technology (SCC #17).

f. Interpret Senate Bill 554 (2002) to reduce barriers to expanding generation (SCC #18).

B. FULL CONSUMER ADVISORY BOARD DELIBERATIONS

At its November 19 meeting, the Board considered all of the recommendations of the subcommittees. As in previous years, the Board also considered recommendations from other interested parties. In addition to the subcommittee recommendations, the Board received three proposals from Jack Greenhalgh, two from the chairman, and one from the Association of Energy Conservation Professionals. The proposals and their sources are listed below in the order in which the Board considered them, and are attached as Appendices C through N.

1. Transition to Competition by Rate Class – Subcommittee on the Status of Competition.

In the SCC's report on the status of competition, the Commission recommended amending the Restructuring Act to allow a large commercial or industrial customer the ability to switch to a competitive service provider without paying a wires charge, provided the customer agrees to commit to market-based pricing if it returns to the incumbent utility. The Subcommittee on the Status of Competition recommended Board consideration of such an amendment to the act. The Board discussed the possibility of including aggregators with load equal to that of a large commercial customer. After some discussion, the Board voted by a vote of 5 to 7 not to recommend that large commercial and industrial customers be able to avoid wires charges.

2. Stranded Costs

a. Subcommittee on the Status of Competition.

The Commission received recommendations that the SCC or the General Assembly should calculate recoverable stranded costs for each utility and the pricing of standard offer service should reflect an amortization of those costs over a fixed period of time. The Subcommittee on the Status of Competition recommended that the Board consider asking the SCC to perform such a calculation and that wires charges be restructured to allow incumbent electric utilities to recover those costs.

b. Jack Greenhalgh.

Greenhalgh recommended that the Restructuring Act be modified to provide a new method for calculation of the wires charge as a mechanism for recovery of stranded costs. Greenhalgh recommended that each utility should provide a quantified estimate for stranded cost to be recovered and the method for validation that these cost are actually stranded as we proceed

through the transition period. Upon approval of these estimates by the SCC, they should be allocated for recovery on a decreasing basis until phased out after 2007. At the end of each year, the actual stranded cost for each year should be calculated and reviewed by the SCC. If the approved amount is less than the collected wires charge, the difference should be subtracted from the end of the scheduled stream of collections. If the approved amount is more than the collected wires charge, the difference should be added to the end, even if it extends the collections beyond 2007. As of January 1, 2007, no further reconciliation would be done and only the amount previously approved for collection would continue to be collected. The primary purpose of adding adjustments to the end of the period is to avoid the existing problem for Competitive Service Providers and Aggregators that they cannot offer anything but short-term contracts to prospective customers because they are unable to forecast the next year's cost. Although the wires charge should be known by October for the next year, it has been well after that so far. As we proceed through the year, the period for which pricing can be known decreases steadily. By mid-year, offers can only be made for a small number of months. Competitors that seek to attract customers from the stability of their incumbent utility must be able to offer longer term contracts with reasonable ability to predict costs over that term.

The Board, upon learning of the Task Force's planned monitoring of stranded cost recovery, withdrew both of these recommendations.

3. Avoiding Minimum Stay Requirements – Subcommittee on the Status of Competition.

The Commission's second recommendation to the Task Force enumerated in the report on Competition was to allow shopping customers who return to the incumbent utility the option to select market-based pricing to avoid minimum stay requirements. The Subcommittee recommended the Board consider amending the Act to reflect this proposal, and the Board voted unanimously in support of this recommendation.

4. Triggers for Transition to Competition – Subcommittee on the Status of Competition.

One proposal to the Commission was to place a five-year moratorium on restructuring to monitor the market development elsewhere. The Subcommittee expressed concerns about arbitrary dates and deadlines for the transition to competition. The subcommittee recommended that, in lieu of a five-year moratorium, the Board consider certain triggers be placed in the Act as conditions precedent to each stage of competition. The Board voted to carry this measure over and study it for another year.

5. Energy Management Work Group – Subcommittee on Energy Efficiency.

The Consumer Advisory Board (CAB) recommends that the Legislative Transition Task Force (LTTF) request the State Corporation Commission (the Commission) to organize an Energy Management Work Group. The purpose of this work group would be to identify approaches to encouraging the emergence of cost-effective energy management options such as real-time pricing, time-of-use pricing, real-time peak signaling and dynamic load response applications, consistent with the transition to a restructured electric energy marketplace. This would involve the Commission's staff extending invitations to numerous energy industry entities

to participate, providing a forum and location for stakeholders to meet periodically, and providing an electronic means of posting and exchanging information to: (i) investigate short-term and long-term approaches to encourage voluntary and cost-effective energy management options to consumers within the Commonwealth; (ii) monitor and evaluate the results of similar investigations and pilot programs occurring in other states for potential applicability to Virginia; (iii) identify obstacles to the emergence of cost-effective energy management in Virginia; and (iv) identify tools and information currently available from local distribution companies to assist such investigation. The Work Group will prepare a report of such findings and recommendations for the Board.

The Board voted unanimously in favor of this recommendation.

6. Consumer Education – Jack Greenhalgh.

Greenhalgh recommended that DMME initiate a modest and clearly focused program of customer education in energy management and energy efficiency that is designed to reduce the cost of electricity to Virginia consumers and reduce the risk of power shortages and extreme price swings at times of peak demand. DMME should coordinate with the Board to define an information program containing some specific initiatives from their report, narrowly focused on the most cost effective communications techniques and targeted to those customers most likely to benefit. The total cost would be in line with the low cost option in the DMME Report. The initiatives would include: (i) educational information on an Internet website, coordinated to avoid redundancy with the SCC's "Choice" site; (ii) one or more brochures to be made available to the public by consumer advocacy organizations, local government agencies, Chambers of Commerce, NFIB, Retail Merchants Associations, Civic Leagues, Professional Clubs, etc.; (iii) a limited speaker's bureau program; (iv) a highly focused direct mail program to the customer types that would most likely benefit the most in the short term; (v) initiatives to incorporate energy efficiency and energy management in building codes and in state government owned buildings; and (vi) assistance to municipalities in understanding and planning for energy efficiency and energy management opportunities in public facilities. The proposed program would be submitted to the Board on or before October 1, 2003.

The Board voted unanimously in favor of this recommendation.

7. Legal Separation for Incumbent Utilities – Subcommittee on Status of Competition.

The Commission received a proposal to allow incumbent utilities to legally separate their generation business from their transmission and distribution business. This proposal was not a recommendation of the SCC, and has not been recommended by any other person. However, the subcommittee recommended opposing this concept if it is raised at some point in the future. The Board agreed unanimously to oppose any proposal to allow legal separation of utilities' generation and transmission and distribution businesses.

8. Facility Energy Efficiency – Jack Greenhalgh.

Greenhalgh proposed that DMME prepare a report for the Board, to be completed prior to July 1, 2003, that educates the Consumer Advisory Board on the following issues: (i) how building codes relative to energy management or load management are originated and approved; (ii) how advances in energy efficiency achieved in other states and other nations are identified and considered for incorporation into building codes; and (iii) whether the state government has the authority to establish unique requirements for state-owned facilities and who would have that authority. The Board recommended unanimously to support this proposal.

9. Aggregation – Bill Lukhard.

Bill Lukhard recommended that the appropriate sections of the Virginia Electric Utility Restructuring Act and the Natural Gas Deregulation Act be amended to have the SCC develop models to be used in pilot programs for municipal aggregation to be available no later than January 1, 2004. The models developed should include both "opt-in" and "opt-out" concepts and any other concepts the SCC may develop. The Board recommended these amendments unanimously.

10. Account Assessment Charge – Association of Energy Conservation Professionals.

The Association of Energy Conservation Professionals recommended that the Home Energy Assistance Fund be funded with the Residential Meters/Account Assessment Charge in the amount of three cents per month, to be incorporated into the existing base customer service charge. If the number of residential accounts is 2,890,609 for 12 months, the charge of $0.36 per account per year would yield $1,040,619 for the Fund that year. The monthly meter/account assessment charge would be collected on a monthly basis by the local distribution company and then deposited into the Treasury of the Commonwealth of Virginia for allocation to the Home Energy Assistance Fund. The Board voted eight to four to recommend this proposal.

11. Legislative Transition Task Force – Bill Lukhard.

Bill Lukhard's second proposal addressed the life of the Legislative Transition Task Force: "Given the consumer concerns, the current lack of a retail competitive market, concerns over a volatile wholesale market, etc., the Legislative Transition Task Force should propose legislation to the General Assembly that would extend the life of the Task Force to at least July 1, 2008, which would provide legislative oversight over electric utility restructuring and development of a competitive market after capped rates and wires charges are currently scheduled to expire." The Board recommended this proposal unanimously.

IV. 2003 WORKPLAN

The Consumer Advisory Board appreciates the opportunity to conduct in-depth review of numerous issues affecting Virginia's consumers in a deregulated market. The Board has embraced its role in monitoring the implementation of restructuring through the eyes of consumers, and will continue to do so during the transition to competition. In the 2003 interim, the Board would like to further study (i) the schedule for transition to competition, (ii) aggregation, (iii) the energy management work group (including energy efficiency and demand-

side management), (iv) consumer education for residential and small business consumers, (v) low-income energy assistance, and (vi) incorporation of energy efficiency into building codes and requirements for state owned facilities. The Board would also like to revisit its study of public benefit charges in other states, for both energy efficiency and low-income energy assistance programs. A continued examination of these issues is needed to ensure the emergence of a competitive market while retaining protection for consumers.

The Board stands willing to continue to assist the Task Force, as it may direct, in its work in ensuring the successful implementation of the restructuring of Virginia's electric utility industry.

Respectfully submitted,

William Lukhard, Chairman
Otis Brown, Vice Chairman
James Copp
Beth Doughty
Oswald Gasser
Robert Goldsmith
Jack Greenhalgh
Ann Hedgpeth
Jack Hundley
The Rev. J. Fletcher Lowe
Denny Parker
Lynda Sharp Anderson
Donald F. Sullivan
Jimmie G. Trent
Steve Walker
Bradley J. Wike
Quentin E. Wilhelmi

Status of the Virginia Energy Choice Consumer Education Program
Legislative Transition Task Force
November 26, 2002

1. The primary role of the Virginia Energy Choice consumer education program in its first two years is to increase awareness of energy restructuring and to direct Virginians to information sources such as a toll-free number and a website to learn more.

2. In the 18 months since it began, the Virginia Energy Choice consumer education program has been successful at building consumer awareness of the Commonwealth's move to a competitive energy supply market. More than 43 percent of Virginians now say they have heard or seen VEC information compared to less than 29 percent in June 2001. Although competitive energy service providers are not currently making offers to consumers, a recent survey sponsored by the SCC revealed that 76.3 percent of Virginians are interested in energy choice.

3. Awareness advertising was introduced to the Commonwealth in phases to correspond to the beginning of electric choice for most Virginians. Phase I advertising began in November 2001 in northern Virginia, southwestern Virginia and the Eastern Shore. Phase II advertising began in May 2002 in central and western Virginia. Phase III advertising began in October 2002 in Hampton Roads.

