COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

Report to the
Commission on Electric Utility Restructuring
of the
Virginia General Assembly

Energy Infrastructure Data Collection

July 1, 2003
Response to Resolution Adopted January 27, 2003

July 1, 2003

TO: The Honorable Thomas K. Norment, Jr.
Member, Senate of Virginia
Chairman, Commission on Electric Utility Restructuring
and
Members of the Commission on Electric Utility Restructuring

The State Corporation Commission is pleased to submit the report required by the January 27, 2003, resolution of the Commission on Electric Utility Restructuring relative to the collection of specific data regarding Virginia's energy infrastructure.

As required by the resolution, the Commission Staff submitted data requests to electric utilities, cooperatives and municipals to collect the data necessary to monitor the dedication of facilities for the provision of electricity service in the Commonwealth. The report itself, summarizes each entity's supply capability and provisions for reserve margins.

Respectfully submitted,

Hullihen Williams Moore
Commission Chairman

Clinton Miller
Commissioner

Theodore V. Morrison, Jr.
Commissioner

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EXECUTIVE SUMMARY

This report is submitted to the Commission on Electric Utility Restructuring in response to a resolution requesting that the Commission collect the data necessary to monitor the dedication of generating facilities to the provision of electric bulk power supply in the Commonwealth. As this report indicates, electric utilities providing service in the Commonwealth have historically served retail load and provided necessary reserves via a combination of company owned generation, purchased power from non-utility generation facilities and purchases from the wholesale market. With the advent of the restructuring of our electric utility industry, our utilities have reduced planned reserve margins and expect to rely largely on the market for the provision of capacity to serve load growth and to provide adequate reserves. This response to the restructuring process is not surprising for a number of reasons.

First, when customers have the legal right to purchase power from the market, incumbent utilities' ability to project load is impacted. In addition to historical variables such as economic conditions and weather, utilities must now contend with the possibility that some load, perhaps significant, may be lost to competitive suppliers. In such an environment, despite the incumbent's potential default service obligations, it is unlikely that they will provide the same level of reserves from hard assets that have been historically available. Should significant investment in new generation be made and customers take advantage of retail access, the implications from a stranded cost perspective are obvious.

With regard to stranded costs, such costs are recoverable during the rate cap period via capped rates and wires charges. Inasmuch as there has been little retail activity, the primary mechanism for stranded costs recovery is capped rates. If a utility makes significant investment in generation plant, earnings produced by capped rates are diminished. Revenues collected and allocated to stranded cost recovery are reduced. In short, capped rates provide a disincentive for utilities to make generation plant investments, especially more capital intensive non-gas alternatives. As a result, reserve margins tend to shrink and/or the wholesale market may be increasingly relied upon to service load growth and to provide adequate reserves in the future.

The existence of a fuel factor in combination with capped rates also incents our utilities to rely on the market rather than construct additional facilities. Inasmuch as the market largely prices power on an energy basis, the bulk of purchased power expenses could flow through the fuel factor,[1] thereby allowing utilities to maintain or increase earnings under capped rates while recovering the cost associated with serving load growth through continued operation of the fuel factor and deferred fuel accounting.

The reliability of the service to Virginians will likely be a long-term issue as the Commonwealth evolves toward the ultimate provision of generation services by the market. The "Energy Infrastructure Data Collection" resolution states: "Given the critical importance of a reliable electric infrastructure to Virginia, the Commonwealth must continue to maintain oversight over the reliability of that infrastructure." It is obvious from our utilities' responses offered during the energy infrastructure workgroup sessions that they envision the competitive market addressing reliability concerns. However, the Federal Energy Regulatory Commission ("FERC") in its Standard Market Design Notice of Proposed Rulemaking ("NOPR") acknowledged that the market cannot be relied upon to provide an adequate generation resource base. In fact, in that NOPR the FERC envisions Regional Transmission entities establishing resource adequacy requirements subject to federal jurisdiction.

[1] This issue arose recently in Virginia Power's fuel factor proceeding, Case No. PUE-2002-00377, and, as a result, the Staff is in the process of studying the appropriate recovery of the fuel costs associated with certain purchase power contracts.

In a recently issued white paper, the FERC indicated that Regional State Committees will be responsible for resource adequacy oversight. This concept was not developed in that document and the FERC proposal relative to state jurisdiction in this regard is unclear. In any event, if the Commonwealth is to maintain oversight over energy infrastructure reliability, it may have to take aggressive actions to do so. While the Restructuring Statute addresses reliability in a number of sections, the most explicit reference to generation reliability is in Section 56-595 which states that the Legislative Transition Task Force shall examine generation, transmission, and distribution system reliability concerns.

REPORT TO THE COMMISSION ON ELECTRIC UTILITY RESTRUCTURING OF THE VIRGINIA GENERAL ASSEMBLY

ENERGY INFRASTRUCTURE DATA COLLECTION

**PURSUANT TO THE JANUARY 27, 2003, RESOLUTION
PASSED BY THE COMMISSION ON ELECTRIC UTILITY RESTRUCTURING
AND
2002 VA ACTS CH 474**

JULY 1, 2003

BACKGROUND AND INTRODUCTION

Chapter 474 of the 2002 Virginia Acts of Assembly (SB 684), required the State Corporation Commission ("Commission" or "SCC") to convene a workgroup of stakeholders relative to Virginia's electric and natural gas industries. Specifically, Chapter 474 required that the workgroup study the "feasibility, effectiveness, and value" of collecting information related to Virginia's energy infrastructure. The Commission filed its report on November 20, 2002, and presented the results of its work to the Legislative Transition Task Force of the Virginia General Assembly ("LTTF") during its December 12, 2002, meeting. Hereinafter, the LTTF will be referred to by its new designation as the Commission on Electric Utility Restructuring ("COEUR").

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 COEUR's consideration.

The COEUR concluded that the Commonwealth must continue to maintain oversight over the reliability of the electric infrastructure and adopted a resolution on January 27, 2003 ("Resolution"), requesting, in part, that the Commission collect the data necessary to monitor the dedication of generating facilities to the provision of electric bulk power supply in the Commonwealth. The Resolution also requested the Commission to report the results of its work to the COEUR on or before July 1, 2003. The COEUR's resolution appears as Attachment 1.

