VIRGINIA STATE CORPORATION COMMISSION

STAFF INVESTIGATION ON THE RESTRUCTURING OF THE ELECTRIC INDUSTRY

IV. VIRGINIA'S ELECTRIC INDUSTRY

A proper evaluation of the potential impact of a restructuring of the electric industry upon Virginia requires a review of the status of the Commonwealth's electric utilities and related activity in our State. That is the purpose of this chapter. Neither a utility nor a state can expect to operate in isolation from neighboring companies or regions. However, with all of the complex issues involved with a transitioning electric industry, one size does not fit all. Actions and reactions in California may not be appropriate in Virginia because of our current cost of power, our economic environment and our tolerance for risk.

We will begin this chapter with an overview of the operating characteristics of each of Virginia's investor-owned utilities and electric cooperatives. Next will be a description of some of the reengineering activities undertaken by our electric utilities. We then evaluate the competitiveness of Virginia's utilities from a regional and national perspective. There have been recent actions or proposals by Virginia utilities or their potential competitors that may have an effect upon restructuring; some of these activities are detailed. Finally we will list recent Virginia General Assembly legislative activity related to electric industry restructuring.

A. An Overview of Virginia's Electric System

The electric industry in Virginia is comprised of five investor owned utilities ("IOUs") and thirteen electric cooperatives ("co-ops"). The IOUs are (1) Virginia Power, a subsidiary of Dominion Resources, Inc.; (2) Appalachian Power Company, a subsidiary of American Electric Power Company ("AEP"); (3) Potomac Edison, a subsidiary of Allegheny Power System ("APS"); (4) Delmarva Power & Light Company; and (5) Kentucky Utilities, a subsidiary of KU Energy Corporation.

The co-ops are Central Virginia Electric Cooperative ("CVEC"), Craig-Botetourt Electric Cooperative, Powell Valley Electric Cooperative, and ten distribution cooperatives that are members of the electric generation-and-transmission ("G&T") cooperative operating as Old Dominion Electric Cooperative ("ODEC"). The ten electric distribution members of ODEC serving Virginia are A&N, BARC, Community, Mecklenburg, Northern Neck, Northern Virginia, Prince George, Rappahannock, Shenandoah Valley and Southside Electric Cooperatives. Two additional ODEC members, Choptank Electric Cooperative in Maryland and Delaware Electric Cooperative, do not serve Virginia consumers.

Approximately 67.8% of Virginia's retail customers are served by Virginia Power, about 16.5% by APCO, 2.7% by Potomac Edison, 1% by Kentucky Utilities and 0.5% by Delmarva Power & Light. ODEC and distribution cooperatives serve approximately 10.6% of Virginia consumers, with the remaining 0.9% served by the remaining co-ops.

Several industry indices are presented in Table IV-A1 for each of the major electricity providers in Virginia. This table presents a 1995 snapshot of the Commonwealth's IOUs and co-ops; however, the average rates for ODEC and CVEC reflect 1994 data. Table IV-A2, compares average 1995 electric bills for each Virginia utility with the national average, a number of select regions, and several other utilities. Overviews of each IOU and co-op are presented in the following sections.

Map IV-A1 and Map IV-A2 illustrate the general area of Virginia served by each investor-owned and cooperative electric utility, respectively.

Virginia Power

Dominion Resources, Inc. ("DRI") is the holding company of Dominion Capital, Inc., Dominion Energy, Inc. and Virginia Electric and Power Company, its largest subsidiary. Virginia Electric and Power Company is the State's largest electric utility operating as Virginia Power and North Carolina Power (herein collectively called Virginia Power) in each of its respective territories. Approximately two thirds of the Commonwealth is served by Virginia Power. The utility provides nearly 72% of its sales to Virginia jurisdictional customers, about 12% each to Virginia non-jurisdictional customers (counties, municipalities, and state and federal facilities) and to FERC customers, and 4% to North Carolina customers. Virginia Power serves a total of approximately 1.9 million customers; it had operating revenues of $4.4 billion, net income of $433 million, and annual sales nearing 69,000,000 MWhs in 1995.

Virginia Power is a member of the Southeastern Electric Reliability Council, a transmission reliability area of the North American Electric Reliability Council, and is interconnected with several neighboring utilities. Duke Power and Carolina Power & Light provide the southern interconnection, APCO and Potomac Edison supply the western ties, and the Pennsylvania-New Jersey-Maryland Power Pool ("PJM") serves the northern interconnection. There are some interconnection constraints which at times limit the west-to-east imports to, and northern exports from, Virginia Power.

Virginia Power has been active in the emerging competitive wholesale market, re-selling purchased power, supplied under a long-term purchase contract with Hoosier Electric Cooperative in Indiana, to midwest utilities when not needed by the Company's customers. This prompted the establishment of the Wholesale Power Group within Virginia Power to develop a marketing business focused on the purchase and sale of wholesale electric power and to extend the trading range beyond the Company's geographical service area. Trading relationships have developed with utilities in Illinois, Missouri, Indiana, Kentucky, Ohio, Vermont, Michigan, and Tennessee in addition to most of the middle and south Atlantic states. Import and export capability and transmission reliability have been, and will continue to be, essential to the growing business of moving electricity.

Virginia Power maintains a diverse, but balanced, capacity mix. The system consists of 17,306 MWs of installed and purchased capacity to supply more than 14,000 MWs of peak demand. This capacity mix is comprised of 18.4% nuclear capacity (reflecting 88.4% ownership in the North Anna Nuclear Generating Station), 27.7% coal-fired capacity, 5.9% natural gas combined-cycle and combustion turbines, 12.3% oil-fired capacity, 9.2% conventional hydro and pumped-storage hydro capacity, and 26.5% purchased power (of which 19% is NUG capacity and the remainder is from utility purchases). The associated energy mix to supply 1995 MWh sales consisted of generation which is 32% nuclear, 39% coal-fired, 2% natural gas, 1% oil-fired, 1% net hydro and 25% purchased power.

Virginia Power currently plans for a generation reserve margin of about 15.5% through 2000 and 14% thereafter. It anticipates a long-term annual compound growth rate of 1.9% in summer peak demand and the maintenance of a load factor of 58% to 60%. The utility is traditionally a summer peaking company, despite higher winter peaks resulting from extreme cold weather in several recent years. Its recent integrated resource plan projects its next capacity addition will be a peaking facility in year 2003. This represents a delay in needed capacity from its previous forecast, a result of increased dependence on limited-term and seasonal purchases to meet expected needs, a significantly diminished target reserve margin and slower growth. The company maintains reasonable fuel inventory levels and storage capacity and is well-located geographically to take advantage of local fuel supplies and low transportation costs.

Virginia Power owns assets exceeding $11.8 billion and maintains a common equity ratio of 43.8% and an Standard and Poor's ("S&P") bond rating of "A" with a stable outlook. According to S&P's Utility Credit Report of April 1995, the utility's major strengths include a healthy service territory, a well-regarded nuclear program, a relatively conservative diversification program within the parent Dominion Resources, a closely controlled purchased power program, a relatively small industrial sector at risk, and competitive rates for the low-cost southeast. Major risks include a sizable dependence upon purchased power that adds to financial leverage, some financial exposure to Clean Air Act compliance, some financial exposure to not-yet recovered nuclear costs, and future nuclear fuel disposal and decommissioning costs.

Virginia Power has established its EVANTAGE division to provide customers with comprehensive packages of energy services and programs, ranging from fuel procurement and energy production to energy use analysis and management. Its initiative to become a full-service energy company was begun by acquiring A&C Enercom in January, 1996. These business units will nationally provide design, implementation and management services, and technological expertise to assist commercial and industrial companies in improving performance and increasing competitiveness.

Table IV-A3 presents an overview of Virginia Power's installed capacity.

Appalachian Power Company

American Electric Power Company, Inc. is the public utility holding company of several electric utilities now operating as AEP Virginia-Tennessee, AEP Indiana-Michigan, AEP Kentucky, AEP Ohio and AEP West Virginia. These utilities combine to comprise the American Electric Power System power pool.

APCO is a wholly-owned subsidiary of AEP engaged in the generation, purchase, transmission and distribution of electric power to retail customers in southwestern Virginia and southern West Virginia. Slightly more than half (51%) of APCO's business serves about 16.5% (approximately 438,000) of the Commonwealth's customers. The utility had operating revenues of over $1.5 billion, net income of nearly $116 million, and annual sales of about 35,500,000 MWhs in 1995.

As a member of the AEP power pool and a signatory company to the AEP Transmission Equalization Agreement, APCO's resources are operated in conjunction with the facilities of other AEP affiliated utilities as an integrated-utility system. The utility owns, or partially owns, nearly 25% (5,858 MW) of the total generating capacity of the entire AEP System power pool (23,759 MW). Its owned facilities consist of capacity which is 86.7% coal-fired and 13.3% conventional and pumped storage hydro. AEP is a member of the East Central Area Reliability Coordination Agreement.

APCO also supplies wholesale electric power to neighboring utility systems through the AEP transmission system. This vast transmission network has enabled AEP to begin to organize and develop the MidWest ISO system. Over 18 utilities have signed to support the associated Independent System Operator Principles. These principles are designed to allow an ISO, under independent management, to provide non-discriminatory open access to the bulk transmission systems in order to maintain functional control of the combined transmission system of its members. The ISO will determine available transmission capability, schedule transactions, and have responsibility for maintaining system security, developing regional transmission tariffs and planning future expansion of the regional bulk transmission system.

APCO is currently capacity deficient, but continues to meet customer demand by sharing, pursuant to the AEP Interconnection Agreement, in the capacity of the entire AEP system. The AEP system currently targets a 20% system reserve margin, but foresees it declining to about 12% over the next 20 years. APCO anticipates a long-term annual compound growth rate of 1.6% in winter peak demand while serving an approximate annual load factor of 57%. The utility projects that it will remain a winter-peaking utility. Its recent integrated resource plan forecasts the next capacity addition to be a peaking facility in year 2001. Despite diminishing reserve margins, the AEP system expects to be a large supplier of future off-system sales.

The AEP system mix consisting of 87.5% coal-fired capacity, 8.9% nuclear capacity, 3.5% hydro capacity, and 0.1% oil-fired capacity, offers stable, low priced energy. APCO owns assets of over $3.7 billion and maintains a common equity ratio of 39.3% and an S&P bond rating of "A-" with a stable outlook. According to Standard & Poor's Utility Credit Report of September 1995, APCO's major strengths include AEP pool membership, a lack of nuclear exposure, a slightly above average sales growth forecast compared to the AEP system, and low production costs accompanied by low rates. Major risks include a need for peaking capacity because of negative reserve margins, increased pool payments to the AEP System for supplying deficient capacity and complying with Clean Air Act requirements, and being located in an industrialized service territory subject to competitive market forces.

Table IV-A4 presents an overview of APCO's installed capacity and associated 1995 costs.

Potomac Edison

Allegheny Power System, Inc. is an electric utility holding company comprised of Monongahela Power Company, West Penn Power Company and The Potomac Edison Company. Potomac Edison is a wholly-owned subsidiary engaged in the generation, purchase, transmission and distribution of electric power to retail customers in northwestern Virginia, western Maryland and eastern West Virginia. Approximately 19.5% of Potomac Edison's business serves about 2.7% (approximately 72,000) of the Commonwealth's customers. Potomac Edison had total operating revenues of over $819 million, net income of over $78 million, and annual sales of nearly 12,700,000 MWhs in 1995.

The three affiliated utilities are pooled together and dispatched as an integrated system to maximize efficiencies among its members. Potomac Edison owns, or partially owns, nearly 25% (2,072 MW) of the total generating capacity of the entire APS system (8,369 MW). Its owned facilities consist of 88.4% coal-fired capacity and 11.6% conventional and pumped storage hydro capacity. APS is a member of the East Central Area Reliability Coordination Agreement.

Potomac Edison also supplies wholesale electric power to neighboring utility systems. In addition to its APS system interconnections, the utility is also tied to Virginia Power, Potomac Electric Power Co., and Baltimore Gas & Electric Co. In addition, APS is interconnected with AEP Ohio and AEP West Virginia, Pennsylvania Electric Co., Pennsylvania Power Co., Duquesne Light Company, Pennsylvania Power & Light Co., Municipal Power-Ohio, and Allegheny Electric Co-op, Inc..

The utility foresees its reserve margin declining from 21% to 16% over the next 20 years, while the APS system anticipates a decline from 22% to 18%. Potomac Edison anticipates a long-term annual compound growth rate of 1.6% in winter peak demand and an approximate annual load factor of 68%. The utility projects to remain a winter-peaking utility and take advantage of a diversity exchange agreement with Virginia Power, a summer-peaking utility. Its recent integrated resource plan forecasts the next capacity addition to be a peaking facility in year 2001.

The APS system mix, consisting of 84.7% coal-fired capacity, 10.7% hydro capacity, 1.0% oil-fired capacity and 3.6% NUG capacity offers relatively stable and low priced energy. Its significant coal requirement affords APS the opportunity to take advantage of contract and spot market coal supplies and low transportation costs.

The utility owns assets of over $1.6 billion and maintains a common equity ratio of nearly 49% and an S&P bond rating of "A+" with a stable outlook. According to Standard & Poor's Utility Credit Report of June 1995, Potomac Edison's major strengths include having operational and financial support from parent APS, being located in a relatively healthy service area, having no nuclear exposure, having sufficient low-cost generating capacity, being a winter peaking utility in a traditionally summer peaking region, exercising aggressive cost control, and being in compliance with Phase I requirements of the Clean Air Act Amendments with manageable exposure during Phase II. Major risks include expensive purchased power to come on-line by 1999, somewhat significant industrial exposure with heavy dependence on one customer and a relatively high APS common dividend payout ratio.

Table IV-A5 presents an overview of Potomac Edison's installed capacity.

Delmarva Power

Delmarva Power & Light Company predominantly operates as a public utility that provides electric and gas service. It is also the parent of several subsidiaries: Delmarva Capital Investment, Inc. ("Delcap"), Delmarva Services Company, Delmarva Energy Company and Delmarva Industries, Inc. Delmarva Power provides electric and natural gas service to customers living on the Delmarva Peninsula, a peninsula encompassing Delaware and extending south along the eastern shore of Maryland and Virginia. Approximately 3% of Delmarva Power's electric business serves about 0.5% (approximately 12,000) of the Commonwealth's customers. Delmarva Power had operating revenues of over $995 million (of which 90% were derived from the sale of electricity), net income of nearly $117.5 million, and annual sales of 12,310,921 MWhs in 1995.

The utility owns, or jointly owns, 2,883 MW of generating capacity. The mix consists of 11.4% nuclear, 38.9% coal-fired, 17.7% oil-fired, 26.7% gas-fired and 5.3% purchased power (of which about one third is NUG capacity). Delmarva Power maintains nuclear capacity through a 7.51% ownership interest in the Peach Bottom Atomic Power Station and a 7.41% ownership interest in the Salem Nuclear Generating Station. The remaining nuclear facility interests are distributed among PECO Energy Co., Atlantic City Electric Co. and Public Service Electric & Gas Co.

Delmarva Power is a member of the PJM power pool and its generation and transmission facilities are operated on an integrated basis with those of several other utilities in Pennsylvania, New Jersey, Maryland and the District of Columbia. Delmarva Power is part of the Mid-Atlantic Area Council.

Delmarva Power targets a reserve margin of about 18%. The utility anticipates a long-term annual compound growth rate of 1.4% in summer-peak demand and an approximate annual load factor of 67%. Its recent integrated resource plan anticipates adding a peaking facility in year 2002 and includes the loss of 150 MWs of ODEC load in 1995, the potential loss of 310 MWs of remaining ODEC load by 2001, and the addition of 172 MWs of the Conowingo Power Company load acquired from PECO Energy Company in June 1995.

Delmarva Power has a diverse fuel mix with significant dependence on oil and gas. Its energy prices are higher compared to utilities to the south of Delmarva, but are competitive with utilities to the north. Current steam generator problems and uncertain outage return dates for both Salem nuclear units will contribute to Delmarva Power's price of electricity remaining relatively high.

The utility owns assets of nearly $2.9 billion and maintains a common equity ratio of nearly 45.5% and an S&P bond rating of "A" with a positive outlook. According to Standard & Poor's Utility Credit Report of April 1995, Delmarva Power's major strengths include having competitive regional rates, maintaining excellent customer relations, having manageable capital spending to satisfy Clean Air Act requirements, having municipal customers under long-term contracts, having a large and stable residential and commercial customer base, having limited nuclear exposure and having a manageable debt retirement schedule. Major risks include having a high common dividend payout ratio, losing ODEC load, having above average wholesale exposure, and having exposure to an interim increase in leverage because of financing for the purchase of the Conowingo Power Company from PECO.

Table IV-A6 presents an overview of Delmarva Power's installed capacity.

Kentucky Utilities

KU Energy Corporation is a holding company whose principal subsidiary is an electric utility, Kentucky Utilities Company. KU Energy also holds a nonutility subsidiary, KU Capital Corporation (KU Capital). Kentucky Utilities is a public utility engaged in producing and selling electric energy in Virginia and Kentucky. It operates as Old Dominion Power Company to serve a portion of southwestern Virginia. Approximately 7% of the utility's business serves about 1% of the Commonwealth's customers (approximately 28,000). Its remaining electric business serves most of central Kentucky's Blue Grass Region and parts of southeastern and western Kentucky. The utility had operating revenues of over $686 million, net income of over $76 million, and annual sales of 17,417,554 MWhs in 1995.

Kentucky Utilities is a member of the East Central Area Reliability Coordination Agreement. The utility supplies wholesale electric power to neighboring utility systems and many municipalities. The utility is interconnected with AEP; PSI Energy, Inc.; Louisville Gas & Electric Company; and Union Light, Heat & Power Company.

The utility's system capability consists of 75% coal-fired capacity, 11.2% gas-fired capacity, 2.8% oil-fired capacity, 0.6% hydro capacity and 10.4% purchased capacity totaling 3,903 MWs. An additional 110 MW combustion turbine is scheduled for commercial operation in 1996.

The utility continues to target a reserve margin of about 15%. Kentucky Utilities anticipates a long-term annual compound growth rate of 1.7% in summer peak demand while serving an approximate annual load factor of 64%. The utility projects to remain a summer peaking utility, even though recent peaks in Virginia occurred during the winter. Its recent integrated resource plan forecasts 485 MWs of peaking generation to be added between 1996 and 2000.

Kentucky Utilities' coal-fired units provided 99% of its total net generation, or about 81% of its system energy requirements in 1995. This significant contribution requires adequate coal supply and inventory. About two-thirds of the utility's coal requirement is met by 3 and 5 year contract purchases while the remaining comes from spot purchases. The location of the utility's coal stations allows Kentucky Utilities the opportunity to take advantage of local coal supplies and low transportation costs.

The utility owns assets of over $1.6 billion and maintains a common equity ratio of 49.6% and an S&P bond rating of "AA-" with a stable outlook. According to Standard & Poor's Utility Credit Report of May 1995, Kentucky Utilities' major strengths include being a regionally and nationally low cost producer, having extremely competitive rates and opportunities for additional off-system sales, having no nuclear exposure, having a diversified, low risk and growing service area, maintaining a solid financial condition with credit conscious management and conservative financing/accounting practices, and having a strong transmission network. Major risks include a high debt leverage when adjusted for purchased power, a relatively small size which may limit its otherwise excellent competitive position, and a near-term level of common dividend payout close to 80%.

Table IV-A7 presents an overview of Kentucky Utilities' installed capacity.

Virginia's Electric Cooperatives

There are currently thirteen electric cooperatives in Virginia serving approximately 11.5% (approximately 319,000) of the electric customers in the Commonwealth. ODEC's ten member co-ops serve approximately 90% of Virginia's cooperative consumers, with the remaining served by the other three co-ops. The member co-ops are regulated by the SCC, but ODEC is regulated by FERC.

ODEC serves its members' power supply needs by providing owned and purchased power to the distribution cooperatives. Currently, Old Dominion is a joint owner with Virginia Power of a nuclear facility and a coal-fired facility. ODEC owns 11.6%, or 208 MWs, of the North Anna nuclear generating station and a 50% interest in the recently completed Clover Power station, or 416 MWs. Combined, these two resources supply approximately half of the members' power supply needs. The remaining need is provided by purchasing additional wholesale power under FERC regulated tariffs.

ODEC operates on a not-for-profit basis and seeks to generate revenues to sufficiently recover its cost of service, generate margins sufficient to maintain reasonable reserves, and meet financial coverage requirements. Any revenues in excess of expenses are designated as net margins. ODEC owns assets of nearly $1.1 billion and had operating revenues of over $357 million, a net margin slightly over $34 million, and annual sales of 7,258,301 MWhs in 1995.

ODEC is a member of the Southeastern Electric Reliability Council and an associate member of the Mid-Atlantic Area Council. Most of ODEC's members are located in Virginia and largely depend on Virginia Power as their partial requirements provider. On the peninsula, ODEC currently depends on Delmarva Power to provide its partial requirements. Old Dominion also has interconnections with APCO and Potomac Edison.

Craig-Botetourt and Powell Valley Electric Cooperatives are distribution cooperatives that belong to the Virginia, Maryland & Delaware Association of Electric Cooperatives, but are not members of ODEC. Craig-Botetourt is headquartered in New Castle, VA serving about 5,800 customers with sales nearing 60,000 MWhs and operating revenues and patronage capital of about $5.5 million in 1995.

Powell Valley Electric Cooperative, headquartered in Tazewell, Tennessee, serves areas in southwestern Virginia and northeastern Tennessee. Approximately 28.5% of Powell Valley's nearly 24,000 customers reside in Virginia. Total sales approximated 407,600 MWhs for its entire region with operating revenues and patronage capital of about $26.6 million in 1995. Since Powell Valley acquires all of its wholesale power from the Tennessee Valley Authority, only its service is regulated by this Commission. TVA's rates are set by the Federal Power Authority and passed on to its wholesale customers.

Central Virginia Electric Cooperative is an independent electric cooperative. CVEC serves about 24,800 customers with 1995 sales of about 410,000 MWhs and operating revenues and capital patronage of $28.6 million.

B. Reengineering Efforts of Virginia's Electric Utilities

In response to rapidly increasing change in the electric industry, utilities in Virginia have begun developing strategies planned to enable them to succeed in a more competitive environment. The utilities have identified remarkably similar objectives to contend with the expected changes. Their objectives generally included the following:

- to safely provide more reliable electric service at competitive prices in an environmentally sound manner via reduced costs and efficient operations;
- to develop innovative ways of meeting the unique needs of various customers and to aggressively pursue new customers by marketing new energy related products and services; and,
- to effectively manage transition to and operation in a more competitive environment through a close relationship with regulators and legislators

The cornerstone of each utility's strategy to succeed in a more competitive environment has been to reorganize. Such reorganizations have been referred to popularly as "*reengineering*" or "*restructuring*." Invariably, reengineering and restructuring have included outsourcing certain functions to achieve cost savings and establishing a strategic-business-unit organizational structure that operates with greater decisionmaking independence and cost control. A review of each Virginia utility's plans for reorganizing follows.

Virginia Power

Virginia Power began a comprehensive strategic planning program called Vision 2000 in March 1994. Vision 2000 represents both a continuation and intensification of the company's ongoing efforts to reduce costs, maintain competitive rates and develop new ways of meeting customer needs. To guide the company in implementing Vision 2000, four strategic initiatives were developed and announced in March 1995, including the following:

(1) Creating a new Virginia Power organization that involved decentralization of services common to the entire corporation, outsourcing certain functions, streamlining the company's power station and divisional structure, and establishing a strategic business unit organizational structure. The company's business units now include nuclear, fossil & hydro, commercial operations, and a new energy services business.

(2) Establishing an energy services business to develop and market new energy-related products and services. Its two primary groups include the Wholesale Power Group and Retail Energy Services, whose trade name is "EVANTAGE." The Wholesale Power Group strives to optimize Virginia Power's existing transmission and generation resources by selling power off-system when prices exceed costs. The mission of EVANTAGE is to offer comprehensive energy solutions tailored to meet the specific needs of customers. As a step in this direction, Virginia Power acquired A & C Enercom in January 1996. A & C Enercom is an Atlanta-based consulting firm specializing in marketing, program planning and design, and engineering expertise serving the utility industry and its customers.

(3) Refocusing the company's traditional businesses in order to lower costs and improve operating efficiencies and customer service.

(4) Working closely with regulators and legislators to protect the interests of customers and stockholders

during the transition to a more market-driven environment.

Since Virginia Power began its Vision 2000 strategic planning process, the company has reduced its workforce by almost 10 percent, or about 1000 employees. Compared to 1987, when the workforce reached an all-time high of approximately 14,000, Virginia Power has reduced its staffing by about 25 percent to slightly more than 9800 employees as of April 30, 1996. Additional staffing cuts will result from the company's remaining reengineering efforts in its business units and its corporate center.

Reengineering of the fossil & hydro business unit is expected to achieve annual savings of up to $60 million in operating and maintenance costs. Significant fuel and capital expenditure savings are also expected. The nuclear business unit reengineering is expected to reduce nuclear controllable costs by about $75 million per year. Reengineering of the commercial operations business could reduce its budget by 20 to 30 percent, but expenditures in the tens of millions of dollars for automation technologies will be required to achieve some of the customer service improvements that have been identified.

Staffing reductions and reengineering are integral aspects of the transformation process which Virginia Power has initiated in response to the accelerating forces of competition. They have helped the company avoid any base rate increases for the past few years despite up to $1 billion in major capital investments, including the Clover power station, a scrubber at the Mt. Storm power station, and two steam generator replacements at the North Anna power station.

APCO

APCO undertook an organizational review known as the Mission Project during the period May 1994 through December 1994. A plan that focused on the specific short term actions that should be taken identified approximately $10.5 million of potential savings related to actions that could begin in the 1995-1996 period.

The $10.5 million of potential savings was created by the reduction of approximately 150 positions through the elimination or outsourcing of activities. Through the first quarter of 1996, 79 positions had been eliminated and other labor costs had been reduced as a result of the Mission Project recommendations for an annual savings of approximately $5.2 million. Related to these reductions were significant incremental costs incurred during this period as employee severance-related expenses. The savings produced by the reductions are being invested in information systems, employee training and development, customer call centers and other areas.

APCO's Mission Project was one of several organizational reviews by the AEP electric utility subsidiaries. In AEP's recent reorganization, the best aspects of the electric utility subsidiary companies' reviews were considered in the creation of AEP's reorganization and operating practices.