4. Due to the slow development of actual competition, the SCC reduced the spending allocations of the overall consumer education budget by more than 30 percent in the second year of the program ($8.52 million in Year 1 to $5.83 million in Year 2). Paid advertising was reduced 50 percent ($3.74 million to $1.86 million). However, consumer outreach and information programs in Year 2 were maintained at the previous level. (Overall estimated budget for the five-year consumer education program is $30.1 million.)

5. With the input of the Virginia Energy Choice Education Advisory Committee, the SCC continued advertising to correspond with the choice phase-in schedule, but at a significantly reduced level. The SCC has stopped its advertising efforts the Phase I area except for limited print and Internet ads in northern Virginia. Most advertising in the Phase II area will end in December. All broadcast advertising in Hampton Roads will end in March 2003 with billboard and newspaper advertising schedules in that area planned until June 2003. Sports sponsorships (mostly radio commercials) continued into the winter with Virginia Tech, UVA and the Washington Redskins based on annual contracts.

6. We have maintained a limited advertising schedule in northern Virginia. There is a significant amount of competitive activity in that region in the natural gas industry. In the Washington Gas service territory, 20 percent of the residential customers and 33 percent of the commercial customers receive natural gas supply service from competitive service providers (according to WGL's website on November 25).

7. Because of the lack of competitive suppliers, the SCC revised the messages in its advertising. Initially the advertising focused on consumers having the opportunity to choose their energy suppliers. The advertising now encourages Virginians to contact Virginia Energy Choice to learn about changes in the energy industry.

8. Since the Virginia Energy Choice program began in June 2001, nearly 600 statewide and community-based organizations have agreed to help educate consumers about energy choice. Combined, the groups have distributed more than 1.3 million education materials.

9. A few examples: Arlington, Caroline, Culpeper and many other counties have included energy choice articles in county newsletters. The cooperative extension service has developed a complete energy education program for agents conducting workshops and presentations. The Baptist General Convention of Virginia included energy choice materials in its publication the *Baptist Herald."* The Urban League of Richmond is conducting a consumer outreach program for seniors. Several Chambers of Commerce around the state have produced newsletter articles, distributed consumer guides and provided website links.

Status of the Virginia Energy Choice Consumer Education Program
Legislative Transition Task Force
January 7, 2003

In Governor Mark Warner's recommended amendments to the 2002-2004 biennial budget, it's been proposed that the State Corporation Commission suspend all activities of the consumer education program as soon as possible and defer the startup of any additional consumer education program activities for the remainder of the biennium. In total, $8.5 million would be transferred to the general fund. The proposed budget language calls for $2 million to be transferred this fiscal year and $6.5 million in the fiscal year that ends June 30, 2004.

Although the state budget and this particular amendment requires General Assembly approval, the SCC must take a number of steps immediately in order to generate the transfer amount cited in the Governor's recommended amendment. If the General Assembly alters the proposal, the SCC will adjust accordingly.

For now --

- All broadcast, print, billboard, and Internet advertising contracts are being canceled.
- Sports sponsorship contracts with the University of Virginia and Virginia Tech will end in March and not be renewed.
- Outreach efforts with community-based organizations will be suspended.
- No new brochures or other printed materials will be produced.
- The toll-free information line will continue to function, but with an automated system beginning February 1 instead of live customer service representatives.
- The SCC's team of communications contractors has agreed to suspend activities and will await further direction from the SCC.
- The Virginia Energy Choice website will continue to function.
- Virginia Energy Choice consumer guides and information materials are still available from the SCC.
- Commission staff will continue to be available for consumer presentations.
- Already approved consumer education grants will be funded, but no new grants will be awarded during the biennium.

RETAIL COMPETITION PILOTS (500 MW)*

Pilot Program for Municipal Aggregation (100 MW)	Competitive Default Service Pilot (200 MW)	Commercial and Industrial Pilot (200 MW)
• Residential and small business customers • Two localities (about 30,000 customers eligible in each) • One locality "opt-in" (customer chooses to participate) • One locality "opt-out" (automatically included unless customer chooses not to participate) • Localities put bid out for suppliers to serve load • 50% reduction in wires charge provides "headroom" for suppliers	• Residential and small business customers • Up to 50,000 customers • Available to customers anywhere in Dominion Virginia Power system • Customers may initially volunteer • If not fully subscribed, SCC may conduct lottery and assign customers (customer may "opt-out") • SCC "groups" customers and solicits bids from suppliers for each group • 50% reduction in wires charge	• Large commercial and industrial customers (>500 kW demand) • Available to customers anywhere in Dominion Virginia Power system • Estimated at 150 customers based on load • Return to Dominion Virginia Power and the safety net of capped rates • 50% reduction in wires charge
Benefits	**Benefits**	**Benefits**
• Provides additional information on municipal aggregation, the most successful method to bring benefits to residential and small business customers • Provides side-by-side comparison of opt-out and opt-in; will be useful in future SCC rulemakings • Localities learn about administrative requirements and costs	• Complements recently established SCC investigation into default service • Provides case study for SCC in developing rules for competitive bidding of default service • Tests processes for grouping customer loads, conducting bidding, and selecting bid winners	• Tests the concept of SCC suggestions in its August 2002 Report to the LTTF • Provides the SCC, Dominion Virginia Power and customers with the opportunity to collect data and gain insight into the future pricing of default service • Provides knowledge that will be essential after the capped rate period ends

Overall Benefits of Pilots

- The Restructuring Act envisions retail pilots as a careful, measured way to determine the most effective means of promoting competition and stimulating market development in Virginia. Pilots will provide the SCC, LTTF and others with valuable information on whether the Act needs further fine-tuning during the 2006 and 2007 legislative sessions before the end of the transition period.
- Pilots offer a measured alternative to premature wholesale changes in the Restructuring Act. These changes might damage the central principles of the Act, developed through careful legislative study and compromise, and jeopardize the future of restructuring in Virginia.
- Pilots will build confidence among stakeholders, including consumers, that choice will work and provide benefits. Pilots will provide an accurate measure of customer and supplier interest in retail choice and provide a "laboratory" to learn about the mechanics of programs such as municipal aggregation, default service bidding and the future pricing of default service.
- Pilots provide information vital to the LTTF, SCC and other stakeholders for the successful transition to competition without long term commitments to hasty and questionable scenarios.

* Pilot programs developed during 2003, implemented in 2004 and conclude in 2005.

2002 SESSION

ENROLLED

SENATE JOINT RESOLUTION NO. 116

Continuing the study by the Legislative Transition Task Force of procedures applicable to the construction of new electric generation facilities.

Agreed to by the Senate, January 25, 2002
Agreed to by the House of Delegates, March 5, 2002

WHEREAS, Senate Joint Resolution No. 467 (2001) directed the Legislative Transition Task Force to study procedures applicable to the construction of new electric generation facilities in the Commonwealth; and

WHEREAS, the Legislative Transition Task Force is established pursuant to § 56-595 of the Virginia Electric Utility Restructuring Act to work collaboratively with the State Corporation Commission in conjunction with the phase-in of retail competition within the Commonwealth; and

WHEREAS, Senate Joint Resolution No. 467 specifically directed the Legislative Transition Task Force to recommend amendments to the Commonwealth's administrative and regulatory procedures as are appropriate to facilitate the approval of construction of sufficient electricity generation capacity to provide a competitive market for electricity in the Commonwealth as soon as practical, without lessening necessary environmental considerations including siting and air quality impacts; and

WHEREAS, on June 12, 2001, the State Corporation Commission commenced Case No. PUE010313 to establish new filing requirements for entities seeking authority to construct and operate electric generation facilities; and

WHEREAS, on August 3, 2001, the State Corporation Commission entered a preliminary order holding that § 56-580 D of the Virginia Electric Utility Restructuring Act supplant the applicability of §§ 56-234.3 and 56-265.2 of the Code of Virginia with regard to the construction and operation of electric generation facilities after January 1, 2002; and

WHEREAS, on December 14, 2001, the State Corporation Commission entered an order adopting regulations amending the filing requirements for applications to construct and operate electric generation facilities; and

WHEREAS, in its December 14, 2001 order the State Corporation Commission also docketed a new proceeding (Case No. PUE010665) in which the Commission will consider (i) additional rules addressing the cumulative environmental impacts of new electric generation facilities, (ii) filing requirements related to market power, and (iii) expedited permitting processes for small electric generation facilities of fifty megawatts or less; and

WHEREAS, the Legislative Transition Task Force has received briefings from the State Corporation Commission, the Department of Environmental Quality, the Piedmont Environmental Council and other groups regarding the procedures applicable to the construction of new electric generation facilities within the Commonwealth; and

WHEREAS, during the course of its work the Legislative Transition Task Force has become aware of an issue regarding the effect of the ability of operators of electric generation facilities within the Commonwealth to exceed the statewide cap on nitrous oxide emissions through the acquisition of air emissions credits from operators of facilities located in other states; and

WHEREAS, the State Corporation Commission's ongoing review of applicable permitting procedures makes it appropriate for the Legislative Transition Task Force to continue its study of electric generation facility permitting procedures; now, therefore, be it

RESOLVED by the Senate, the House of Delegates concurring, That the study by the Legislative Transition Task Force of procedures applicable to the construction of new electric generation facilities be continued. In conducting the study, the Legislative Transition Task Force shall examine the effects of emissions credit trading on the statewide cap on nitrous oxide emissions.

All agencies of the Commonwealth shall provide assistance to the Legislative Transition Task Force in its conduct of this study, upon request.

The Legislative Transition Task Force shall complete its work by November 30, 2002, and shall submit its written findings and recommendations to the Governor and the 2003 Session of the General Assembly as provided in the procedures of the Division of Legislative Automated Systems for the processing of legislative documents.

Implementation of this resolution is subject to subsequent approval and certification by the Joint Rules Committee. The Committee may withhold expenditures or delay the period for the conduct of the study.

MEMORANDUM OF AGREEMENT

The Department of Environmental Quality ("Department") and the State Corporation Commission ("Commission") enter into this memorandum of agreement ("Agreement"), pursuant to §§ 10.1-1186.2:1 B and 56-46.1 G of the Code of Virginia ("Code"), regarding coordination of reviews of the environmental impacts of proposed electric generating plants and associated facilities ("Impact Review").

1. This agreement supersedes any prior written agreements between the Department and the Commission on the matters addressed herein.

2. The Department and the Commission will notify the other party in writing of the appropriate contact persons for the actions described in this Agreement.

3. The Commission's Staff will notify the Department in writing within five (5) business days of receiving an application for certification of an electric generating facility. No later than ten (10) business days after receipt of the environmental impact analysis information contained in the application, the Department will advise the Commission's Staff and the applicant in writing as to:

   A. the completeness of the information received;

   B. the estimated length of time required to conclude the Impact Review; and

   C. whether the proposed facility is located in a region that was designated, as of July 1, 2001, as serious nonattainment for the one-hour ozone standard as set forth in the federal Clean Air Act.

   If the Department determines the environmental impact analysis information contained in an application is incomplete, within ten (10) business days of notifying the applicant the Department will notify the Commission's Staff in writing and include a listing of the information needed to initiate the Impact Review. The Department and the Commission's Staff may confer from time to time on these matters.