This report represents the Commission's initial analysis of a very difficult and complex task – analyzing and evaluating electric utilities' resource plans, projected loads, and forecast reserve margins.[2] In the discharge of this task, the Commission Staff has formulated data requests,[3] reviewed initial responses to these data requests, issued numerous supplemental data requests, reviewed supplemental and revised responses to the original and supplemental data requests,[4] talked to the assigned utility representatives, and held face-to-face meetings with the state's two largest utilities. In addition to the complexity of the subject matter, the lack of uniformity in terminology among the utilities and the different perspectives between the operations and planning divisions within each utility have contributed to the challenge of the assigned task. Furthermore, in some cases the Commission Staff has posed questions relative to the utilities' long range forecasts and then received feedback from which the Staff has been unable to formulate meaningful conclusions. As a result, this initial report is fairly general in nature and omits some detailed, utility-specific data. In addition, the report analyzes forecast

[2] In this report, reserve margin is calculated as a percentage of peak demand.
[3] In response to the Resolution, the Commission Staff issued data requests on March 17, 2003, to the investor owned utilities; on March 18, 2003, to the electric cooperatives; and on March 19, 2003, to the municipal electric utilities. The data requests asked for, in part, five years of historical data and five years of forecast data related to the following categories: peak loads, generating resources dedicated to serving load in Virginia, power purchases and sales, reserve margins, and the basic operating indices for generating units dedicated to the provision of service.
[4] Revisions were being submitted to the Commission as late as June 20, 2003.

data only through 2007. The Commission intends to continue to analyze relevant data, seek further clarification of the issues, address longer-range forecasts, and issue a more detailed report in the future.

GENERAL DISCUSSION

In the Commission's November 20, 2002, report on the feasibility, effectiveness and value of collecting data pertaining to Virginia's energy infrastructure ("November 20, 2002, Report"), a number of principles relative to the reliability of an electric utility infrastructure were posited. These principles remain firm seven months later. As discussed in that report, one must focus on both transmission and generation facilities when discussing the reliability of a bulk power supply infrastructure. Transmission and generation are substitutable, inter-dependent, and complimentary. A generation fleet is obviously no more reliable than the transmission system delivering the generation output. Likewise, an extraordinarily reliable transmission network cannot provide adequate service if installed generation capacity is inadequate or if its reliability is substandard. While the following discussion will deal primarily with generation, an understanding of the integrated nature of transmission and generation as a bulk power supply system is critical in the context of gauging bulk power infrastructure reliability.

Prior to the passage of the Virginia Electric Utility Restructuring Act ("Restructuring Act"), the SCC monitored the reliability of Virginia's electric utility infrastructure from several perspectives. Each of Virginia's investor-owned electric utilities was required (pursuant to Section 56-234.3 of the Virginia Code) to submit annually a detailed resource plan that presented long-term load projections and the utility's plans for serving projected load via a combination of generation additions, transmission enhancements, firm power purchases from neighboring utilities/non-utility generators, and load management. Inherent within that process was the development of an appropriate reserve margin to accommodate the realities of load forecast error, unexpected unit outages, abnormal weather, and a number of other factors. While the Commission did not specify absolute reserve levels, the Staff regularly reviewed utility studies that determined reserve needs. In some instances, the Commission expressed concern relative to appropriate reserve margins and directed further study. On one occasion, higher reserves were instituted as a result of such a directive. The Commission's oversight of this planning process not only focused on the level of reserves, but on installed capacity mix as well to determine whether an appropriate portfolio of base load, intermediate and peaking generation facilities, combined with power purchases, was planned to minimize reliability risk and to optimize the cost of service to ratepayers.

As part of its oversight of Virginia utilities' generation infrastructure, the Commission also closely monitored the actual operational performance of generating units and encouraged high performance levels by tying authorized equity returns to generating unit efficiencies. This program was implemented to recognize the impact of generating unit performance on reserve requirements, and on fuel expenses, which are recovered on a dollar-per-dollar basis from retail consumers.

With passage of the Restructuring Act, the Commission's role concerning reliability is now less defined. Based on the comments provided for and cited in the November 20, 2002 Report, the electric utilities believe that the Commission's authority with respect to generation reliability has been significantly diminished and that the market will play a larger role in determining the amount and characteristics of incremental capacity that is commercialized and dedicated to the service of Virginia.

The Federal Energy Regulatory Commission's ("FERC's") recent Notice of Proposed Rulemaking ("NOPR") on its wholesale power market platform is a revolutionary proposal that has significant implications for the oversight of generation as well as transmission reliability. The NOPR essentially envisions mandatory participation in a regional transmission organization ("RTO") that would operate a generation market for managing transmission congestion and energy imbalances. Reserve margins would ultimately be required by such organization and, a Market Monitor would be charged with monitoring market power and imposing pricing constraints pursuant to FERC jurisdiction. In a white paper describing potential modifications to the original NOPR,[5] the FERC notes that reserve margin requirements would be established by regional planning committees. The white paper also indicates that it does not intend to diminish state authority over reserve requirements. The white paper does not, however, fully explain the roles of states in these planning committees or how disputes will be resolved. It is quite possible that the FERC will be final arbiter if states fail to agree. Additionally, it is not clear whether a state could practically impose a reserve requirement that differs from that of the region. The policies implicit in the FERC's NOPR represent a radical departure from previously held beliefs that the market would establish reliability levels and competition would control pricing with little regulatory intervention. The NOPR not only proposes increased federal regulation over both the pricing and reliability of electric service but also shifts regulation from the state to the federal level to some yet unknown degree.

Should Virginia's utilities join an RTO such as the PJM Interconnection, LLC ("PJM") that operates a regional market or should the FERC proposal be implemented, jurisdiction

[5] April 28, 2003, Federal Energy Regulatory Commission, Docket No. RM01-12 White Paper – Wholesale Market Platform.

relative to generation reliability will be shifted largely away from the states. Should Virginia, for example, require its utilities to maintain a higher generation reserve than required by the RTO, those reserves would likely be shared with customers within the footprint of the RTO, which is likely to span multiple states. During periods of generation shortage, customer load may be shed on a pro-rata basis without an explicit dedication of excess reserves to Virginia consumers who would ultimately bear the costs of such reserves.

As a result, the possible impact of the FERC Notice of Proposed Rulemaking must be considered when evaluating the "feasibility, effectiveness and value" of continuing to collect the data outlined in Senate Bill 684 and the COEUR Resolution. It should be noted, however, that both PJM and the FERC envision, at least theoretically, a model that allows states that do not deregulate generation or that impose generation price caps to continue to dedicate generation from an economic perspective to their native load. The FERC has indicated that it will wait until Congress produces a final version of a comprehensive energy bill before issuing a ruling on its wholesale power market platform, since the bill could impact the time frame for implementation of the FERC plan, as well as address whether utilities are required to participate in regional transmission organizations.

The COEUR has concluded, as noted previously, that the Commonwealth must continue to maintain oversight over the reliability of its electric infrastructure. The COEUR adopted its Resolution requesting that the Commission collect the data necessary to monitor the dedication of generating facilities to the provision of electricity service in the Commonwealth. The next section provides a summary of the data that was collected from the state's electric utilities.

CURRENT ENERGY INFRASTRUCTURE

Virginia Electric and Power Company d/b/a Dominion Virginia Power

Virginia Electric and Power Company, doing business in Virginia as Dominion Virginia Power and in North Carolina as Dominion North Carolina (herein collectively called "Virginia Power" or "DVP"), serves approximately 2 million retail customers in Virginia, as well as customers in northeastern North Carolina. Virginia Power owns approximately 14,000 MW of generating capacity, which is managed by their affiliate Dominion Generation, and has access through contracts to the output from over 3,000 MW of non-utility generating facilities ("NUGs"). In recent years the Company also has purchased short-term firm capacity from the wholesale market to meet its energy and capacity needs.