In order to better position AEP and its subsidiaries for increasing competition among suppliers of electricity and to ultimately provide its customers with customized unbundled service at competitive prices, on January 1, 1996, AEP began to realign its organization. The electric utilities started doing business as "American Electric Power," and AEP created distinct power generation and energy transmission and distribution groups. The realignment established four functional business units: power generation, energy delivery and customer relations, nuclear generation, and corporate development. Corporate development is responsible for developing new business opportunities which are primarily non-utility activities. Various administrative and other support services will be provided to these business units. The business units and support services are functional organizations placed over existing corporate structures. In the realignment, no new entities will be formed and no utility assets will be transferred. As a result of the realignment, the AEP Service Corporation and the electric utility subsidiaries expect to provide improved services more efficiently. Power generation, nuclear generation, and accounting are expected to perform their functions with a total of approximately 1080 fewer staff.

Other vital new activities undertaken by the electric utility subsidiaries include the establishment of Key Account and National Account management programs to quickly respond to AEP's top customers' service and energy requirements and potentially gain new business as competition intensifies. Also, the electric utility subsidiaries are undertaking the development of certain customer equipment and customer consulting services closely related to their core utility business for present and anticipated retail and wholesale customers.

Delmarva

Delmarva has taken a broad spectrum of actions to position itself for coming competition. In the fall of 1994, as part of a strategy to reduce costs and increase sales, the company initiated an early retirement program which reduced the workforce by 296 people, or 10.5 percent. In addition, the Company has undertaken a series of work process redesigns to improve performance and reduce costs. Areas that have undergone redesign include information systems and fleet services. The entire customer service chain is undergoing an extensive process review and redesign at the present time.

In February 1996, the company announced plans to pursue a "Collaborative for Change and Customer Choice." The collaborative process is designed to enable regulators, customers and the company together to proactively make the necessary changes and realize the benefits of a competitive market.

To continue the company's evolution to adapt to changes in the electric industry and the changing needs of customers, Delmarva initiated an organizational restructuring in March 1996. The company aligned into three business units -- energy supply, energy services, and regulated delivery. These business units have a collective vision and will be supported by a group of internal corporate and business support services, known as infrastructure and support services.

Potomac Edison

Allegheny Power's functional restructuring began with its decision to form "one" company, a process it plans to complete by September 1, 1996. Allegheny Power plans to modify policies, procedures, and systems to support the one-company approach by 1997.

The Company intends to implement a reengineering process throughout the organization by the end of 1996. The reengineering will establish five business units and the operating companies' operating divisions will be consolidated into seven regional offices. The business units include generation, transmission, planning and compliance, operations, and corporate services and supply chain.

As a result of the reengineering process, the Allegheny Power workforce will be reduced from 5,836 to 4,652 people, a reduction of 1,184 people (or 20.3%).

In Virginia, staffing will be reduced from 158 people down to 104 people.

Allegheny Power expects to realize savings of $194 million over the next 5 years (after an initial loss in the first year), primarily as a result of the reduction in workforce and increased efficiency. However, the majority of the savings will be used to pay $110 million in reorganization costs and $68 million in information technology enhancements, in part to improve customer service. The net savings will then amount to $15 million over a five year period. Potomac Edison expects to save $4.5 million over a five year period (after an initial loss in the first year).

Summary

The above discussion demonstrates that utilities in Virginia have begun to develop and implement restructuring strategies to enable them to succeed in a competitive environment. It is particularly important that utilities recognize the need to maintain reliable service as part of their strategies for success. Utilities should be aware that the objective of maintaining reliability may not be entirely compatible with the objective of lowering prices via downsizing and cost cutting. Although utilities seek lower prices in order to maintain their existing customer base and to pursue new customers in a competitive environment, price may not be the most important factor in determining the loyalty of commercial, industrial, and residential customers. Attention to customer needs, reliability, and power quality may be equally important. While utilities profess they are striving to meet customer needs and improve reliability, one study found a perception among commercial and industrial customers that utility power quality and reliability have declined as utilities have begun downsizing. In the residential area, the study results showed more service interruptions, more customers affected by variations in power quality, and less customer satisfaction with reliability of electric service. Clearly utilities may be challenged to manage simultaneously cost-cutting restructuring programs, increasing growth, and rising customer expectations.

C. Competitiveness of Virginia's Electric Utilities

In this section we attempt to assess the competitiveness of Virginia electric utilities and cooperatives nationally. Average rates and rate trends for Virginia investor owned utilities are compared with average regional and national electric rates. Also a number of ratios derived from FERC Form 1 annual reports and Rural Utilities Service ("RUS") Form 7 annual reports for 98 electric companies, including Virginia's investor-owned utilities and electric cooperatives, are reviewed. As discussed previously, the overall potential for lower electric prices should depend on the relative efficiency or competitiveness of a utility or region.

Investor-Owned Utilities Electric Rates

Based on average bills as reported by the Edison Electric Institute ("EEI"), we calculated average costs per kWh for residential, commercial and industrial customers in Virginia, the United States, the South-Atlantic region and the Mid-Atlantic region during the period 1982-1996. The results of these calculations are summarized on graphs numbered IV-C1 through IV-C4. Graph IV-C2 presents real electrical costs for Virginia Power and the United States based on changes in the Gross National Product Implicit Price Deflator since 1982. This graph clearly shows that the real (adjusted for inflation) cost of electricity has declined nationally as well as for Virginia Power's customers.

The Old Dominion Power Company, Appalachian Power, and Potomac Edison have very competitive residential rates with averages that are typically below the regional and U.S. averages. Calculations of average residential rates were based on monthly usages of 1,000 kWh per month. Virginia Power's and Delmarva's residential averages for this usage level are below the Mid-Atlantic averages and above the U.S. and South-Atlantic regional averages.

Average commercial rates reflect monthly usages of 30,000 kWh and demands of 100 kW (a 41 percent load factor). Commercial rates for Old Dominion, Appalachian Power, and Potomac Edison are typically below the regional and U.S. averages. Delmarva's commercial averages, similar to its residential rates, exceed U.S. and South-Atlantic regional averages while remaining below the Mid-Atlantic regional averages. Virginia Power's commercial rates appear to be more competitive, as compared to residential rates, since they are typically below U.S. averages. Virginia Power's commercial rates are, like its residential rates, above the South-Atlantic regional averages.

With the exception of Delmarva, the industrial rates of Virginia's investor owned utilities appear to be quite competitive since their average industrial rates are typically below the national, Mid-Atlantic and South-Atlantic averages. This is significant since competitive pressures for utilities are greatest for larger customers with higher load factors. Virginia Power's industrial rates appear to be more competitive than either its commercial or residential rates. This is probably due to differences between Virginia Power and other utilities in cost allocation methodologies and rate design philosophies. Industrial averages reflect a 68.5 percent load factor (usage of 25,000 MWh per month and a 50 MW demand). We were unable to compare industrial rates for very large, high-load-factor customers since the maximum usage reported by the EEI reflects a 68.5 percent load factor and a maximum demand of 50 MW.

We attempted to gain some insight into allocation and rate design differences by calculating industrial rates as a percentage of residential rates (average industrial rate divided by corresponding average residential rate). The results of this analysis indicate that Virginia's ratemaking policies, as compared to those in other states, have resulted in lower rates to industrial customers relative to other customer classes. For example, the average Virginia Power industrial price per kWh represented less than 50 percent of the average residential price in July 1995, while the ratios for the other regions exceeded 60 percent. In fact, the ratios for all Virginia investor-owned utilities are typically below the industrial/residential ratios for the U.S. and the South-Atlantic and Mid-Atlantic regions.

Although we believe that the above comparisons are not sufficient for definitive conclusions, these comparisons do provide some useful information. For example, the rate comparisons indicate that Old Dominion Power, Appalachian Power and Potomac Edison have relatively low rates. This implies that competition is less likely to produce benefits for the customers of these utilities than it is for the customers of less competitive utilities. There may even be a possibility that prices in a competitive market will exceed the rates charged by utilities under current regulation. Virginia Power has competitive industrial rates and less competitive residential and commercial rates. Consequently, competitive pressures may have less of a relative impact on Virginia Power's customers than those of other utilities.

Competitive pressures could, of course, drive overall costs down and benefit all customers. However, such pressures could impact customer classes differently with certain customers being adversely impacted while others see benefits.

Annual Report Comparisons

In evaluating the competitiveness of utilities in Virginia, we also reviewed 1994 FERC Form 1 annual reports for investor-owned utilities and 1994 RUS Form 7 annual reports for cooperatively owned utilities. We utilized data from these reports to calculate 52 attributes for 98 electric utilities, power pools, holding companies or cooperatives, including Virginia's jurisdictional electric utilities and cooperatives. Certain calculations were not made for individual utilities due to unavailable data or the nature of a utility's business. The number of non-Virginia electric cooperatives included in this analysis is limited because of a lack of readily available information. A complete list of the companies reviewed is at the end of this section in Table IV-C1.

The companies included in our analysis are located predominantly in the MAAC, SERC, and ECAR reliability regions. Other companies located in areas where restructuring initiatives are actively being considered were also reviewed. The information reviewed for each company reflects total company information as opposed to state jurisdictional information.

The calculated indicators for each of the utilities reviewed are listed on Table IV-C2. These indicators were chosen to rank competitiveness and/or exposure to competitive losses. There may be reporting or accounting differences between companies and the information is limited to the calendar year 1994. Consequently, this analysis is subject to possible distortions associated with abnormal weather (like January of 1994), nuclear refueling, and extended maintenance outages, etc. Nevertheless, we believe that these numeric indicators will be useful in evaluating the potential impact of electric utility restructuring on Virginia utilities.

We developed a number of graphs of certain attributes to better analyze and present the results of our analysis of annual financial reports. Each graph is intended to provide rankings of two related attributes for a quick reference of a utility's competitiveness/exposure in those areas. The graphs have been designed such that companies with plots closest to the lower left corner of the graph or either the X axis or the Y axis have the better ranking in the areas represented on a particular graph.

For example, Graph IV-C5 plots each utility's average annual industrial cost per MWh against that utility's percentage of industrial energy consumption. This graph is intended to provide an indication of each company's potential exposure to the loss of industrial customers. Companies with low average industrial rates and lower industrial consumption are expected to be less likely to be impacted by the loss of industrial customers due to retail competition. Consequently, companies with points closest to the lower left corner of the graph will have lower exposures while companies closer to the upper right corner of the graph will have greater exposures. Virginia companies are labeled on the graphs while companies located outside of Virginia are not.

This analysis supports the results of earlier rate comparisons and indicates that the Virginia investor-owned utilities seem to be in relatively good shape with respect to the potential loss of industrial customers. Of the 93 companies with industrial sales, Kentucky Utilities (Old Dominion Power), Potomac Edison, Appalachian Power, Virginia Power and Delmarva have the 6th, 13th, 18th, 26th, and 33rd lowest average industrial rates respectively. Virginia's cooperatives appear to be subject to greater exposure to retail competition since their industrial rates seem relatively high. However, our results are somewhat misleading since industrial customers are combined with commercial customers in the RUS annual reports for cooperatives.

Our analysis is also intended to provide insights to the potential exposure of Virginia utilities to wholesale competition. In evaluating wholesale exposure, we reviewed average rates for resale customers and the percentage of usage by resale customers. The results suggest that Appalachian Power, Potomac Edison, and Delmarva may be subject to greater exposure in the wholesale markets with rates in the mid to higher ranges. Virginia Power's resale rates are among the highest. However, Virginia Power's exposure is somewhat mitigated by the company's lower level of resale activity. Although Virginia Power's wholesale exposure seems limited, the company's profitability could still be negativity impacted by significant wholesale competition.

Wholesale exposure will of course be impacted by the nature and status of each company's wholesale contracts. Companies with fixed contracts with extended remaining terms have less exposure to wholesale pressures than companies with contracts that expire in the near future. Virginia Power's wholesale contracts typically have remaining terms of approximately nine years.

The distribution and transmission functions of electric utilities seem less likely to be subject to competitive forces than the power supply function. Consequently, we attempted to look at certain attributes (total cost of power, load factor, production investment, production costs) to assess how well the power supply costs of Virginia utilities compare to utilities in other states and regions. Power supply related attributes are analyzed on Graphs IV-C8 and IV-C9. Distribution cooperatives were not included in these graphs since their supplies are obtained predominantly through wholesale supply contracts and their costs are driven in large measure by their suppliers. We reviewed information for the PJM power pool and the American Electric Power and Allegheny Power systems since certain Virginia utilities receive supplies from those systems. Delmarva participates in the PJM pool, while Appalachian Power and Potomac Edison are members of the AEP and APS systems respectively.

The power supply attributes indicate that Kentucky Utilities, Appalachian Power, and Potomac Edison have competitive power sources of energy while Delmarva, Old Dominion Electric Cooperative and Virginia Power have less competitive power supplies. AEP appears very competitive, while PJM seems less competitive. ODEC, which supplies power to the majority of Virginia's electric cooperatives, does not appear to be in a competitive position. However, the calculations of average power costs include purchased power costs and ODEC may be able to improve its competitive position by renegotiating some of its purchased power contracts.

The calculation of total power costs includes a calculation of the carrying costs for production related investments (return on investment, taxes, depreciation, etc.). In performing the calculations we utilized a modified version of the FERC's spreadsheet for determining transmission and production related carrying costs. The FERC spreadsheet calculates a levelized rate base, which impacts the needed return and related taxes, instead of the declining rate base methodology that is typically utilized in retail ratemaking. Consequently, we modified the spreadsheet to calculate rate base in accordance with accumulated depreciation reserves. We utilized Virginia Power's currently authorized equity return of 11.4 percent as a proxy for all utilities since equity returns for the various utilities are not included in the annual reports.

We included load factors in our analysis of power supply costs to provide an indication of how fixed capacity costs are being spread for each utility. Load factors were used in lieu of capacity factors since the annual reports do not include capacity levels for purchased power contracts. While lower load factors can be construed as having a negative impact on a utility's competitiveness since unit costs are typically higher when fixed costs are spread across lower volumes, we believe that lower costs coupled with lower load factors provide a positive indication of a utility's competitiveness. Increased market access may provide utilities with opportunities for load factor improvement and drive down average unit costs if they have lower production costs. On the other hand, higher costs and higher load factors leave little room for improvement since fixed costs are already spread over a larger base.

Virginia Power's competitive position could be enhanced through greater wholesale access since it has one of the lowest load factors. Virginia Power's non-carrying production cost (fuel and production related operating and maintenance costs including purchased power) appears relatively high and seems to imply that the company will not be as competitive in the wholesale market. However, the calculation of Virginia Power's non-carrying production cost is misleading since it includes purchased power demand costs and tends to overstate the company's truly variable production costs. The annual reports do not include sufficient information for eliminating such fixed costs.

Virginia Power's higher overall power costs are largely attributable to its purchased power costs. These costs averaged 6.45 ¢/kWh in 1994, while the cost of power produced by units directly owned by Virginia Power is estimated to be 3.73 ¢/kWh. The company's overall average power cost in 1994 was 4.35¢/kWh. Based on 1995 data, the overall cost of power from Virginia Power's owned units remained the same despite the addition of a scrubber at the Company's Mount Storm generating station and commercialization of Clover Unit No. 1. The Company's purchased power costs were 6.04¢/kWh and overall power costs were 4.31¢/kWh in 1995. A number Virginia Power's non-utility purchased power contracts reflect a front loading of capacity payments during the first fifteen years of the contracts. However, the drop-off in capacity payments in those front-end loaded contracts after fifteen years are largely offset by escalating capacity payments in other contracts. Consequently, Virginia Power's purchased power costs won't improve substantially until contracts begin to mature in the 2015 to 2018 time frame.

ODEC also has a low load factor. However, ODEC's ability to improve its cost position is limited by its partial ownership the North Anna nuclear generating station and the Clover coal-fired generating station. These units have very low variable operating costs and are fully dispatched. Consequently, ODEC cannot hope to lower its average costs by pursuing off-system sales. Costs associated with the Clover generating station were not included in our annual report analysis since the units began commercial operation subsequent to 1994. Clover's fixed costs are relatively high since the station is new and has not been depreciated to any great extent. Although Virginia Power owns half of the Clover generating station, the impact of the higher fixed costs will be proportionally less for Virginia Power than for ODEC due to the size of its system.

We attempted to measure the productivity of Virginia's electric companies by examining salaries, numbers of employees, and distribution investments. The results of this examination indicate that PJM, Virginia Power, and Delmarva have high salaries and/or greater numbers of employees per utility customer. The other Virginia jurisdictional investor-owned utilities typically have poorer attributes in both of these areas than do electric cooperatives. This should be expected since investor-owned utilities typically own and operate generating units requiring more engineering expertise and skilled labor, while cooperatives typically purchase the bulk of their power supplies. Many companies have undertaken, or are undertaking, reengineering and downsizing programs. The results of these programs have not been reflected in the above analysis. Other factors such as customer density, regional differences in the overall cost of living, and percentage of underground versus overhead electric service could contribute to utility differences.

We also calculated the average distribution investment per customer for each utility in an attempt to gauge the impacts of customer densities. These results indicate that cooperatives are adversely impacted by lower customer densities. Potomac Edison, Delmarva, and Virginia Power also have relatively high distribution investments per customer. Those utilities with higher distribution investments per customer may not be adversely impacted by the advent of retail wheeling since transmission and distribution services will, in all likelihood, continue to be treated as monopoly services, at least in the near term. Higher investments per customer do, however, contribute to perceptions of utility inefficiency.

While the usefulness of the annual report analysis is limited in certain respects, we believe that certain general conclusions can be made. First, it appears that Appalachian Power, Potomac Edison and Kentucky Power are quite competitive in many areas. Potomac Edison, Appalachian Power and their respective affiliated systems do, however, seem to have some exposure to wholesale competition. Any erosion of their wholesale customer bases or revenues could result in shareholder losses or reallocations of cost responsibility to retail customers and adversely affect their retail competitiveness. Depending on the ratemaking treatment of functional unbundling, or spin-off of generating assets, deregulation of their power supply functions could actually increase retail rates for companies with power costs that are below market prices. Given the relatively low power costs of Kentucky Utilities and the AEP and APS systems, customers of those systems could be adversely affected if these utilities gain access to other markets without corresponding protection for existing customers.

Delmarva and Virginia Power both seem to be in less competitive positions. Consequently, competitive pressures could drive down their costs and increase productivity. However, these benefits could be offset largely by transition costs if full or substantial recovery is allowed. Potential cost reductions by Virginia Power may be constrained by its limited ability to control costs associated with its purchased power contracts. Continued recovery of such costs through retail rates or transition surcharges will limit competitive benefits for customers located in Virginia Power's service territory. Increased wholesale competition may be beneficial to Virginia Power since the company may have a greater opportunity to improve its load factor through off-system sales. Virginia Power does appear less productive than other investor owned utilities with respect to its number of employees and level of salaries, although such costs represent a relatively small portion of a utility's total cost of service. Consequently, competitive forces could serve to drive down these costs and subsequently lower retail rates. However, Virginia Power and other utilities are already being subjected to such pressures and are aggressively attempting to lower costs through downsizing and reengineering programs.

D. Virginia Legislative Activities

Virginia Power was active in the 1996 legislative session seeking changes that, in its view, would enable it to be competitive if and when retail competition becomes a reality. Other parties sought legislative study of competition and restructuring. An outline of the various statutory changes that were made during the 1996 legislative session and a brief discussion of each change follows (Appendix III contains a copy of all legislative changes discussed in this section).

<u>Senate Joint Resolution 118</u>

Senate Joint Resolution 118 established a joint subcommittee to study restructuring and potential changes in the electric utility industry in Virginia and determine the need for change. The joint subcommittee will consider this investigation into restructuring of the electric industry and consult with the Commission regarding issues. The Commission is directed to provide technical assistance. The joint subcommittee shall submit its findings and recommendations to the Governor and the 1997 session of the General Assembly.

<u>Sections 13.1-620 and 13.1-627B</u>

Section 13.1-620 has long required all corporations that conduct the business of a public utility to incorporate as a public service company. It does not allow public service companies to have general business powers in the Commonwealth; however, such corporations may conduct such other nonpublic service business if it is "*related or incidental to its stated business as a public service company*." The original version of House Bill 589 amended § 13.1-620D. to define "*related to and incidental to [a public service corporation's] stated business" to include a "public service company's provision of goods or services (i) that complement or enhance the provision of public utility service or a customer's utilization of a public utility service or (ii) that are approved by the Commission*." This proposed change did not make the final version of the bill. Some electric utilities feel, however, that if various portions of their business are to be made competitive they will need flexibility to provide additional services to effectively compete with other providers who are not similarly constrained regarding the services they may offer.

The final version of House Bill 589 that was passed by the General Assembly amends Virginia Code § 13.1-627B. to authorize public service companies to enter into joint ventures or similar business associations, subject to the following limitations: (1) the ventures must encompass activities in which public service companies could independently engage in; (2) public service company equity and debt with recourse in any single venture may not exceed one percent of equity; and (3) total public service company equity and debt with recourse in all such joint ventures or associations may not exceed five percent of equity. Upon application by the public service company, the Commission may approve those partnership agreements, joint ventures, or other associations that exceed the equity investment criteria set forth by the legislation.

Virginia Code § 25-233

If a corporation or entity possessing the power of eminent domain, such as a municipality, wants to condemn the property of another corporation that also has the power of eminent domain, such as an electric utility, Code § 25-233 requires the Commission to certify that a public necessity or essential public convenience requires the condemnation. The statute was amended in the last session of the General Assembly to give the Commission the additional authority to establish whether any payment for stranded investment is appropriate in a condemnation proceeding and, if so, the amount of such payment and any conditions thereof.

An example of the Commission's use of this new authority is a municipality exercising its powers of eminent domain to condemn the facilities owned by a public utility that are within the municipality's city limits. Before condemning a utility's facilities a municipality would have to obtain Commission certification that a public necessity or an essential public convenience required such action. If the municipality were allowed to condemn the utility's facilities, the Commission would be required to establish whether any payment for stranded investment was appropriate and, if so, the amount of such payment and any condition of payment.

Virginia Code §§ 56-76 and 56-77

Virginia Code § 56-77 was amended to authorize the Commission to exempt public service companies from all or parts of the requirement that the Commission review and approve certain contracts or arrangements between public service companies and affiliated entities. The exemption may be granted by the Commission if it is determined that such an exemption is in the public interest. In addition, the Commission may revoke exemptions which have been granted, if that action is determined to be in the public interest.

Virginia Code § 56-46.1

Virginia Code § 56-46.1 was amended to permit the Commission to consider the effect upon economic development in the Commonwealth of constructing a proposed electric utility facility within Virginia. The amendment requires the Commission to consider any improvements in service reliability that would result in the construction of such facility.

It is arguable that this legislative change may lessen the degree, or at least change the character, of need an applicant must show to construct generation facilities. If so, this may encourage the development of new independent generation.

Virginia Code § 56-235.7

Virginia Code § 56-235.6 was added to the Virginia Code in the 1996 legislative session. This Code section authorized the Commission to determine the proper rate, if any, to be paid by the federal government to an electric utility for any and all costs stranded due to cessation of retail service by the utility to the government facility because of the facility's purchase of electricity from another supplier.

The Code section provides that the Commission's jurisdiction shall not arise unless and until the effective date of any federal action that allows a federal governmental facility to purchase electricity from a supplier other than the local electric public service company.

Virginia Code § 56-235.2

Virginia Code § 56-235.2 was amended to authorize the Commission to approve special rates, contracts, or incentives to individual public utility customers or classes of customers where it finds such measures to be in the public interest. The amendments also authorize the Commission to approve alternate forms of regulation for electric companies, including the use of price regulation, ranges of authorized returns, categories of service, and price indexing if certain criteria are met. The amendments require the Commission, prior to approving special rates, contracts, incentives, or other alternative plans, to assure that such action protects the public interest, will not unreasonably prejudice or disadvantage any customer or class of customers, and will not jeopardize the continuation of reliable electric service.

The provisions of this statute give the Commission broad latitude to respond to the changing environment for electric utilities.

E. Competitive Activity in Virginia

There have been measures undertaken by Virginia utilities and decisions by the Commission that are in response to developing competition in the electric industry. In a sense, a transition has already begun. Earlier in this chapter we described some of the internal reengineering efforts by Virginia electric utilities. In this section we will present some of the activities, experiments and proposals that have an effect on utility customers and suppliers.

Non-Utility Generators and Competitive Bidding

The event that precipitated competitive bidding for generating capacity was the passage in 1978 of PURPA. The Commission has been supportive of Virginia's utilities attempt to provide the most reliable capacity and energy mix to its customers. It has recognized, however, that a balance of build and purchase options is necessary to maintain system integrity and to best serve the Commonwealth. The Commission concluded the following in an order:

As noted earlier, cogeneration is a relatively new innovation in this country. While we applaud and support its development, we are not prepared on this record to force the state's major electric utility to place complete reliance on mere promises for all its future needs.

The Commission instituted a non-rulemaking proceeding to consider competitive bidding for NUG purchases. It found that the *"general concept of bidding for new power supplies is a permissible response to PURPA and the FERC regulations."* The Commission referred to its approach as "*competitive negotiation*" to distinguish it from a sealed, price-only type of bid. In addition to price, other factors needed to be considered, such as the use of Virginia fuels, a high percentage of steam or electricity used by the host firm, and other identifiable benefits to Virginia's citizens. Competitive negotiation *"can result in an even more realistic assessment of costs as determined, not in theory, but by the marketplace."*

This Commission was one of the first to endorse competitive bidding. It has not been a problem-free venture. The existence of high-cost NUG contracts is discussed in other portions of this report. However, approval of competitive bidding programs was an early recognition of the competitiveness of the generation market.

Variable Pricing

On May 29, 1989, Virginia Power filed an application to conduct a rate experiment for daily variable pricing rates for its large general service customers. Rate Schedule 10, the result of that application, provides a tariff wherein each day of the year is designated by the Company as one of three possible classifications. The designation is based on factors such as weather, fuel, and other variables affecting the Company's cost of production. Each day's classification is available to participants on the preceding day.

The purpose of the rate is to provide a more appropriate price signal to the customer which better reflects the Company's cost of production for a given time period. A better price signal will encourage the customer to make more efficient energy purchase decisions. Thus, the customer will be encouraged to reduce consumption during periods when capacity and reserves are constrained and increase purchases during times of sufficient capacity. The philosophy behind the rate is to offer a more dynamic rate design.