4. In accordance with §§ 56-46.1 A and 56-580 D of the Code, permits and approvals required for an electric generating plant and associated facilities that are issued or granted by a federal, state or local governmental entity charged by law with responsibility for issuing permits or approvals regulating environmental impact and mitigation of adverse environmental impact will be deemed to satisfy the requirements of §§ 56-46.1 A and 56-580 D of the Code with respect to all matters that (i) are governed by the permit or approval, or (ii) are within the authority of, and were considered by, the governmental entity in issuing such permit or approval, and the Commission will impose no additional conditions with respect to such matters.

5. In accordance with §§ 10.1-1186.2:1, 56-46.1 A, and 56-580 D of the Code:

   A. No later than sixty (60) days after initiating the review of the environmental impact analysis information contained in the application, the Department will submit to the Commission's Staff in writing:

      (i) a notification that the Impact Review has been completed; or

      (ii) a notification that the Impact Review has been suspended due to matters discovered during the review. The notification will include a description of the information needed to resume the review.

   B. Enclosed in the written notification described in 5.A.(i), above, for all Completed Impact Reviews the Department will submit a written report to the Commission which includes:

      (i) a summary of the findings and any recommendations for the Commission's consideration which resulted from the review; and

      (ii) a list of all environmental permits and approvals required for the proposed facility which were identified during the Impact Review, and the federal, state, or local governmental entity responsible for granting each permit and approval identified during the review.

      For each environmental permit or approval identified during the Impact Review, the Department's report will include:

         (a) for each governmental entity that grants an environmental permit or approval, a listing of environmental issues identified during the review process, which (1) are not governed by the environmental permit or approval, or (2) are not within the authority of, and not considered by, the governmental entity in issuing such permit or approval; and

         (b) the current status of, and any changes in the estimated length of time to conclude, all environmental permit or approval processes.

6. In accordance with § 10.1-1186.2:1 C of the Code, the Department may request assistance from agencies of the Commonwealth as needed to complete reviews of the environmental impacts of proposed electric generating plants and associated facilities.

7. If requested by the Commission's Staff, one or more members of the Department's Staff will appear as a witness at the Commission's evidentiary hearing to testify regarding the activities of the Department with respect to the proposed electric generating plant and associated facilities. The Department also may coordinate the testimony of other governmental agencies on environmental issues.

8. If requested by the Commission's Staff, the Department will endeavor to provide, or seek to coordinate from other governmental entities issuing environmental permits or approvals, expert assistance to the Commission's Staff on issues regarding environmental impacts and mitigation of adverse environmental impacts.

Robert G. Burnley

Robert G. Burnley, Director — 8/14/2002
Department of Environmental Quality

Clinton Miller

Clinton Miller, Chairman — 8/14/2002
State Corporation Commission

Theodore V. Morrison, Jr.

Theodore V. Morrison, Jr., Commissioner — 8/14/2002
State Corporation Commission

Hullihen Williams Moore

Hullihen Williams Moore, Commissioner — 8/14/2002
State Corporation Commission

SCC Staff Restructuring Overview
Legislative Transition Task Force Meeting
June 21, 2002

1. Competitive activity in service territories now open to competition.

Competitive Offers in service territories of AEP, Allegheny Power or Conectiv. There have been no competitive offers in the service territories of AEP, Allegheny Power or Conectiv since January 1, 2002 when these service territories were fully opened to retail choice.

Competitive Officers in Virginia Power service territory. Currently, residential customers in the northern region of the company's service area are eligible to shop as are one-third of the statewide Commercial and Industrial customers. There is currently one competitive service provider ("CSP") with an offer for residential customers: Pepco Energy Services ("Pepco").

Pepco currently offers *renewable energy* to residential customers at a price approximately two cents per kWh *higher* than Virginia Power's price to compare. Put another way, customers choosing this Pepco offer pay two cents more per kWh for their generation than non-shopping customers. Pepco has signed up 2,265 residential customers (as of June 12, 2002) in response to this offer. Pepco Energy Service also has 24 commercial customers that have contracted for *non-renewable* generation in Virginia Power's service territory. The power contracts between these commercial customers and Pepco are established on a bi-lateral basis, and so the generation prices paid by these customers are not available.

On September 1, another one-third of Virginia Power's customers in the Central/Western region of its service territory will have retail choice with the final third (Eastern region) eligible to shop beginning January 1, 2003. Thus, on January 1, 2003, all areas served by Virginia Power will be eligible to shop for generation supply.

NOVEC's planned phase-in of retail choice on July 1, 2002. On February 1, 2002, Northern Virginia Electric Cooperative filed its compliance tariffs for opening its territory to retail access effective July 1, 2002. In its filing, NOVEC included rates, charges and terms and conditions for unbundled default and distribution electric service. It also provided its proposed Competitive Service Provider tariffs. In a closely related proceeding, the Commission reviewed the wires charge proposal by NOVEC and the other electric cooperatives.

In their wires charges proposal, the cooperatives sought Commission authority to "float" their generation market prices in tandem with their unbundled generation rates, as adjusted monthly to reflect changes in the cost of fuel/wholesale power.[1] The purpose of this proposal

[1] Pursuant to the Restructuring Act, ODEC Cooperatives can adjust the generation cap in connection with the recovery of fuel costs; non-ODEC Cooperatives can make such an adjustment to reflect changes in purchased power costs.

was to maintain a constant, *annual* wires charge for shopping cooperative customers (as required under the Restructuring Act) while simultaneously ensuring that cooperatives are permitted to flow through fuel/wholesale power adjustments to their generation rates. This cooperative proposal was approved by Commission order on May 24, 2002.

Additionally, a Commission Order concerning NOVEC's compliance tariffs was entered on June 18, 2002.

Overall assessment of Retail Choice activity, to date. There is little shopping activity in Virginia at this time. Staff has heard from potential CSPs that the structure of Virginia's Restructuring Act acts as a deterrent to the development of a competitive retail market for generation. Specifically, they say, price caps and wires charges do not allow enough "headroom" to make an offer that covers their energy costs, marketing costs and permit a return. However, some incumbent utilities have said that it's early in the process, and that competition will need time to develop. Both views were expressed in the context of comments solicited by the Staff in connection with the Commission's preparation of its second annual report on the Status of the Development of Retail Competition in the Commonwealth pursuant to § 56-596 A of the Restructuring Act (discussed below).

Statutory and Regulatory References: § 56-577 of the Restructuring Act requires retail choice in all incumbent utilities' service territories by January 1, 2004. Commission's final order in Case No. PUE000740, established timeline for all incumbents to be fully phased in by January 1, 2004.

2. The Commission's retail access consumer education program.

The first year of the Commission's five-year statewide consumer education program had one primary goal -- assist the SCC with its legislative directive to advance the development of a competitive energy supply market by providing clear, accurate and objective information to Virginia consumers. As such, the program is guided by the §§ 56-592.1 and 56-596 of the Restructuring Act.

Ongoing research shows that progress has been made in building awareness of Virginia Energy Choice. As a result of Phase 1 advertising and outreach, consumer awareness of Virginia's transition to retail choice rose from 28.8 percent to 40.2 percent; business leader awareness rose from 38.4 percent to 51.9 percent. The research also shows that Virginians still have a lot to learn about energy restructuring, not surprising given the early stages of a developing market. Overall, interest in choice remains high at 71.9 percent.

The program, launched last November in Phase I areas (Northern and SW Virginia), has been effective at building consumer awareness. As such, the SCC is staying the course regarding its consumer education effort in the Phase II area (Central Virginia), which began this month, and the Phase III area (Tidewater) which will get underway in the fall.

Modifications are being made on account of the current lack of market activity. Grassroots efforts have been strengthened. Paid advertising levels have been reduced by approximately one-third. This approach allows the competitive market to be introduced to consumers in newly phased-in areas of the state while reducing the overall visibility of the program in areas where the market is open, but offers are extremely limited to allow for active shopping.

The following chart summarizes the Virginia Energy Choice Year One expenditures, and also shows the original Year Two Budget, and the recently revised budget for Year Two.

	Year 1 Actual	**Year 2 Original**	**Year 2 Revised**
Advertising	$4.52 million	$4.14 million	$2.74 million
Grassroots	$1.23 million	$1.10 million	$1.10 million
Public Relations	$670,000	$380,000	$380,000
Contract Services	$2.1 million	$1.75 million	$1.75 million
Total	**$8.52 million**	**$7.37 million**	**$5.97 million**

Since it appears for now that competition is developing at a slower pace than anticipated, flexibility is important. A shift in messaging to manage consumer expectations is warranted. This strategic shift will affect the priority in which key knowledge points are communicated - away from knowledge needed for "active shopping" toward information needed to reinforce the fact that it is never too early to learn about the coming competitive market. The message can also communicate consumer protections.

As program effectiveness continues to be evaluated, knowledge gained from research and practical experience will be used to develop the most effective communications strategies over the remaining years of the education effort. The SCC will continue seeking advice and input from the program's consumer education advisory committee and, of course, the LTTF and its Consumer Advisory Board.

Highlights from the 1st year –

* 500,000 consumer guides distributed
* 102,000 visitors to the Virginia Energy Choice web site
* 9,000 calls to the Virginia Energy Choice call center
* 275 community-based organizations are helping educate their members
* 155 print news articles about program published throughout the state

Statutory Reference: The Consumer Education Program's scope and funding is established under § 56-592.1 of the Restructuring Act. It is funded through the Commission's special regulatory tax (§ 58.1-2900).

3. Activities related to the Commission's development of its second annual competition status report pursuant to 56-596.

As required by § 56-596 B of the Restructuring Act, the Commission is preparing its annual report on the status of retail competition to by filed by September 1, 2002. As outlined below, the report follows the report structure established in this statute, and will be presented as follows:

Part 1 - Status of Competition in the Commonwealth. A comprehensive review of the transition from retail pilot programs to full retail access is being prepared. It will include all restructuring related activities that have occurred since last year's report.

Part 2 - Status of the Development of Regional Competitive Markets - We have once again contracted with Dr. Ken Rose of the National Regulatory Research Institute to prepare this section of the report.

Part 3 - Recommendations to Facilitate Effective Competition in the Commonwealth - A letter was sent to over 60 parties on April 24th (copy attached) Sixteen parties provided written comments. A discussion meeting was held on June 4th. At that meeting, 29 people (not counting Staff) were present representing 14 parties. The Staff has requested supplemental written comments by July 1st.

4. The Commission's aggregation investigation.

By Order dated March 18, 2002, in Case No. PUE-2002-00174, the Commission established an investigation of aggregation services. The purpose of the investigation was to determine whether as part of the phase-in of retail choice, further clarification with respect to aggregation is needed.

The Staff was directed to conduct the investigation with input from a stakeholder working group. The Commission outlined three specific categories for review: (i) licensing of aggregators, (ii) contractual relationships between aggregators and their customers, and (iii) the impact of incumbents' aggregator affiliates on the development of effective competition within the Commonwealth.

On May 1, 2002, a Work Group meeting was held. Twenty-five interested parties joined Commission Staff members to discuss the issues identified in the Commission's Order as well as other issues identified by the group.

On May 22, 2002, Staff sent a memo summarizing six main issues discussed in the Work Group meeting (copy attached) and requested additional comments by June 10, 2002 (subsequently extended to June 28). This memo went to the Work Group meeting participants as well as other interested parties that were unable to attend the May 1 meeting.