Dominion Virginia Power filed a plan for separation of its distribution, transmission and generation functions on November 1, 2000. It proposed to accomplish this goal by creation of an affiliated company, Dominion Generation, to which Virginia Power would transfer all of its electric generating plants, all purchased power contracts, all contracts for the purchase of fuel, and all personnel needed to manage and operate the plants and contracts. Electricity produced by the generating plants would no longer be subject to regulation by the Commission, but would instead fall within the jurisdiction of the FERC. Virginia Power proposed that the plants be operated as exempt wholesale generators, making sales of power only in the wholesale market. By Commission Order dated December 18, 2001, the Commission denied approval of Virginia Power's proposed plan. Instead, the Commission directed the Company to separate its generation, distribution and transmission functions through creation of divisions within the Company to manage and operate each function. As a condition of functional separation by division, the Commission ordered Virginia Power to make its generation assets, including the

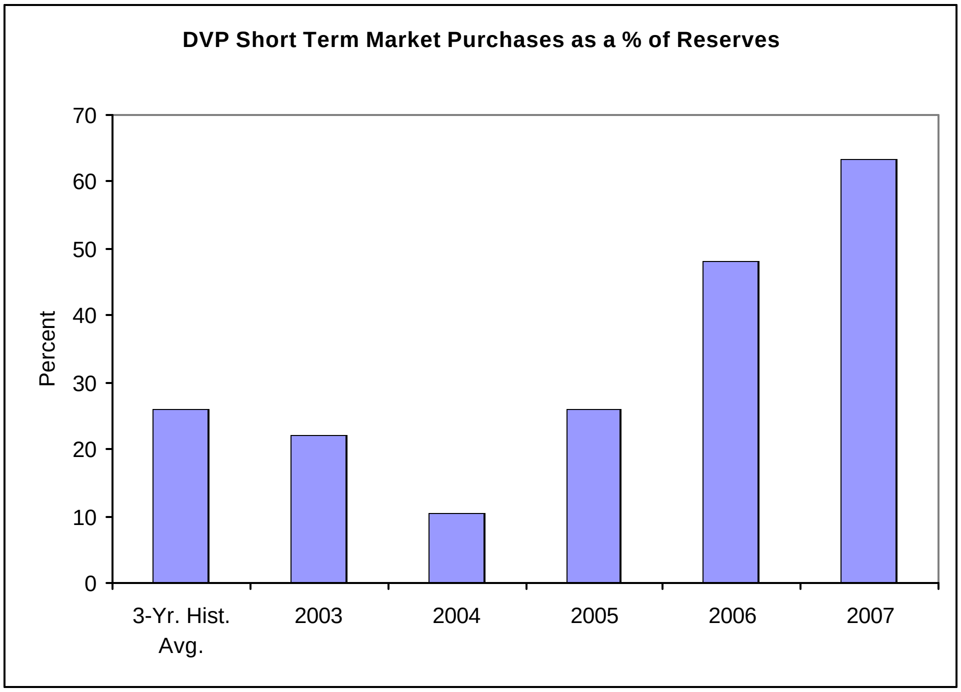
Mt. Storm, West Virginia, generating plant, available for electric service during the capped rate period and any period in which Virginia Power is designated to provide default service in Virginia.

From 1998-2002, DVP's reserve margin was widely variant, but averaged approximately 12%. During this time frame, the Company's control area summer peak demand increased at an average annual compound growth rate of 2.62%, amounting to a total increase over the period of 10.9%. This represents an increase of almost 1700 MW of load growth. Also during this 5-year time period, installed capacity increased by 8%, or 1300 MW; however, in 2000, a long-term contract with AEP for 500 MW from AEP's Rockport plant expired. In order to support its 12% average reserve margin, DVP depended on short-term purchases from the wholesale market for between 250 MW and 600 MW over the period 2000-2002.

For the five-year forecast period 2003-2007, DVP forecasts that its combined capacity[6] is expected to decrease by 1.1%[7], after increasing by 3.4% from 2002 to 2003.[8] During the same time period, DVP forecasts its obligated summer peak load decreasing initially and then increasing over the final three years of the period. The Company forecasts a reserve margin, relying both on units dedicated to serving load and on purchased power, of 13.5% in 2003, and targets 12.5% through 2007.[9] The Commission is continuing to investigate the extent to which these purchases are backed by specific units. While DVP projects some increase in its installed

[6] Here, combined capacity refers to the sum of installed capacity and capacity supplied by NUG contracts.
[7] The decrease is a result of expiration of certain NUG contracts.
[8] The increase in 2003 is due primarily to the addition of a natural gas-fired combined cycle unit at the Company's Possum Point Power Station.
[9] Historically, prior to restructuring, DVP typically forecast reserve margins above 18%. In the 1996 Staff Report on the Restructuring of the Electric Industry, Staff noted that Virginia Power planned for a reserve margin of about 15.5% through 2000 and 14% thereafter. Virginia Power also projected a long-term annual compound growth rate of 1.9% in summer peak demand.

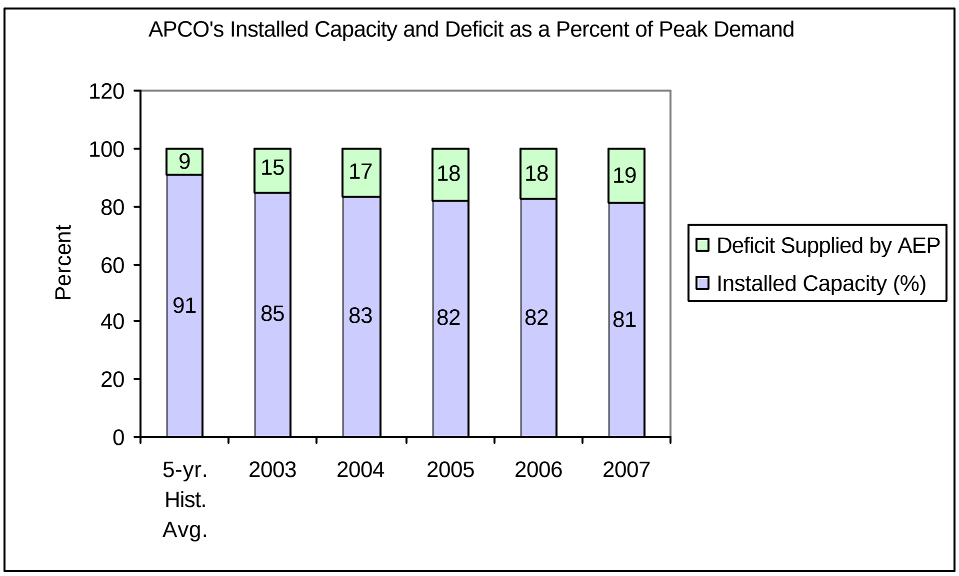
capacity, the increase is insufficient to meet adequate reserves through 2007, and therefore the Company forecasts an increased reliance on wholesale purchased power from the market (after a one-year decrease in 2004) in order to maintain adequate reserves (see graph below).