There are currently 200 customers signed for the Schedule 10 rate, the maximum currently allowed to participate. In 1994, the Company requested to make Schedule 10 permanent, but asked to maintain the 200 customer limit previously set. The SCC directed the Company to maintain the experimental nature *"until such time as the Company is prepared to offer the rate to any and all interested customers."*

On June 24, 1996, Virginia Power requested Commission approval to remove both the customer limit and the experimental label from Schedule 10. *"The Company believes that dynamic rate structures provide the greatest ability for rates to track costs and also present customers with greater opportunities to manage and control their electric costs."*

On December 21, 1994 Virginia Power filed an application for approval of a proposed Schedule RTP, a real-time pricing rate. The Company proposed the experimental schedule for large industrial customers exceeding an electric load of 10 MW and meeting service requirements under large general service primary voltage (Schedule GS-4).

Under Schedule RTP, firm prices for electricity change hourly. The prices are established at 5:00 p.m. for the following day and are based on projected incremental hourly production costs with adjustments for line losses and gross receipts taxes plus a margin of 0.6¢/kWh. Participants have an opportunity to exercise greater control over their electric energy costs and potentially realize significant savings. The Company was supported by most large industrials and the Staff. Schedule RTP was viewed as a positive step in the development of cost-based offerings and was recognized as an opportunity to monitor and evaluate how traditional rate-of-return regulation may be combined with market-oriented programs. The experimental rate provides better pricing signals to customers while assisting the Company in retaining its existing load and competing for incremental load. Schedule RTP was approved as an experimental program for five years to obtain data to assess the true effect of the program.

Virginia Power recently requested to modify Schedule RTP by reducing the threshold from 10 MW to 5 MW and extending the schedule to commercial and Schedule GS-3 customers. Currently six customers are participating under Schedule RTP, representing about 28% of their load. Lowering the threshold would result in about 60 additional customers being eligible for the tariff. The Company claims this program can be extended without any significant administrative costs since the infrastructure is in place.

Merchant Plants

On December 30, 1991, Patowmack Power Partners, L.P. ("PPP" or "Patowmack"), filed an application seeking Commission approval and certification of an independent power production facility with a capacity of 315 MW, to provide peaking capacity and energy for delivery to Potomac Electric Power Co. ("Pepco"), operating in Maryland and the District of Columbia. The original application was continued generally when the regulatory commissions of Maryland and D.C. refused to approve Pepco's applications for pass through of the cost of the purchased power.

In March 1995, the Commission Staff filed a motion to dismiss the application. PPP responded with an amended application seeking approval and certification of a 185 MW "demonstration plant," to be operated on behalf of Siemens AG, a manufacturer of power generation equipment. There was no committed purchaser of the plant's capacity at the time and it would be operated primarily to demonstrate the reliability of the Siemens' turbine. The energy produced during the demonstration phase would be sold to Virginia Power.

The Commission denied the amended application. Based on the record, it could not identify a public need in Virginia for the power produced by the facility. The SCC determined that PPP was a public utility because the plant would produce electricity for sale directly or indirectly for public use. It also determined such power was not currently needed by Virginia customers, and there was no assurance that the power would be available for use in Virginia if a need arose in the future.

The Patowmack application relied on existing law governing Virginia electric utilities. The Commission acknowledged that such statutes *"may not adequately address the needs of an evolving and increasingly competitive electricity market" and that evaluation of certification procedures during the restructuring investigation may reveal a need to suggest revision of some or all of the sections of the Code at issue in the case."*

Dispersed Energy Facilities

On June 4, 1993, Virginia Power filed an application with the Commission for approval of Schedule DEF (Dispersed Energy Facility Rate) on an experimental basis. The Company proposed to offer, voluntarily to any large industrial or commercial customer, generating facilities at or near the customer's site.

The Commission did not approve the request primarily because it failed to meet the statutory requirements for an "experiment" under Virginia Code § 56-234 and it lacked specifics regarding cost, size or duration of a project. The proposal was viewed as a means to mitigate a potential loss of load from a class of customers which would likely result in stranded costs. Although the Commission denied this application, it emphasized its commitment to promoting innovative ways of providing energy services to Virginia customers and recognized the changes taking place in the electric industry. The Commission also stated that it might consider a specific DEF-type proposal that was adequately presented.

In December 1995, Virginia Power filed an application to build a DEF facility for Chesapeake Paper Products Company. The proposal was to construct a complete combined cycle facility including a natural gas pipeline, and provide, for a fee, various management and procurement services. The application was determined to be incomplete and an amendment was filed June 19, 1996. The matter is currently pending before the Commission. A further discussion of dispersed energy is included in Chapter V, Section E of the Report.

PJM Power Pool Proposal

On November 30, 1995, nine of ten members of the Pennsylvania-New Jersey-Maryland Power Pool filed with the FERC a plan to increase competition in the region. There are four primary components of the PJM proposal. First, a pool-wide transmission tariff will provide open access and offer comparable service to all wholesale transactions. This rate should simplify transactions while more accurately reflecting transmission costs. It will be administered by the ISO and will eliminate dealing with each individual company for transactions through the pool.

Second, the proposal will develop a regional energy market open to all wholesale power traders. The ISO will dispatch the system on economic merit based on the bid prices posted by the suppliers for energy available for interchange.

Third, the ISO will administer pool operations, operate the regional energy market, and administer transmission service.

Fourth, the ISO will administer an improved pool-wide transmission planning process using Mid-Atlantic Area Council principles, criteria, and procedures.

The PJM Companies hope to implement the new structure by the end of 1996, but have not yet filed the final detailed plan with the FERC.

AEP Midwest ISO

On February 12, 1996, a group of utilities including AEP announced an agreement to develop the Midwest ISO, responsible for insuring non-discriminatory, open-access transmission and the planning and security of the combined bulk transmission systems. Working groups will be formed by the utilities involved to develop protocols for operations, administration, planning, pricing, management structure, and dispute resolution. Implementation of the ISO will require completion of facilities, installation of computer equipment and personnel training. It is likely that management of the ISO will report to a board of directors comprised of varied interests. Ownership of transmission facilities will be maintained by the respective utilities with the obligation to physically maintain and operate them.

The association began with six utilities and has expanded to over 18 utilities. Detailed plans are expected to be filed with the FERC in late 1996 and implemented in phases following approval.

Virginia Power's Transmission Alliance

On June 19, 1996, a group of four utilities announced an alliance aimed to coordinate movement of large blocks of power. The utilities participating are Virginia Power, Allegheny Power, Centerion Energy and Ohio Edison. They will strive to work together in managing their high-voltage transmission lines and develop a means to fairly pay one another for use of their partners' lines.

The goal is to use reliably the transmission system to load a growing number of energy producers. Since the four companies' transmission systems are so closely interconnected, any transfer of power through one system often flows through an interconnection and into a neighbor's system. Their approach to be adequately and fairly compensated for use of their networks should encourage open access of the transmission systems. The alliance also hopes to jointly schedule and coordinate power transfers to avoid overloading their transmission lines and causing outages. The alliance hopes to have a coordination and compensation system in operation by early 1997.

Customer Choice

In February 1996, Delmarva Power proposed to the Maryland Public Service Commission ("MPSC") that methods be developed to allow the Company's customers to choose their electricity suppliers. The Company requested that the MPSC issue an order establishing an Issues Development and Solutions ("IDEAS") for Customer Choice Forum.

Delmarva proposed that a broad cross-section of interested parties work together to develop methods to change the current regulatory regime to allow direct access for all its retail customers. The IDEAS Forum would allow discussion of issues raised by the proposal to allow direct market access for all customers and explore possible solutions to implement such choice. Participating parties are not compelled to agree to any proposal or make any concession. On June 19, 1996, the first forum was conducted in Wilmington to discuss several key issues regarding electric restructuring.

Recently, a group of seven utilities, including the Allegheny Power System, announced a new alliance called Partnership for Customer Choice ("PCC"). The utilities have been promoting customer choice and advocating federal legislation for the past several months. PCC members have been at odds with the Edison Electric Institute regarding how the electric utility industry should respond to federal restructuring efforts. The new alliance issued a statement of principles to guide the new organization on June 18, 1996.

The principles state that all customers, including retail customers, have the right to choose an electric supplier as soon as possible. PCC would like a federal law guaranteeing full customer choice by late 1997 with implementation by late 2000. It would also like to see the elimination of PUHCA, PURPA, state certification of need and siting laws, the lack of reciprocity among states, and any financial benefit providing a competitive advantage to electricity suppliers (i.e., taxes).

PCC states that, in addition to guaranteeing customer choice, customer protection is essential. States should continue to regulate local distribution within the standards set by the federal non-discriminatory open access rules. Local distributors, with state oversight, will supply electricity to customers where competitive conditions are unfavorable.

Another principle states that transmission systems must enhance market efficiency. This implies that all transmission owners should be subject to FERC approved conditions and pricing and participating utilities should support development of ISOs, or comparable mechanisms, to foster efficiency, competition, broadened markets, and reliability while mitigating against market power and self-dealing.

Energy Services

Utilities are increasingly focused upon energy-services businesses. As these businesses evolve, new approaches to meeting customer needs will emerge. Industrial customers in particular may be searching for packages to supply all their energy needs. Utilities are looking for innovative ways to satisfy and keep their customers. An increasing focus on customer satisfaction has sparked utilities to broaden their list of available services, including but not limited to electricity.

In 1995, Virginia Power launched EVANTAGE, a new division created to offer enhanced services to existing customers. Its primary objective is to sharpen the customers' competitive edge through better energy management by selling a full range of energy products and services. EVANTAGE will offer advise on energy usage and management, fuel procurement, and electrical system maintenance.

Examples of innovative resolutions to particular situations include the proposed dispersed energy facility at Chesapeake Paper Products Co. and a newly signed contract to design and construct a transmission line for an electric cooperative. In early 1996, Virginia Power acquired two energy services divisions from A&C Enercom to provide expertise in marketing, technology, processes and the environment. Virginia Power also hopes this acquisition will position the Company to expand their customer focus beyond the current service area.

Virginia Power's developing energy services business is likely to produce controversy as the utility extends its business into energy-related activities where competitors in varying forms already exist. Increasingly, large and well-financed companies affiliated with out-of-state utilities are also entering these markets, and regulated utilities will likely seek to respond as Virginia Power appears to be doing.

Virginia Power's EVANTAGE is but one of the energy-services concepts developed by Virginia utilities in an effort to offer enhanced customer satisfaction. A further discussion of energy-services activities is contained in Chapter IV, Section B.

V. RESTRUCTURING ISSUES

There are many issues that will be faced by utilities, legislators, state and federal regulators and consumers in a transition to a more competitive electric industry. The purpose of this chapter is to address the parameters of some of those issues. It is impossible to identify all possible issues or supply answers to all of the problems that may be encountered. Until more is known about the details of the market structure that will evolve, discussion and analysis of major issues is the best that can be done.

The issue discussions in this chapter build upon the industry background we have attempted to lay out in the first four chapters. The issues are not presented in any order of importance, although the first two discussion sections are of obvious significance -- market structure and stranded cost recovery.

A. Possible Market Structures

Competitive power markets can be structured in a number of ways. Consequently, market models could be based on regional power pools, bilateral contracts, independent transmission operators, retail wheeling or combinations of these alternatives. Industry models in other countries and those under consideration in some states typically include all of the above alternatives to varying degrees. In addition, there may be variations within these models. For example, a retail-wheeling-based model could provide end users with either direct access, indirect (virtual) access or both. The different models also may reflect a particular blueprint for transitioning to a competitive market. For example, a transition proposal may seek to retain nuclear generating assets and/or high-cost, non-utility contracts in retail rate bases while "spinning-off" other generating facilities. In short, the menu of competitive market models and transition mechanisms is practically infinite. Furthermore, many of the elements which comprise these models are not well defined. For example, there does not appear to be any commonly accepted definition of a power pool or of an independent transmission operator.

The ultimate success or failure of a competitive power market will depend heavily on its structure, on whether all customers can respond to changing market conditions, and on the resolution of transitional issues associated with stranded costs, market power and the separation of generation and transmission. Electric utility restructuring may fail to develop a competitive market or may require an extended transition period if these issues are not handled properly. We have reviewed a number of industry models and competitive market options in order to gauge their relative strengths and weaknesses. These models/options include regional power pools ("POOLCOs"), ISOs and retail wheeling. The following discussion will attempt to generally describe these alternatives.

Regional Power Pools

Regional power pools are central to a number of existing models and restructuring proposals. Power pools serve to aggregate electrical supplies through competitive bidding and to resell those supplies to electric distribution companies and, in some instances, end-users at market clearing prices. The British, Norwegian, Chilean and Argentinean models described earlier feature POOLCOs. A regional power pool is also prominent in the California model. These power pools are different from traditional U.S. power pools, like the existing PJM pool, in that transactions reflect supplier bids in lieu of the traditional "split-the savings" approach, where differences in the production costs of a buyer and a seller are shared. Traditional pools are generally closed to suppliers who are not pool members. POOLCO advocates maintain that competitive power pools create short-term efficiencies through improved dispatch, facilitate bilateral contracts through the creation of spot markets, and allow all customers to have access, either direct or indirect, to competitive markets.

POOLCOs are generally envisioned as non-profit organizations or regulated entities that are restricted from having an interest in generating resources; they typically require an independent transmission operator. The operation of the transmission grid can be included as a function of the power pool or may be performed by a separate entity or entities. Competitive power pools act as clearinghouses for power supplies by providing hourly or half-hourly price signals. Prices are generally determined through a matching of projected loads with bids from prospective suppliers where all selected suppliers are paid the highest winning bid (often referred to as system marginal prices) regardless of their actual bids. The highest winning bid will be based on the price paid for the last kWh needed to supply the projected load; this matching assumes no transmission constraints.

Power pools can be structured in a number of ways and may pose unique challenges depending on their structure and circumstances. For example, the PJM power pool proposal would allow utilities to continue to utilize existing resources to first meet native loads while pool transactions represent excess generation supplied to the pool or additional generation purchased from the pool. This proposal would effectively allow PJM member companies to avoid incurring stranded costs for pool transactions since those transactions would only represent short-term energy transactions or incremental capacity costs. Embedded capacity costs would continue to be recovered from retail ratepayers. The PJM proposal may, however, discourage new non-utility entrants since they would be forced to compete with utilities whose fixed costs are recovered through retail rates.

The AEP proposal, on the other hand, would require that generation be excluded from retail rates and that all generation related costs be recovered through pool prices. This proposal could either create stranded costs for utilities or subject existing customers to higher market prices if they are currently served by low cost utilities, since recovery of capacity costs would be required through the power pool regardless of actual embedded cost. Given AEP's strong competitive position and lower cost generating resources, AEP's existing customers may be subject to higher prices if an AEP power pool is created.

There are, of course, transitional mechanisms which could be implemented to mitigate such a negative impact. However, in response to our inquiry regarding whether existing customers who have funded the depreciation of low cost assets would be allowed a share of the margins associated with market based revenues in recognition of their historical relationship, AEP replied as follows: *Purchasing power does not convey an ownership right to the facilities used to provide that power any more than purchasing goods in a store would transfer an ownership interest in the store to the customer.* This perspective ignores the fact that captive customers supported AEP's investments over the long term (including times when the system had excess capacity) without alternatives. Utilities with higher stranded cost exposures are using equity arguments to support stranded cost recovery since they have had obligations to serve customers within their service territories. The logical extension of AEP's argument would be no stranded cost recovery for any utility.

Some pools include separate capacity payments for bidders who make generation available. These capacity payments are determined administratively and are paid in addition to the pool clearing prices regardless of actual bid selection. This capacity element is intended to give economic signals to encourage the construction of needed incremental capacity.

In Britain, capacity payments are calculated by multiplying a subjective value of lost load (customer outage costs) by a loss of load probability. The loss of load probability for each half-hour of the following day is calculated 24 hours in advance, taking into account demand uncertainty and the probabilistic reliability of generating units. The value of lost load was initially set in 1990 and is indexed to inflation. Since the loss of load probability is a function of generating unit availability, dominant generators were able to "game" capacity payments by declaring certain generating units unavailable. This practice was subsequently outlawed.

Purchasers from power pools typically pay prices that are higher than pool clearing prices plus capacity payments (if capacity payments are made separately) due to transmission constraints, load forecasting errors, unit outages, etc. These additional costs may be included in either the pool price to purchasers or as a transmission cost component depending on the model. In Britain, the difference between the price paid by purchasers and the system marginal price is sometimes referred to as "uplift." Uplift could include costs associated with "out-of-merit" generation, spinning reserves, ancillary services, etc. "Out-of merit" generation may be required since market clearing prices are based on projected loads for the next day and an assumption that there are no system constraints. If loads are unexpectedly large, selected units are forced off-line, or if there are transmission constraints, unscheduled or "out-of-merit" units may need to be used.

Prices for electricity traded through competitive power pools can be very volatile since load and available resources are constantly changing. Suppliers and purchasers can stabilize or hedge prices through "contracts for differences" which are typically traded outside of a pool. In their simplest form, these contracts require payments from suppliers to purchasers when pool prices exceed the price specified in a contract and payments from purchaser to supplier when pool prices are less than the contractual price. These price hedging mechanisms can influence bidding strategies since suppliers with secure contracts for differences may be obligated to provide a minimum level of generation or to provide power by purchasing from the pool. These generators may submit extremely low bids, possibly zero, to assure that they are dispatched. Generators can bid zero since they will always receive the pool clearing price for their actual generation. Other factors such as "minimum take" requirements in fuel supply contracts where storage is not available may also cause suppliers to submit lower bids.

Certain types of generating units have substantial costs (unit commitment costs) associated with the starting of units or maintaining units in a status where power can be produced quickly. Some POOLCOs have separate provisions for compensating generators for unit commitment costs while others do not. For example, in Argentina start-up costs for steam turbines are paid if the previous shut-down was required by the pool. In other systems, start-up costs may not be explicitly addressed. Consequently, base load generators in those systems may submit lower bids to assure that their units are dispatched. Other circumstances may compel bidders to submit inflated bids. For example, transmission constraints may require that a particular unit be operated for voltage support. In these instances, the owner of that unit may submit an inflated bid in anticipation of a constraint.

Power pool opponents argue that POOLCOs (1) fail to send appropriate price signals since they are based on hourly or half-hourly pricing, (2) will continue regulatory intervention, and (3) are incompatible with customer choice and fail to address the issue of market dominance. Others such as William W. Hogan, Harvard University -- Center for Business and Government, argue that the primary purpose of a spot market is to allow market forces to optimize generating mixes and load shapes over the long term. He notes:

Because many parties will find contracts useful for managing their short- and medium- term operations and cash flows, on any given day much of the demand in the electricity market will be covered by contracts, so that spot market prices may determine only a small fraction of the money flows between consumers and generators. This does not make the spot market any less important or its price signals any weaker. Even with a high level of contracting, the spot market will determine the price expectations against which future contracts will be written, will facilitate contracting and entry and will maintain efficient operations by, among other things, providing strong incentives for incremental generation and load management when demand threatens to exceed supply. When spot prices increase to high levels, even a fully contracted generator has strong incentives to produce up to and beyond its contracted amount and even a fully contracted buyer has strong incentives to reduce its demand and sell its contracted but unused energy into the spot market.

Hogan also addresses issues of market dominance and continued regulatory interference. With regard to regulatory interference he notes:

Regulators will have oversight of POOLCO and could interfere with the market. The fear expressed is that the existence of a regulated entity that has a degree of control over the system dispatch and all power flows provides a forum and an opportunity for regulators to intervene and redirect power or money among various groups. This criticism may be true on its face. The POOLCO would be a regulated entity under FERC jurisdiction. But whether or not this is a problem depends on whether or not there is an alternative. And with current technology it is not possible to physically bypass the system operator, and no unregulated alternative for this system operator has been offered or can be seriously imagined. Hence regulatory oversight is unavoidable....

In addressing market dominance, he notes:

Market power issues must be addressed in regional generation markets. No simple design can overcome a fundamental concentration of market power. The new market model for generation needs to recognize concentrations of ownership and provide mechanisms to prevent monopoly pricing through dominance. However, as discussed below, the new POOLCO institution of the competitive market will create alternatives for regulating generation that can prevent monopoly pricing while preserving competitive pricing, both of which will differ from cost-of-service pricing. Most importantly, the POOLCO model removes barriers to entry, through open access, without erecting any new barriers. Where remaining concentrations of ownership exist, the POOLCO provides a framework for dealing with the effects. Where market power exists, POOLCO makes the situation better, not worse. The POOLCO model by itself is not a complete solution to the problem of market power, but the attractions of the POOLCO are not reduced by a concern over possible abuses of market concentration.

Power pools should not be implemented without giving consideration to bilateral contracts, at least on a wholesale basis, since customers/suppliers may desire stable prices or greater supply assurances. The volatility of spot-market prices and the importance of bilateral contracts are discussed by Larry E. Ruff who states:

An electricity spot market is necessary for combining efficiency with competition but is not sufficient because, by itself, it provides no way for an individual generator to deal directly with a consumer and (the same problem stated a different way) leaves both generators and consumers exposed to the risks of the highly volatile and unpredictable spot-market prices. The solution is clearly some sort of bilateral contract allowing generators and consumers to deal with one another directly or through intermediaries -- but without distorting the dispatched-based spot market that exists to minimize the total costs of meeting demand.

Based on the conclusions of Hogan and Ruff, a competitive power market may require regional power pooling and bilateral contracts.

Independent System Operators

The functional separation of transmission services seems to be a prerequisite for a competitive market since adequate market access is critical to sustaining true competition between power suppliers. Hogan observes:

Contrary to the presumption underlying the extreme version of the invisible hand model for electricity dispatch, the electric system with current technology requires the very visible hand of the system operator to manage the short-term power flows and associated operation of generating plants. The basic coordination functions will always be there, somewhere. A system coordinator or pool is required in support of any electricity market....

FERC's Order 888 has provided a major impetus for the functional separation of wholesale transmission services, and the on-going development of independent system operators seems to be congruent with FERC's vision of open access transmission by combining independent utility transmission systems into larger coordinated regional operations.

ISOs, if developed, are expected to independently manage bulk transmission systems. Management responsibilities will include ensuring system security and providing non-discriminatory open access transmission service to eligible parties. ISOs will probably operate in conjunction with a power pool, bilateral contracts or a combination of a pool and bilateral contracts to form a competitive market. ISOs will likely be restricted from having any interest in generating resources and may not, at least initially, actually own transmission facilities (though they may eventually own new or expanded transmission resources). Existing transmission facilities will continue to be owned by existing utilities even though those facilities may be controlled by an independent system operator. These transmission operators will develop and implement open access transmission tariffs which will be subject to the jurisdiction of FERC. ISOs may also be responsible for planning bulk system improvements, determining available transmission capability and scheduling transmission transactions.

We are concerned about the impact that transmission unbundling and the creation of ISOs may have on the siting and construction of transmission facilities. Under the current industry structure, utilities have obligations to meet the needs of their native customers by constructing necessary facilities. This obligation includes the construction of both transmission and generation facilities and presumably requires that the least cost alternative be pursued. Under this system, utilities must consider local environmental and economic impacts in selecting the best alternative for meeting the needs of their customers. There is a certain symmetry in this system since local needs must be considered against local siting issues. State regulators provide a forum for developing an appropriate balance of these potentially conflicting issues.

Siting of transmission facilities, which can have tremendous impact on a large number of people, can be quite controversial. While it is difficult to construct such facilities under the current industry structure, these facilities are easier to justify since the individuals who are negatively impacted by the siting of the lines also contribute to the need for such lines and thus will benefit from them. This may not be the case under a scenario where an ISO is planning the bulk transmission system on the basis of requirements that are driven more by the interests of bulk power exchanges and less on the basis of local needs. Under an unbundled transmission regime, initial need determinations may be made by ISOs and/or FERC. Local siting decisions may continue to be subject to state regulatory approval. It is not clear whether state regulators will continue to make determinations of the need for the facility in conjunction with siting decisions or whether state deliberations will simply consider siting issues. In either event, it will be increasingly difficult for state regulators to balance local interests against regional or national economic interests. This could significantly complicate and prolong an already extended approval process for high voltage transmission facilities.

The pricing of transmission services and a utility's compensation for transmission investments will be fundamentally altered by the development of ISOs for two primary reasons. First, the ratemaking practices of FERC differ from those of most state regulators. Second, transmission rates for an ISO presumably will be based on the overall average transmission cost of a region instead of an individual utility's costs. While these pricing differences may have positive impacts such as reducing transmission rate "pancaking" and reducing the impact of "contract path" pricing, they may also have the effect of over-compensating low-cost transmission providers and under-compensating high-cost providers. While ISOs may have positive implications for the construction of transmission facilities in areas where "contract path" pricing may have not provided adequate compensation, we are concerned that average pricing implications of ISOs may have negative implications for the construction of needed transmission facilities since the incremental cost of extensive new transmission enhancements is likely to exceed the embedded cost of older existing facilities.

The Merits/Disadvantages of Competitive Models

Power pools, bilateral contracts and independent transmission operators are possible mechanisms for continuing and possibly increasing competition in power supply markets. While there are a number of concerns regarding these mechanisms, they may be essential to a workable and fully competitive wholesale power supply. They may also be essential to a competitive retail market. Power pools may be critical to the formation of a spot market for electricity which, in turn, may provide essential information to support a futures market and bilateral contracts. ISOs may be essential to the provision of non-discriminatory open-access-wholesale power and efficient transmission service. Consequently, power pools and ISOs may be viewed as interdependent, with one having little value without the other. This may explain why many of the descriptions of existing and proposed competitive models fail to provide a clear distinction between the two mechanisms. In fact, the two mechanisms may be combined and discussed as a single entity under certain models.

Generation and transmission are also interdependent from an operating perspective. Operation of bulk power systems require the coordination of generation and transmission. This operation also requires a number of ancillary services. It is often difficult to distinguish between generation, transmission and these services. This difficulty is illustrated by the following excerpt from a report issued by the Oak Ridge National Laboratory:

...cleanly unbundling these services will be difficult because some services draw on multiple pieces of equipment and because individual pieces of equipment often contribute to more than one service.... For example, a generating unit provides real power and energy (the kW and kWh outputs that are the primary purpose of the machine). In addition, generators produce reactive power, which contributes to operation of the transmission system. The mass of generators plus the ability to control voltage and frequency help to maintain a stable electric system. Transmission lines provide the transportation link between generators and consumers. In addition, these lines absorb reactive and real power, thereby consuming services.