By August 1, 2002, Staff will file a report with the Commission detailing the results of its investigation, together with any recommendations Staff proposes for the Commission's consideration and review.

Statutory Reference: Section 56-588 of the Restructuring Act establishes the licensing requirements for aggregators; the definition of "aggregator" in § 567-576 of the Restructuring Act, establishes a definition framework for aggregation, while also identifying some activities that are not "in and of themselves" ultimately indicative of aggregation activity.

5. Merchant plant activity (applications, orders, etc.).

As evident from the attached chart, there is continued interest in the construction of merchant generation plants within the Commonwealth..

As we have previously reported to you, on December 14, 2001, the Commission adopted new rules for power plant filings and sought comment on additional rules regarding the cumulative impacts of power plant proposals and market power considerations. Since then, the 2002 Session of the Virginia General Assembly enacted Senate Bill 554. This bill established a statutory framework concerning the relationship between this Commission and DEQ and environmental reviews associated with proposed facilities.

In the meantime, the Commission's Staff has continued its work on proposed rules concerning market power, the cumulative effects of power plants on gas pipelines and on streamlined certification procedures. The Staff held stakeholder workgroup meetings concerning these issues in February and March of this year, and stakeholders filed written comments. The Staff subsequently filed its report with the Commission concerning issues other than cumulative environmental impacts on April 19, 2002.

An important component of SB 554 (set forth in new § 10.1-1186.2:1 B of the Virginia Code) is the legislative directive to the SCC and DEQ that the two agencies enter into a Memorandum of Agreement ("MOA"), "regarding the coordination of reviews of the environmental impacts of proposed electric generating facilities that must obtain certificates from the State Corporation Commission." Following extensive discussions between the two agencies, a draft MOA has been prepared. The SCC and DEQ have invited written comments from interested persons on the draft MOA, which also is scheduled to be published in the Virginia Register for the purpose of inviting public comment prior to the MOA's finalization. Comments will be received on July 10 and 24.

The final MOA will be completed as soon as possible thereafter. The SCC will act under the new statutory standards in SB 554, beginning July 1, in both new and pending cases before the SCC. Pending the MOA's final form, and ultimate adoption by the two agencies following the comment period, the two agencies are working cooperatively with respect to the coordination of these reviews. Copies of the MOA and the Commission's Order inviting comments are attached.

7. Staff inquiry into stakeholder views concerning default service furnished by non-incumbents via bidding process pursuant to 56-585 B 2.

Section 56-585 of the Restructuring Act requires incumbent utilities to provide default service to those retail customers who do not or cannot obtain service from an alternative supplier. Default service is also available to consumers whose alternative supplier fails to perform. Under the current language of § 56-585, and consistent with the Commission-established phase-in schedule, default service will be provided to retail customers of Virginia's incumbent electric utilities effective January 1, 2004. Default rates (when that service is provided by incumbents) are the incumbents' capped rates until July 1, 2007. Thereafter, default service when provided by incumbents will be priced by the Commission to reflect generation prices prevailing in the "competitive regional electricity market," or some proxy for that market.

While the Commission can require the incumbent distribution utility to provide one or more components of default service, the Restructuring Act permits the Commission to designate alternative default service providers via a competitive bidding process conducted by the Commission. Consistent with the public interest, the Commission may, in conjunction with that bidding process, designate such alternative default service providers: (i) for specific components of that service, (ii) for specific geographic areas within the Commonwealth and (iii) for one or more classes of customers.

The SCC Staff has initiated an effort to determine the interest in and feasibility of having default service provided by alternative default suppliers in furtherance of this statutory option. Consequently, by letter dated June 10, 2002 (copy attached), the SCC Staff solicited written input from restructuring stakeholders on this topic and has scheduled at meeting on October 4, 2002, for purposes of obtaining further input on this important topic.

8. Staff inquiry into stakeholder views concerning the gathering of reliability data, as per Senate Bill 684 of the 2002 Session.

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, gas transmission facilities, and gas storage facilities serving the Commonwealth. This information encompasses data relative to the electric and gas loads imposed by Virginia consumers and the dedication of the facilities to the service of those loads.

In response to this legislative directive, the Commission's Staff has solicited written comments from stakeholders (see, attached letter) addressing the *"feasibility, effectiveness and value"* of collecting the information detailed in Senate Bill 684, giving consideration to (i) the Commission's responsibilities under the Restructuring Act, and (ii) the language in Senate Bill 684 relative to the *"... purpose of monitoring the adequacy of the energy infrastructure within the Commonwealth..."* Additionally, the Staff will convene a meeting of interested stakeholders on July 10, 2002 to discuss the issues raised by SB-684.

9. **Wires Charges. Staff inquiry into stakeholder views concerning the calculation of market prices for purposes of determining incumbents' wires charges.**

As directed by §56-583 A of the Virginia Electric Utility Restructuring Act, the State Corporation Commission must calculate projected market prices for generation for the purpose of establishing wires charges for customers taking electric service from Competitive Service Providers (CSPs).

As we reported to you last year, a hearing concerning the market pricing of generation for purposes of determining wires charges was held before the Commission in September 2001. The principal issue before the Commission was the determination of an appropriate market price methodology, i.e., whether to base the price on forward-looking data versus historical data or some combination. An order was issued by the Commission on November 19, 2001. Wires charges and prices to compare were established for Virginia Power. Prices to compare were determined for AEP, Allegheny and Connectiv (Delmarva), companies that had waived their rights to collect wires charges (although AEP's waiver of wires charges was limited to calendar year 2002, only).

The Commission has begun the process of setting wires charges for 2003. As part of that process, incumbent utilities are required to file proposals on or before July 1, 2002, related to the calculation of projected market prices as per Commission Order in Case No. PUE-2001-00306 (11/19/01).

The Commission Staff is once again soliciting ideas from stakeholders (including electric utilities, competitive service providers, consumer groups, gas utilities and business associations) to assist the Commission in developing a comprehensive review of methods that may be considered to calculate projected market prices and resulting wires charges (see, attached letter). Staff is most interested in soliciting stakeholder views concerning potential appropriate changes to the methods of calculation applicable to incumbents' in their upcoming July 1 market price filings. Such changes may include conceptual changes and/or different or additional data sources. For example, Staff is interested in exploring the appropriateness, feasibility and method of potentially incorporating the value of generating capacity into the current method of market price determination. As an important follow-up to responses from stakeholders on this topic, the Commission Staff will host a stakeholder meeting on July 24, 2002 to continue the discussion.

10. **Development of competitive metering and billing rules.**

Overview. On May 15, 2001, pursuant to § 56-581.1 D and F, the Commission established dockets to establish rules and regulations for implementation of supplier (i.e., CSP) consolidated billing and competitive metering. With respect to each of these matters, the Commission directed the Staff to invite interested parties to participate in a work group to aid in the Staff's development of proposed rules. Based on input solicited from participants in the workgroups through a series of meetings and e-mail correspondence, the Staff submitted a report on February 14, 2002, proposing rules for competitive metering services, and a report on May 24, 2002, proposing rules for supplier consolidated billing service. Comments on the Staff's proposed metering rules have been received and a Commission Order adopting final rules is

pending. Comments on the Staff's proposed supplier consolidated billing rules are due on June 27, 2002.

The development of proposed rules for supplier consolidated billing and competitive metering presents significant challenges due to the lack of significant competitive metering and billing activity nationally, and therefore, a corresponding lack of proven market structures and standardized business practices. In fact, many states have delayed or slowed implementation efforts for these services. This is likely attributable to the relatively slow pace with which competitive retail and wholesale electricity markets have developed.

Competitive Metering. With respect to metering, the Staff is not aware of significant market development of competitive metering in any state where such competition is authorized. It was the consensus opinion of work group participants that the most critical aspect of metering service relative to advancing competitive electricity markets was the availability and accessibility of interval meter data by customers and suppliers. Accordingly, the initially proposed competitive metering rules focus on ensuring that customers and/or suppliers have a reasonable option for obtaining advanced or interval metering service, including direct access to meter data. Such service would allow suppliers to send improved price signals to their retail customers and would enhance the value of competitive energy management services. The Staff, with the assistance of the metering work group, is continuing its evaluation of other elements of metering services and will submit another report with additional recommendations later this summer.

Supplier Consolidated Billing. With respect to supplier consolidated billing, the Staff has proposed amending existing retail access rules for utility consolidated billing to incorporate reciprocal requirements for both utility and supplier consolidated billing. Additionally, the Staff has proposed requiring a supplier to provide the incumbent utility and the Staff with notice at least 30 days in advance of offering such service to allow for validation of the supplier's system testing and for establishment of satisfactory creditworthiness with respect to state, local and regulatory consumption tax collections. To avoid the potential for unwarranted service disconnection due to miscommunication between the utility and the supplier, the Staff also has proposed that utilities be required to issue disconnect notices directly to retail customers, separate from the supplier consolidated bill.

It should be noted that work group representatives of the investor-owned electric utilities proposed that, subsequent to the Commission's adoption of final rules for supplier consolidated billing, incumbent utilities not be required to proceed with system development of standardized electronic data exchange protocols. The utilities represented that due to: 1) the significant system development cost; 2) the current uncertainty of market development and the potential for substantial future rework; and 3) limited supplier participation, a more appropriate alternative at present would be to allow incumbent utilities to work with any interested suppliers to develop a work-around to standardized electronic protocols until such time as supplier interest increases in providing this service. Suppliers offering informal comments to the Staff have generally agreed with this approach at the current time and the Staff supported this proposal in its report to the Commission.

11. Distributed Generation.

The Restructuring Act in § 56-578 D requires the Commission to enable the permitting and interconnection of "distributed generation." These generating facilities are interconnected at the distribution (versus transmission) level, hence "distributed generation." For working purposes, the Staff has been treating units interconnected at the distribution level, with capacities between 500 kilowatts and 10 megawatts, as distributed generation.

A draft of proposed standards for distributed generation was provided by the Staff to stakeholders with a request for feedback by April 19, 2002. Comments were received from AEP, VP, Rappahannock Electric Cooperative, Conectiv, and Columbia Gas. Staff is scheduled to meet with these respondents on June 21, 2002, to further discuss and consider their suggestions for integration into a new draft standard. The Staff also hopes to incorporate into proposed Virginia standards, elements from national standards being developed by the National Association of Regulatory Commissioners ("NARUC") and the Institute of Electrical and Electronics Engineers, Inc ("IEEE"), as and when they are finalized. Ultimately, proposed standards for distributed generation interconnection will be submitted by the Staff to the Commission for its review and approval.

12. Regional Transmission Organizations.

An update on the status of Regional Transmission Organizations ("RTO) and their development, has been furnished to the LTTF as a separate report.

APPENDIX O: Applications to Join Regional Transmission Entities

§ 56-577. Schedule for transition to retail competition; Commission authority.

A. The transition to retail competition for the purchase and sale of electric energy shall be implemented as follows:

1. ~~On or before January 1, 2001, each~~ Each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity shall join or establish a regional transmission entity, which entity may be an independent system operator, to which such utility shall transfer the management and control of its transmission system, subject to the provisions of § 56-579.