<u>Appalachian Power Company d/b/a AEP-Virginia</u>

The Appalachian Power Company ("Apco"), which operates as part of American Electric Power ("AEP"), provides retail electric service to over 480,000 customers in southwestern Virginia; the Company also provides retail electric service to parts of West Virginia. Apco and four other electric utility companies within AEP have operated for many years on an integrated system basis, under a five-member "Interconnection Agreement," providing electric service in five states – Virginia, West Virginia, Ohio, Michigan, and Indiana. Each member company has been responsible for providing capacity necessary to serve its load and a pro-rata share of system reserves. To the extent a member was capacity deficient, it purchased needed capacity from "capacity excess" companies pursuant to an Interconnection Agreement approved by the FERC. To the extent a member company consumed more system-generated energy than was produced by its own units, such energy purchases were also made on a cost-of-service basis pursuant to the Interconnection Agreement.

Apco has historically been a deficient company regularly depending upon both capacity and energy from the other member companies of the AEP system. Capacity charges paid by Apco to other member companies have been recovered from Virginia retail ratepayers through base rates, while purchased energy costs have been recovered through the fuel factor. The following chart illustrates Apco's capacity deficiency status.



The next chart indicates that from 1998 through 2002, Apco's reserve margin fluctuated between positive 1.1% and negative 10.3%. For the same period, the AEP system reserve margin varied between 25.2% (in 2000) and 11.6% (in 2002). While Apco as a stand-alone company had insufficient reserves during this period, its membership in AEP essentially provided Apco with AEP system reserves. However, as a result of electric utility restructuring in Ohio, the AEP reserves may not be available to Virginians in the future.

Reserve Margins as a % of Demand

Year	Apco	AEP
1998	-5.7	15.6
1999	-3.1	11.7
2000	-8.9	25.2
2001	-10.3	13.1
2002	1.1	11.6
2003	-6.3	15.0
2004	-7.6	12.9
2005	-9.2	11.8
2006	-9.9	11.5
2007	-11.5	9.6

The Ohio plan requires corporate separation, and as a result, we have been advised that Ohio Power, an excess capacity member of AEP, now has the option of selling its generation facilities. As a result, the net excess capacity of the Ohio AEP member companies[10] might no longer be dedicated to the service of the integrated AEP load. In fact on July 24, 2001, AEP filed with the FERC to replace the five-member Interconnection Agreement with a three-member agreement reflecting AEP's desire to separate the capacity of Ohio Power and Columbus Southern from the provision of service to the integrated AEP load. Under the three-member agreement, AEP would lose a portion of its excess capacity and would suffer from reduced reserve margins or would have to rely more on the wholesale market in order to maintain reserves at currently existing levels. The Commission Staff is in the process of evaluating the effect of the three-member agreement on reserves provided to Apco's customers that are backed by hard assets.

[10] Columbus Southern is a capacity and energy deficient member of the AEP system, but its deficiency is insignificant when compared to the excess capacity provided by Ohio Power.

Inasmuch as Apco is largely dependent on the excess capacity of Ohio Power, the Virginia Commission intervened in the aforementioned FERC proceeding and a settlement agreement was reached. As a result of that settlement agreement, AEP has agreed to provide the energy and capacity necessary to augment Apco's own units through July 2007 at specified costs. However, specific units are not dedicated to the provision of that capacity/energy. The current reserves associated with the three-member agreement that are available to Apco's Virginia consumers is backed by actual generating facilities. Future capacity needs above this level are assumed to be provided by the market. Subsequent to July 1, 2007, the capacity needs of Apco presumably will be provided from its own units, from other AEP utilities pursuant to the three member operating agreement, and from the market.

It should be noted that while AEP received conditional approval from the FERC on September 26, 2002, relative to replacing the five-member agreement with the three-member agreement, AEP has not yet implemented the three-member agreement. At this time we are unsure of AEP's plans in this regard. In any event, neither Apco nor AEP has apprised the Commission of plans to add any new capacity (either installed or purchased), and, as demonstrated in the previous chart, reserves have been forecast to decline at least through 2007.

Potomac Edison Company d/b/a Allegheny Power

The Potomac Edison Company provides retail electric service to nearly 90,000 customers within fourteen counties in northwestern Virginia. It also provides retail electric service in western Maryland and eastern West Virginia. Potomac Edison is one of three regulated electric utility operating subsidiaries doing business as Allegheny Power.[11] Allegheny Power is the

[11] Monongahela Power Company, serving customers in Ohio and W.Va.; West Penn Power Company, serving customers in Pennsylvania; and The Potomac Edison Company, serving customers in Maryland, W.Va. and Va.

energy delivery business of Allegheny Energy, Inc. ("AEI"),[12] delivering electricity and natural gas to about three and one-half million customers in parts of Maryland, Ohio, Pennsylvania, Virginia, and West Virginia. Allegheny Power is currently participating in PJM WEST,[13] an extension of the PJM RTO.

On May 25, 2000, The Potomac Edison Company ("Potomac Edison") filed an application with the Commission for the functional separation of its generating assets from its transmission and distribution assets, as required by the Restructuring Act. In the application, Potomac Edison proposed to transfer to AES[14] its non-Virginia generating assets, and to an affiliate certain contractual entitlements to generation. In addition, Potomac Edison entered into a Memorandum of Understanding ("MOU") with the Commission Staff that contained certain representations and undertakings that the Company made in order to comply with the requirements of the Restructuring Act. On July 11, 2000, the Commission approved Potomac Edison's request to transfer its generation resources to AES, noting that the representations and undertakings set forth in the MOU, as supplemented on July 7, 2000, provided satisfactory assurance that the incumbent electric utility's generation assets, or their equivalent, would remain available for electric service during the default service period.

As mentioned previously, Potomac Edison transferred all of its generating assets to AES in 2000. Potomac Edison provides for 100 percent of its Virginia default service requirements through a Power Sales Agreement ("PSA") with AES, dated January 1, 2001. The PSA provides

[12] AEI., with headquarters in Hagerstown, Md., is an integrated energy company that owns or controls over 12,000 MW of generation. Subsidiaries include Allegheny Energy Supply, LLC ("AES") and Allegheny Power.
[13] While PJM West is now operational, and Allegheny is actively participating in PJM West, the SCC has not yet granted approval for the ultimate transfer of management and control of Allegheny's transmission assets to PJM West under Sections 5577 B and 56-579 of Virginia's Restructuring Act.
[14] AES, formed in 1999, is a non-regulated energy company that generates electricity and actively markets competitive wholesale energy commodities. AES owns all of Potomac Edison's former generating facilities.

for required firm energy and capacity to meet its default services schedules, as issued by the control area operator. Although this is a firm power contract, specific units are not assigned to serve the load. The former Potomac Edison generating facilities are committed and dispatched into the PJM market based on market prices, independent of Potomac Edison's Virginia load obligation. The PSA expires at the end of the Virginia statutory transition period, or 2007, whichever is earlier. As a signatory of the PJM West Reliability Assurance Agreement ("RAA"), Potomac Edison indicates that it meets the PJM system-wide Installed Reserve Margin ("IRM"), which is 17% for the 2003/2004 planning period.[15] Over the five-year forecast period 2003-2007, Potomac Edison forecasts that annual winter peak load will decrease 14.7% in 2003, and then increase at an average annual compound growth rate of 2.36% through 2007.