Given the interdependence of generation, transmission and ancillary services, decisions regarding the installation of a new generating unit cannot be made without knowledge of transmission related issues and vice versa. The functional separation of generation and transmission could create a gap where integrated planning for these facilities is lost, since generation and transmission facilities may be substitutable in certain circumstances. For example, transmission constraints may be relieved through the installation of generation or via the redispatch of existing units. It is unclear how efficient economic decisions involving such trade-offs will be made in an environment where generating decisions are made on the basis of market-driven economics and transmission decisions are made through central planning by an ISO.

There have been a number of problems associated with the British model that can be associated with the interplay between generation and transmission. Nigel Evans provides the following illustration:

The electricity system in England and Wales was developed in the 1950s and early 1960s by building a large number of small (principally coal-fired) power stations, which were located throughout the network. Post privatisation, both National Power and PowerGen embarked on a major plant closure programme targeted initially at these older less efficient stations. However, because the stations typically provide essential low voltage support, it was necessary for NGG [National Grid Company] to reinforce its transmission network prior to the stations being closed. During the period after the generators had notified the Grid of their intentions to close the stations, but prior to NGG having completed necessary reinforcement work, each of the stations was able to exert considerable market power. They were required to run, irrespective of their bid price, because of their role in supporting the network.

Others have also commented on the potential conflicts between generation and transmission in the British model. They note that, although the transmission provider in Britain could take steps to minimize generation related costs that are imposed by transmission constraints, the transmission provider had little incentive to do so.

As noted earlier, the integrated operation of an electrical system requires a number of ancillary services, some of which are described in detail in Section F of this chapter. Some of these services can, in theory, be supplied by the competitive market while others must be provided by a central operator. For example, a central operator must manage the transmission grid and certain generating units to control frequency and voltage levels in order to maintain reliability. It is extremely difficult to develop clear delineations between ancillary services and to properly assign costs to monopoly functions. The possible ramifications of this complication were summarized by Kirby, Hirst and Vancoevering as follows:

Utilities, because they currently control and operate electrical systems, have more information on the costs of some of these services than do customers, independent power producers, or power brokers. Because utilities are competing with these other parties, they have an incentive to shift costs to them. This potential conflict of interest and information asymmetry complicate the task for regulators (as well as for researchers). To the extent that some of the ancillary services discussed here can be provided competitively (e.g., by nonutility entities), the problem is greatly reduced. However, regulators will have to pay close attention to those services that can be provided only by the system operator.

Given the complexity of the bulk transmission grid and its dependence on generating resources and ancillary services, ISOs and other transmission operators will have considerable influence on generation requirements and costs. There are a number of uncertainties associated with whether market forces and functional transmission unbundling will result in a coordinated operation of the bulk power system. System integrity may suffer if the provision of these various services are not properly coordinated.

For example, an ancillary service that may be supplied by the competitive market is the scheduling of unit outages for maintenance. System operators typically schedule maintenance on an annual basis by coordinating unit outages to ensure that expected loads are met at the lowest cost while maintaining reliability. In a competitive market, individual suppliers will schedule outages on the basis of price expectations. Suppliers to a given market may have the same expectations and schedule outages at or near the same time as others, thereby jeopardizing reliability and increasing prices. This possibility may require intervention by a central operator, perhaps an ISO, or by some other measure, such as an administratively determined capacity payment to maintain reliability.

In any event, a central operator must have the ability to override market driven decisions at certain times. Ruff recognizes this prospect and makes the following observation:

For many commodities more mundane than electricity, efficient transportation service requires -- indeed, is best defined as--the coordinated operation of geographically dispersed production and transmission assets to meet geographically dispersed demands at least cost. Such an integrated service cannot be provided by a "transmission service provider" using transportation assets alone, but requires coordination of both production and transportation assets.

One extreme view is that such influence is so pervasive that central operators, perhaps ISOs, will ultimately control all generators and that the development of such operators will simply substitute large quasi-governmental bureaucracies for existing utilities.

While we do not fully subscribe to this last view, we are quite concerned about reliability issues that may be created and economic efficiencies that may be lost through the functional separation of generation and transmission. Although these issues are highlighted by experiences associated with the British model, perhaps the most widely recognized and discussed restructuring model, they seem to be receiving only limited attention. We have raised these issues in our data requests to electric utilities, non-utility generators, and industrial customers and have received responses that are less than reassuring.

AEP, which is actively promoting the formation of a Midwest ISO, has apparently not yet resolved some of these issues and appears to assume that market forces will take care of these problems. We posed the following data request to AEP and other parties:

Transmission and generation capabilities are substitutable in certain instances, for example, generation can be added or dispatched to relieve transmission constraints or transfer capability can be utilized to justify lower generating reserves. How will these tradeoffs be recognized from both operating and planning perspectives under a poolco concept? Would units that "must run" under certain conditions, i.e. transmission constraints, have market power under a regional pooling arrangement?

AEP responded by stating that many questions remain to be addressed and that answers to many questions raised by the Staff have not been developed at this time. Other parties offered little additional guidance with respect to an appropriate competitive model for preserving the ability to balance transmission and generation decisions. We believe that these issues are not mere details that are yet to be resolved, and we are concerned by the apparent dismissal of these types of issues by many participants in the restructuring debate.

Retail Wheeling

Certain proponents of increased competition in the electric utility industry maintain that market forces can do a better job in determining prices for electricity and maintain that wholesale competition is not sufficient to provide a complete interaction between buyers and sellers of electricity. These proponents believe that the market mechanisms discussed above must include direct access (retail wheeling) in order to be completely effective.

The Electricity Consumers Resource Council ("ELCON"), which represents large industrial electric consumers, is perhaps the most vocal advocate of electric utility restructuring. ELCON states the following about the benefits of retail competition:

Competition in the U.S. electricity industry -- particularly retail competition -- will benefit all end users by: (a) providing a broader range of products and services with greater value at competitive prices, and (b) creating new business opportunities throughout the economy, with the potential for new jobs and income growth.

ELCON and others, including the Virginia Committee for Fair Utility Rates, argue that all customer classes should have the opportunity to choose among competing suppliers of generation services. Direct access for retail customers is generally thought to require retail wheeling, since electricity transmission and distribution services continue to have monopoly characteristics. Retail wheeling would allow customers to purchase power supplies competitively and to have those supplies delivered by a local electric utility.

The Citizens for a Sound Economy Foundation ("CSEF") also supports increased competition and recently issued a report promoting retail wheeling. The report concludes that deregulation (retail wheeling) should proceed expeditiously since it would increase our Gross Domestic Produce, ("GDP"), lower prices and increase employment. The report predicts that the GDP will, over the long run, increase by 2.6 percent per year or $191 billion in 1995 terms if retail wheeling is initiated throughout the United States. The report acknowledges that deregulation will diminish the stock market value of many utilities but notes that gains to consumers will far outstrip losses to producers.

The report is a theoretical work that gives little recognition to practical issues and concerns. It is largely predicated on an assumption that electrical consumption is purely a function of price. The authors believe that for every 1 percent reduction in price there will be an approximate 1 percent increase in the consumption of electricity.

We believe that electrical demand is, at least in the short run, somewhat inelastic (usage is driven by factors other than price). Our belief is directly contrary to the author's assumption of perfect elasticity. John Kowka, Jr., Professor of Economics-George Washington University, indicates that while there are studies that support this higher elasticity assumption that most studies conclude that electrical demand is essentially inelastic with elasticities of 0.5 to 0.8, with residential users lower than industrial users. The CSEF study's basis premise is that electrical demand is totally driven by price and virtually every calculation and prediction made in the report is either directly or indirectly influenced by the elasticity assumption. Lower assumptions of elasticity would virtually invalidate the entire study.

Aside from the questionable demand elasticity assumption, the report contains a number of other assumptions and representations that are questionable. For example, the report includes tables which present average bill reductions for current consumption levels for each state. These reductions represent an across the board average reduction of 26 percent and fail to account for differences in average rates, customer mixes, elasticities, etc. that may exist between states.

Projections of the costs associated with increased use of existing steam units assume that there will be no increase in average fuel costs. This seems questionable since utilities are currently dispatching units on an economic basis and the most efficient units are currently being used at higher levels. Increased use will, therefore, require that older, less efficient, dirtier units be operated at higher-capacity factors. Some of this increased utilization will be from oil fired units which typically have higher fuel costs. It also seems likely that the increased demand for coal would cause an increase in coal costs.

The report also does not explain how reliability can be sustained with increased steam plant utilization or why increased consumption of approximately 26 percent will not result in a need for new capacity. It completely dismisses any problems associated with transmission constraints and the functional separation of transmission and generation.

The report does not address any efficiency losses that may be associated with functional separation. These losses may be quite large. Professor Kowka estimates that the economies associated with vertical integration are substantial (27 percent or greater). While such economies may not be entirely lost through functional separation and deregulation they certainly bear consideration.

In a letter to Congressman Dan Schaefer, Chairman-Subcommittee on Energy and Power, four prominent economists: ; J. Gregory Sidak-American Enterprise Institute; James Q. Wilson-University of California; William J. Baumol-New York University; and Daniel F. Spulber-Northwestern University, have expressed significant skepticism with respect to the claims of Professor's Maloney and McCormick. There is a wide divergence of opinion regarding full open access in the U.S. even when practical uncertainties are set aside and retail wheeling is viewed from a purely academic perspective.

Retail wheeling is a relatively new proposal with which there is virtually no experience in the United States. Although there are a number of proposals and experiments to implement retail wheeling in the U. S., direct access has not occurred to any significant extent. Thus far, direct access has been limited to larger customers under the British, Chilean and Argentinean models. Direct access is available to all customers in the Norwegian model, however, we have been unable to locate any information regarding the actual operation of retail wheeling for smaller customers in Norway. Given this limited experience with retail wheeling, particularly for smaller customers, it is difficult to envision how retail wheeling will actually function.

Direct access would, at least in theory, provide a number benefits. First, retail wheeling would largely eliminate the central planning process for new power supply resources since suppliers and consumers would communicate directly. Assuming that market forces will result in the timely addition of needed resources and better price signals, this direct communication would provide for a better matching of supply and demand and eliminate costly capacity excesses. Retail wheeling may also serve to reduce regulatory or legislative intervention which could mandate the forced funding of certain social programs that are not directly related to the provision of electric service.

Unfortunately, retail wheeling may exacerbate many of the problems discussed elsewhere in this report. It is unclear whether market forces will provide accurate and timely signals that will lead to construction of needed base load generating facilities, which are characterized by long construction lead times and significant capital requirements. It also may be difficult to provide better price signals to residential and small commercial customers; consequently, retail wheeling may not produce a better matching of supply and demand.

Retail wheeling is controversial for a number of other reasons, as well. These reasons range from detailed technical questions, such as requirements for ancillary services and the pricing of wheeling services, to very broad questions associated with public service obligations and regulatory authority. Direct access could have differing impacts on various customers depending on the timing of access and the impact that market forces will have on the pricing of electricity. Certain customers, particularly low income or rural customers, may in reality have limited choices even if legislative revisions and/or regulatory modifications provide for direct access.

Direct access may disadvantage certain customer groups if those groups do not have viable choices for obtaining electric supplies or if retail wheeling results in a transfer of wealth from small customers to large customers. We think this concern may be valid, especially because the transaction costs of alternative supplies for small customers are proportionally greater than those for large customers due to their relative usage levels.

For example, equitable retail wheeling may require that a customer's consumption be monitored on a "real-time" basis since a competitive market will likely reflect very volatile prices. This type of monitoring will require specialized metering which is capable of measuring consumption on a time-differentiated basis. Existing meters for most small customers simply record energy consumption without any time differentiation. Time-differentiated meters are more expensive than conventional meters and potential competitive savings for small customers must be weighed against these additional metering costs. The higher usage levels of large customers makes it much easier to absorb these additional costs.

Small customers also may be less capable of controlling their consumption in response to changing market conditions. For example, a residential customer who uses electricity for heating cannot readily reduce consumption during extremely cold weather and consequently may incur higher market prices that are associated with higher seasonal demands. It may be argued that such customers should incur higher costs since they are significant contributors to seasonal demand swings. However, these customers provide system diversity that currently allows utilities, and will allow future supply aggregators, to capitalize on differing types of generating technologies and regional differences in seasonal capacity requirements. Issues of equity aside, these customers may be harmed by a movement to direct access.

The volatility of prices that may arise from a competitive market may not be acceptable to many customers, though it may be possible to reduce volatility through various means. We expect that electric prices will be highest during periods of peak demands and that these peaks will correspond with the periods when the weather-related electric requirements of many small customers are the greatest. This could give rise to a twofold impact on small customers where they will have higher usage requirements due to severe weather at a time that corresponds to peak electric prices. This could pose a severe hardship on some residential customers, particularly those with low or fixed incomes.

This is precisely the situation that occurred earlier this year for many residential gas customers when colder weather caused the cost of natural gas to increase significantly during a period when heating requirements were at their greatest. Despite the fact that this Commission's purchased gas clause -- which governs the recovery of gas costs from customers -- levelizes gas costs to some degree, many customers received unusually high gas bills. Price volatility in electric markets may be even greater than that for natural gas markets.

Price volatility may also impose other requirements on customers that will further detract from the viability of "choice" for smaller customers. Since electricity cannot be readily stored and generation and consumption have to coincide, scheduled deliveries for a customer must correspond to that customer's consumption or additional costs may be imposed on other customers. As a hypothetical example, a customer may schedule deliveries of 100 kWh in an hour when electricity has a lower price but only utilize 75 kWh. The unused 25 kWh must be utilized elsewhere since electricity cannot be readily stored. The original customer may then expect delivery of his 25 kWh at some subsequent hour. This may impose additional costs on the system if the 25 kWh delivery is made in an hour when electricity prices are higher. Consequently, retail wheeling will either require that customers closely balance their supplies and consumption or that an aggregator provide a balancing service. In either event, small customers are disadvantaged since they may not be capable of predicting their loads and will probably incur some cost associated with assuring that supplies match demands. A supply aggregator could help to capture customer diversity and minimize these imbalance costs much like traditional utilities.

Unfortunately, potential aggregators may be reluctant or unwilling to acquire supplies on behalf of small customers due to their relatively high transaction costs and the fact that certain customer groups may have greater difficulty in paying their bills. While there is no history regarding whether power suppliers will seek to provide service to all customer groups, a number of studies regarding other goods and services indicate that certain customer groups may be viewed as undesirable customers. Studies have shown that banking services and credit may not be readily available for certain consumer groups and that other needed services provided by grocery stores, pharmacies, laundromats, health care facilities, etc. are either unavailable or very expensive in certain areas. Based on these experiences in other areas and industries, we are concerned that low-income customers, customers on fixed incomes, and customers located in rural areas may not have sufficient options if the traditional utility service obligations are reduced as a result of direct access.

The potential economic benefits to aggregators in serving small customers will likely be less than that for serving large customers because of economies of scale. In addition, aggregators will naturally concentrate on large customers who already have the means and expertise for pursuing retail wheeling opportunities. These large customers not only have greater scale economy but, in most cases, offer less risk of non-payment of bills. It may take some time for these large customer markets to develop and aggregators may not pursue less lucrative, small customer markets until their more lucrative targets are fully served. Consequently, small customers may not have legitimate opportunities until after large customers are served and may not be able to benefit from temporary base load and capacity excesses that may currently drive down electric prices.

Traditional utilities could help resolve many of these issues by continuing to acquire supply resources for small customers. However, utilities may be reluctant to continue to serve as aggregators for these customer groups because direct access may represent the ultimate breach of the regulatory compact. As discussed earlier, the "regulatory compact" obligates utilities to provide reliable and reasonably priced service to all customers within their service territory in exchange for an exclusive franchise to provide electrical service in the territory and an opportunity to earn a reasonable return on investment. This compact currently involves the construction of generating units, transmission lines and distribution systems. Retail wheeling would fundamentally alter this implicit arrangement by reducing the ability of utilities to recover a reasonable return on its investments in generating facilities or expenses associated with purchased power contracts. As discussed in other sections of this report, the "regulatory compact" is central to arguments for the recovery of stranded costs associated with existing utility facilities. Retail wheeling may have other implications with respect to the "regulatory compact," in particular on future utility obligations and customer responsibilities. The prospect of direct access raises the question of whether utilities should continue to have an obligation to make long-term commitments to meet the supply needs of retail customers or whether customers must assume responsibility for meeting their own needs under a retail wheeling model.

This may at first appear to be a rather simple issue since it seems inequitable to require utilities to make financial commitments to provide power supplies to customers who do not have comparable obligations to the utility. However, electricity is essential from a human needs perspective since it has a limited number of alternatives for critical end-uses. The essential nature of electricity, coupled with the possibility that certain customers may not have sufficient alternatives for assuring that they have adequate power supplies, may require that utilities have an ongoing responsibility to be the supplier of last resort in certain situations. Consequently, utility responsibilities should be reviewed and clearly specified prior to allowing customers direct access to assure that customers are fully informed and that competitive interests are properly balanced against public interest considerations.

The continued imposition of supply obligations may place utilities at a competitive disadvantage when serving large customers; therefore, utilities may be reluctant to accept such responsibility. This reluctance coupled with stranded cost implications may compel utilities to attempt to exercise control over small customers who have fewer alternatives for avoiding monopoly influences.

Although retail wheeling has a value in that it will reinforce competitive pressures, it raises a number of complex issues, including increased stranded costs for utilities, inequitable results for differing customer groups and possible subversion of the intent of regulatory reform. These issues and the rates, rules and conditions of retail wheeling will have to be carefully developed if direct access is to be successful and equitable.

<u>A Possible Alternative to Retail Wheeling</u>

Indirect, or virtual, access may offer an alternative to retail wheeling while mitigating some of the potential harmful consequences of the direct access. William Hogan advocates such an approach. He states:

The usual practice applies the label "retail wheeling" to expansion of competition to include sale of electricity to retail customers. This label appealed to a comfortable fiction that suggested power could be directed from one source to another destination by "wheeling" through the wires of intervening utilities. For a variety of reasons, the traditional retail wheeling approach is an exceptionally bad and misleading model of the actual operation of an electricity market. ... Major obstacles to retail wheeling are in the potential for jurisdictional conflict and uneconomic bypass leaving assets stranded. The traditional retail wheeling model envisions the delivery of power from a particular generating plant to a particular customer, paying a separate charge for the transmission service through the local utility. In the United States, however, this simple act of unbundling the transmission all the way to the customer raises the possibility that the entire transmission rate becomes Commission [FERC] and not state jurisdictional. The reality of such a change would greatly complicate regulation at the state level, especially during the period of transition to a more competitive market. Even fear of such a jurisdictional impact could foreclose the regulatory change.

Ruff reinforces Hogan's views by stating:

The fundamental logical flaw in traditional wheeling and in current efforts to extend it is the assumption that something called "transmission service" can be defined and priced as a commodity separate from electrical energy itself. In this view, a competitive generator can buy transmission service from a grid utility through one window, and efficiently bundle the two together to provide delivered electricity to its customers! But such separation of transportation is fundamentally inconsistent with the way many efficient markets operate in the real world.

Both Ruff and Hogan seem to be recognizing that wheeling arrangements, both at wholesale and retail levels, are wheeling money rather than actual electricity. Based on this premise, they advocate models that are based on financial instruments like contracts for differences. Hogan indicates that only two ingredients are needed to give retail customers complete access to wholesale markets -- an arms length wholesale spot market and a time-of-use tariff. He believes that a spot market will develop for electricity and that such a market will provide buyers and sellers with a trading mechanism. Time-of-use tariffs would allow users to remain as customers of their traditional utility under traditional cost-of-service rate principles and to attain indirect access to the energy component of the spot market.

Hogan maintains that this approach is functionally equivalent to wheeling, but easier to implement, and claims that it will accomplish the following:

- provide customer choice by allowing customers to have full freedom and choice through contracts for difference that conform to the reality of the electricity market;
- reduce central planning for all commodity resource procurement and moves this responsibility to the competitive market;
- shift no jurisdictional responsibility;
    - require no new legislation since state regulatory authorities already have authority to establish time-of-use rates;
- strand no assets since customers remain under traditional cost-of-service tariffs;
    - support efficient investments in the sources of energy since recovery of sunk costs are independent of competitive energy prices; and,
- provide for the support of worthy social programs.

B. Stranded Costs

The debate regarding restructuring of the electric industry has highlighted issues surrounding the economic impact of a structural transition to a competitive environment. If competitive forces replace the existing regulatory pricing and control paradigm, the economic value of utility investments will be determined by market equilibrium as opposed to embedded historical costs. While this type of economic displacement occurs virtually by definition in any industry under transformation from a regulatory pricing scheme to a competitive market, the size and capital intensiveness of the electric utility industry significantly magnify the potential economic impact.

Any potential reduction in the economic value of an existing asset during a transition because of a shift from embedded-cost pricing to market-based pricing, is frequently referred to as a "stranded cost" ("stranded investment," "transition cost," "stranded asset," or "stranded commitment"). On the other hand, specific assets, and perhaps even the entire asset portfolio of certain utilities, could increase in economic value resulting in "stranded benefits." In many respects, stranded costs/benefits are simply the transfer of wealth which would result from changing the rules of the game absent public policy intervention. Therefore, regulators, legislators, and/or the courts may have to identify and quantify these stranded costs and benefits, determine the appropriate parties that should bear the economic losses or realize any economic gains, and establish equitable disposition mechanisms.

Since there is little serious discussion about deregulating the electric distribution or transmission functions, the current focus is on generation related stranded costs. There is general agreement that, in aggregate, on a national level, industry restructuring could result in substantial stranded costs relative to historical production investment and commitments. A study by the Oak Ridge National Laboratory states:

Based on our analysis, the most plausible estimates of transition costs range from $69 to $99 billion, but we found estimates in the literature that ranged from about $20 billion to upwards of $500 billion.

The large divergence in estimates of stranded costs reflects the difficulty of defining and quantifying stranded costs, as well as the distinct agendas of sponsoring groups.

The stranded cost issue may not be as significant in Virginia as in states where regulated electric rates are much higher, such as California and several New England states. However, the degree of significance in Virginia may depend on the timing and orderliness of transition to a competitive market, the final structure of the market and the effectiveness of actions aimed at mitigating potential stranded costs. In any event, while it is premature to offer a definitive comprehensive solution at this time, the potential economic impact of public policy decisions with respect to the recovery treatment of stranded costs/benefits justifies exposition and consideration of several underlying fundamental issues. Additionally, certain preliminary regulatory and legislative actions may be desirable in order that maximum flexibility is maintained by the Commission to implement appropriate policy as events evolve and key, but currently unknown, variables become more clear.

Market Pricing Considerations

As stated above, stranded costs/benefits arise from changes in the economic value of assets during transition from regulated electricity prices to competitive market prices. This asset revaluation is attributable to the revenue margin (the portion of revenue that exceeds variable costs) lost or gained as a result of both arriving or departing customers and existing customer price changes in moving from regulated electricity prices to market prices. The economic value of an asset is the present value of the future net revenue stream (or net cash flow) which will be realized from the asset, which in turn is a function of the future prices of the output produced by the asset. Therefore, in order to accurately project total stranded costs, it is necessary to forecast long-term prices under both competitive market prices and regulated rate scenarios.

Regulated electricity prices are currently based on the prudently-incurred, average-embedded cost of the utility. This cost includes the carrying costs of depreciated plant and inventory investment, the fulfillment of prior commitments (e.g., resource contracts), and other expenditures deferred for recovery purposes, as well as current on-going operating expenses. Competitive market prices are, of course, a function of supply and demand, without direct consideration of sunk investment costs.

In a competitive market, price tends to approach the incremental cost of producing the last unit of product. In economic theory, this is referred to as "marginal cost." In the short-run, when market production capacity or supply exceeds demand, the incremental or marginal cost is simply the *variable operating costs* associated with producing the last unit of product. Historical investment in plant capacity is a sunk cost and cannot be modified in the short-run. Therefore, any sale priced above variable cost will not only recover the producer's incremental cost but also contribute to its carrying cost of investment. Obviously, a small contribution toward investment recovery is preferable to no contribution should the sale be lost to one of many eager competitors.

On the other hand, in a market with a short-run capacity (supply) shortage, prices will tend to rise to the level that the market will bear, since new capacity cannot be added instantaneously. Depending on the price elasticity of demand, which measures the degree of willingness of consumers to adjust consumption of a product according to a change in price, such a scenario may lead to price gouging and windfall profits until new capacity or supply becomes available.

In either case, over the long-run, as demand grows in a capacity-excessive market or power plants are added in a capacity-deficient market, prices will tend to reflect the total cost of new production. Thus, over the long term, electricity prices should provide for recovery of a market-required return on new capital plant investment.

Costs (or benefits) may be stranded not only because of the displacement of the regulatory-average-embedded cost by the competitive-marginal cost of total new production, but also as a result of various short-run and long-term market aberrations or imperfections such as supply/demand imbalances, infrastructure limitations, information deficiencies, market entry barriers, market power, and regulatory influences. In fact, current estimates of stranded costs can be viewed as potential cost shifting which may arise from short-run market imperfections if there is an immediate shift from regulation to competition.

For example, a study published in July of 1995 by Moody's Investors Service calculated estimates of the Southeastern Reliability Council Region stranded costs over a ten year period based on forecast market energy and capacity prices of 2 cents per kWh and $30 per kW, respectively. While the forecast energy price would be roughly equivalent to reasonable expectations of average marginal-energy costs for the region, slightly more than the cost of energy from coal generation, the estimated capacity price might be too low to support investment in a new combustion turbine, the least expensive conventional capacity option. Such a conclusion, however, is not inconsistent with Moody's assumptions or with basic competitive market principles. Moody's believes there is excess capacity in the market, thereby largely reducing the value of current capacity. In response to such low prices, one would anticipate a market response of deferring new capacity additions until prices rise reflecting a need for new capacity. From this perspective, the market would be reacting correctly to efficiently allocate resources; customers that have the capability to access such energy (for the most part, large customers) would be paying the appropriate market price. However, from another perspective, these customers would not be paying for the full capacity cost of the reliability or inexpensive energy which they are receiving. This would have the effect of increasing stranded cost exposure above the level that would exist if the embedded cost of current assets was compared to today's cost of new plants. In effect, absent a recovery mechanism, these fortunate customers would enjoy a lower price of energy, shifting a portion of the costs to any remaining captive ratepayers or utility investors.