2. On and after January 1, 2002, retail customers of electric energy within the Commonwealth shall be permitted to purchase energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth during and after the period of transition to retail competition, subject to the following:

a. The Commission shall separately establish for each utility a phase-in schedule for customers by class, and by percentages of class, to ensure that by January 1, 2004, all retail customers of each utility are permitted to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth.

b. The Commission shall also ensure that residential and small business retail customers are permitted to select suppliers in proportions at least equal to that of other customer classes permitted to select suppliers during the period of transition to retail competition.

3. On and after January 1, 2002, the generation of electric energy shall no longer be subject to regulation under this title, except as specified in this chapter.

4. On and after January 1, 2004, all retail customers of electric energy within the Commonwealth, regardless of customer class, shall be permitted to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth.

B. The Commission may delay or accelerate the implementation of any of the provisions of this section, subject to the following:

1. Any such delay or acceleration shall be based on considerations of reliability, safety, communications or market power; and

2. Any such delay shall be limited to the period of time required to resolve the issues necessitating the delay, but in no event shall any such delay extend the implementation of customer choice for all customers beyond January 1, 2005.

The Commission shall, within a reasonable time, report to the General Assembly, or any legislative entity monitoring the restructuring of Virginia's electric industry, any such delays and the reasons therefor.

C. Except as may be otherwise provided in this chapter, prior to and during the period of transition to retail competition, the Commission may conduct pilot programs encompassing retail customer choice of electric energy suppliers, consistent with its authority otherwise provided in this title and the provisions of this chapter.

D. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this section.

E. By January 1, 2002, the Commission shall promulgate regulations establishing whether and, if so, for what minimum periods, customers who request service from an incumbent electric utility pursuant to subsection D of § 56-582 or a default service provider, after a period of receiving service from other suppliers of electric energy, shall be required to use such service from such

incumbent electric utility or default service provider, as determined to be in the public interest by the Commission.

§ 56-579. Regional transmission entities.

A. As set forth in § 56-577, ~~on or before January 1, 2001,~~ each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity shall join or establish a regional transmission entity , which hereafter may be referred to as an ~~("~~"RTE~~),~~" to which such utility shall transfer the management and control of its transmission assets, subject to the following:

1. No such incumbent electric utility shall transfer to any person any ownership or control of, or any responsibility to operate, any portion of any transmission system located in the Commonwealth without obtaining, following notice and hearing, the prior approval of the Commission, as hereinafter provided.

2. The Commission shall develop rules and regulations under which any such incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity within the Commonwealth, may transfer all or part of such control, ownership or responsibility to an RTE, upon such terms and conditions that the Commission determines will:

a. Promote:

(1) Practices for the reliable planning, operating, maintaining, and upgrading of the transmission systems and any necessary additions thereto; and

(2) Policies for the pricing and access for service over such systems~~,~~ ~~which~~ that are safe, reliable, efficient, not unduly discriminatory and consistent with the orderly development of competition in the Commonwealth;

b. Be consistent with lawful requirements of the Federal Energy Regulatory Commission;

c. Be effectuated on terms that fairly compensate the transferor;

d. Generally promote the public interest, and are consistent with (i) ensuring ~~the successful development of interstate regional transmission entities~~ that consumers' needs for economic and reliable transmission are met and (ii) meeting the transmission needs of electric generation suppliers both within and without this Commonwealth, including those that do not own, operate, control or have an entitlement to transmission capacity.

B. The Commission shall also adopt rules and regulations, with appropriate public input, establishing elements of regional transmission entity structures essential to the public interest, which elements shall be applied by the Commission in determining whether to authorize transfer of ownership or control from an incumbent electric utility to a regional transmission entity.

C. The Commission shall, to the fullest extent permitted under federal law, participate in any and all proceedings concerning regional transmission entities furnishing transmission services within the Commonwealth, before the Federal Energy Regulatory Commission. Such participation may include such intervention as is permitted state utility regulators under ~~FERC~~ Federal Energy Regulatory Commission rules and procedures.

D. Nothing in this section shall be deemed to abrogate or modify:

1. The Commission's authority over transmission line or facility construction, enlargement or acquisition within this Commonwealth, as set forth in Chapter 10.1 (§ 56-265.1 et seq.) of this title;

2. The laws of this Commonwealth concerning the exercise of the right of eminent domain by a public service corporation pursuant to the provisions of Article 5 (§ 56-257 et seq.) of Chapter 10 of this title; however, on and after January 1, 2002, a petition may not be filed to exercise the right of eminent domain in conjunction with the construction or enlargement of any utility facility whose purpose is the generation of electric energy; or

3. The Commission's authority over retail electric energy sold to retail customers within the Commonwealth by licensed suppliers of electric service, including necessary reserve requirements, all as specified in § 56-587.

E. For purposes of this section, transmission capacity shall not include capacity that is primarily operated in a distribution function, as determined by the Commission, taking into consideration any binding federal precedents.

F. ~~On or after January 1, 2002, the~~ Any request to the Commission for approval of such transfer of ownership or control of or responsibility for transmission facilities shall include 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. The Commission may approve such a transfer if it finds, after notice and an opportunity for a hearing, that the transfer satisfies the conditions contained in this section. If a proposed transfer does not satisfy a condition contained in this section, the Commission may require that the transmission system be upgraded prior to approving such a transfer.

G. The Commission shall report annually to the Legislative Transition Task Force its assessment of the success in the practices and policies of the RTE facilitating the orderly development of competition in the Commonwealth. Such report shall set forth actions taken by the Commission regarding requests for the approval of any transfer of ownership or control of transmission facilities to an RTE, including a description of the economic effects of such proposed transfers on consumers.

APPENDIX P: Preservation of State Jurisdiction Regarding Reliability Issues

§ 56-579. Regional transmission entities.

A. As set forth in § 56-577, on or before January 1, 2001, each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity shall join or establish a regional transmission entity (RTE) to which such utility shall transfer the management and control of its transmission assets, subject to the following:

1. No such incumbent electric utility shall transfer to any person any ownership or control of, or any responsibility to operate, any portion of any transmission system located in the Commonwealth without obtaining the prior approval of the Commission, as hereinafter provided.

2. The Commission shall develop rules and regulations under which any such incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity within the Commonwealth, may transfer all or part of such control, ownership or responsibility to an RTE, upon such terms and conditions that the Commission determines will:

a. Promote:

(1) Practices for the reliable planning, operating, maintaining, and upgrading of the transmission systems and any necessary additions thereto; and

(2) Policies for the pricing and access for service over such systems, which are safe, reliable, efficient, not unduly discriminatory and consistent with the orderly development of competition in the Commonwealth;

b. Be consistent with lawful requirements of the Federal Energy Regulatory Commission;

c. Be effectuated on terms that fairly compensate the transferor;

d. Generally promote the public interest, and are consistent with (i) ensuring the successful development of interstate regional transmission entities and (ii) meeting the transmission needs of electric generation suppliers both within and without this Commonwealth.

Moreover, no such transfer shall result in the direct or indirect transfer of jurisdiction from this Commonwealth to the Federal Energy Regulatory Commission or any other entity over the reliability or price of generation serving current or future load in this Commonwealth; nor shall any such transfer negatively affect the reliability or pricing of such generation.

§ 56-580. Transmission and distribution of electric energy.

A. The Commission shall continue to regulate pursuant to this title the distribution of retail electric energy to retail customers in the Commonwealth and, to the extent not prohibited by federal law, the transmission of electric energy in the Commonwealth.

B. The Commission shall continue to regulate, to the extent not prohibited by federal law, the reliability, quality and maintenance by transmitters and distributors of their transmission and retail distribution systems.

C. The Commission shall develop codes of conduct governing the conduct of incumbent electric utilities and affiliates thereof when any such affiliates provide, or control any entity that provides, generation, distribution, transmission or any services made competitive pursuant to § 56-581.1, to the extent necessary to prevent impairment of competition.

D. The Commission shall permit the construction and operation of electrical generating facilities upon a finding that such generating facility and associated facilities (i) will have no material adverse effect upon reliability of electric service provided by any regulated public utility and (ii) are not otherwise contrary to the public interest. In review of a petition for a certificate to construct and operate a generating facility described in this subsection, the Commission shall give consideration to the effect of the facility and associated facilities on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact as provided in § 56-46.1. In order to avoid duplication of governmental activities, any valid permit or approval required for an electric generating plant and associated facilities issued or granted by a federal, state or local governmental entity charged by law with responsibility for

issuing permits or approvals regulating environmental impact and mitigation of adverse environmental impact or for other specific public interest issues such as building codes, transportation plans, and public safety, whether such permit or approval is prior to or after the Commission's decision, shall be deemed to satisfy the requirements of this section with respect to all matters that (i) are governed by the permit or approval or (ii) are within the authority of, and were considered by, the governmental entity in issuing such permit or approval, and the Commission shall impose no additional conditions with respect to such matters. Nothing in this section shall affect the ability of the Commission to keep the record of a case open. Nothing in this section shall affect any right to appeal such permits or approvals in accordance with applicable law. In the case of a proposed facility located in a region that was designated as of July 1, 2001, as serious nonattainment for the one-hour ozone standard as set forth in the federal Clean Air Act, the Commission shall not issue a decision approving such proposed facility that is conditioned upon issuance of any environmental permit or approval.

E. Nothing in this section shall impair the distribution service territorial rights of incumbent electric utilities, and incumbent electric utilities shall continue to provide distribution services within their exclusive service territories as established by the Commission. Nothing in this chapter shall impair the Commission's existing authority over the provision of electric distribution services to retail customers in the Commonwealth including, but not limited to, the authority contained in Chapters 10 (§ 56-232 et seq.) and 10.1 (§ 56-265.1 et seq.) of this title.

F. Nothing in this chapter shall impair the exclusive territorial rights of an electric utility owned or operated by a municipality as of July 1, 1999, nor shall any provision of this chapter apply to any such electric utility unless (i) that

municipality elects to have this chapter apply to that utility or (ii) that utility, directly or indirectly, sells, offers to sell or seeks to sell electric energy to any retail customer outside the geographic area that was served by such municipality as of July 1, 1999, except any area within the municipality that was served by an incumbent public utility as of that date but was thereafter served by an electric utility owned or operated by a municipality pursuant to the terms of a franchise agreement between the municipality and the incumbent public utility. If an electric utility owned or operated by a municipality as of July 1, 1999, is made subject to the provisions of this chapter pursuant to clause (i) or (ii) of this subsection, then in such event the provisions of this chapter applicable to incumbent electric utilities shall also apply to any such utility, mutatis mutandis.

G. The applicability of this chapter to any investor-owned incumbent electric utility whose portion of total energy sales subject to the jurisdiction of the Commission does not exceed 10 percent shall be suspended until the Commission determines that residential customers within such utility's exclusive service territory in any other state are permitted to purchase electricity from competitive service providers. During any such suspension period, the utility's rates shall be (i) its capped rates established pursuant to § 56-582 for the duration of the capped rate period established thereunder, and (ii) determined thereafter by the Commission on the basis of such utility's prudently incurred costs pursuant to Chapter 10 (§ 56-232 et seq.) of this title.

APPENDIX R: Pilot Programs for Aggregation

§ 56-577. Schedule for transition to retail competition; Commission authority.