It should be noted that Potomac Edison's credit ratings have been downgraded numerous times since 2002, in large part as a result of the financial difficulties of its parent, AEI. AEI's deteriorating financial performance has been largely attributed to weak wholesale power markets and problems with its energy trading activities. AEI is currently exploring options to avoid having to seek bankruptcy protection which could impact Potomac Edison's ability to provide reliable service.

Delmarva Power & Light Company d/b/a Conectiv

Delmarva Power & Light Company ("Delmarva") is engaged in the supply, transmission, distribution, and sale of electric energy to approximately 22,000 retail customers and one wholesale customer in Virginia's two Eastern Shore counties. The remainder of Delmarva's

[15] In the 1996 Staff Report on Restructuring, Staff noted that Potomac Edison anticipated its reserve margin would decline from 21% to 16% over the next 20 years, while the APS system anticipated a decline from 22% to 18%. Potomac Edison also projected a long-term annual growth rate of 1.6% in winter peak demand.

electric service customers are located in Delaware and Maryland. The Company owns no generating capacity. The Delmarva transmission system is operated as part of the PJM RTO.[16] On August 1, 2002, with the closing of the merger involving Conectiv and Potomac Electric Power Company ("Pepco"), Pepco Holdings, Inc. ("PHI") became the parent company of Pepco, and Conectiv, and all of their subsidiaries, including Delmarva, a Conectiv subsidiary.

Delmarva submitted applications on February 4 and April 12, 2000, to satisfy, in part, the statutory requirements for a plan for the functional separation of generation, retail transmission and distribution pursuant to the Restructuring Act. In addition, Delmarva sought approval for, among other things, a three-phased divestiture of all its generating facilities, and transfers of control of transmission facilities. In its application, Delmarva committed to purchase power from competitive markets for the purpose of meeting any on-going default service requirements imposed by the Commission pursuant to the Restructuring Act.

On June 12, 2000, Delmarva filed, by motion, a Memorandum of Agreement ("MOA") between the Company and the Staff that set forth agreements reached between Delmarva and the Staff for resolution of certain issues raised by the Company's plan. The Staff filed a report on June 15, 2000, providing support for the MOA. The MOA established a Rate Case Protocol that would assure that the generation component of future rates would be no higher than it would have been had Delmarva continued to own its generating assets. The Rate Case Protocol also recognized that Delmarva's embedded cost of generation could change over time, and so established mechanisms for adjusting future rates accordingly. On June 29, 2000, the

[16] While PJM is now operational, and Delmarva is actively participating in PJM, the SCC has not yet granted approval for the ultimate transfer of management and control of Delmarva's transmission assets to PJM under Sections 5577 B and 56-579 of Virginia's Restructuring Act.

Commission approved Delmarva's plan for the functional separation of its generation from its transmission and distribution, through divestiture of its generation assets, as modified by the June 12, 2000, MOA.

From 1998-2002, Delmarva's Virginia service territory coincident summer peak loads exhibited no particular trend. For the five-year forecast period 2003-2007, Delmarva forecasts that summer peak loads for its Virginia territory will decrease by 6.3% in 2003, and then increase by an annual compound growth rate of 3.2%.

Delmarva fulfills its supply obligation through a full requirements contract with a wholesale supplier. Delmarva notes that the supplier uses a "portfolio approach" for allocating its capacity since the supplier also has load obligations in Delaware, Maryland, and New Jersey. Delmarva makes no allocation of capacity among states within the Delmarva zone[17] of PJM. Hence, no units are specifically dedicated to serving Virginia load. PJM does the dispatching of the generation in the entire region and so sets capacity obligations for the region. As of June 1, 2003, the capacity obligation for the Delmarva zone will be determined by a PJM forecast load model and allocated based equally on the zone's load contribution in the past five years and the zone's load contribution of the previous summer. As a signatory of the PJM RAA, Delmarva indicates that it meets the PJM system-wide IRM of 17% for the 2003/2004 planning period. Delmarva reports that PJM's approved target IRMs have decreased from 20.5% for 1997/1998 to 17% for 2003/2004. The calculated, but as of yet unapproved, target IRM for 2004-05 is 16.4%. The IRMs for 2005/2006 and 2006/2007 have not been calculated.[18]

[17] A zone is an area within the PJM Control Area as set forth in the Tariff.
[18] In the 1996 Staff Report on Restructuring, Staff noted that Delmarva targeted a reserve margin of about 18%. Delmarva also projected a long-term annual compound growth rate of 1.4% in summer peak demand.

Kentucky Utilities Company d/b/a Old Dominion Power Company

Kentucky Utilities Company ("KU"), a public service company doing business in Virginia as Old Dominion Power Company, and Louisville Gas & Electric Company ("LG&E") are the two regulated subsidiaries of LG&E Energy Corporation, headquartered in Louisville, Kentucky. Kentucky Utilities Company provides electric service to more than 448,000 customers in 77 counties of Kentucky and approximately 29,500 retail customers in Wise, Lee, Russell, Scott, and Dickinson Counties in southwest Virginia. The Company has no wholesale customers in Virginia. LG&E, an electricity and gas utility based in Louisville, Kentucky, serves customers in Louisville and sixteen surrounding counties.

KU and LG&E plan and provide for their capacity needs on a joint basis. KU and LG&E have established a planning reserve margin target in the range of 13-15% as discussed in their Integrated Resource Plan ("IRP"). A reserve margin target of 14% was being used for 2002.

KU and LG&E have a joint generation capacity of over 7,000 MW, of which over 4,000 MW is owned by KU. Some of the capacity is represented by generating units that are jointly owned by the two companies. The generating units on the KU system, all located in Kentucky, are dedicated to serve all KU load obligations including those in Virginia. In addition to owned generating plants, the Company has purchased power contracts that provide firm capacity. Currently, the Companies have contracted for the purchase of firm summer capacity from Electric Energy Incorporated ("EEI"), Ohio Valley Electric Corporation ("OVEC"), and Owensboro Municipal Utilities ("OMU").

In 2002, KU applied to the Commission for, and was granted authority to, acquire from its affiliate, LG&E Capital Corporation, a 63 percent interest in four 152-MW combustion turbines ("CTs") located in Trimble County, Kentucky. LG&E will own a 37 percent interest.