To emphasize this point, the 1995 average industrial prices of Virginia's investor-owned electric utilities were in the range of 3.5 to 4.6 cents per kWh. Most, if not all, of these utilities are aggressively pursuing cost savings through restructuring and reengineering efforts, the impact of which should allow for reductions in their rates. By comparison, the costs of new production, based on projected levelized costs of a two-unit, advanced-combined-cycle power plant is likely to approach or exceed 4 cents per kWh when the costs for line losses, transmission service, administration, back-up power, and other ancillary services are added. If there is excess capacity, open competition may drive prices down toward utility variable cost levels (at least for certain customers) and create stranded costs in Virginia. It is important to realize that, under such circumstances, it appears likely that much of the price reduction and stranded costs would be attributable to market reaction to supply/demand imbalances and not to excessive utility rates.

The unique characteristics of electricity supply and demand complicate determination of optimal generating capacity. In fact, as pointed out in another section, it is not clear that significant excess capacity currently exists in surrounding regions, at least from an overall reliability standpoint. Due to (1) the generally accepted essential nature of reliable electric service, (2) the virtual inability to efficiently or effectively store electricity, (3) the widely divergent demand at different times during the day, season, or year, and (4) the significant impact that abnormal weather may have on demand, capacity reserves in excess of demand are necessary for most of the hours of the year. While many utilities have significantly lowered their target reserve margins and reduced preventive maintenance programs and manning levels as the threat of competition has grown, it remains to be seen if acceptable reliability can be maintained with lower future reserves. Furthermore, although the market may perceive an excess capacity condition in the short-run and establish prices accordingly, market perceptions are not necessarily correct and may be modified over time. Unfortunately, if such short-term market perceptions are wrong, relatively long lead times for capacity expansion could result in unacceptably low reliability, including painful human impacts and costly economic disruptions. Most competitive markets experience supply shortages from time to time; even market proponents must acknowledge that competitive markets tend to work better over the long-run than in the short-run. However, if one is without heat or air conditioning, it may be difficult to appreciate the long-run benefits of competitive markets.

As pointed out in other sections of this report, another event which may drive market prices below total new production cost is a sub-optimal capacity mix as represented by excess base-load capacity with its low-variable-energy costs and sunk-high-fixed costs. Absent market power, utilities may be forced to package this low-cost energy with relatively inexpensive combustion-turbine capacity for reliability resulting in a lower total price (perhaps in the 2.5 to 3.0 cents per kWh range) than the cost of new production. While limited-term and short-term energy packages priced similar to this are available in the wholesale market today, in most cases the high fixed costs of the base-load capacity are included in the utilities' retail ratebases, with recovery from ratepayers all but guaranteed absent findings of imprudence. Any contribution above variable costs from off-system sales merely reduces therecovery sought from retail ratepayers with no net loss to shareholders.

Obviously, in the case of open competition, historical plant investment would be at risk. A key variable is whether, even in the short run, utilities would continue to offer packages below total average cost with fixed costs not being recovered. The answer is dependent not only on the significance of supply/demand imbalances and the market perception that electricity is a commodity, but also on the effectiveness of the market structure in precluding the exertion of market power by large suppliers. It is difficult to imagine a regional power market where the capacity of a utility the size of AEP or Virginia Power would not compose a substantial percent of total market capacity, in effect providing the potential for significant influence in market pricing, especially during periods of high demand. Certainly, the growing trend of mergers and acquisitions within the industry does not assuage the concern of market power. In addition, the enormous capital requirements and lead times required pose a significant barrier to market entry, and existing and potential environmental limitations may prevent entrants that would dilute market power. Finally, all other things being equal, there would be substantial risk differences between companies with a large diversified portfolio of generating assets and those with only a few. From a financial markets' perspective, the industry could be one in which "bigger is better," establishing a basic conflict between the desires of the capital markets and the creation of a competitive electric power market.

While large producers may have market influence on the supply side of the equation -- wholesale, industrial, and large commercial customers may have considerable market power on the demand side. Beyond the economically attractive load characteristics of these customers, they generally have vastly superior knowledge, information, infrastructure, and options than smaller commercial or residential customers. With power suppliers intent on protecting shareholder interest and large customers focused on minimizing electrical energy costs, it is not difficult to understand the incentives which may exist to shift costs, especially embedded capacity costs, from large customers to small customers who may have limited options. For example, in order to keep a large customer, a utility may be tempted to dedicate a largely depreciated base-load plant with costs well below the utility's total average embedded costs to a large customer (the same effect as packaging low-cost energy from coal-fired generation with low-fixed-cost capacity from combustion turbines). This is just a more sophisticated form of providing price breaks to large customers using the argument that a small contribution above variable costs from that large customer is better for smaller captive customers than no contribution at all. Of course, this is a dilemma that regulators increasingly face today from innovative rate design proposals, which may be proposed under the guise of economic development rates.

The preceding discussion attempts to address several potential market influences which may affect pricing, and consequently stranded costs, in a competitive electric generation market. One consideration frequently overlooked in debates regarding pricing in a competitive power market is the degree of regulatory intervention that may be imposed. Given the importance of reliable universal electric service and infrastructure limitations, such as transmission constraints and ancillary service requirements, it is unlikely that power generation market pricing will be totally free from regulatory influence. For example, in at least three foreign competitive systems (Great Britain, Chile and Argentina), capacity prices are separated from energy prices and are established administratively.

Obviously, the existence or impact of each influence will largely be determined by the final structure of the market, which we do not know today. In fact, even the process for establishing a competitive market is unclear. Further, although much discussion has centered on POOLCOs and bilateral contracts, no comprehensive U.S. competitive models with fully developed operational details have been presented. Absent a more fully defined competitive market structure, any estimates of market pricing or stranded costs in an industry with the complexities of electric generation are speculative at best.

Several studies have attempted to estimate stranded costs for specific companies as well as the industry as a whole. While many of these studies involve elaborate models and large quantities of data, the methodologies are usually based on relatively simplistic market principles which fail to fully appreciate the complexities of markets in general and the electricity industry in particular.

Such studies serve useful purposes in identifying significant issues, focusing scrutiny, and advancing understanding; however, it is premature and inappropriate to rely on specific current estimates for purposes of determining stranded cost recovery policy. Realistically, it is highly doubtful that the complex behavioral dynamics of market participants can be predicted over an extended period of time with any accuracy, even after the establishment of a competitive market.

Embedded Cost Concerns

While the embedded costs and rates of Virginia's investor-owned electric utilities do not appear excessive, the same claim cannot be made by many utilities nationally. The significant national divergence in electric rates is a key driving force behind the momentum to transition to a competitive power market, as discussed in a previous chapter.

There are several fundamental reasons underlying such price differences. Similar to occurrences in other industries, some utilities have simply been poorly managed. Additionally, service territory characteristics have a major impact on average embedded costs and rates. Largely beyond management's control, a utility's load factor, service area density, geographical location relative to fuel supplies, environmental limitations, and historical load growth patterns (i.e., timing and type of capacity additions) greatly define current embedded costs. Finally, the regulatory and legislative obligations in the form of social and environmental programs, as well as regulatory intervention in utility resource decisions and utility-specific tax treatment, vary from state to state.

It seems more than a coincidence that the utilities with the highest rates are in those states traditionally considered to be havens of legislative and regulatory activism. To the extent transition to a competitive power market is pursued, utilities which have shouldered and continue to shoulder regulatory obligations will be at a severe disadvantage to competitors that are exempted from these same obligations. Even the basic obligation to serve, which every electric utility currently bears, may have to be reconsidered in a competitive environment.

On a national level, embedded production cost problem areas may be categorized into four basic groups: utility-owned generating assets, long-term resource obligations (contracts), regulatory assets, and public policy programs. In addition to potential inequities with respect to state and local tax treatment and regulatory obligations, there are two primary areas of specific concern in Virginia -- nuclear assets and long-term NUG purchased power contracts.

AEP, Delmarva, Virginia Power, and ODEC have varying degrees of exposure to risks associated with nuclear generating assets. The specific plants, including capacity and percent of company installed capacity, are Cook (2110 MW -- 9% of AEP), Salem and Peach Bottom (328 MW -- 11% of Delmarva), and Surry and North Anna (3184 MW -- 18 % of Virginia Power). ODEC owns 11.6% of the North Anna plant or 208 MW. APCO has no direct ownership interest in the Cook plant and receives minimal energy from the plant through AEP's interconnection agreement; however, as a subsidiary of AEP, APCO has some potential exposure to nuclear liability. Delmarva owns approximately 7.5% of both the Salem and Peach Bottom plants, which are operated by Public Service Electric and Gas and Philadelphia Electric Company, respectively. Virginia Power owns and operates Surry and North Anna.

In the context of national nuclear plant investment, the costs of these plants are not exorbitant, although certainly they are much larger than embedded fossil steam investment on a basis of equivalent size. Larger concerns entail potential catastrophic plant-specific operating events, industry wide safety and regulatory issues, and increased decommissioning and nuclear fuel disposal costs. Given the significant national improvement in nuclear generating unit performance, safety, and operating costs, the as yet unknown rear-end costs may pose the most significant threat. To the extent nuclear unit life extension is sought and obtained from the NRC, total average embedded production costs may decrease further with longer depreciation and decommissioning recovery periods; however, life extension would also increase the quantity of spent nuclear fuel that must be disposed. The possible cost reduction effects of life extension combined with reengineering efforts and the sustained trend of improving capacity factors may result in these nuclear plants being very competitive with new production facilities on a total cost basis.

Since Virginia Power has the most significant nuclear investment, it is appropriate to note that Surry and North Anna are two of the lowest total production cost nuclear plants in the country. Virginia Power's abandoned project costs associated with four canceled nuclear units has largely been recovered. The remaining unrecovered balance in the Virginia jurisdiction is approximately $73 million net of deferred taxes, most of which will be recovered by March, 1999.

While the potential impact on stranded costs resulting from nuclear investment is mostly speculative at this time, Virginia Power's high-cost non-utility generator contracts pose a significant and immediate problem. Unfortunately, not only do these contracts provide for high capacity payments, but, as a group, the energy costs are excessive by today's standards as well, resulting in relatively low dispatch. In aggregate, the weighted average capacity factor for the large dispatchable NUGs (over 85% of total NUG capacity) was approximately 30% in 1995 with an average total cost of 8.3 cents per kWh. While the total average production costs of Virginia Power's owned generating facilities appear to be competitive to the total costs of new production, the burden of these high-cost NUG contracts may place Virginia Power at a competitive disadvantage. It is ironic that these contracts, arising from PURPA mandates and Virginia Power's strategic capacity acquisition plans which, in part, reflected efforts to exert competitive cost pressures to the industry, appear to have resulted in a competitive disadvantage.

With the substantial stranded cost threat posed by these contract obligations in a competitive environment, Virginia Power has been pursuing several strategies to mitigate their excessive cost, including contract buyouts, buydowns, and renegotiations, as well as alternative fuel supply options. Virginia Power has also been pursuing vigorous enforcement of contract provisions, invoking penalty remedies in some cases. The Company has met with modest success in its efforts; however, the potential threat of these high cost contracts is far from being resolved. While Virginia Power and the NUGs should be encouraged to continue pursuit of negotiated remedies, if progress slows, a formal Commission inquiry may become unavoidable. Even without the introduction of competition, serious consideration must be given to whether ratepayers should continue to shoulder the full costs of these contracts. Virginia Power fuel factor cases from 1990 to 1995 have been held open and may provide an appropriate venue for such a review.

Several parties to this case, as well as national publications, have raised the issue of the significant regulatory assets (receivable from ratepayers) which arose, along with offsets in deferred income taxes on the liability side of the balance sheet, from accounting changes related to implementation of tax normalization. The issue of regulatory assets is complex and for many companies represents an enormous amount of dollars. It is debatable whether the regulatory assets created as a result of tax normalization are legitimate stranded costs. We recognize the importance of the issue and will continue to study its effect upon Virginia's electric utilities.

Policy Considerations

In considering the appropriateness of stranded cost recovery within a scenario of retail competition, it is essential to understand key components of the long-standing "regulatory compact" between electric utilities (investors) and the general public (represented by state legislators and regulators). Until recently, the vertically-integrated electric utility has been viewed as a natural monopoly due to economies of scale, market barriers presented by massive capital requirements, the essential nature of electric service in meeting human needs, and the physical characteristics of electricity and utility plant infrastructure. Historically, public officials concluded that the public interest would best be served by providing exclusive retail service franchises and regulated rates which allow for the recovery of prudently incurred costs (including the opportunity to earn a fair, risk-adjusted return on investment) by the utility in exchange for its obligation to provide reliable service at a reasonable rate to all those within its service territory. It must be understood that this "regulatory compact" is not the figment of someone's imagination or some hazy, nebulous doctrine; rather, it is a concise summary of real federal and state law and regulatory commission rules, tariffs and practices which have driven investment decisions, ensured access to relatively low-cost capital markets, and, in fact, underlain the current asset holdings and structure of the industry. In providing the capital for investment required for electric utilities to meet their obligation to serve, investors have accepted lower returns than may be available from other investments in exchange for the lower risk implied by investment recovery through regulation.

For the most part, the "regulatory compact" has served the public interest as intended. The United States has the world's most reliable interconnected electric system with service delivered, on average, at low prices as compared to other industrialized nations. Given the contribution of investors to the public interest success of the current system, it would seem inequitable to ask these investors to bear the entire economic dislocation costs produced by a change in the rules. Of equal importance, given the widespread public holdings of electric utility equity, either directly or indirectly through mutual and pension funds, ratepayers and investors may be one and the same, to a large extent.

A justification for allowing stranded cost recovery is the provision of stability to what might otherwise be an extremely disruptive transition. As discussed above, given the supply/demand imbalances that may currently exist, retail competition initially could favor large customers with significant price breaks below the total cost of new production. Without a stranded cost recovery mechanism, captive customers or utility investors would be left to subsidize these discounted price breaks.

Critics of stranded cost recovery frequently argue that equity investors assume the risk of losses in exchange for equity returns and should not expect to be protected from such losses. However, as mentioned previously, the regulated returns which have been established are risk adjusted. While the risk of regulatory disallowances have been included in this risk adjustment, the returns probably did not contemplate a massive change in the fundamental laws which govern the industry. Historically the business risks assumed by holders of electric utility equity have been that of regulation, weather, load growth, and management resource and operating decisions. On the other hand, during a transition to a more competitive model, utilities may be provided with opportunities to earn higher returns and absorption of some stranded costs may consequently be appropriate.

Additionally, it is argued that competition in the electric industry has been debated for an extended period of time and utilities and their investors should have made preparations. This argument ignores the fact that no electric utility has been released from its regulatory obligations during this period nor have authorized returns significantly increased to compensate for a transition to a competitive market.

While stranded cost recovery may appear appropriate from the standpoint of fairness, if full stranded cost recovery is guaranteed, incentives may be lacking for utilities to mitigate stranded costs through prudent cost reduction, renegotiation of long-term obligations, aggressive marketing of available energy and capacity, and avoidance of additional strandable investment. However, if less than full recovery of prudent stranded cost is allowed, then symmetry may require that utilities be allowed to retain a portion of the gains from mitigation efforts or a portion of stranded benefits if the utility's cost is below market prices.

Another symmetry issue with respect to less than full stranded cost recovery is the treatment of high-cost NUG contracts. Nationally, a consensus seems to be emerging that existing contracts should not be modified. Given the competitive market advocacy of private power producers, these entities should be willing at a minimum to share proportionately in the pain of transition. Inconsistent treatment of NUG contracts and the stranded costs of utilities would be especially disconcerting in that NUG contracts are among the largest contributors to potential stranded costs for some utilities.

Even if utilities are allowed full stranded cost recovery, such recovery will likely be bound by a specific time frame. Under such circumstances, one would question whether it is appropriate to maintain the sanctity of NUG contracts with a utility when the utility's statutory franchise with its customers is eliminated. While the authority of the SCC is not clear with respect to these contracts, options may be available to pursue this matter of equity with FERC or the courts. As pointed out in a response to Commission Staff interrogatories, a fundamental requirement of PURPA was that ratepayers would not be adversely affected by the required purchase of power from cogenerators and small power producers. In many respects, this requirement was subordinated by the FERC's implementing rules which mandated commitments based on estimates of long-term avoided cost.

FERC's Order 888 sanctioned state regulatory commissions' retail stranded cost recovery jurisdiction where state law provides such authority. This Commission has wide ratemaking authority in Virginia, which probably includes the authority to provide for recovery of stranded costs and establish a recovery mechanism. In the 1996 legislative session, Virginia's General Assembly enacted legislation specifically authorizing the Commission to determine stranded costs in cases of municipalizations and federal facility departures. While the Commission may have such authority for all retail customers in Virginia under the auspices of its ratemaking authority, a further review of this matter may be appropriate to determine if specific legislative clarification by the General Assembly is desirable. It may also be advisable to put all current retail customers on notice of potential stranded cost obligations.

Stranded Cost Calculation Issues

Several administrative and market approaches for quantifying stranded costs have been discussed in industry literature. Market based approaches require the actual sale of generation assets which allows for a clear comparison of market value versus embedded cost. However, in addition to the radical nature of such actions, market approaches increase the complexity of addressing purchase power contracts, the largest potential embedded cost problem in Virginia. While asset sales might be necessary to address market power concerns, it would be an inappropriate and drastic measure solely for purposes of determining stranded cost.

Many administrative methodologies attempt to determine how much revenue margin (revenue in excess of variable costs) is lost or gained over a specified period of time from market price changes relative to embedded cost rates and from arriving and departing customers. These approaches require projections of market dynamics and prices, as well as assumptions regarding utility mitigation results and avoidable costs. Each of these variables is dependent on numerous unpredictable factors, with the unavoidable result that stranded costs/benefits are dynamic, ensuring that any up-front projection of stranded costs/benefits will be wrong. Clearly, projecting stranded costs would be exponentially more difficult than the task of estimating avoided costs was under PURPA. Even if true-ups are incorporated into the process, they may be difficult to administer mechanically. For example, in a market with a POOLCO, a utility's prices and its avoidable costs would vary significantly over the course of the daily, seasonal, or annual load curve. How much distortion will be introduced by using an average market price and average avoidable utility costs? In a market which has both a POOLCO and bilateral contracts, the spot market and contracts of varying lengths will have different prices. What would be the correct price to use in stranded cost calculations? How would natural customer load changes be distinguished from utility mitigation efforts or market dynamics? Should such load changes be treated differently?

Acceptance that stranded costs cannot be accurately calculated may prevent many of the same mistakes that were made in developing and applying complex avoided cost methodologies with poor results. While common sense applications of simple approaches will also produce inaccurate results, such approaches provide a clear and easily understood definition of the game rules up-front, as well as avoid the disruptions produced by the futile pursuit of accuracy which tends to accompany more sophisticated approaches.

Our message is to "KEEP IT SIMPLE." Though we do not advocate a particular methodology, an example may be in order. In the event of a decision to transition to full retail wheeling, a wires charge or access fee (per kWh, KW or both) may be developed for each customer rate schedule based on the allocated cost of service which reflects the full fixed costs associated with production and power supply costs. Those customers wishing to access alternative energy suppliers would pay 100 percent of this wires charge in the first year of a multi-year transition period. Over subsequent years, the access charge would decline on an incremental basis to zero.

Critics would argue that such an access charge is anti-competitive, especially in the initial years; however, the purpose of a transition period is to minimize operational and financial disruptions within the industry. Utilities might be able to enhance earnings in the early years by marketing excess energy or capacity with fixed costs being recovered largely by the access charge, but the utilities would need to use such opportunities to address any stranded cost problem areas in preparation for the end of the transition period.

Of course, broad stranded cost recovery mechanisms such as the ones discussed above are only necessary with a large, wide-scale implementation of retail wheeling. To the extent this is not the case, the obvious preferential approach for addressing stranded costs would be on a case-by-case basis which allows for full consideration of the specific circumstances of each situation. Furthermore, given the utilities' current focus on reducing costs and the eventual resolution of supply/demand imbalances, the need for any stranded cost recovery mechanism may dissipate depending upon if and when retail wheeling becomes a reality.

Summary

Stranded costs/benefits are driven by the difference between market prices and rates based on embedded costs. Prior to the possible formation of a new market structure, or even a reasonable blueprint for transition, it would be premature to formulate a comprehensive stranded cost recovery policy. Stranded costs/benefits are a transition issue which must be addressed subsequent to determining the destination. Given the current unknowns relative to potential market structure and retail competition, it is essential that the Commission maintain maximum flexibility to address transition issues at the appropriate time. It is also essential to maintain awareness of the potential impact on stranded costs that policy decisions may have during this period of uncertainty. For example, PURPA requirements, demand side management activities, and accounting deferral mechanisms all have the potential for affecting stranded costs.

Given the long-standing and publicly beneficial "regulatory compact," it may be argued fairness requires the opportunity for utility recovery of a significant portion of prudent stranded costs that may result from the potential transition to retail competition. However, guaranteed full recovery of stranded costs may not provide sufficient incentives to optimize mitigation efforts. For symmetry, stranded benefits (market prices higher than embedded costs) must be considered in conjunction with stranded costs policy.

The Commission has broad authority under existing ratemaking statutes which should allow for the determination and assessment of retail stranded costs. The Commission may wish to consider whether additional legislative confirmation of such authority is appropriate. Additionally, the Commission should consider whether to provide notice to all retail customers with respect to potential stranded cost liability if restructuring emerges as a significant possibility in Virginia.

Based on current average revenues from industrial customers, it appears that the embedded costs and rates of Virginia's investor-owned utilities are not generally excessive with respect to the total cost of new production. However, the review of average rates and average embedded power supply costs during the course of this study is insufficient to make precise definitive findings. Further, Virginia Power's high-cost NUG contracts are significantly above the costs of new production and the Company's own generation production costs, thereby exerting upward pressure on its total power supply costs. Virginia Power is pursuing numerous options with the NUGs in an attempt to lower the cost of these contracts. The Commission should encourage and closely monitor these activities. These contracts have not yet been formally reviewed under traditional regulatory scrutiny. Such a review may become appropriate depending on the timeliness and results of Virginia Power's efforts.

While market prices cannot be forecast with any degree of certainty at this time, a more detailed assessment of the embedded costs and rate schedules of Virginia's utilities should be pursued through comprehensive cost of service reviews for each utility. In such reviews, traditional allocation methodologies should be reexamined to ensure the equitable allocation of costs between rate schedules, with the elimination of cross-subsidies. Rates and embedded costs for various services need to be unbundled where possible, including potential ancillary services, as well as transmission and distribution service. Fixed costs and variable costs also need to be identified for each of the various production services. Finally, usage characteristics and the cost of serving customers within each rate schedule should be evaluated for comparability, with inconsistencies identified for possible new rate schedules in order to limit future "cherry picking" opportunities for possible future competitors. This effort should provide additional insights into potential stranded costs/benefits, serve as a fundamental building block for the development of a stranded cost recovery mechanism should one be needed, and, through an improved allocation of embedded costs, possibly minimize total stranded costs to be recovered.

As a result of a sub-optimal national capacity mix with excessive base-load capacity, short-run competitive market prices may be driven below the total cost of new production, reflecting low-cost-coal energy packaged with low-cost combustion-turbine capacity. The fruition of this possibility will depend on the competitive market structure and the influence of various market imperfections. Should such a scenario develop, a substantial amount of embedded cost could be stranded in Virginia, at least in the short-run. Without provisions for stranded cost recovery, it is likely that this scenario would benefit large, market savvy customers at the expense of small (perhaps captive) customers or utility investors.

In the long run competitive market prices should approach the total costs of new production, ignoring market imperfections. Therefore, it is possible that a delay in the implementation of retail wheeling, assuming that capacity/demand imbalances are resolved, could reduce or eliminate the stranded cost issue in Virginia. On the other hand, an immediate opening of retail competition could necessitate implementation of a comprehensive stranded cost policy and methodology. In this event, we urge the Commission to avoid the futile pursuit of accuracy through complex methodologies which, as evidenced by experiences in calculating avoided cost, may have unfortunate consequences despite the best of intentions. As a transitional tool, a broad based stranded cost policy and methodology should be targeted at minimizing economic disruptions and characterized by ease of understanding and simplicity of application.

C. Capacity Optimization and Future Reserves

The potential benefits and detriments of electric supply deregulation will be influenced by the levels and mix of electric capacity within an interconnected region. Electric supply costs are expected to fluctuate with supply and demand and to be lower during periods of excess supply and higher during periods of extraordinary demand. Construction of generating capacity, and hence, reliability of electrical supplies in a deregulated market could be influenced by how potential investors and electric suppliers view market opportunities. These opportunities will in turn be influenced by the level and nature of existing generating capacities. In short, the adequacy and cost of electric supplies in a competitive, market driven environment will depend on a number of complex and interdependent factors. We have reviewed the 1995 NERC report "Electricity Supply and Demand" in an effort to assess the future availability and utilization of generating capacity under various scenarios.

Expected Regional Electric Generating Capability

Based on the NERC data, projected reserve margins for the ECAR, MAAC, MAIN and SERC reliability regions have been calculated. The results of these reserve margin calculations are presented on graphs in Volume II. Graph V-C1 reflects reserve margins which incorporate both projected capacity additions and projected load reductions associated with future load management programs. As can be seen from this graph, future reserve margins are expected to be in the 16-23 percent range. The bottom of this range is low in relation to historic standards, but may be sufficient for assuring adequate electric supplies if increased transmission access does, in fact, result in a better utilization of existing generating facilities. However, future capacity additions underlying these projections can be viewed as speculative since they reflect unspecified resources, unsigned non-utility contracts or projects that have not been financed. Utilities may be unwilling to enter into commitments for such resources in a competitive environment. Utility reliance on future load management programs is also troubling since the results of such programs are difficult to predict and utilities may respond to competitive pressures by discontinuing or limiting demand-side activities. Consequently, additional reserve margin calculations were performed to eliminate uncertainties with respect to capacity additions and the expected results of load management programs.