A. The transition to retail competition for the purchase and sale of electric energy shall be implemented as follows:

1. On or before January 1, 2001, each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity shall join or establish a regional transmission entity, which entity may be an independent system operator, to which such utility shall transfer the management and control of its transmission system, subject to the provisions of § 56-579.

2. On and after January 1, 2002, retail customers of electric energy within the Commonwealth shall be permitted to purchase energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth during and after the period of transition to retail competition, subject to the following:

a. The Commission shall separately establish for each utility a phase-in schedule for customers by class, and by percentages of class, to ensure that by January 1, 2004, all retail customers of each utility are permitted to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth.

b. The Commission shall also ensure that residential and small business retail customers are permitted to select suppliers in proportions at least equal to that of other customer classes permitted to select suppliers during the period of transition to retail competition.

3. On and after January 1, 2002, the generation of electric energy shall no longer be subject to regulation under this title, except as specified in this chapter.

4. On and after January 1, 2004, all retail customers of electric energy within the Commonwealth, regardless of customer class, shall be permitted to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth.

B. The Commission may delay or accelerate the implementation of any of the provisions of this section, subject to the following:

1. Any such delay or acceleration shall be based on considerations of reliability, safety, communications or market power; and

2. Any such delay shall be limited to the period of time required to resolve the issues necessitating the delay, but in no event shall any such delay extend the implementation of customer choice for all customers beyond January 1, 2005.

The Commission shall, within a reasonable time, report to the General Assembly, or any legislative entity monitoring the restructuring of Virginia's electric industry, any such delays and the reasons therefor.

C. Except as may be otherwise provided in this chapter, prior to and during the period of transition to retail competition, the Commission may conduct pilot programs encompassing retail customer choice of electric energy suppliers, consistent with its authority otherwise provided in this title and the provisions of this chapter. The Commission shall develop models for conducting pilot programs for municipal aggregation, including opt-in, opt-out, and any other model the Commission deems to be in the public interest. The Commission shall report such models to the Legislative Transition Task Force no later than November 1, 2003.

D. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this section.

E. By January 1, 2002, the Commission shall promulgate regulations establishing whether and, if so, for what minimum periods, customers who request service from an incumbent electric utility pursuant to subsection D of § 56-582 or a default service provider, after a period of receiving service from other suppliers of electric energy, shall be required to use such service from such incumbent electric utility or default service provider, as determined to be in the public interest by the Commission.

§ 56-589. Municipal and state aggregation.

A. Counties, cities and towns (hereafter municipalities) and other political subdivisions of the Commonwealth may, at their election and upon authorization by majority votes of their governing bodies, aggregate electrical energy and demand requirements for the purpose of negotiating the purchase of electrical energy requirements from any licensed supplier within this Commonwealth, as follows:

1. Any municipality or other political subdivision of the Commonwealth may aggregate the electric energy load of residential, commercial and industrial retail customers within its boundaries on a voluntary, opt-in basis in which each such customer must affirmatively select such municipality or other political subdivision as its aggregator. The municipality or other political subdivision may not earn a profit but must recover the actual costs incurred in such aggregation.

2. Any municipality or other political subdivision of the Commonwealth may aggregate the electric energy load of its governmental buildings, facilities and any other governmental operations requiring the consumption of electric energy. Aggregation pursuant to this subdivision shall not require licensure pursuant to § 56-588.

3. Two or more municipalities or other political subdivisions within this Commonwealth may aggregate the electric energy load of their governmental

buildings, facilities and any other governmental operations requiring the consumption of electric energy. Aggregation pursuant to this subdivision shall not require licensure pursuant to § 56-588 when such municipalities or other political subdivisions are acting jointly to negotiate or arrange for themselves agreements for their energy needs directly with licensed suppliers or aggregators.

Nothing in this subsection shall prohibit the Commission's development and implementation of pilot programs for opt-in, opt-out or any other type of municipal aggregation, as provided in § 56-577.

B. The Commonwealth, at its election, may aggregate the electric energy load of its governmental buildings, facilities, and any other government operations requiring the consumption of electric energy for the purpose of negotiating the purchase of electricity from any licensed supplier within this Commonwealth. Aggregation pursuant to this subsection shall not require licensure pursuant to § 56-588.

2. That the State Corporation Commission shall develop models for conducting pilot programs for municipal aggregation of natural gas customers, including opt-in, opt-out, and any other model the Commission deems to be in the public interest. The Commission shall report such models to the Legislative Transition Task Force no later than November 1, 2003.

APPENDIX S: Term of Legislative Transition Task Force

§ 56-595. Legislative Transition Task Force established.

A. The Legislative Transition Task Force is hereby established to work collaboratively with the Commission in conjunction with the phase-in of retail competition within the Commonwealth.

B. The Task Force shall consist of ten members, with six members from the House of Delegates and four members from the Senate. Appointments shall be made and vacancies filled by the Speaker of the House of Delegates in accordance with the principles of Rule 16 of the House of Delegates and the Senate Committee on Privileges and Elections, as appropriate.

C. The Task Force members shall be appointed to begin service on and after July 1, 1999, and shall continue to serve until July 1, ~~2005~~ 2008. They shall (i) monitor the work of the Virginia State Corporation Commission in implementing this chapter, receiving such reports as the Commission may be required to make pursuant thereto, including reviews, analysis, and impact on consumers of electric utility restructuring programs of other states; (ii) determine whether, and on what basis, incumbent electric utilities should be permitted to discount capped generation rates established pursuant to § 56-582; (iii) after the commencement of customer choice, monitor, with the assistance of the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs; (iv) examine utility worker protection during the transition to retail competition; generation, transmission and distribution systems reliability concerns; energy assistance

programs for low-income households; renewable energy programs; and energy efficiency programs; and (v) annually report to the Governor and each session of the General Assembly during their tenure concerning the progress of each stage of the phase-in of retail competition, offering such recommendations as may be appropriate for legislative and administrative consideration in order to maintain the Commonwealth's position as a low-cost electricity market and ensuring that residential customers and small business customers benefit from competition.

D. There shall be established a Consumer Advisory Board effective July 1, 1999. The Consumer Advisory Board shall consist of seventeen members. The Senate Privileges and Elections Committee shall appoint six members. The Speaker of the House of Delegates shall appoint six members. The Governor shall appoint five members. Appointed members shall be from all classes of consumers and with geographical representation. The Consumer Advisory Board shall assist the Legislative Transition Task Force in its work as prescribed in this section, and on other issues as may be directed by the Legislative Transition Task Force.

APPENDIX T: Home Energy Assistance Fund Assessment

§ 56-581.2. Energy Assistance Assessment.

Each distributor or other provider of billing services shall collect an energy assistance assessment from each of its customers whose billing address is within the Commonwealth in the amount of three cents per month. All energy assistance assessments shall be remitted within thirty days to the Department of Social Services for deposit in the Home Energy Assistance Fund established pursuant to § 63.1-338. Each distributor or other provider of billing services shall reduce collected assessment amounts to the minimum amount necessary to defray costs of collecting the assessments, not to exceed three percent of the amount collected. State and local taxes shall not apply to the energy assistance assessment.

DRAFT Language concerning election to take competitive supply without paying wires charges.

New Subsection E in 56-583 (Wires Charges).

E. 1. Notwithstanding the provisions of §§ 56-582 D and 56-585 C, and effective not later than July 1, 2004, individual customers [**Options: (i) within the industrial and commercial rate classes, (ii) within other specified customer classes, (iii) meeting specific demand criteria, (iv) within such customer classes, or meeting such demand criteria as may be established by the Commission**] of incumbent electric utilities under this Chapter may elect, upon giving prior notification to such utilities, to purchase retail electric energy from licensed suppliers thereof without the obligation to pay wires charges to any such utilities as otherwise provided under this section.

2. Any such customers (i) making such election, and (ii) thereafter exercising that election by obtaining retail electric energy from suppliers without paying wires charges to their incumbent electric utilities, as authorized herein, shall not be entitled to purchase retail electric energy from their incumbent electric utilities thereafter at the capped rates established under § 56-582, for the duration of the capped rate period expiring on July 1, 2007.

3. a. Such customers making and exercising such election may thereafter, however, purchase retail electric energy from their incumbent electric utilities at rates based upon market prices for generation capacity and energy, as such rates may be determined and approved by the Commission.

b. As used in this subdivision, the term "rates based upon market prices for generation capacity and energy" means:

OPTION ONE: The additional cost to incumbent utilities of either (i) acquiring power from the market, or (ii) generating the power with their own available generation units to serve returning customers, whichever is less.

OPTION TWO: The price incumbent utilities would pay to obtain power in the market, regardless of whether utilities can self-generate the power for returning customers at a lower cost.

OPTION THREE: Commission to determine method for establishing market-based rates to be paid by returning customers based on special Commission proceeding convened for that purpose, in which all stakeholders and interested parties can participate.

4. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this subsection.

APPENDIX V: Wires Charge Exemption for Switching Customers

§ 56-583. Wires charges.

A. To provide the opportunity for competition and consistent with § 56-584, the Commission shall calculate wires charges for each incumbent electric utility, effective upon the commencement of customer choice, which shall be the excess, if any, of the incumbent electric utility's capped unbundled rates for generation over the projected market prices for generation, as determined by the Commission; however, where there is such excess, the sum of such wires charges, the unbundled charge for transmission and ancillary services, the applicable distribution rates established by the Commission and the above projected market prices for generation shall not exceed the capped rates established under § 56-582 A 1 applicable to such incumbent electric utility. The Commission shall adjust such wires charges not more frequently than annually and shall seek to coordinate adjustments of wires charges with any adjustments of capped rates pursuant to § 56-582. No wires charge shall be less than zero. The projected market prices for generation, when determined under this subsection, shall be adjusted for any projected cost of transmission, transmission line losses, and ancillary services subject to the jurisdiction of the Federal Energy Regulatory Commission which the incumbent electric utility (i) must incur to sell its generation and (ii) cannot otherwise recover in rates subject to state or federal jurisdiction.

B. Customers that choose suppliers of electric energy, other than the incumbent electric utility, or are subject to and receiving default service, prior to the expiration of the period for capped rates, as provided for in § 56-582, shall pay a wires charge determined pursuant to subsection A based upon actual usage of electricity distributed by the incumbent electric utility to the customer (i)

during the period from the time the customer chooses a supplier of electric energy other than the incumbent electric utility or (ii) during the period from the time the customer is subject to and receives default service until capped rates expire or are terminated, as provided in § 56-582.

C. The Commission shall permit any customer, at its option, to pay the wires charges owed to an incumbent electric utility on an accelerated or deferred basis upon a finding that such method is not (i) prejudicial to the incumbent electric utility or its ratepayers or (ii) inconsistent with the development of effective competition, provided that all deferred wires charges shall be paid in full by July 1, 2007.

D. A supplier of retail electric energy may pay any or all of the wires charge owed by any customer to an incumbent electric utility. The supplier may not only pay such wires charge on behalf of any customer, but also contract with any customer to finance such payments. Further, on request of a supplier, the incumbent electric utility shall enter into a contract allowing such supplier to pay such wires charge on an accelerated or deferred basis. Such contract shall contain terms and conditions, specified in rules and regulations promulgated by the Commission to implement the provisions of this subsection, that fully compensate the incumbent electric utility for such wires charge, including reasonable compensation for the time value of money.