The CTs are expected to commence commercial operation in June 2004. KU and LG&E believe that acquisition of the CTs will afford the companies the most reasonable, least-cost means of reliably meeting their loads during the 2004-2006 period. Further, the two companies believe the load forecast indicates a need for additional peaking capacity by 2007 to meet growing demand and maintain, in a least-cost manner, a reserve margin target of 14 percent.

From 1998-2002, KU's reserve margin decreased from nearly 20% to 17.6%. Over the same period, peak demand increased at a 2.31% average annual compound growth rate, installed capacity increased by 15.4%, and firm purchased capacity decreased by 33.8%.

For the five-year forecast period 2003-2007, KU forecasts that its installed capacity will be increased 13%. During the same time, KU estimates that the Kentucky and Virginia combined[19] summer peak load will increase at an average annual compound growth rate of 3.36%, or 18% for the total period. The Company's forecast reserve margin is expected to increase from 12.5% in 2003 to 18.6% in 2004 (as a result of the new CTs), and then decrease gradually to approximately 11% in 2007,[20] which means KU will be relying more on LG&E in 2006 and 2007 to maintain the combined 13%-15% margin. KU's firm purchases of power are expected to decrease by 5.3% from 2002 to 2007.

<u>Virginia's Electric Cooperatives</u>

There are currently thirteen electric cooperatives in Virginia serving approximately 11.5% of the electric customers in the Commonwealth. The co-ops are Central Virginia Electric

[19] According to KU, peak load for Virginia is not forecast separately.
[20] In the 1996 Staff Report on Restructuring, Staff noted that KU continued to target a reserve margin of about 15%. KU also projected a long-term annual compound growth rate of 1.7% in summer peak demand.

Cooperative ("CVEC"), Craig-Botetourt Electric Cooperative ("CBEC"), Powell Valley Electric Cooperative ("PVEC"), and the following ten distribution cooperatives that are members of the electric generation-and-transmission ("G&T") cooperative Old Dominion Electric Cooperative ("ODEC"): A&N, BARC, Community, Mecklenburg, Northern Neck, Northern Virginia, Prince George, Rappahannock, Shenandoah Valley and Southside Electric Cooperatives. There are two additional ODEC members, Choptank Electric Cooperative in Maryland and Delaware Electric Cooperative, that do not serve Virginia customers.

CVEC, CBEC, and PVEC purchase their power from sources outside ODEC. ODEC's ten Virginia members purchase the bulk of their power supply needs from ODEC, and a small portion from the Southeastern Power Administration ("SEPA"), which originates at the Kerr and Philpott Dam projects. The energy infrastructure for CVEC, CBEC, CVEC and ODEC is discussed below.

<u>CVEC</u>. Central Virginia Electric Cooperative is headquartered in Lovingston, Virginia and serves approximately 29,650 members in 14 counties. The Cooperative owns and operates three 1,600 kW diesel generators at the Ellis Generating Station, which went commercial in 1993. The units are used for peak shaving and are operated at the time of the DVP peak, but not necessarily at the time of the CVEC peak.

CVEC relies on wholesale full requirements power contracts for its power supply. Presently, CVEC is under contract with Dominion Virginia Power through December 31, 2004, to provide power at the 15 delivery points connected to the DVP system. In addition, CVEC and CMS Marketing, Services, and Trading (now Constellation Power Source ("Constellation")) entered into a contract that began on May 22, 2002, and provides for energy and capacity at the seven AEP delivery points on the CVEC system through May 31, 2012. The contract also provides that energy and capacity will be received at the 15 DVP delivery points beginning January 1, 2005, and extending through May 31, 2012. Again, the contract does not require specific unit designation within the Constellation system; however, the transmission agreement with AEP for delivery through their system does require a specific network resource designation.

From 1998-2002, CVEC's demand increased by 12.6%, while installed peaking capacity remained constant. For the five-year forecast period 2003-2007, CVEC forecasts no change in installed capacity. During the same time period, CVEC estimates that winter peak load will increase 29.4% (a 5.29% average annual compound growth rate). CVEC does not forecast reserve margins since reserves are provided by the full requirements contracts.

CBEC. Craig-Botetourt Electric Cooperative is headquartered in New Castle, Virginia and serves approximately 6,083 members in six Virginia counties and one West Virginia county. The Cooperative owns no generation. CBEC relies on purchased power contracts with AEP (60%), Dominion Virginia Power (30%), and SEPA (10%). All contracts are automatically renewable on an annual basis but may be canceled with one-year notice prior to the anniversary date.

From 1998-2002, CBEC's winter peak demand increased by 31.3% (7.03% annual compound growth rate). For the five-year forecast period 2003-2007, CBEC forecasts no increase in winter peak demand from 2002 to 2003, and an increase in winter peak demand of 19% (4.46% annual compound growth rate) from 2003 to 2007. CBEC does not forecast reserve margins since reserves are provided by the full requirements contracts.

PVEC. Powell Valley Electric Cooperative is headquartered in New Tazwell, Tennessee and serves approximately 7,533 members in three Virginia counties. Powell Valley owns no generation and obtains its power through a full requirements contract with the Tennessee Valley Authority.

From 1998-2002, PVEC's winter peak demand increased by 17.3% (a 4.1% average annual compound growth rate). For the five-year forecast period 2003-2007, PVEC forecasts no change in installed capacity. During the same time period, PVEC approximates winter peak load increasing by 17.5% (3.27% annual compound growth rate). PVEC does not forecast reserve margins since reserve margin planning targets are provided by the full requirements contracts.

ODEC. ODEC was organized in 1948, to identify new power sources for its growing member systems, but remained inactive until power costs surged during the 1970s. After being staffed full-time in 1976, Old Dominion began serving its members' power supply needs by purchasing wholesale power and selling it to them at cost. In 1983 ODEC purchased an 11.6% (214 MW) undivided interest in Dominion Virginia Power's North Anna Nuclear Power Station, representing ODEC's first ownership of power generation. ODEC also owns 50% (441 MW) of the Clover Power Station, which was designed and constructed by ODEC but is operated by Dominion Virginia Power. In 2002, ODEC obtained 8 MW of diesel peaking generation divided between two Virginia sites – one in Southampton County and one in Amelia County.

In 1999 ODEC initiated preliminary steps toward building gas-fired combustion turbine ("CT") peaking generation units to serve the member cooperatives on the Delmarva Peninsula and in Northern and Central Virginia. In 2000 it focused its efforts on licensing three potential combustion-turbine sites – Rock Springs, Maryland; Louisa County, Virginia and Fauquier County, Virginia. The Rock Springs facility consists of 4 CTs. The 5 CT's in Louisa County have a total capacity of 455 MW went into commercial operation in June of 2003. The Marsh

Run facility in Facquier County has a May 1, 2004, commercial operation date and will consist of 3 CT units with a combined capacity of 465 MW.