The omission of load reductions associated with demand-side programs had a more significant impact on projected reserve margins than did the omission of uncertain capacity additions. Reserve margins produced by these calculations are represented on Graph V-C2. As evidenced by this graph, reserves in the SERC and MAIN regions drop to alarming levels if expected loads materialize, additional supply resources are not added or acquired, and demand-side load reductions do not materialize. Reserve margins would also drop to unusually low levels for the ECAR and MAAC regions. The results of this analysis should be viewed as a "worst case scenario" since the electric industry would almost certainly respond to unacceptably low levels of reliability. However, this graph highlights the uncertainties that are currently faced by the electric utility industry and provides an indication of how quickly electric supplies can become constrained if market resource commitments are not made.

It is difficult, if not impossible, to predict the impact of power supply deregulation on the adequacy of future generating resources. Under a competitive power supply scenario, capacity will be added in response to expected market clearing prices or as a result of bilateral power supply contracts. In an ideal power supply market, interactions between supply and demand should result in an optimal level of generating capacity. Such a market requires that both suppliers and consumers have accurate and timely information and the ability to respond to such information. Unfortunately, meters that are currently installed for most electric customers are incapable of providing real-time information to consumers. While real-time meters are available, it would be quite expensive to upgrade metering capabilities for all customers. Even if such technology is installed, consumers would have to have a comprehensive knowledge of the electric industry and the financial wherewithal to properly respond to changing market conditions. Imbalances between supply and demand are likely to occur in a deregulated market due to problems associated with the sharing of information between electric suppliers and consumers. Depending on the magnitude of such problems, power supply deregulation could result in mismatches that are even greater than those seen in the current regulated electric utility industry with periods of unreliable power supplies.

An ideal power supply market should also be free of market concentration or control by potential suppliers. Utilities currently own substantial amounts of generating unit resources and, if left unchecked, may be able to control or greatly influence market prices in certain regions or under certain conditions. Additional entry by competitors could undermine such influence, however, new suppliers must overcome a number of substantial barriers to entry, such as siting restrictions and huge capital requirements. Undue utility influence would not be eliminated in any reasonable period of time. While market power may be eliminated through divestiture or other methods, it may be difficult to identify all areas of potential abuse and to eliminate potential market dominance by utilities. On the other hand, market dominance by existing suppliers could increase electric prices to the point where generating capacity is added at a faster pace and reliability (at least in terms of reserve margin) could actually be increased over present levels. The reserve margin of electric supplies in a competitive power supply market will rely on a number of factors, including how such a market is structured and whether consumers have timely and accurate price signals and the ability to respond to such signals. If competitive markets are implemented poorly, electric supplies could be either unreliable or expensive.

Capacity Optimization

Competitive benefits for consumers also will depend on the nature of the capacity that's being added. As discussed earlier, there appears to be an excess of base load-capacity in this region. This excess can be blended with new peaking capacity (having lower capital costs) to produce reliable supplies at costs that are below the incremental cost of power that can be supplied by a new stand-alone unit. This excess base load situation could give existing utilities a significant advantage in a competitive market. New entrants also may be able to purchase unneeded base-load generation from utilities on a short term or interruptible basis and repackage this generation with other services to provide a broader array of innovative services. These types of arrangements could serve to lower prices in the short term. It should be noted that utilities have historically capitalized on excess base-load generation to facilitate economy transactions, and increased transmission access for wholesale transactions may serve to improve the utilization of this excess base-load capacity. It is unclear whether retail access would improve the overall utilization of existing base-load resources to any measurable extent or if it would simply reallocate the benefits of these lower cost supplies.

It also is difficult to predict how a competitive power market would respond once excess base-load supplies are depleted by load growth, unit attrition or stricter environmental requirements. Base-load units are very capital intensive and may not be added as readily in a competitive market where potential investors will be subject to greater financial risk. If the financial risks of adding needed base-load capacity are too great and investors add peaking capacity or combined-cycle capacity instead, a competitive power supply market could result in increased reliance on natural gas as a generating fuel. Such a reliance may be inappropriate given the potential volatility of natural gas from both supply and cost perspectives and may be ill advised from a fuel diversity perspective.

The 1995 NERC report "Electricity Supply and Demand" was reviewed in an attempt to gauge how quickly the excess base-load supplies will be spent. Based on projections of coal-based generation, capacity factors were calculated for coal-fired generation in the ECAR, SERC, MAIN and MAAC reliability regions. These calculations are summarized on graph V-C3. Based on these projections, it appears that there will be adequate base-load capacity throughout the next decade. However, many of the existing base-load units are older and have emission-control systems that are inadequate by current standards for new units. Increased emissions standards could reduce the viability of operating many of these base-load units at increased levels and have a significant impact on the adequacy of coal-based generating supplies.

D. Municipalization

A recent concept related to electric restructuring is municipalization, wherein customers of the existing utility elect to shop for power through a municipal entity. In Virginia, for example, representatives of the City of Falls Church publicly discussed and pursued the use of the municipal entity to find a new supplier of electricity for itself and its residents, replacing Virginia Power as the sole provider of electricity. Under such an approach the municipal entity would become a wholesale customer of the new supplier, with the transaction subject to FERC jurisdiction.

Municipalization could occur through several different approaches. A municipality could construct its own distribution system, purchase transmission service from the existing utility and purchase power from a third source in the wholesale market. A second approach would be to acquire, through purchase or condemnation, the existing utility's distribution system, purchase transmission service and shop for power. A third version is sometimes referred to as "municipalization lite" (i.e., the Falls Church approach), where the municipal entity would act simply as an aggregator of load, own minimal facilities and purchase transmission, distribution and perhaps other services from the existing utility, while purchasing power from a third source. Another variation could impact an existing utility even outside of the jurisdictional boundaries of the municipality. This type of plan would have the government-created entity purchase a substation outside of the municipality's normal retail-load boundaries and then supply power to the existing utility's former retail customer by purchasing transmission to its new delivery point for resale to the end user.

Another threat to utilities would be the creation of a municipal (or other governmental) entity to supply power to a large end-user. The Energy Policy Act of 1992 may offer some protection to utilities by excluding "sham" transactions from those for which it will mandate wheeling, but this area of law remains unclear. FERC's Order 888 also addresses stranded cost recovery for a retail-turned-wholesale customer, though the jurisdictional authority of states, as opposed to that of FERC, to address such matters remains in dispute.

Several critical issues arise in the context of municipalization. For instance, what powers exist under state law which might allow creation of municipal entities that would supplant the franchised utility? Municipalities in Virginia may establish electric and gas utility operations, and some have. There also exists the issue of whether, even in a municipalization that does not involve the actual condemnation of facilities, there is a taking of the utility's exclusive right to serve under the state-sanctioned franchise system. Virginia Power raised this question in the Falls Church proceeding at the Commission. It is clear, however, that a municipality which seeks to acquire the existing local utility's facilities through condemnation must receive approval from the State Corporation Commission pursuant to § 25-233 of the Code of Virginia.

As with other aspects of electric restructuring, municipalization also raises the issue of stranded costs at the state and federal level. If the existing utility has made significant long-term investments in generating facilities to serve customers who will be purchasing power from a third party, how should the costs of such facilities be recovered? When a customer left the system in the past, such costs were typically reallocated to remaining customers of the utility. These costs were relatively small, and the loss of a customer often had the effect of delaying more costly investment by the utility to meet load growth. Today the stakes are considerably higher, with the possibility of significant adverse effects on the party or parties which must pay for stranded assets. The potential impact on remaining customers and on the existing utility's shareholders will have to be evaluated and addressed, as will the barrier to shopping for power if the costs are imposed on those customers who wish to receive power from another supplier. State commissions and FERC dispute their respective jurisdictional roles in addressing such matters.

The Virginia General Assembly in its 1996 session enacted legislation that affects municipalization and its potential consequences. Section 15.1-292 of the Virginia Code addresses the power of cities, counties, and towns to acquire and operate electric plants and other public utilities. This statute was amended to provide that any acquisition, takeover or displacement of the services of an existing utility must first be approved by a majority of the voters voting in a referendum. In addition, § 25-233, pertaining to condemnation of the property of an entity which also possesses the right of eminent domain, was amended to provide that, if the Commission approves a condemnation, it shall establish for use in any condemnation proceeding whether any payment for stranded investment is appropriate and, if so, the amount of such payment and any conditions thereof.

Proponents of municipalization maintain that it is an effective means of obtaining access to competitive supplies of electricity for residential, commercial, and business customers alike. Opponents argue that it is a method of shifting historical costs associated with uneconomic assets to an existing utility's remaining ratepayers or stockholders, or cream-skimming an existing utility's most lucrative customers. If the electric industry is restructured and electric utilities are functionally or structurally unbundled, municipal utilities, like cooperatives, may hold the potential for becoming aggregators of customers for purposes of securing competitive supplies. However, the existing distribution company should be able to act effectively as an aggregator since it already has the assets and work force in place to provide the delivery of electricity. In addition, it must be remembered that a municipal distribution utility would be, in effect, an unregulated monopoly, though ultimately accountable to its citizens.

E. Dispersed Energy Projects

As the energy services business continues to develop and expand, innovative approaches to meeting the needs of customers will emerge. As part of the much-discussed corporate reengineering which has swept across American businesses in recent years, corporations and other businesses may be looking to outsource more of their energy needs, and commercial and residential customers may also be interested in total energy packages. Increasingly, utilities will feel pressure from competitors to offer a basket of services, including but not limited to electricity, to retain customers seeking different ways to meet their total energy needs. Affiliates of major utility companies serving other jurisdictions have established offices in Virginia and are making contact with large electric users -- offering a variety of services and establishing business relationships which will facilitate the sale of electricity as part of total energy packages if and when retail competition is allowed. Utilities claim that they need greater flexibility to meet current competition and prepare for the possibility of competition for its core product in the future.

An example of the different services that may be offered is a dispersed energy facility. As discussed earlier in this Report, in 1993, Virginia Power filed an application with the SCC for approval of its proposed Schedule DEF (Dispersed Energy Facility Rate) on an experimental basis. The proposal would have authorized Virginia Power to offer on a voluntary basis to any large commercial or industrial customer, generating facilities at or near the customers' sites. These facilities would have been made available to as many as ten commercial and industrial customers with a maximum total electrical output from all such facilities of 200 MW.

The Commission rejected the proposal principally because it did not meet the statutory requirements for an "experiment" and because the proposal lacked specifics. However, the Commission, in noting its commitment to innovative ways of delivering energy service and recognition of the changing nature of the electric utility industry, stated that it might well consider a specific DEF-type proposal that was presented with adequate justification.

During the same time frame that the Commission was considering the DEF proposal, a subsidiary of Louisville Gas and Electric Company ("LG&E") announced plans to enter into an agreement with DuPont, which has manufacturing facilities (including significant cogeneration capacity) in Virginia. LG&E proposed that it might own, at least in part, generating facilities which would produce electricity for sale to DuPont. Virginia Power challenged the proposal, principally as an invasion of its exclusive service franchise. Legislation was introduced to help advance the project, but it was unsuccessful. At the Commission, LG&E and DuPont argued that details of their arrangement had not been fully developed and that any Commission action other than dismissal of Virginia Power's complaint was, at best, premature. Ultimately the project was abandoned for unspecified business reasons.

In late 1995, Virginia Power filed an application with Chesapeake Paper Products Company to build a DEF facility at Chesapeake consisting of a natural gas-fired combustion turbine and a heat-recovery steam generator, an electric generator and related support facilities. Virginia Power would provide additional services, including fuel procurement, for a fee, and a natural gas pipeline would be built. The application was incomplete and in June, 1996 it was refiled. The matter is currently pending before the Commission.

While the Staff has not, at this writing, filed a report or testimony concerning the specific application pending before the Commission, the Staff generally supports authorization to engage in such activities where they are beneficial to a particular customer, not unduly discriminatory, and are otherwise in the public interest. If it is assumed that such offerings will be made by other entrants, such as LG&E and Enron, who may ultimately compete for all of the energy business of a customer if such competition is permitted, fairness would seem to dictate that the utility be permitted to offer such services. More importantly, the customer who has special energy needs should be able to look to its provider of electric service for a broad range of services, and maintaining and enhancing the customer relationship with the utility may, in appropriate circumstances, benefit other customers as well. The Commission would, however, need to assess possible stranded cost issues.

DEF projects appear to be an appropriate area for competition. Similar services could likely be provided, at least in large part, by non-utility parties under current law, but transactions may involve unnecessarily complex arrangements regarding ownership and other measures. Eliminating such barriers would be an important step toward greater competitive choice for customers. Utilities might, however, question whether their exclusive right to serve was being diluted by such a measure, and some appropriate limitations might be justified. If this option is pursued, backup and other ancillary services which only the utility can realistically provide should be made available to such projects on an unbundled and comparable basis to those provided to the utility's own DEF offerings.

F. Ancillary Services

The provision of electric service, for the most part, has been and continues to be performed by a vertically integrated utility. The utility is responsible for the production of electricity as well as the delivery of the electricity to its customers through both transmission and distribution lines. In providing electricity to its customers, a utility is also required to provide ancillary services to its customers in order to ensure safe and reliable electrical service. Most customers have viewed electric service as a single product and are oblivious to the other services being provided by their electric utility. These ancillary services must be clearly identified in the functional separation of generation and transmission since certain critical services may continue to have monopoly characteristics. Inappropriate distinctions of monopoly services could give certain parties undue market power and potentially distort market signals or result in the loss of operational efficiencies if critical functions are not adequately provided by market forces.

In order to ensure a safe and reliable electrical system, utilities built heavily interconnected electrical systems. The benefits of an integrated electrical system are improved reliability and efficiency. However, the consequence of a fully-integrated electric system is that any change in load, interconnection or generation simultaneously affects all other interfaces, generators and load. Most ancillary services provided by utilities are intended to ensure that these changes do not cause problems elsewhere on the interconnected grid. Some ancillary services are planning related and help ensure that utilities have the least cost generating unit configuration operating at all times. The ancillary services, as discussed herein, relate to both the generation and transmission functions.

In recognition of the fact that utilities are interconnected and in order to overcome some of the reliability concerns, most large utilities serve as control areas. The function of a control area is to divide a nationally-interconnected electrical system into smaller areas to ensure reliability.

With the intention of encouraging competition in the electric industry through elimination of market power, many people are advocating the disaggregation of the traditional vertically integrated electric utility along the functional lines of generation, transmission and distribution. Moreover some are advocating the unbundling of electric services even further to the point where ancillary services may become subject to competition. These advocates believe that the generation of electricity is no longer a natural monopoly, but view transmission and distribution as natural monopolies which should continue to be regulated. Some argue that the disaggregation of the vertically integrated utility is necessary because of the, "*dual role played by the traditional utility as (1) the decision-maker concerning who generates electricity for its service territory, and (2) a candidate for the job of generating electricity for the same service territory*."

The services provided by an electric utility, which are included in the bills paid by most customers are listed below beginning with basic services and proceeding through ancillary services. These services are necessary for the provision of reliable service. Moreover, with the exception of large industrial customers, most users will not have the expertise to decide which services they want or, for that matter, need.

Generating Capacity: Industrial customers pay for generating capacity in a monthly charge, commonly referred to as demand charge. This charge could be viewed as "reserving" a portion of the utility generating capability. For large industrial customers, this charge is usually determined based on an allocation of capacity costs to the industrial rate class and on each individual customer's coincidental peak. For residential customers, the demand charge is included in their rate per kWh.

This service may not be required for all customers. For example, currently in Virginia there are interruptible gas customers who pay no demand charges. The customer, due to the utility's ability to interrupt service, does not place a capacity burden upon the utility. If a customer chooses to become an interruptible customer, or in some other fashion, reduces its capacity burden on the utility, it may be able to reduce or eliminate the demand charge. However, in our opinion, capacity costs which are intended to lower energy costs (e.g., the capacity cost of a coal unit versus a peaking unit) should continue to be paid, in part, by interruptible customers.

Energy Supply: This represents the actual electricity that is produced at generating facilities and transmitted to end users. This service does not necessarily need to be provided by the utility. Moreover some customers, who self generate or who have signed bilateral contracts may not want this service.

Power Delivery: This is the service of actually moving electricity from the generator to the end users. In order to increase efficiencies, utilities have designed and built fully-integrated transmission facilities rather than point-to-point connections. These interconnected transmission facilities can carry a limited amount of power. Therefore, most customers also pay a transmission capacity payment based on their peak demand.

This service could also be viewed as a discretionary service. For instance, a customer who self generates on site or has contract with a third party to build a dedicated facility could avoid using the transmission grid. However, that customer is giving up the reliability provided by the utility back-up power supply. The customer would essentially become an island.

Capacity, energy and delivery are the three main functions or services provided by electric utilities. Any of these three services are optional to the extent a customer chooses to self generate. For reliability reasons a customer may still want some commitment from its utility for back-up power. The ability to self generate has been and continues to be a right afforded to all electric consumers in Virginia. However, in order for a third party to provide any of these three basic services, the Code of Virginia would have to be changed.

Utilities also provide ancillary services which are currently included in the bundled electrical service.

These ancillary services, as stated earlier, are intended to increase the reliability and lower the cost of electric service. Three ancillary services deal mainly with managing the generating assets. They are unit commitment, economic dispatch and emissions management. These three services are considered to be planning functions and, hence, are intended to help the utility provide the least cost generating mix at all times.

Unit Commitment: This is the decision-making function that attempts to match sufficient capacity with load at the lowest possible cost. This function could be viewed as broadly as the integrated resource plans filed with the Commission. However, we agree with the Oak Ridge report that the ancillary service as part of unit commitment deals with the daily and weekly planning of which units to run, keep spinning or shut down. While this service is not necessary, without least cost planning the cost of electricity would no doubt be higher.

Economic Dispatch: This function is the continuous real-time decision making process by which the actual mix of generating units and power-purchase and power-sale opportunities are matched with current customer demands to minimize the total variable cost of generation. This service, too, is not strictly necessary; however, without it electricity costs would probably be higher.

Emissions Management: Since the passage of the 1990 Amendments to the Clean Air Act, utilities have been restricted on the total amount of emissions they can produce from their generating facilities. This encourages utilities to find the least-cost way to cut emissions. Emissions can be included in economic dispatch. With the creation of an allowance trading market, utilities can couple emissions management with economic dispatch. Like unit commitment and economic dispatch, emissions management is not a necessary service, however, without it there is a greater chance that emissions limits would be exceeded, resulting in significant penalties which would raise the price of electricity.

In reviewing the generation-related ancillary services listed below, it is important to keep in mind that electricity cannot be readily stored. Therefore, when a customer flips a switch and increases the demand for electricity, the utility must instantaneously produce and deliver the additional energy requested by the customer.

Spinning Reserves: There are two types of spinning reserves that are intended to increase reliability. The first type is referred to as "load following reserve" and is that which supplies incremental customer demand, i.e., assures that additional load is met the moment it appears on the system. The second type is referred to as "reliability reserve" and is that which is available to replace the sudden loss of a generating unit. Since the reserves must be instantaneously available, they must be provided by units which are already on-line and running, hence "spinning."

Unscheduled Energy: If a restructured electric industry allows bilateral contracts, there may be instances where a customer may buy electricity from a supplier other than the vertically integrated utility. In instances where the customer's demand is greater than the supply provided by the bilateral contract, that customer will place a burden on the utility's generating facilities. This is referred to as unscheduled energy. Moreover, this may result in a burden on the utility's transmission facilities. When a vertically integrated utility meets all customer demands, unscheduled energy is viewed as load-following spinning reserve. However, once that customer leaves the utility, unscheduled energy service must be viewed differently.

Supplemental Operating Reserve: To cover occasions where spinning reserves are not sufficient, utilities maintain supplemental operating reserves supplied mostly by peaking units which can be fully operational in 10 to 30 minutes. The balance of a company's supplemental operating reserves are obtained from interruptible loads and neighboring utility systems.

Stability Enhancements: Under normal conditions electric generators operating in an interconnected system run in synchronization with each other at the standard system frequency of 60 Hz (60 cycles per minute). Major disturbances, such as transmission line short circuits, may cause nearby generating units to tend toward loss of synchronism. This tendency is aggravated by limited transmission capacity at a generating station (e.g., 2 lines instead of 3) and by heavy loading on the transmission system (as might occur with increasing transmission access and competition). Additional transmission capacity is an expensive solution to this problem and is generally the last resort. Power system stabilizers can be added to the generating unit to dampen rotor oscillations and maintain unit synchronism.

Time Correction: Electric clocks keep time based on the 60 Hz frequency of electricity. However, this frequency can have some variation in it. Therefore, without a correction mechanism, the time displayed by clocks would become inaccurate. This frequency correction service is inherent in generation operation and cannot be unbundled.

Local-Area Security: At times, due to a transmission constraint, the most economical generating unit may not be dispatchable. If the unit is a remote generating facility connected to the grid by a constrained transmission line, the utility may have to reduce power from this optimal unit. Instead the utility may have to operate a more expensive unit close to the load. The more expensive unit is said to be providing local area security. This service could be provided by a third party.

Nonoperating Reserves: Due to the lengthy time period necessary to construct a generating facility, utilities must maintain a certain level of generating capacity available to replace a unit which may be out of service or to meet a large unanticipated demand. This additional generating capacity is referred to as nonoperating reserves or reserve margin. A customer could avoid paying for this service by allowing the utility to interrupt services before the utility needs to use its nonoperating reserves. This service could also be provided by a third party.

Black Start Units: Most generating units need electricity to come on line from a cold start. However, under conditions of a system collapse, it may not be possible to draw power from the grid to bring units online. Therefore, utilities have constructed generating facilities capable of coming online without electricity. These facilities are referred to as black start units. Since black start units are vital to the system, a customer must receive this service. However, any generating facility, even those not owned by the utility, could be black start units.

The following ancillary services relate to the transmission function. In reviewing these transmission-related ancillary services, it is important to remember that the transmission grid is the means by which electricity is transmitted from the generators to the customers. Additionally, the transmission grid provides the link between generating units, which serves to increase reliability, lower overall production costs and makes possible wholesale transactions involving electricity.

The capacity of the transmission network is dependent on the location of the various generating units relative to the demand for electricity, the individual characteristics of the units online, and the availability of the reactive power compensation devices. A change in any of these factors influences the capacity of the transmission grid. Therefore, it is important to continually monitor the transmission system.

It is also important to remember that electricity flows over the path of least resistance. When a contract for power delivery specifies a single path, the electricity will not necessarily follow this path. Therefore, the power may flow into a third party's transmission system, referred to as loop flows, placing a burden on that utility's transmission capacity.

Transmission Reserves: Reserve capacity is required on the transmission grid. The reserve capacity is needed to provide instantaneous accommodation to replace output from a disabled generator with generation from another location. Customers who have no reliability requirements may not need the transmission reserves, and may in fact provide transmission reserves to the utility by going on an interruptible rate. However, the utility would still need to monitor the transmission grid to know when to interrupt the customer.

Real-Power-Loss Replacement: Transmitting power over long distances results in line losses (or real power losses) due to electrical resistance associated with transmission facilities. These losses depend on the network's configuration and the location of generating facilities and load centers. These losses constantly vary with changes in load and generation. These losses must be made up through additional generation which could be provided by third parties.

Reactive Power Management and Voltage Regulation: Electrical facilities and connected loads generally have capacitance or inductance which requires reactive power current flow in addition to the real power current flow required by connected load and transmission losses. Net reactive power in a utility system is inactive and is supplied remotely by generating units and locally by capacitor banks. These reactive power flows increase transmission line losses.

Power Quality (Wave Form): Customers and power suppliers need to maintain power supply as close as possible to a 60 Hz sine wave. Many loads, especially, electronic equipment, can be adversely affected if the sine wave is distorted. The sine wave can be distorted by certain power supply and load applications. These disturbances fall into the categories of harmonics of the 60 Hz wave and notching of the 60 Hz sine wave. These harmonics can be controlled through filtering.

Repair and Maintenance: Most utilities have repair crews available 24 hours a day to handle any unscheduled outage. The crews must have the knowledge and the resources available to repair the damaged equipment causing the outage. Additionally, in order to avoid outages, utilities perform routine maintenance of its transmission and distribution systems to minimize the number of outages. While this service is clearly a service that all electric users need, it does not necessarily have to be performed by the utility. However, the service must be coordinated by the utility with the operation of the remaining system.

Metering and Billing: Metering refers to the measurement of the amount of energy each customer uses in a given period. Individual customers are metered at the point of delivery. Sales between utilities are measured at the points of interconnection. Billing requires that the billing party know customer uses and charges for the specific pattern of uses. While any party could perform these two functions, jointly or separately, it has traditionally been performed by the utility. Each customer needs this service.

In this section of the report, we have identified the basic services provided by the vertically integrated utility. These basic services include generating capacity, energy supply and power delivery. In order to ensure that these functions are performed in a safe, reliable and least costly manner, utilities also provide ancillary services. As the discussion above points out, some of these services are optional. Moreover, some of these services could be provided by other parties, perhaps at a cheaper rate. How much cheaper is debatable given that AEP's total cost of ancillary services has been estimated to be about 11.5% of the total cost of generation and transmission. Given the relatively small amount that there is to gain, it is important to remember that these services are intended to increase reliability; the addition of another provider of these services may cause reliability to diminish.

G. Business and Financial Risk

Increased competition within the electric utility industry likely will mean changes in the risk profiles for all electric utilities. A company's total risk can be divided into two components -- its business risk and its financial risk. Business risk is generally defined as the uncertainty associated with a firm's future earnings. Some of the general factors that impact a utility's business risk are the market and service territory economy, competitive position, the fuel and power supply situation, power plant operations, asset concentration, regulation, and management-related issues. Numerous challenges exist which now threaten to increase business risks in the electric industry overall: downward pressure on electricity prices, low demand growth, decreasing margins, downward pressure on the average credit rating of utility bonds, slow reaction to change by regulators, industrial customers demanding lower prices and more specialized services, environmental cost pressures, nuclear operating costs and decommissioning challenges, and increased exposure to stranded costs.

The other component of a company's risk, financial risk, is the portion of total risk beyond basic business risk. Financial risk results from the use of financial leverage (i.e., the issuance of debt and/or preferred stock). Financial theory holds that prudent management should lower financial risk to offset high business risk; a means of lowering financial risk is to reduce the use of leverage. Thus, in an increasingly competitive environment with rising business risk, a utility should reassess the levels of debt and equity in its capital structure.