E. 1. Notwithstanding the provisions of subsection D of § 56-582 and subsection C of § 56-585, and effective not later than July 1, 2004, and subject further to the availability of capped rate service under § 56-582, (i) individual customers within the industrial and commercial rate classes of incumbent electric utilities, subject to such demand criteria as may be established by the Commission, and (ii) aggregated customers of incumbent electric utilities in all rate classes, subject to such demand criteria as may be established by the

Commission, may elect, upon giving prior notice to such utilities, to purchase retail electric energy from licensed suppliers thereof without the obligation to pay wires charges to any such utilities as otherwise provided under this section.

2. Any such customers (i) making such election and (ii) thereafter exercising that election by obtaining retail electric energy from suppliers without paying wires charges to their incumbent electric utilities, as authorized herein, shall not be entitled to purchase retail electric energy from their incumbent electric utilities thereafter at the capped rates established under § 56-582, for the duration of the capped rate period expiring on July 1, 2007.

3. Customers making and exercising such election may thereafter, however, purchase retail electric energy from their incumbent electric utilities at market-based rates for generation capacity and energy. Such rates shall be determined and approved by the Commission after notice and opportunity for hearing. The methodology established by the Commission for determining such rates shall be consistent with the goals of (i) promoting the development of effective competition and economic development within the Commonwealth as provided in subsection A of § 56-596, and (ii) ensuring that neither incumbent utilities nor retail customers who do not choose to obtain electric energy from alternate suppliers are adversely affected.

4. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this subsection.

DRAFT Language concerning election to forego capped rates in exchange for the right to avoid minimum stay.

New Subdivision E 2 in 56-577 (current E would be renumbered E 1)

E. 2. Effective not later than July 1, 2004, retail customers of electric energy (i) purchasing such energy from licensed suppliers, and (ii) otherwise subject to minimum stay periods[1] prescribed by the Commission pursuant to subdivision E 1, shall nevertheless be exempt from any such minimum stay obligations by agreeing to purchase electric energy at market-based rates from incumbent electric utilities or default providers concurrent with seeking to purchase electric energy from such utilities or providers after a period of obtaining electric energy from another supplier. Such rates shall be based upon market prices for generation capacity and energy, as determined and approved by the Commission.

3. As used in this subdivision, the term "market prices for generation capacity and energy" means:

OPTION ONE: The additional cost to incumbent utilities of either (i) acquiring power from the market, or (ii) generating the power with their own available generation units to serve returning customers, whichever is less.

OPTION TWO: The price incumbent utilities would pay to obtain power in the market, regardless of whether utilities can self-generate the power for returning customers at a lower cost.

OPTION THREE: Commission to determine method for establishing market-based rates to be paid by returning customers based on special Commission proceeding convened for that purpose, in which all stakeholders and interested parties can participate.

[1] Under the Commission's current regulations developed pursuant to § 56-577 E, customers with a demand of 500 kW or higher are subject to a twelve-month minimum stay period upon returning to their incumbent utilities for capped rate service after receiving service from an alternate supplier.

4. Notwithstanding the provisions of §§ 56-582 D and 56-585 C 1, however, any such customers exempted from any applicable minimum stay periods as provided in subdivision E 2 shall not be entitled to purchase retail electric energy from their incumbent electric utilities thereafter at the capped rates established under § 56-582, and expiring on July 1, 2007, unless such customers agree to satisfy any minimum stay period then applicable while obtaining retail electric energy at capped rates.

5. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this subsection.

APPENDIX X: Minimum Stay Requirements

§ 56-577. Schedule for transition to retail competition; Commission authority.

A. The transition to retail competition for the purchase and sale of electric energy shall be implemented as follows:

1. On or before January 1, 2001, each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity shall join or establish a regional transmission entity, which entity may be an independent system operator, to which such utility shall transfer the management and control of its transmission system, subject to the provisions of § 56-579.

2. On and after January 1, 2002, retail customers of electric energy within the Commonwealth shall be permitted to purchase energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth during and after the period of transition to retail competition, subject to the following:

a. The Commission shall separately establish for each utility a phase-in schedule for customers by class, and by percentages of class, to ensure that by January 1, 2004, all retail customers of each utility are permitted to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth.

b. The Commission shall also ensure that residential and small business retail customers are permitted to select suppliers in proportions at least equal to that of other customer classes permitted to select suppliers during the period of transition to retail competition.

3. On and after January 1, 2002, the generation of electric energy shall no longer be subject to regulation under this title, except as specified in this chapter.

4. On and after January 1, 2004, all retail customers of electric energy within the Commonwealth, regardless of customer class, shall be permitted to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth.

B. The Commission may delay or accelerate the implementation of any of the provisions of this section, subject to the following:

1. Any such delay or acceleration shall be based on considerations of reliability, safety, communications or market power; and

2. Any such delay shall be limited to the period of time required to resolve the issues necessitating the delay, but in no event shall any such delay extend the implementation of customer choice for all customers beyond January 1, 2005.

The Commission shall, within a reasonable time, report to the General Assembly, or any legislative entity monitoring the restructuring of Virginia's electric industry, any such delays and the reasons therefor.

C. Except as may be otherwise provided in this chapter, prior to and during the period of transition to retail competition, the Commission may conduct pilot programs encompassing retail customer choice of electric energy suppliers, consistent with its authority otherwise provided in this title and the provisions of this chapter.

D. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this section.

E. 1. By January 1, 2002, the Commission shall promulgate regulations establishing whether and, if so, for what minimum periods, customers who request service from an incumbent electric utility pursuant to subsection D of § 56-582 or a default service provider, after a period of receiving service from other suppliers of electric energy, shall be required to use such service from such

incumbent electric utility or default service provider, as determined to be in the public interest by the Commission.

2. Effective not later than July 1, 2004, and subject further to the availability of capped rate service under § 56-582, retail customers of electric energy (i) purchasing such energy from licensed suppliers and (ii) otherwise subject to minimum stay periods prescribed by the Commission pursuant to subdivision 1, shall nevertheless be exempt from any such minimum stay obligations by agreeing to purchase electric energy at market-based rates from incumbent electric utilities or default providers concurrent with seeking to purchase electric energy from such utilities or providers after a period of obtaining electric energy from another supplier. Such rates shall be determined and approved by the Commission after notice and opportunity for hearing. The methodology established by the Commission for determining such rates shall be consistent with the goals of (i) promoting the development of effective competition and economic development within the Commonwealth as provided in subsection A of § 56-596 A, and (ii) ensuring that neither incumbent utilities nor retail customers who do not choose to obtain electric energy from alternate suppliers are adversely affected.

3. Notwithstanding the provisions of subsection D of §§ 56-582 and subdivision 1 of subsection C of 56-585, however, any such customers exempted from any applicable minimum stay periods as provided in subdivision 2 shall not be entitled to purchase retail electric energy from their incumbent electric utilities thereafter at the capped rates established under § 56-582, and expiring on July 1, 2007, unless such customers agree to satisfy any minimum stay period then applicable while obtaining retail electric energy at capped rates.

4. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this subsection.

APPENDIX Y: Prohibiting Power Generators from Withholding Generation

§ 59.1-9.7:1. Manipulation of electricity prices unlawful.

It is unlawful for any person who owns or controls an electric power generation facility and is engaged in the business of generating electric power for sale, in the course of such business, to engage in the manipulation of electricity prices by withholding from commerce any electric power that has been committed to satisfy reserve requirements, if such withholding of electric power:

1. Limits or reduces the amount of electricity that the facility generates, makes available for sale into the relevant market, or both;

2. Is not justified by legal or operational constraints consistent with sound utility practices; and

3. Is done for the primary purpose of increasing the price of electricity in the market in which such electric power, if not withheld, would have been sold.

APPENDIX Z: Consolidated Billing by Cooperatives and Municipal Utilities

§ 56-581.1. Competitive retail electric billing and metering.

A. Effective January 1, 2002, (i) distributors shall offer consolidated billing services to licensed suppliers, aggregators, and retail customers, and (ii) licensed suppliers and aggregators shall be permitted to bill all retail customers separately for services rendered on and after the first regular meter reading date after January 1, 2002, subject to conditions, regulations, and licensing requirements established by the Commission.

B. Effective January 1, 2003, licensed suppliers and aggregators may offer consolidated billing service to distributors and retail customers for services rendered on and after the first regular meter reading date after January 1, 2003, subject to conditions, regulations, and licensing requirements established by the Commission.

C. Upon application by a distributor or upon its own motion, the Commission may delay any element of the competitive provision of billing services to retail customers for the period of time necessary, but no longer than one year, to resolve issues arising from considerations of billing accuracy, timeliness, quality, consumer readiness, or adverse effects upon development of competition in electric service. The Commission shall report any such delays and the underlying reasons therefor to the Legislative Transition Task Force within a reasonable time.

D. The Commission shall promulgate such rules and regulations as may be necessary to implement the provisions of this section in a manner that is consistent with its Recommendation and Draft Plan filed with the Legislative Transition Task Force on December 12, 2000, to facilitate the development of effective competition in electric service for all customer classes, and to ensure

reasonable levels of billing accuracy, timeliness, and quality, and adequate consumer readiness and protection. Such rules and regulations shall include provisions regarding the licensing of persons seeking to sell, offering to sell, or selling competitive billing services, pursuant to the licensure requirements of § 56-587.

E. The Commission shall implement the provision of competitive metering services by licensed providers for large industrial and large commercial customers of investor-owned distributors on January 1, 2002, and may approve such services for residential and small business customers of investor-owned distributors on or after January 1, 2003, as determined to be in the public interest by the Commission. Such implementation and approvals shall:

1. Be consistent with the goal of facilitating the development of effective competition in electric service for all customer classes;

2. Take into account the readiness of customers and suppliers to buy and sell such services;

3. Take into account the technological feasibility of furnishing any such services on a competitive basis;

4. Take into account whether reasonable steps have been or will be taken to educate and prepare customers for the implementation of competition for any such services;

5. Not jeopardize the safety, reliability or quality of electric service;

6. Consider the degree of control exerted over utility operations by utility customers;

7. Not adversely affect the ability of an incumbent electric utility authorized or obligated to provide electric service to customers who do not buy such services from competitors to provide electric service to such customers at reasonable rates;

8. Give due consideration to the potential effects of such determinations on utility tax collection by state and local governments in the Commonwealth; and

9. Ensure the technical and administrative readiness of a distributor to coordinate and facilitate the provision of competitive metering services for its customers.

Upon the reasonable request of a distributor, the Commission shall delay the provision of competitive metering service in such distributor's service territory until January 1, 2003, for large industrial and large commercial customers, and after January 1, 2004, for residential and small business customers.

F. The Commission shall promulgate such rules and regulations as may be necessary to implement the authorization related to competitive metering services provided for in subsection E. Such rules and regulations shall include provisions regarding the licensing of persons seeking to sell, offering to sell, or selling competitive metering services, pursuant to the licensure requirements of § 56-587.

G. An incumbent electric utility shall coordinate with persons licensed to provide competitive metering service, billing services, or both, as the Commission deems reasonably necessary to the development of such competition The foregoing shall apply to an affiliate of an incumbent electric utility if such affiliate controls a resource that is necessary to the coordination required of the incumbent electric utility by this subsection.