When ODEC's 50% ownership in the Clover station is combined with its 11.6% ownership stake in the North Anna Nuclear Power Station, and its CT peaking units, ODEC owns about 80% of the generating needs of its 12 members. (This will increase to greater than 100% with the completion of the Rock Springs and Marsh Run CTs.) The other 20% is purchased from other suppliers through contractual arrangements. This purchased power is delivered over transmission facilities – located within other utilities' control areas (DVP, AEP, and PJM West and PJM East) – to the individual cooperative delivery points. Beginning in 2004, ODEC will rely in part on wholesale purchased power contracts with DVP and Constellation Power Source. The contracts with Constellation terminate in 2007. ODEC forecasts that in 2006 it will need additional purchased power from the competitive marketplace.

Over the period 1998-2002, ODEC's reserve margin increased from a deficit to a positive 1.7%. Over the same period, demand increased by 24% (a 5.5% average annual compound growth rate), installed capacity remained constant, and firm purchased capacity increased 67.6%.

For the five-year forecast period 2003-2007, ODEC forecasts that installed capacity is expected to increase 142 %, and purchased power capacity is expected to decrease by nearly 75%. ODEC expects summer peak load to decrease by 8.1% from 2002 to 2003. From 2003 to 2007 it forecasts summer peak load to increase a total of 14 % (a 3.29% average annual compound growth rate). ODEC's forecast reserve margin for its combined owned generation capacity and purchased power, is expected to increase from 12% to 20%. From 2003 to 2007, ODEC's reliance on firm purchased power is expected to decrease by 50% from 2002 levels in 2003, and then decrease by 50% again from 2003 to 2007.

Virginia's Municipal Electric Utilities

Municipal utilities are operated by local governments to provide communities with reliable, responsive, not-for-profit electric service. The American Public Power Association ("APPA") is the service organization for the nation's municipal public power utilities. APPA was created in 1940 as a non-profit, non-partisan organization. Its purpose is to advance the public policy interests of its members and their consumers, and provide member services that ensure adequate, reliable electricity at a reasonable price, with the proper protection of the environment.

Sixteen municipal entities in Virginia have membership in APPA and the Municipal Electric Power Association of Virginia ("MEPAV"). Fifteen of the 16 are also members of either of two Joint Action Agencies: the Blue Ridge Power Agency and the Virginia Municipal Electrical Association No. 1. The ultimate goal of the organizations, through the strength of numbers, economies of scale, and cooperative, "joint" action, is to pursue those activities which will insure the most reliable and lowest cost wholesale electric power supplies possible for their members today and in the future. The Town of Front Royal is the only Virginia public power municipal that is not a member of one of the two Joint Action Agencies.

Blue Ridge Power Agency. Blue Ridge Power Agency ("Blue Ridge" or "BRPA") is a non-profit corporation established in 1988 under the laws of the Commonwealth of Virginia. It is a "joint action" agency that operates as directed by the Board of Directors. Each member utility appoints one Director and one Alternate from its organization to the Board.

Blue Ridge represents its members' best interest in several forums by direct staff involvement and/or coordination of the efforts of its attorneys and consultants. The current efforts of Blue Ridge and its staff are focused mostly in negotiating and administering its power supply and associated transmission contracts. There are currently eight members of the agency that are not regulated by the SCC, including seven municipalities and one state institution: City of Bedford, City of Bristol, City of Danville, City of Martinsville, City of Radford, Town of Richlands, City of Salem, and Virginia Tech. Two electric cooperatives regulated by the SCC, CVEC and CBEC, are also members.

The eight unregulated Blue Ridge members purchase over 95% of their energy and capacity needs via long term contracts with suppliers. They own virtually no dependable capacity and are able only occasionally to generate at the time of their system peak using small hydro and diesel generators. The combined nameplate capacity of their generating units totals only 25 MW. In 2001 BRPA's eight unregulated members purchased 3,049,431 MWh and generated only 43,036 MWh while serving 108,028 customers.

Currently, the BRPA aggregate load (net of owned generation) is supplied by full requirements contracts with American Electric Power, Appalachian Power Company, and CINergy Corporation. Over the period 1998-2002 the eight unregulated Blue Ridge members' 1-hour aggregate coincident peak load increased by 4.7%. Forecast peak load is expected to increase 7.8% from 2002 to 2007. The full requirements power suppliers are responsible to maintain reserve margins that cover the BRPA load.

<u>Virginia Municipal Electric Association No. 1</u>. The Virginia Municipal Electric Association No. 1 ("VMEA") was created as a non-profit organization for the purpose of providing reliable power supply for its seven members: Town of Blackstone, Town of Culpeper, Town of Elkton, City of Franklin, City of Harrisonburg, City of Manassas, and Town of Wakefield. These seven unregulated VMEA members purchase nearly all of their energy and capacity needs via long term contracts with suppliers. They own 93.2 MW of installed capacity

consisting almost entirely of diesel generators that are installed for peak shaving and emergency power. In 2001, VMEA purchased 1,576,628 MWh and generated only 1,100 MWh while serving 42,872 customers.

Currently, the VMEA aggregate load (net of owned generation) is supplied by a full requirements contract with Dominion Virginia Power, which expires on December 31, 2007, and 6.1 MW from SEPA. For the period 1998-2002 the seven unregulated VMEA members' 1-hour aggregate non-coincident peak load fluctuated slightly. Forecast aggregate non-coincident peak loads are expected to increase by 8% from 2003 to 2007. Peak load reserve margins and reserve margin planning targets are part of the full requirements power supply contracts, and are the responsibility of DVP.

<u>Town of Front Royal</u>. The Town of Front Royal is the only municipal power utility in the Commonwealth that is not a member of either Blue Ridge or VMEA No. 1. Front Royal does not own any generating units. The Town has an existing power supply contract with Allegheny Power that expires on June 30, 2003. It will be replaced by a new full requirements power supply contract with Dominion that expires on June 30, 2006. Front Royal's peak load has remained fairly constant and is expected to remain stable over the forecast period 2003-2007. In 2001, Front Royal purchased 157,839 MWh for its 7,037 customers.

SUMMARY ANALYSIS

This section aggregates the responses provided by the utilities into topic-specific, as opposed to utility-specific, assessments. As such, this section is loosely divided into three parts. First, the utilities' responses are analyzed from the perspective of owned or dedicated capacity specifically dedicated to serving Virginia load. Next, reserve margins are addressed. Finally, the utilities' reliance on purchased power is considered.

Both Potomac Edison and Delmarva have transferred and/or sold their generating units to unregulated affiliates and have entered into purchased power agreements to supply their needs. These agreements are subject to FERC jurisdiction and do not dedicate specific resources to Delmarva's or Potomac Edison's Virginia customers.

Apco has historically relied on its FERC approved interconnection agreement with its AEP affiliates to augment its own generation for the provision of electricity service in Virginia. Under the agreement, Apco's major generating plants are dispatched in combination with the plants of the other AEP member companies. This centralized system dispatch assures that the entire AEP system load, including that in Virginia, is supplied in a reliable and economical manner. If AEP implements the 3-member interconnection agreement, Apco will rely to a greater extent on the competitive market for its reserves.