Credit rating agencies may apply different financial ratio guidelines to electric utilities now and in the future to reflect the changing risk profiles of electric utilities. Standard & Poor's, for example, revised its financial ratio guidelines in 1993 due to a belief that more stringent financial risk standards were needed to counter mounting business risk. This change in the financial ratio guidelines resulted in a number of utilities being placed on CreditWatch with negative implications. S&P notes that a utility with a stronger competitive position, more favorable business prospects, and more predictable cash flows can handle greater financial risk while maintaining the same credit rating. Both S&P and Moody's Investors Services are anticipating erosion in the average electric utility bond rating. S&P expects that over time the average utility will have a 'BBB+' rating, down from the current 'A-'. However, S&P notes that as the industry splits into generation and transmission companies, the transmission entities may warrant 'AA' ratings due to the lack of competition in that area. Moody's expects changes in the industry to drive its average rating for electric companies down from the current 'A3' to 'Baa1' over the next two to three years.

Most likely bond investors will require higher interest rates to reflect higher risk. Also, rating agencies will be likely to continue raising their standards for a utility to maintain its bond rating. An increase in interest rates will have a significant impact on the electric industry due to its capital intensive nature.

Equity investors (i.e., electric utility stockholders) are in a slightly different position than bondholders. Steven M. Fetter of Fitch Investors Service has noted that, "*For the near term, the equity holder stands to be at greater risk than the bondholder. Recent dividend cuts, price declines in the overall utility equity market, and incentive based mechanisms that require company efficiency gains merely to maintain the status quo all stand to have a negative impact on utility shareholders*." Shareholders will have to decide whether to continue their investment in a perhaps riskier company than what they originally invested in or whether to shift to another investment.

Rural electric cooperatives are also affected by the changing electric utility industry. Both electric generation and transmission cooperatives ("G&Ts") and distribution cooperatives face increasing business risk. However, unlike investor-owned utilities, the G&Ts will be shielded in the near term from competition in the wholesale market because EPAct protects the long-term all-requirements contracts they have with their distribution cooperative members. The distribution cooperatives are also expected to be somewhat shielded from the effects of competition (specifically, initial retail wheeling initiatives) because the majority of their customers are residential -- the last class of customers expected to have access to competitive prices. As a result, both G&Ts and distribution cooperatives may have more time than investor-owned utilities to prepare for competition. Challenges or risks for G&Ts include generally higher rates than investor-owned utilities, transmission constraints, lower equity ratios and capacity planning problems. Another challenge is the reduced availability of guaranteed loans from the Rural Utilities Service. This may force more G&Ts and distribution cooperatives to turn to alternative lenders and/or the capital markets.

In general, cooperatives will be pressured to cut costs and improve financial profiles. Moody's Investors Service expects that, like the investor-owned utilities, the average credit quality of cooperatives that issue public debt will decline. However, the rating agency anticipates that the ratings of the stronger G&Ts will remain stable or improve as a result of their size, sophistication, and competitive advantages.

The cost of capital will rise for independent power producers. Currently NUGs contract with a utility for the sale of the power from its facility. The contract price includes payment for both the capacity that is available and the energy received. In a competitive, retail wheeling environment, purchasers may be reluctant to sign long-term contracts with NUGs. New capacity may be constructed as merchant plants, offering power for sale in the spot market. The NUG, no longer able to use a contract from a utility to secure favorable financing terms, may be faced with a higher cost of capital based largely on projections of the cost of power that will be produced from the merchant plant relative to projections of the market price of power during its life span.

Clearly, an increase in the overall risk profile of the electric industry will drive up the cost of both debt and equity capital. Therefore, in a competitive electricity market, the incremental cost of raising capital will rise, thus raising the cost of adding new generation. These increased costs must be factored into projections of the future cost of power, but most analyses do not mention this factor.

H. Incentive Regulation

Many advocates of a competitive market model have highlighted the drawbacks of traditional rate base/rate-of-return regulation. Two particular drawbacks are the lack of incentives for utilities to control operating costs and the incentive for utilities to make investments which can be added to rate base and used to justify increased rates. In order to overcome the poor incentives provided by traditional rate-of-return regulation, many state utility commissions are moving toward incentive ratemaking plans. In a response to a data request sent in this proceeding, Virginia Power stated, "*Alternative plans such as these could provide needed stability during a period of transition to increased competition, and also provide utilities with an opportunity to capture the benefits of their restructuring efforts and to utilize these benefits in a manner that will be in the best interest of all stakeholders.*"

The various forms of incentive ratemaking include price caps, revenue caps, rate of return bands with sharing mechanisms, targeted incentives or a combination of two or more of these forms. In this section of the report, we discuss the various types of incentive ratemaking mechanisms and the pros and cons of each from a general, theoretical and regulatory view. From this analysis we present guidelines which the Commission may wish to follow in either promulgating an alternative form of regulation or for evaluating a plan proposed by an electric utility. Additionally, we review the applicability of current regulatory accounting practices under a more competitive electricity market and/or regulation under an incentive ratemaking plan.

Theoretical and Institutional Justifications

In recent years, incentive regulation has been touted as both an improvement over conventional rate-of-return regulation and as a means of providing a transition to a competitive regime for electric utilities. A great deal of the impetus away from rate-of-return regulation arises from economic distortions and institutional difficulties that arise from traditional regulation.

The most fundamental distortion comes from the fact that traditional regulation, with rates based on average costs, leads to prices that do not properly track changes in short-run supply and demand conditions. Other distortions have also been shown over the past thirty-five years or so. Two of the more well known are the so-called Averch-Johnson effect, whereby regulated firms overinvest, and what economists term Xinefficiency, the tendency not to minimize production costs.

The Averch-Johnson effect arises from the existence of incompletely exploited monopoly power (due to regulation) and an allowed rate-of-return in excess of the marginal cost of capital. These conditions can lead companies to pad their rate base by adopting excessive levels of capital investment or take on additional business at unremunerative rates. A fair amount of conflicting opinion exists over the presence and/or implications of the Averch-Johnson effect, although a great deal of research has investigated the tendency of a regulated firm to waste capital. That work, as well as the empirical research that has been done is conflicting. Questions even have arisen as to whether, on balance, the Averch-Johnson effect is harmful or beneficial. Still, the theoretical implications are clear and many regulators and analysts assumed the effect was present before competitive pressures entered the industry.

X-inefficiency, or the lack of incentives to minimize production costs, is probably the more obvious distortion of rate-of-return regulation. Recent cost-cutting efforts by utilities seem to imply that inefficiencies were widespread. The presence of X-inefficiency implies that the regulated firm does not have the same incentive to reduce costs as an unregulated firm due to its ability to pass through to ratepayers its costs. The reduced incentives extend to lower levels of technological innovation and less motivation to respond to consumer preferences. Moreover, there may be an incentive to increase expenses to mask an overearnings position.

Another distortion, with varied effects, is an actual or perceived asymmetry of risk relating to utility investments. Arguments relating to this asymmetry point out that when regulators pass ex-post judgments on utility investments, the ultimate effect is that the regulated firm can do no better than earn its allowed rate of return or less. At other times risks and losses from poor investments may be transferred to ratepayers while profits continue to flow to the regulated firm. This form of asymmetric risk reinforces a lack of incentive to minimize costs.

There are other inefficiencies and costs that are related to the regulatory process itself. At the simplest level, the regulatory process with its hearings, appeals, prudence reviews, and oversight of regulated firms imposes a significant cost upon utilities, regulators, and intervenors. Regulated firms always have more and better information about their operations than regulators, and regulators, with this disadvantage, have difficulty distinguishing efficient from inefficient behavior. Thus, rate-of-return regulation, combined with the disadvantages faced by regulators in ensuring efficient behavior, can lead to something approaching a cost plus contract ensuring the presence of the X-inefficiencies described above.

Basic Nature of Incentive Regulation

Incentive regulation is based on some measure of performance by the regulated firm, and may range from modifications of traditional rate-of-return regulation to substantially different alternatives, such as price regulation. Two very distinct aims underlie the arguments for its implementation. First, incentive regulation is seen as a means to reduce the disincentives to innovate and minimize costs that exist under traditional rate-of-return regulation. Second, the belief is that this form of regulation is better suited to a partially competitive market structure.

Implicit in the belief that this method of regulation improves upon traditional regulation is the idea that regulators cannot directly lead regulated firms to make efficient investment and operating decisions. Explicitly, the idea is to provide regulated firms with more general financial incentives as are found in non-regulated competitive markets. Many proponents also view incentive regulation as a simpler, less costly, regime that allows regulators to be more passive and allows them to guide regulated firms to efficient results. This last proposition is questionable; yet, it is offered widely as an additional advantage over rate-of-return regulation.

Incentive regulation is not a new concept. In the electric industry, examples of incentive regulation have been tried occasionally since the 1920s, with at least one form (sliding scale) employed in England in the middle of the last century. Recent years have seen increased interest in such plans, particularly with the increasing emphasis on competition.

On its broadest level, performance-based regulation represents a shift in regulatory emphasis from equity for consumers to economic efficiency. There is a trade-off between efficiency and fairness, and a commission must be aware of this trade-off when considering regulatory regimes that promote economic efficiency.

Traditional rate-of-return regulation has not been overly concerned with economic efficiency (which implies efficient resource allocation among other desirable properties) in regulated industries. Traditional regulation has been more concerned with equity, that is, controlling the monopoly power that utilities could exert over consumers. Thus, from an economic perspective, the rates under rate-of-return regulation are administered prices that are based on a firm's accounting costs plus an allowed return on investment. These rates, or prices, bear little or no relation to economically efficient prices.

Comprehensive performance-based regulation represents an attempt by regulators to provide a framework where competitive market conditions will develop or be allowed to operate; thus the primary purpose of incentive regulation is to seek alternatives to traditional rate-of-return regulation in order to induce utilities to become more efficient. This means that utilities must be given incentives to produce at minimum cost and to employ efficient pricing schemes. In theory, this implies that a utility must operate at the lowest possible cost it can achieve, that is, its true marginal cost. In practice, the utility must be induced to achieve lower costs in administrative practices and production costs while at the same time choosing efficient pricing policies. The numerous alternative regulatory models described below have been devised in an attempt to achieve these objectives.

Incentive ratemaking plans can be characterized into three major classifications: comprehensive incentives, targeted incentives, and hybrid or mixed approaches. Although the current interest focuses on comprehensive plans, incentive regimes which are put into practice are likely to be in the hybrid category. Several types of incentive regulation plans including price caps, revenue caps and sliding scales are discussed below.

Price Caps

Under a price cap incentive mechanism, prices for the monopoly services provided by a utility are set for an extended period of time without reference to the utilities costs other than at the beginning of the period. Under a price cap incentive mechanism, a utility's prices for its monopoly services are set initially through some procedure, such as a rate hearing, and then maintained for an extended period. Mechanisms can be implemented that adjust rates over specified periods to reflect changes in productivity, inflation, and unforeseen occurrences.

In the most general case, price caps for a monopoly service(s) are determined by an index of the form:

$P_t = P_{t-1} (1 + I - X) Z$

where: P_t = utility prices for a service(s) in time t

I = percent change in inflation or utility costs, etc.

X = productivity offset

Z = adjustment for unforeseen events beyond management's control

This formula is often referred to as a CPI-X formula and has been widely applied in telecommunications incentive regulation.

The price caps constitute an upper bound on prices; however, a utility can set prices lower than the caps at the firm's discretion. In practice, changes to the price ceiling can be made at specified intervals. The adjustment mechanism is accomplished by the variables I, X, and Z. Inflation in the utility's costs is measured by the I variable which may be based upon any one of a number of indices. Many current recommendations specify the gross domestic product implicit price deflator as a suitable index, but other indices of utility cost may be used or constructed. The consumer price index has been used, particularly in telephone incentive ratemaking plans.

Utility cost inflation is reduced by the productivity offset X. The value of this variable may be determined in many ways (government statistics are one example), although it can be a difficult number to measure accurately.

The Z factor is meant to capture changes not directly resulting from the control of a utility's management, such as changes in the taxation of the industry.

Once the plan is in effect, prices will be modified by the above formula for a specified period. Usually this period is four or five years in length. After that time, the plan can be recalibrated or "trued-up" and then implemented again. During the period between true-ups, ratepayers can be protected by a sharing mechanism where once a utility's profits exceed or fall below pre-determined rates of return, the gain or loss is shared at pre-agreed upon proportions.

Price cap plans are often extolled for their simplicity, but this may be an overstatement. It may be safer to say that the information requirements to implement such a plan may be less than for typical rate-of-return regulation, but they are not minimal. In particular, the information required to construct reasonable indices necessary for a properly designed price cap plan can be substantial, and in truth, may not be available to an acceptable degree. This last point leads to an important caveat in regard to capping mechanisms. It cannot be assured (and indeed, there may be no reason to believe) that simple price cap equations will provide accurate predictions of a utility's minimum future costs.

Price caps, however, can alter a utility's incentives compared to rate of return regulation. They can help eliminate the Averch-Johnson effect and X-inefficiency that may occur under rate-of-return regulation. For example, a bias toward building capacity rather than purchasing power can be eliminated. Price caps also provide incentives towards welfare maximizing pricing, but they should not necessarily be viewed uncritically as the answer to the perceived problems with rate-of-return regulation.

Price caps have also been criticized, perhaps unjustly, for discouraging energy efficiency by utilities. This criticism arises because under this type of capping mechanism, a utility will have an incentive to increase its sales up to the point where marginal revenues equal marginal costs. For this reason, environmental advocates tend to favor revenue caps over price caps, because capping revenues limits the extent to which utilities have the incentive to increase sales. This criticism may be undeserved and indeed has been attacked. Price caps may not encourage the "wasting" of energy; they could very well encourage energy use according to market forces resulting from more accurate price signals.

Revenue Caps

Revenue caps are similar to price caps, but in this case regulators set a maximum amount of revenues that a utility is allowed to earn. There is also a variation of this mechanism in which revenues-per-customer are the object of the regulatory cap. A special type of revenue cap, referred to as earnings revenue adjustment mechanism or revenue decoupling, has been experimented with in several states.

The most general form of a revenue cap mechanism is expressed as:

Rt = (Rt-1 + CGA Cust) (1 + I - X) Z

where: Rt = authorized revenues in time t

CGA = customer growth adjustment factor ($/cust)

Cust = annual change in the number of customers

I = percent change in inflation or utility costs, etc.

X = productivity offset

Z = adjustments for unforeseen events beyond management's control

As with the price cap, the revenue cap is subject to an inflation index that is beyond the utility's control, as well as a productivity index and a Z factor. As with the price cap mechanism, this mechanism would be in force for a pre-determined length of time, and an earnings share mechanism is usually attached for earnings above or below specified levels.

The fixed term and pre-set revenue formula provides the utility with certainty as to its share of productivity improvements and thus, leads the utility to a more economically efficient level of operation than it might choose otherwise. Thus, under this mechanism, a utility is permitted to maximize its profit margin below the revenue cap, but this maximization will be accomplished largely by minimizing total costs.

The information necessary to implement a revenue cap mechanism is similar to that required for a price cap plan. In particular, information is needed on the utilities own costs and for reasonable construction of the indices used.

Environmentalists tend to favor the revenue caps, because of the strong incentive under the mechanism to minimize costs rather than increase sales as a price cap may do. Yet, while this seems plausible, revenue caps have many undesirable properties with respect to the incentives they offer to utilities, in particular the incentive to charge monopoly prices.

Sliding Scales (or Rate-of-Return Band-widths)

Sliding scales or rate-of-return band-width regulation is one of the oldest forms of regulation and has been used at varying times in the United States since the 1920s. Under this form of regulation, a utility's rates are set according to conventional cost-of-service principles, but the utility's return on equity is allowed to fluctuate within a range (or band) of its authorized return. When a utility's earned return exceeds (or falls below) the established band, its rates are adjusted to lower (or raise) the utility's return on equity within the band. This mechanism also allows for a sharing mechanism to be incorporated to protect both ratepayers and the utility. Thus, the plan allows both utilities and their customers to benefit from more efficient operation by the firm.

In its simplest form, a sliding scale mechanism can be expressed as:

rt = rt-1 - (rt-1 - r*)

where: = sharing parameter (between 0 and 1)

r* = allowed return on equity

rt = utility return on equity in period t

When a utility's earned return falls within the established band, will be set at zero and no sharing takes place.

Implementation of a sliding scale plan requires a commission to select the sharing constant, , in addition to setting prices and the target rates of return. This is an important and not necessarily simple consideration, because the level of incentives the plan offers depends upon the value of , the proper value of which, in turn, depends upon economic and technological considerations.

Sliding scale plans have the advantage of being easy to understand, while at the same time requiring no information on productivity or input costs. These plans also use traditional utility accounting and rate-making principles and provide explicit incentives for cost minimization.

A disadvantage of sliding scale plans is that they emphasize minimization of accounting costs rather than economic costs. The plans also result in prices that are not flexible enough in the face of changing conditions. Sliding scale plans are most visible in recent years as supplemental mechanisms to price or revenue cap plans, although Alabama Power has been regulated under this type of plan since 1982.

Targeted Incentives

A more common type of performance-based regulation, at least over the past fifteen years or so, has been that of targeted incentives. These incentives are aimed at a specific aspect of a utility's operation in order to promote better performance within that particular aspect. Many areas of a utility's operation may be targeted for these types of incentives; historically, however, most of these incentives have targeted generating unit performance.

Targeted incentives consist of three components:

1. the specific program target

2. standard of performance measurement

3. rewards and penalties

The reward can be defined in terms of dollar amounts of higher (or lower) revenues or as basis points of a utility's return on equity.

A major disadvantage of targeted incentives is that rewarding performance in specific areas of operation may not be the most efficient set of incentives. Targeted incentives, however, are finding acceptance when used in conjunction with price or revenue caps to protect particular areas of a utility's operation such as quality.

Mixed Regulatory Approaches

Mixed regulatory approaches represent some combination of components from traditional cost-of-service regulation and the four types of performance-based regulation discussed above. Practically, any performance-based plan will be, in fact, a mixed approach. The aforementioned rate-of-return band-width regulation of Alabama Power is one example.

A common plan of this type combines a capping mechanism with a rate-of-return band-width to allow for sharing gains and losses between shareholders and ratepayers of a utility. In addition, targeted incentives are often included for reasons such as protection of service quality. Even elements of cost-of-service regulation are included implicitly through provisions such as the Z factor to adjust price and revenue indexes.

The exact formulation of a mixed regulatory approach will necessarily depend upon myriad factors ranging from political and policy considerations along jurisdictional lines to economic and technological factors specific to a given utility or group of utilities.

Possible Benefits of Incentive Regulation Over Rate-of-Return Regulation

Incentive regulation attempts to address the inadequacies of rate-of-return regulation, particularly in the case of emerging competition within some of the markets of a given utility. At least in theory, incentive regulation possesses many desirable properties. These proposed benefits may be grouped into three broad categories: (1) economic efficiency gains; (2) benefits when a utility has both competitive and monopoly markets; and (3) regulatory benefits.

Economic efficiency gains through incentive regulation may be those of both resource and allocation. Resource efficiency is simply the efficiency in investment and operating decisions that minimize costs. Incentive regulation, by allowing the utility to keep a greater share of any cost savings, can promote these gains to a greater extent than is possible under rate-of-return regulation. Allocative efficiency, one of the basic properties of competitive markets, may be improved (assuming safeguards against excess profits are in place) as pricing flexibility can lead to prices which more closely reflect the marginal costs of the utility.

Incentive regulation is particularly compelling in cases where a utility is faced with both competitive and monopolistic markets. For example, proponents argue that a properly designed price-cap plan can provide ample protection from price increases to captive customers while making it possible to grant more flexibility to utilities to sell and market their services than can standard rate-of-return regulation.

It also may avoid the complexities created when utilities offer non-monopoly service, because a comprehensive incentive regulation plan reduces the need to examine the allocation of utility common cost to a new service. The allocation of common costs to monopoly service is implicitly set by the performance-based regulating mechanism. Thus, captive customers can be protected from new utility ventures, while at the same time shareholders see reduced regulatory risk from having profits "expropriated" by regulators. For these reasons, incentive regulation is seen as a good transition model to fully competitive markets. However, the allocation of common cost remains important from the perspective of avoiding unfair competition.

In theory, costs for commissions and intervenors as well as utilities could be less under incentive regulation. While the cost of an initial rate hearing is substantial, subsequent costs could very well be less. Incentive regulation lends itself to a lighter regulatory burden because the comprehensive plans implicitly acknowledge the information asymmetry between regulated firms and the regulators. Therefore, regulators do not necessarily need to expend considerable effort and expense to bridge this information gap. Many regulators and industry representatives thus admire this simplicity, at least on paper, of comprehensive incentive regulation.

Possible Drawbacks to Performance-Based Regulation

While often supported for its apparent simplicity and efficiency advantages over rate-of-return regulation, many questions remain as to the benefits of performance-based regulation. These questions range from theoretical or technical issues to those of a practical and/or political nature. An adequate assessment must take place at various levels with the relevant question always being: Do both the policy and economic benefits of performance-based regulation justify its implementation? It is difficult to give a definite answer to that question. It depends on the particular characteristics within a jurisdiction and the utilities located there, on the construction of the model being proposed, and on the policy choices that a regulatory body wishes to pursue. The underlying assumption under an incentive ratemaking plan is that suitably competitive conditions exist or, where it does not exist, that utilities and their consumers will benefit from performance-based regulation. Perfectly competitive markets, by the economic definition, do not exist and are a standard by which to measure market organization rather than a condition which can be met in practice. Therefore, one cannot assume that where some level of competition is feasible that a "competitive" market which improves upon rate-of-return regulation will result.

Distilling these comments, it can be asserted that in markets with suitable competition, performance-based regulation (e.g., price caps) can lead to lower prices; however, when a regulated firm under a price cap faces no real threat of competition from other firms it is unlikely that it will lower its prices below the maximum level set by regulators. In this instance, rate-of-return regulation can provide protection to consumers as well as performance-based regulation.

Similarly, the inefficiencies resulting from traditional regulation most likely are not the same across jurisdictions and, in many cases may not be large. It may not be true for a given utility that there are a great amount of inefficiencies that can be improved upon. It is entirely possible that the level of cost savings to be achieved in any one instance is small enough that the expense and potential risks of instituting a performance-based regulation plan is unjustified.

Claims that performance-based plans are simple to administer are highly doubtful. These plans can introduce substantial complexity into the regulatory process in several major respects. For example, it may be necessary to institute multiple incentive mechanisms covering one or more portions of a utility's operation (e.g., separating generation from transmission and distribution). This will entail devising suitable plans for each part of the business. These multiple incentives could possibly alter a utility's incentives and lead to a less than optimal result.

Another complication arises from the necessity to determine which of a utility's markets are competitive. These judgments in themselves are complex, and there is a temptation to make simple determinations which are wholly inappropriate for the goals of the plans. Nor are performance-based plans necessarily "general" plans. Each utility may need its own plan design, and these designs may be appropriate only for specific conditions and trends, such as those for input prices and technology. Regulators will need to monitor these trends and alter the plans if they are no longer appropriate.

Indeed, even more basic than the issue of how long a plan may reflect reality is whether the plan as originally constructed is an adequate representation of conditions faced by a utility and its customers. A key illustration of this point is the consideration of the specific indices used as part of the formulas which will be used to adjust rates. A price index to adjust a utility's rates should reflect the firm's costs as closely as possible.

The potential problem with any price index is twofold. The greatest danger is that of using an inappropriate index for a particular measure. There are also certain mathematical properties of indices which may distort the measurements. The example of the Consumer Price Index ("CPI") can serve to illustrate both problems. On the one hand, the CPI is a wholly inappropriate index upon which to base future price increases in electricity, because the CPI is influenced by the prices of items such as food and medical care. There is also the problem of bias in the index. Economists generally agree that the CPI overstates inflation by .5% to 1.5%. Another price index frequently used is the Gross Domestic Product, but this is still a far from perfect measure. In fact, a general, widely accepted index that does closely correlate to a utility's cost does not exist, although specific indices could be constructed for each company.

Similar difficulties exist in deciding upon the measurement of the X factor, or productivity. A measure of productivity can be constructed in various manners, but the relevance of any particular measure to a given utility is an open question. At best, many productivity estimates are just that -- estimates. At worst, they may be simply arbitrary.

In deciding upon either inflation or productivity measures, many of the issues raised here may seem small or inconsequential; however, the inflation and productivity measures in a given plan are in large part responsible for the path of electricity prices over time, and if electricity prices do not correspond to a utility's actual costs, a basic assumption behind performance-based plans is violated.

Determining a utility's actual costs is but one of the major components of a performance-based regulation plan. One of the major goals of a performance-based regulation plan is to induce a utility to operate at a lower level of costs and increase its efficiency of operation. This goal leads directly to the issue of appropriate incentives for the utility, as well as safeguards to ensure that a utility does not lower its costs by reducing quality and reliability.

Any comprehensive performance-based regulation plan will need a quality control mechanism to deter a utility from realizing cost savings through lower quality of service rather than more efficient operation; however, designing such a mechanism is not a simple task. The difficulties come not so much in choosing the variables to measure, but rather that the level of service quality, as a function of prices and quality, is a "moving target."

It also should not be assumed that current levels of service are appropriate. These levels may be too high, given the incentive under rate-of-return regulation to pad costs; although lower target levels of service may provoke criticism by customers. There are other considerations in designing quality mechanisms, but the points mentioned above serve to illustrate that the design of a performance-based plan is not simple.

The sharing mechanisms are components of performance-based regulation plans which simply distribute the efficiency gains under performance-based regulation plans among shareholders and consumers. Although plan design is flexible, the basic idea is to define a target return on equity, sometimes referred to as the "deadband," with the sharing mechanism designed around the target. Careful design of this mechanism is important to provide the proper incentives to stimulate a utility to efficient production while at the same time allowing consumers to share in the gains. It should be noted that sharing mechanisms, in fact, reduce the effectiveness of a performance-based plan. The most effective stimulus to utility improvements would be to let the utility keep 100% of any savings, but this is rarely a practical option. The specification of this formula is important, because an improper design can lead to strategic behavior on the part of utilities.

There are similarities in the regulatory implications of performance-based regulation and rate-of-return regulation that often are not stated explicitly. These similarities should temper overly enthusiastic assessments of performance-based regulation as a definite improvement over rate-of-return regulation.

Determining the baseline revenue requirement under performance-based regulation is the same as under rate-of-return regulation. Utilities still have an incentive to hide their actual costs and indeed the process of setting base revenues is likely to be more contentious and exhibit more strategic behavior on the part of both utilities and interested parties than a normal rate case under rate-of-return regulation. Moreover, there is ample enough room for error that a comprehensive performance-based regulation could build inefficiencies and distortions into rates for an extended period of time.