H. Notwithstanding the provisions of § 56-582, the Commission shall allow a distributor to recover its costs directly associated with the implementation of billing or metering competition through a tariff for all licensed suppliers, but not those that would be incurred by such utilities in any event as part of the restructuring under this Act. The Commission shall also determine the most

appropriate method of recovering such costs through a tariff for such licensed suppliers; however, such method shall not unreasonably affect any customer for which the service is not made competitive.

I. The Commission shall adjust the rates for any noncompetitive services provided by a distributor so that such rates do not reflect costs associated with or properly allocable to the service made subject to competition. Such adjustment may be accomplished through unbundled rates, bill credits, the distributor's tariffs for licensed suppliers, or other methods as determined by the Commission.

J. Municipal electric utilities shall not be required to provide consolidated billing services to licensed suppliers, aggregators or retail customers. Municipal electric utilities and utility consumer services cooperatives shall not be required to undertake coordination of the provision of consolidated ~~or direct~~ billing services by suppliers and aggregators; however, the exemptions set forth in this subsection shall not apply if any such municipal electric utility or utility consumer services cooperative, or its affiliate, offers competitive electric energy supply to retail customers in the service territory of any other Virginia incumbent electric utility. The Commission may permit any municipal electric utility or utility consumer services cooperative that pursues such competitive activity to maintain such exemption upon application to the Commission demonstrating good cause for relief. In addition, upon petition by a utility consumer services cooperative, the Commission may approve the provision of competitive metering services by licensed providers for large industrial and large commercial customers of such cooperative on or after January 1, 2002, and for residential and small business customers of such cooperative on or after January 1, 2003, as determined to be in the public interest by the Commission consistent with the criteria set forth in subsection E.

APPENDIX AA: STRANDED COSTS WORK GROUP

Background

Section 56-584 of the Virginia Electric Utility Restructuring Act (the "Act") provides:

> Just and reasonable net stranded costs, to the extent that they exceed zero value in total for the incumbent electric utility, shall be recoverable by each incumbent electric utility provided each incumbent electric utility shall only recover its just and reasonable net stranded costs through either capped rates as provided in § 56-582 or wires charges as provided in § 56-583.

Subdivision C, clause (iii) of § 56-595 of the Act provides that the members of the Legislative Transition Task Force shall:

> [A]fter the commencement of customer choice, monitor, with the assistance of the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs . . .

As customer choice has commenced in the Commonwealth, it is appropriate for the Legislative Transition Task Force to initiate the process of monitoring whether the recovery of stranded costs has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

Requested Actions

The Legislative Transition Task Force hereby requests the State Corporation Commission to:

1. Convene a work group, consisting of Commission staff and such persons as the Commission deems appropriate to represent the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, for the purpose of developing consensus recommendations, consistent with the provisions of the Act, regarding the issues listed in paragraphs 2 and 3. The chairman of the Legislative Transition Task Force will designate two of its members to monitor the progress of the work group.

2. 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; and

3. By November 1, 2003, present to the Legislative Transition Task Force the work group's consensus recommendations, developed using the methodology developed pursuant to paragraph 2 (b), regarding:

(a) The amount of each incumbent electric utility's just and reasonable net stranded costs.

(b) The amount that each incumbent electric utility has received, and is expected to receive over the balance of the capped rate period, to offset just and reasonable net stranded costs from capped rates and from wires charges.

4. Report to the Legislative Transition Task Force's Subcommittee on Stranded Costs, which will be reactivated to oversee the implementation of this resolution, regarding the matters described in paragraphs 2 and 3, which reporting shall be made prior to the submission of the reports to the Legislative Transition Task Force that are due by July 1, 2003, and November 1, 2003, respectively.

5. Determine whether the work group has access to information necessary for the development of recommendations on the issues set out in paragraphs 2 and 3, and, if the work group has been unable to obtain necessary information, give prompt written notice of the issue to the chairman of Legislative Transition Task Force, with a copy to its staff.

6. Take all reasonable and appropriate actions to ensure that State Corporation Commission staff and other work group participants do not make unauthorized disclosures of information regarding incumbent utilities' stranded costs and amounts received to offset stranded costs that is provided in confidence to the work group.

7. Request that the Commission staff and persons who are invited to participate in the work group act in good faith to develop consensus recommendations on the issues set out in paragraphs 2 and 3.

8. If the work group members are not able to develop consensus recommendations regarding the issues set out in paragraphs 2 and 3, include in its reports to the Legislative Task Force and the Subcommittee on Stranded Costs, as appropriate, (i) the recommendations of the Commission staff and other members of the work group regarding the issues and (ii) an analysis by Commission staff of such recommendations.

9. Include in its reports to the Legislative Transition Task Force any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate in order to address any overrecovery or underrecovery of just and reasonable net stranded costs.

Adopted by the Legislative Transition Task Force on January 27, 2003.

APPENDIX BB: ENERGY INFRASTRUCTURE DATA COLLECTION

Background

Senate Bill 684 (2002) required that the State Corporation Commission study the feasibility, effectiveness and value of collecting specific data relative to the energy infrastructure serving the Commonwealth. The Commission filed its report on November 20, 2002, and presented the results of its work to the Task Force 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 Task Force's consideration.

Given the critical importance of a reliable electric infrastructure to Virginia, the Commonwealth must continue to maintain oversight over the reliability of that infrastructure.

The information that the Commission is requested to review and analyze at this time is not as extensive as envisioned by Senate Bill 684. The Task Force may request the Commission to expand this data collection effort to accommodate a more detailed analysis should the Task Force find that it is necessary.

Requested Actions

The Legislative Transition Task Force hereby requests the State Corporation Commission:

1. To the extent it is not currently doing so, to collect the data necessary to monitor the dedication of facilities to the provision of electricity service in the Commonwealth. At a minimum, such an effort should review the dedication or allocation of specific generation to the Commonwealth for the five-year period ending December 31, 2002. Historical reserve margins should be calculated and basic operating indices for the units dedicated to the provision of service should be documented. Such indices should include but not necessarily be limited to: availability factors, equivalent availability factors, capacity factors, heat rates, forced outage rates, and equivalent forced outage rates.

2. To review utility resource plans, projected loads, and expected reserve margins, and should identify those units that will be dedicated to the service of Virginia load and the provision of reserve margins.

3. To continue to collect actual data, to the extent of the Commission's authority to collect such data pursuant to Virginia Code §§ 56-234.3 and 56-249.6 and subdivision B 3 of § 56-585 B 3.

4. On or before July 1, 2003, to report the results of its work to the Task Force, giving due regard to the confidentiality of the specific detailed data that it has collected.

5. To provide subsequent reports as the Commission deems necessary or as requested by the Task Force.

Adopted by the Legislative Transition Task Force on January 27, 2003.

APPENDIX CC: ENERGY MANAGEMENT WORK GROUP

Background

Subdivision C, clause (iv) of § 56-595 of the Restructuring Act provides that the members of the Legislative Transition Task Force shall ". . . examine energy efficiency programs."

As customer choice has commenced in the Commonwealth, it is appropriate for the Legislative Transition Task Force, with the assistance of the Consumer Advisory Board, to continue to monitor the availability of energy efficiency programs for consumers, to enable consumers to receive the maximum benefit from competitively priced electricity.

Requested Actions

The Legislative Transition Task Force hereby requests the State Corporation Commission to:

1. Convene a work group, consisting of Commission staff and such persons as the Commission deems appropriate to represent the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, for the purpose of developing consensus recommendations, consistent with the provisions of the Act, regarding the issues listed in paragraphs 2 through 5.

2. Investigate short-term and long-term approaches to encourage voluntary and cost-effective energy management options to consumers within the Commonwealth

3. Monitor and evaluate the results of similar investigations and pilot programs occurring in other states for potential applicability to Virginia

4. Identify obstacles to the emergence of cost-effective energy management in Virginia.

5. Identify tools and information currently available from local distribution companies to assist such investigation.

6. Make an annual report, prior to September 1, to the Consumer Advisory Board covering the activities, findings, and proposals of the Work Group for the prior year and any recommendations for legislation. The report should identify funding requirements and potential sources to pursue options identified by the Work Group.

7. Request that the Commission staff and persons who are invited to participate in the work group act in good faith to develop consensus recommendations on the issues set out in paragraphs 2 through 5.

8. Include in its reports to the Consumer Advisory Board any recommendations for legislative or administrative action that the Commission, the work group, or both, determine to be appropriate.

APPENDIX DD: Authorization for Stranded Cost Activities

§ 56-595. Legislative Transition Task Force established.

A. The Legislative Transition Task Force is hereby established to work collaboratively with the Commission in conjunction with the phase-in of retail competition within the Commonwealth.

B. The Task Force shall consist of ten members, with six members from the House of Delegates and four members from the Senate. Appointments shall be made and vacancies filled by the Speaker of the House of Delegates in accordance with the principles of Rule 16 of the House of Delegates and the Senate Committee on Privileges and Elections, as appropriate.

C. The Task Force members shall be appointed to begin service on and after July 1, 1999, and shall continue to serve until July 1, 2005. They shall (i) monitor the work of the Virginia State Corporation Commission in implementing this chapter, receiving such reports as the Commission may be required to make pursuant thereto, including reviews, analysis, and impact on consumers of electric utility restructuring programs of other states; (ii) determine whether, and on what basis, incumbent electric utilities should be permitted to discount capped generation rates established pursuant to § 56-582; (iii) after the commencement of customer choice, monitor, with the assistance of the Commission, the Office of the Attorney General, incumbent electric utilities, suppliers, and retail customers, whether the recovery of stranded costs, as provided in § 56-584, has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs; (iv) examine utility worker protection during the transition to retail competition; generation, transmission and distribution systems reliability concerns; energy assistance programs for low-income households; renewable energy programs; and energy efficiency programs; and (v) annually report to the

Governor and each session of the General Assembly during their tenure concerning the progress of each stage of the phase-in of retail competition, offering such recommendations as may be appropriate for legislative and administrative consideration in order to maintain the Commonwealth's position as a low-cost electricity market and ensuring that residential customers and small business customers benefit from competition.

D. There shall be established a Consumer Advisory Board effective July 1, 1999. The Consumer Advisory Board shall consist of seventeen members. The Senate Privileges and Elections Committee shall appoint six members. The Speaker of the House of Delegates shall appoint six members. The Governor shall appoint five members. Appointed members shall be from all classes of consumers and with geographical representation. The Consumer Advisory Board shall assist the Legislative Transition Task Force in its work as prescribed in this section, and on other issues as may be directed by the Legislative Transition Task Force.

E. The Task Force shall be authorized to establish one or more subcommittees of its membership, to meet at the direction of the chairman of the Task Force, for any purpose of within the scope of the duties of the Task Force, including but not limited to assisting in the monitoring of whether the recovery of stranded costs has resulted or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs. The chairman of the Task Force is further authorized to designate one or more members of the Task Force to observe or participate in the discussions of any work group convened at the request of the Commission in furtherance of its duties under this chapter. Members of the Task Force shall receive such compensation as provided in § 30-19.12, and shall be reimbursed for reasonable and necessary incurred in the performance of their duties as provided in §§ 2.2-2813 and 2.2-2825.