All of Virginia Power's owned capacity and NUG contracts are allocated to Virginia Power's load in Virginia and North Carolina. The Company has enough owned capacity to meet approximately 90% of its peak load obligation, and could meet the entire load obligation when the NUG contracts are included. However, in order to meet its target reserve margin, the Company must rely on additional power supply contracts, which cannot be attributed to specific units.

The generating units on the KU system, all located in Kentucky, are dedicated to serving all KU load obligations, including those in Virginia. Furthermore, Virginia's load is not forecasted separately. KU can meet its projected load with installed units but most of its reserves are met by firm long-term contracts for purchased power which cannot be attributed to specific generating units.

ODEC is in the process of building capacity and soon will be able to meet all of the generating needs of its 12 members. CBEC, CVEC, and PVEC essentially rely on full requirements purchased power contracts for their needs. Likewise, BRPA, VMEA and the Town of Front Royal rely almost exclusively on full requirements contracts. These purchased power contracts provide reserves deemed adequate by the supplier; however, this dependence on others carries increased risk in an uncertain economic environment.

Target and actual reserve margins also vary among the utilities. Virginia Power is forecasting a reserve margin of 13.5% in 2003 and then 12.5% for each year through 2007. This represents a decrease from their historical targets of 15.5% that were reported in the 1996 Staff Report on the Restructuring of the Electric Industry.

Those companies such as Potomac Edison and Delmarva that are members of a regional transmission organization ("RTO") rely upon the RTO's system-wide reserve margin. The PJM RTO system-wide reserve margin has decreased from 20.5% in 1997 to 17% in 2003 and is expected to be 16.4% in 2004. Similarly, as an operating company subsidiary of AEP, Apco relies on the generation of other AEP companies to maintain an adequate reserve margin for its customers. Absent the other member companies, Apco projects increasingly negative reserve margins from 2003 to 2007. Even AEP projects a system-wide decrease in reserve margin from 15% in 2003 to 9.6% in 2007.

KU and LG&E plan and provide for their capacity needs on a combined system basis and established a system reserve margin target of 14% for 2002. In the 1996 Staff Report on the

Restructuring of the Electric Industry, Staff noted that KU was targeting a reserve margin of about 15%. KU's reserve margin is expected to decrease to approximately 11% by 2007.

ODEC's reserve margin is expected to increase from approximately 12% in 2003 to 27% in 2004 (as a result of its new combustion turbine units), then decline to 20% through 2007 as demands increases. CVEC, CBEC, PVEC and the municipal utilities report that their reserves are considered part of their full requirements contracts.

In addition to a trend of decreasing reserve margins, some companies report a growing reliance on purchased power, at least through 2007, for their reserves. The municipals and the non-ODEC electric cooperatives have no plans to add new capacity and so will have to purchase more power through their full requirements contracts in order to meet increasing loads. KU and AEP have not forecast additional purchases, but their forecast reserve margins are decreasing as a result. Virginia Power will have to increase its reliance on short-term purchases from the wholesale market to maintain its target reserve margin. ODEC on the other hand forecasts a reduced reliance on purchased power.

CONCLUSIONS

Based on the energy infrastructure data collected from the state's electric utilities, the extent to which the various utilities own resources dedicated to serving customers in Virginia ranges from 0% to 100%. All of the utilities rely on at least some purchased power from the wholesale market that is not backed by specific units. Furthermore, companies are either relying on increased amounts of purchased power to meet their loads and maintain their target reserve margins, or reserve margins are forecast to decline beyond 2003. In addition, it appears in several cases that planning reserve margins have decreased since the mid-1990s. In short, the data collected support the finding expressed in the Commission's November 20, 2002 Report: "In recent years, in response to an evolution of a market driven paradigm, our utilities have shortened their planning horizon, reduced planning reserve margins and increased reliance on purchased power."

In Virginia, Potomac Edison's ability to provide reliable service could be impacted by the deteriorating financial performance of its parent, AEI, which has been largely attributed to weak wholesale power markets and problems with its energy trading activities. AEI is currently exploring options to avoid having to seek bankruptcy protection. Recent litigation has hinted that increased reliance on purchased power through the market could increase utilities' exposure to the risks associated with the sudden loss of such contracts due to the bankruptcy of power marketers. For example, on June 13, 2003, the U.S. District Court for the Southern District of New York permitted NRG Power Marketing, Inc. to stop supplying power to Connecticut Light & Power Co. in accordance with the findings of the Bankruptcy Court. If FERC orders NRG to uphold its contract with CL&P, it isn't clear how the conflicting orders from the bankruptcy and district courts would be resolved.

As noted in the Commission's November 20, 2002, Report, this trend now appears to be reversing. For example, PJM requires load serving entities to maintain specific reserve levels with resources that meet PJM's deliverability test. Likewise, this concept is embodied in the FERC Notice of Proposed Rulemaking related to a wholesale power market platform. It is noteworthy, however, that both the PJM model and the FERC wholesale power market platform model, effectively shift some degree of oversight responsibility for transmission and generation reliability from the states to the FERC. The NOPR largely adopts the PJM model, and that model is in a state of evolution. It appears that if Virginia utilities join PJM as it is currently structured, or some RTO envisioned by the FERC NOPR, Virginia's jurisdiction over the reliability of the bulk power system (generation and transmission) serving the Commonwealth would be diminished. Under such a scenario, the supply requirements of the state's utilities could be met through purchased power contracts negotiated by the RTO with the reserves being shared by the various members. While the economic dedication of units may continue for a state that has not deregulated or has maintained rate caps, the reliability of the bulk power system may nevertheless reflect the reliability of a broad geographic region encompassed by the RTO in which the state lies.

Following on the theme of uncertainty expressed in the Commission's November 20, 2002, Report, the ultimate status of the FERC NOPR remains unknown and the impact of that NOPR on existing RTOs, including PJM, still cannot be determined. The Commission has not formally considered the applications of Virginia's major utilities for membership in a specific RTO,[21] and any conditions that the Commission might require for such membership have not been established. At this point, the Commission cannot determine whether any RTO that Virginia's utilities might join will exercise (under FERC jurisdiction) control over only transmission operation, planning and pricing, or whether such control will also extend to generation dispatch, reserve requirements and market power control. In short, the electric utility industry is in a state of extreme uncertainty and will likely remain so for the foreseeable future.

[21] On December 19, 2002, Apco filed a Substitute Application in Case No. PUE200-00550 requesting approval to transfer functional and operational control of its transmission facilities to PJM. On March 7, 2003, the Commission issued an order requiring notice and directing that Apco submit additional information including a study of the costs and benefits of joining PJM. DVP is expected to file a similar request prior to July 1, 2003.

To the extent of the Commission's authority, the Commission will continue to collect the data necessary to monitor the dedication of facilities to the provision of electricity service in Virginia. The Commission will review utility resource plans, projected loads, and expected reserve margins. The Commission will provide subsequent reports as the Commission deems necessary or as requested by the COEUR.

ATTACHMENT NO. 1

LTTF RESOLUTION

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.