In terms of regulatory costs, a major benefit of performance-based regulation is derived from the reduced number of rate cases arising from this form of regulation. It is also likely, judging from experiences to date, that any reduced administrative costs from fewer rate cases will be at least partially offset by increased monitoring and evaluation costs. Therefore, if the regulatory goal is to reduce the direct costs of regulation, regulators are likely to be disappointed. This leads to one of the major criticisms of performance-based regulation; namely, that it is just a more complex method of doing what regulatory commissions have been doing for years, setting rates and leaving them fixed for an extended period of time.

There are also likely to be political costs attendant upon a comprehensive performance-based regulation plan. Several reasons make this so. Even though its limitations are well known among regulators and utility managers, the basic concept of rate-of-return regulation is understandable and accepted to a reasonable degree by most consumers. The decoupling of costs and earnings may not be as readily understood and accepted by ratepayers, particularly when the more esoteric benefits (e.g., efficient resource allocation, etc.) are considered.

If a utility's rate of return rises to higher than expected levels the public outcry may force regulators to intervene to adjust rates downward. Similarly, low rates of return may force upward adjustments. In either case consumers may lose confidence in regulators, and rate cases may be more frequent than regulators assume.

Finally, comprehensive performance-based regulation plans do not readily lend themselves to social goals such as demand side management programs.

Practical Applications for Virginia

The Virginia Commission has used incentive regulation in the past. As described in Chapter 3, beginning in the early 1980s the Commission tied the allowed return on equity within an established range to an electric utility's generating unit performance. The better a utility's generating units performed the higher the allowed return on equity. Conversely, the worse a utility's generators performed, the lower the allowed return. This is considered a targeted incentive mechanism. In this case, the Commission was trying to provide an incentive for utilities to operate their generating units efficiently. The Commission has also used forms of price caps and earnings bands to set and evaluate rates for local telephone companies.

As noted earlier, there are two primary reasons why the Commission may choose to adopt an incentive ratemaking plan in place of traditional rate-of-return regulation. First, the Commission may believe that traditional ratemaking has provided poor incentives to electric utilities to operate efficiently and that a performance-based ratemaking plan will provide better incentives. Second, the Commission may believe that an incentive plan provides for a better transition to a competitive electricity market than traditional rate-of-return regulation.

In regard to the first point, based on the recent reengineering and restructuring efforts by electric utilities in Virginia in the face of the threat of competition, it is clear that traditional rate-of-return regulation has not provided as effective cost-cutting incentives as the threat of competition. The question then is, will performance-based ratemaking provide better incentives to be efficient? These reengineering efforts should result in lower costs in the future. If the Commission were to take the approach that all of these savings should go to ratepayers, then there is no incentive to cut costs in the future. Therefore, we believe that an incentive ratemaking plan, properly designed and implemented, should benefit all stakeholders.

The second reason the Commission may choose to implement an incentive ratemaking plan is because of the belief that it will provide a better ratemaking model during the transition to a more competitive industry. There is no doubt that the electricity industry is becoming more competitive, at least on the wholesale level. In addition, some electric utilities have recently begun to expand into unregulated businesses which may provide services to regulated customers. We expect such activity to intensify in the future. Under traditional rate-of-return regulation, the appropriate ratemaking for the unregulated ventures will be very complex and, no doubt, contentious. Under a properly designed and implemented incentive ratemaking plan these issues may become less complex and contentious.

Another advantage an incentive ratemaking plan may offer over traditional ratemaking is pricing flexibility for electric utilities. The prices established under a price-cap plan are just that -- caps or upper limits on prices -- which means utilities are able to charge rates below the capped price. During the 1996 session of the General Assembly, legislation was passed to allow the Commission to approve, outside of the context of a rate case, special rates or incentives to individual customers or classes of customers provided no one else's rates go up as a result of the special rates. Under an incentive ratemaking plan, utilities could have more flexibility to offer the special rates contemplated in the new legislation. The Commission could also build in safeguards, such as price caps, to ensure that other consumers' rates do not rise.

A properly designed and implemented incentive ratemaking plan can provide a utility better incentives to operate efficiently and may also provide a better transition ratemaking model. It appears the most reasonable type of performance-based plan for an electric utility is a price cap plan with an earnings band. A price cap plan would offer the most pricing flexibility for the utility while protecting captive customers. This is not necessarily the case under a revenue cap plan. Revenue caps provide the incentive for a utility to charge monopoly prices. The attempt may be to lower the demand for electricity, which coupled with the higher prices serves to keep the utility under the revenue cap. Moreover under a utility-wide revenue cap, the utility may be able to reduce revenues from one source (e.g., an economic development rate) and offset the decrease in revenues with an increase from another source.

A price-cap plan should offer the incentive for a utility to cut costs in order to increase its profitability. The utility would have the greatest incentive to cut costs if it were allowed to keep all cost savings. This would essentially lift the restriction on the level of earnings for a utility. However, under this sort of sharing plan, ratepayers would derive no benefit. Therefore, if the Commission determines that a new regulatory approach is warranted, we would suggest consideration of a rate-of-return, earnings-band mechanism whereby ratepayers would share in the cost savings achieved. In order to provide a greater incentive to cut costs, the sharing mechanism should be progressive, meaning the more cost savings achieved, the greater the percentage of savings that the utility retains.

It would be advisable for a utility to use a portion of its share of the cost savings achieved under this sort of plan to write off regulatory assets which have been created by past regulatory accounting practices. Once all regulatory assets have been written off, it should be up to the utility to decide where its share of the savings are allocated. In a response to a Staff data request, Virginia Power proposed using the excess profits to write down strandable assets. In the section on stranded costs within this report it was explained that the level of stranded costs will be hard to determine and should be done on a case-by-case basis. Therefore, to the extent a utility believes it has strandable costs, that utility should use, at least in part, its share of the cost savings achieved under a price cap plan to write down these costs. In this manner, a price cap form of regulation can be used to transition a utility into a more competitive environment.

With a greater incentive to cut costs in order to increase profitability, a concern is that quality of service may decline. Service quality standards may need to be established. If the utility's service quality drops to an unacceptable level, then the Commission could impose significant penalties against the utility. It is important to establish the service standards and penalties prior to entering into a plan.

Most price-cap plans have at least one automatic adjustment mechanism built in to increase prices. These types of adjustments can present problems since they raise prices automatically when rates may already be high enough to generate earnings in excess of a utility's cost of capital. Moreover, there are no indices available which fairly represent the growth over time of the costs of an electric utility. Therefore, any automatic increase intended to mirror an increase in an electric utility's costs is arbitrary at best. Until competition has adequately developed to protect consumers, we suggest that if a utility finds that its rates under the price cap plan are inadequate to earn its cost of capital, then that utility should be required to file for approval to increase its rates.

One of the more contentious aspects of an incentive ratemaking plan is the initial setting of rates or the establishment of the price caps. There are numerous ways that rates could be established before entering into a plan. The Commission could simply conclude that current rates are adequate and use the current rate as the cap. As an alternative the Commission could require that all electric utilities, before entering into a plan, reduce rates by a set percentage. A third alternative would be for the Commission to require a traditional rate case be performed in which rates are formally established. Finally, the Commission could use the Statistical Benchmark Modeling approach. Under this approach, a regression model is developed using a group of utilities' costs in order to establish future costs of the Virginia utility entering into the plan.

In order to determine the baseline prices of Virginia utilities before entering into a price cap plan, we recommend that all electric utilities be required to undergo a traditional rate case. Utilities under a price cap plan should be required to annually file Virginia jurisdictional rate-of-return statements for purposes of reviewing earned returns on equity during the reporting periods. Only limited adjustments to per book results should be made to recognize differences between Generally Accepted Accounting Principles and regulatory accounting treatment. Additionally, the Commission may wish to remove from this monitoring process any services which become fully competitive or deregulated.

There are several ratemaking adjustments such as automatic-adjustment clauses, deferred-accounting mechanisms and regulatory assets, which are logical methods for dealing with certain issues under traditional rate-of-return regulation. However, under an incentive-ratemaking plan, the use of these accounting mechanisms must be reconsidered. An automatic-adjustment clause is an accounting mechanism which allows dollar-for-dollar recovery of certain expenses. The automatic-adjustment clause tracks certain expenses and automatically adjusts revenues in response to changes in these expenses. The Commission has stated that such an expense must be relatively volatile, a major expense and one which the utility incurs on a continuous basis yet has little or no control over. An example of a true automatic-adjustment clause is the Purchased Gas Adjustment clause which is used by gas utilities to track and adjust gas costs charged to customers on a quarterly basis with no formal Commission review. Any expense over which a utility has control of the initiation, design and application should not be subject to an automatic adjustment clause. Furthermore, allowing the utility to recover certain costs through such a mechanism removes these costs from the more rigid review process incorporated within utility rate proceedings.

The difference between an automatic-adjustment clause and a deferred-accounting mechanism is often blurred. A deferred-accounting mechanism allows the dollar-for-dollar tracking of certain expense items much like an automatic-adjustment clause. However, it is the degree of regulatory oversight that determines whether a deferred-accounting mechanism is an automatic-adjustment clause. An example of a deferred-accounting mechanism is the accounting treatment afforded the capacity payments made by Virginia Power through its NUG contracts. The capacity payments Virginia Power incurs under its purchased power contracts are tracked in an account and compared to a capacity recovery factor previously built into rates. In a future rate proceeding, revenues may be adjusted as a result of the deferral balance.

Other types of deferred-accounting mechanisms are for extraordinary costs that are incurred in a particular accounting period but are not currently recovered through rates. These costs are typically deferred to a later period and amortized for a specified time period. An example of this type of deferral account is when the Commission decides to allow an extraordinarily large amount of storm damages, incurred in one period, to be deferred and amortized over a future period for ratemaking purposes. One concern with a deferred-accounting mechanism is that several years may elapse between the expenditure and the next base rate case.

Once the Commission has deferred an expense for future recovery it is considered a regulatory asset.

Generally speaking, a regulatory asset is an asset that results from rate actions of regulatory agencies which differ from Generally Accepted Accounting Principles. As a regulatory asset, costs would be deferred and then amortized over the period of future benefits. Although this would provide the utility with the opportunity to recover costs, it would not guarantee dollar-for-dollar recovery. Generally, the Commission has excluded regulatory assets from rate base. This treatment prevents the utility from earning a return on the unamortized deferral.

While there are no automatic-adjustment clauses in place for electric utilities, all of the electric utilities have regulatory assets and fuel factor mechanisms. Automatic-adjustment clauses, deferred-accounting mechanisms and regulatory assets may well have been appropriate methods for dealing with certain expenses under traditional ratemaking. Under these accounting methodologies, the assumption is that current ratepayers will also be the future ratepayers who will pay these costs. The move toward a more competitive electric industry seems to undermine this assumption. Therefore, if the Commission determines that a transition to a competitive structure is appropriate, we recommend the end of the use of deferred accounting and regulatory assets for electric utilities. Moreover, once an electric utility is operating under an incentive ratemaking plan, the use of a fuel-factor-adjustment clause should be reexamined. In exchange for the opportunity to earn higher returns, utilities should be required to take on additional risks.

The Financial Accounting Standards Board also appears to require that under an incentive ratemaking plans and with the move towards competition in the electric industry, the continued use of Statement of Financial Accounting Standard ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation*, needs to be reconsidered. SFAS No. 71 is intended to provide guidance in preparing general purpose financial statements for public utilities and other companies with regular operations that meet certain criteria. The criteria summarized from paragraph 5 of that statement include: (1) that rates for regulated services be set by a third party regulator or by the utility's governing body; (2) that rates be designed to recover the cost of providing the regulated services; and (3) that, in light of competition and the demand for the service, the rates charged be such that all costs are reasonably expected to be recovered from customers.

Incentive ratemaking especially can impact the second criterion in evaluating whether or not a utility's rates are set on the costs to provide service. Many incentive ratemaking plans appear to base rates on factors other than the utility's specific costs. However, if these plans are coupled with sharing and other adjustment mechanisms, the lines become blurred. In order to evaluate an incentive ratemaking plan to determine the continued applicability of SFAS No. 71, the following items should be considered.

1. A price cap plan that requires sharing of all earnings variations should be considered cost-based regulation. However, an incentive ratemaking plan that requires sharing if actual earnings vary by a wide range around a utility's authorized earnings may be a departure from cost-based regulation.

1. If initial rates are set based on a utility's cost of service then rates may be considered cost based.

1. If a utility has an opportunity to file for an increase in rates when revenues do not keep up with cost increases or if the regulator is empowered to initiate a rate proceeding against the utility if revenues outpace costs, then rates could be considered cost based.

1. If an incentive ratemaking plan provides for changes in revenues based on changes in costs beyond the utility's control, then rates could still be considered cost based.

1. If an index used to adjust prices is tied to the costs of the specific company, the cost/revenue

relationship is more closely maintained than if a general price index is utilized.

If it is determined that a utility's rates under an incentive ratemaking plan are not cost-based, then it would need to apply SFAS No. 101, *Regulated Enterprises -- Accounting for the Discontinuation of Application of FASB Statement No. 71*. If a utility adopted SFAS No. 101 it would have to immediately write-off all regulatory assets and liabilities that would not have been recognized in an unregulated environment. This could have a significant impact on the financial health of electric utilities in Virginia. Therefore, during the transition to a more competitive electricity industry, any incentive plan developed should have the goal of keeping electric utilities under SFAS No. 71 until regulatory assets are at a manageable level.

Summary

We do not propose a blanket incentive ratemaking plan for all electric utilities in Virginia. Rather, the discussion in this section is intended to provide guidance for the Commission in evaluating incentive ratemaking plans which may be proposed by electric utilities. During the transition to a more competitive electricity market, an incentive-ratemaking plan may provide a better transition ratemaking model. Moreover, an incentive-ratemaking plan should provide better incentives for utilities to continue to cut costs in the future. However, the Commission and the electric utilities should not look at incentive ratemaking as the cure for all ills of traditional regulation. Problems will exist under incentive ratemaking plans. All parties should remember that the success of performance-based ratemaking depends upon its application, design and implementation.

I. Demand Side Management

In Chapter 2, Section B of this report, there is a discussion of the Commission's current policy on the treatment of demand side management ("DSM") activities. Compared to many other states' promotions of DSM, the Commission's encouragement of cost-effective DSM programs has been considered conservative. Before approval, Virginia's utilities have been required to conduct a cost/benefit analysis of any proposed DSM program. A critical component of the benefit side of the equation is an evaluation of the expenses the utility may be able to avoid by promoting conservation or load management. For instance, if, by shifting consumption of electricity from peak to off-peak, a load management program would allow the delay of construction of a generating unit, the capital savings would represent a benefit to the company.

As discussed in this report, the current cost of spot-market energy is very low. In addition, most utilities do not at this time have substantial long-term capacity needs. In other words, the expenses that can be avoided by a utility through the promotion of DSM programs have gone down. That makes a DSM proposal harder to justify using a cost/benefit analysis.

Lower avoided costs not only may preclude a utility from pursuing DSM, but it may also convince a utility to abandon existing DSM activities. Delmarva has recently requested Commission approval to close all of its current DSM programs in Virginia to new customers. In its filing Delmarva specifically cites "*near-zero avoided capacity costs and low avoided energy costs*" that make its current DSM programs less attractive than when originally proposed.

If market forces play an increasing role in the electricity market, real-time prices will send more accurate signals to consumers encouraging energy savings. The existence of a futures market may enable entrepreneurs to market energy-efficiency services in novel ways. Participating customers likely will pay for the energy-efficiency products and services they receive without the benefit of subsidies, relying instead upon savings on energy bills. The new energy-efficiency services may focus not only on saving electricity, but upon improving customer comfort, convenience and productivity. Utilities and other suppliers may use energy services as a marketing tool to attract and retain customers.

There have been predictions that a restructuring of the electric industry will mean the end of DSM. A more likely result will be a change in the method of delivery of DSM services and a revised focus of the intended results. The Commission's policy of promoting cost-effective DSM need not change. It has served the Commonwealth well, prevented uneconomic expenditures that increase electric rates (as has happened in other states) and should remain an effective policy as the industry undergoes restructuring.

J. Long-Range Planning

The function of planning has been more important for the electric industry than perhaps any other industry. The long lead times and high capital costs required for the addition of generating capacity or transmission lines has necessitated an unusually long planning horizon for the industry. Also, the obligation to serve the electric needs of customers within a franchised service territory has caused electric companies to rely upon their forecasts of increased demand for service. These forecasts have generally projected 15 to 20 years into the future. Obviously plans covering such a long time period are subject to change. That is a risk that electric utilities have faced, and unanticipated changes in demand levels have created problems, such as an excess of generating capacity.

As more competitors enter the electric generation market, the close coordination between transmission and generation will continue to be essential. The siting of capacity additions, the transfer capabilities among interconnected systems and the type of capacity needed are elements of the coordinated effort involved in electric utility planning. The planning functions of generation, transmission and distribution are not independent. Virginia Power has stated: "*Continued, and even increased, coordination of all three planning functions is necessary to assure reliable operation of the combined generation and transmission system with minimal environmental change. Anything less than a fully integrated planning process involving these three areas could be detrimental to the electric system*".

It appears that the electric industry of the future may separate the generation and transmission of electricity into separate business units; perhaps there will even be a divestiture of generation. Planning issues regarding generation necessary to the operation of the transmission system (e.g., reactive support and area protection) and transmission conditions affecting generation facilities (e.g., grid connections and interconnection constraints) will remain, but perhaps without a single entity to evaluate, decide and implement solutions. This could cause a less than optimal allocation of generation and transmission resources causing the price of electricity to be higher than necessary.

In other parts of this report we have expressed the concern that an electric industry based upon spot-market prices will not provide adequate signals for the construction of appropriate capacity. In particular, the need for base-load capacity may be neglected because of the large capital expenditures and long lead times involved. Under traditional planning an electric utility would not be reluctant to commit to construction of base-load capacity because of rate base treatment and the regulatory compact. While traditional regulation has been deficient in providing proper cost-cutting signals, it has been effective in assuring that an adequate long-term supply of generating capacity has been available for a utility's customers.

The planning horizon of electric utilities has already shrunk. As just mentioned, traditionally plans and forecasts have covered 15 to 20 years, mainly because of the long lead time needed for base-load plant siting hearings, regulatory approvals and construction. Now utilities understandably are reluctant to commit to expenditures until absolutely necessary. The increase in risk and potential for stranded costs make capacity investment especially for base-load capacity a last resort. This has tended to shorten the planning horizon of utilities.

Perhaps an ISO or some other entity will coordinate regional planning efforts in the future. With the diversity of capacity within a region there may be efficiencies gained from such an effort. At this time, however, there are no blueprints as to how transmission and generation planning will be conducted in a competitive environment, only unanswered questions.

Confidentiality of Data

Investor-owned utilities in Virginia have been required to file Ten Year Forecasts or Twenty Year Resource Plans for many years. Most of the data contained within these plans has been considered public information. As the electric industry has become more competitive, utilities are becoming more reluctant to disclose their plans for the future because potential competitors may be able to use the information to their advantage. Last summer APCO requested that its Twenty Year Resource Plan be treated as confidential. The Company cited an incident in which information from a previous plan had been used by a competitor. In discussions with APCO, it was agreed that its 1995 Plan would not be considered confidential. The Staff did agree, however, to consider the problem before the next Twenty Year Resource Plan was due.

We have noticed that some utilities now file with the Commission a "regulatory" plan that is inconsistent with its internal business plan. Data is filed with the Commission for the purpose of complying with requirements while the company has no intention of following the filed plan. Such a plan is of no use to the Commission and a waste of resources for the company. It is imperative that a utility's regulatory plan and business plan be consistent.

We can understand the reluctance of utilities to divulge their plans when they are operating in an environment that is becoming increasingly competitive. However, as previously discussed, the Commission in a recent hearing to consider planning standards proposed in EPAct, mandated that investor-owned utilities that submitted Twenty Year Resource Plans should have informed discussions with interested parties as a part of the planning process. Such discussions may foster cooperation between the electric utilities and interested parties and give utilities an opportunity to receive possibly valuable suggestions from those with other perspectives. However, since EPAct was issued in 1992, and even since last September's Commission order, competitive activity has increased in the industry. We recommend that the Commission re-evaluate its order for public meetings concerning Twenty Year Resource Plans and consider the appropriate status of information contained in all plans filed by utilities with the Commission. The electric industry is in an unprecedented and unsettling stage of its history. It is imperative that the Commission and its Staff be accurately apprised of the thoughts and plans of Virginia's utilities. Unless certain information is treated as confidential, we may face a continuing conflict.

K. Environmental Impacts

The generation of electricity contributes substantially to air pollution in the U.S. Power plants currently are responsible for over two-thirds of all sulfur dioxide ("SO2") emissions, about one-third of all NOx emissions, and over one-third of the man-made greenhouse gas emissions (e.g., carbon dioxide). While SO2 emissions are capped at a national level which will fall significantly as Title IV of the 1990 Clean Air Act Amendments is fully implemented, future emissions of other air pollutants from the electricity sector are less certain. Much of the uncertainty can be attributed to the implications of increased competition in electricity markets.

The environmental consequences of increased competition in the electric industry depend on how the sellers and buyers of electricity respond to a more open industry structure. For example, emissions may rise in regions where generators have excess capacity which can be sold to previously inaccessible distant markets as a result of open transmission access. At the same time, emissions in the purchasing region could decrease. If competition leads to lower electricity prices, then the overall demand for electricity could rise, resulting in higher emissions. On the other hand, emissions could decrease if competition accelerates investment in low-cost, relatively clean gas combined cycle or combustion turbine units. However, environmentalists and other industry observers generally agree that allowing greater access to the transmission grid is likely to increase generation and, therefore, emissions of NOx and carbon dioxide from existing Midwestern coal-fired generators, especially in the early years of open transmission access and more competitive electricity markets. NOx emissions are a by-product of industrial production and a major contributor to smog. State regulators and some utilities in the Northeast have claimed that increased emissions will hamper efforts to bring air quality in urban areas into compliance with the standards established in the 1990 amendments to the Clean Air Act.

The environmental impacts arising from the restructuring of the electric industry may be broadly classified into two categories. Direct environmental impacts are caused by changes in generation and transmission patterns that may result from greater trading opportunities. Since restructuring does not repeal any existing environmental laws, utilities still must obey all regulations concerning environmental pollution.

The second category of environmental impacts would be those caused by a change in the traditional manner in which regulation has forced electric utilities to operate. As a result of greater freedom and exposure to market forces, electric utilities are likely to abandon some social objectives such as promoting energy conservation or the use of renewable energy.

FERC conducted an assessment of the expected direct environmental impacts of implementing its Order 888. It prepared an Environmental Impact Statement ("EIS") first published in draft form and, after comments, in final form. In its assessment, FERC first examined the effect of its Order 888 upon (1) shifts in generation from existing plants, (2) changes in the future mix of electric generating capacity and (3) increases in inter-regional transmission. The impacts these changes would have on major air emissions were then evaluated at regional and national levels.

FERC's draft EIS showed very little impact from its Order 888 upon the environment. It determined that the relative price of natural gas versus coal had a far greater impact on NOx emissions than the Order. Increases in transmission capacity were determined to have a very small effect on estimated emissions, and in most cases the effect would be beneficial. In the worst possible scenario in the draft EIS, NOx emissions increased by only 2% by 2000 and 3% by 2005.

FERC's draft EIS on its open access role was reviewed by the Environmental Protection Agency ("EPA") and several environmental groups. The EPA concluded that FERC made a reasonable choice of models to conduct its analysis, but did not agree with the scenarios and assumptions used by FERC. As a result, FERC analyzed some additional scenarios, but did not change its conclusions in its final EIS.

Overall, the EPA is concerned that the understanding of the potential impacts of competition on the electric utility industry is limited and subject to uncertainties. It also found that relatively small changes in key assumptions, that are within a reasonable range of each other, can result in large changes in emissions than found in the final EIS. As an example, the EPA notes that the utilization of coal-fired units in the model is highly dependent on the assumptions made regarding unit availability rates and transmission charges. The EPA believes that there are other plausible assumptions that could have been made concerning these variables. Using these other assumptions would have led to much higher NOx emissions.

The EPA referred the FERC's analysis in its final EIS to the Council on Environmental Quality ("CEQ"). On June 18, 1996, the CEQ issued a policy statement agreeing that the FERC Order 888 could lead to increased emissions and outlined a three-pronged strategy proposal to mitigate the potential increases. First, CEQ endorsed EPA's proposal to work closely with state air quality regulators to control NOx emissions. Eventually EPA and the states will be expected to develop an "cap and trade" program for NOx. Second, FERC should play a role in assuring restructuring does not lead to sharply increased pollution by determining what efforts it can take if EPA's actions do not bring about a decrease in NOx emissions. Finally, DOE can assist by establishing a tracking system to monitor air emission changes occurring as a result of increased wholesale activity.

The analysis in the final EIS points out the uncertainties associated with the environmental impacts that may result from the open access order. The direct effects are uncertain given the sensitivity of the analytical results to small changes in main assumptions. The indirect effects are uncertain because they depend upon the future framework in which the restructured industry will operate. That framework will help determine the operating practices followed by the industry and associated environmental impacts.

L. Gross Receipts Tax

In Virginia, all revenues of public service companies are assessed a gross receipts tax ("GRT") except for revenues from interest, dividends and the sale of assets. In order to avoid a double taxation of revenues, public service companies are able to deduct from their taxable revenues the cost of purchased power if the purchase is from another Virginia public service company. Since independent power producers are not considered public service companies for tax purposes, they are not subject to the GRT. Rather, as any other corporation doing business in Virginia, independent power producers are subject to a state income tax.

Wholesale electric transactions are also subject to the GRT if the sale is within Virginia and is made by a Virginia public service company. However, if the sale is outside of Virginia, including sales by a Virginia public service company, the wholesale transaction is not subject to either a GRT or a Virginia state income tax. Therefore, if a Virginia utility is selling power to an out-of-state utility and the transfer point is outside of Virginia, no Virginia taxes are collected. Additionally, a power sale by a non-Virginia utility to a Virginia utility is also exempt from any Virginia tax. However, when the power is resold by the Virginia utility, the revenues derived are subject to a GRT.

From 1990 to 1996 the annual total gross receipts taxes collected from electric utilities has ranged from $80.9-$99.3 million. In 1996, the total collected was $99.3 million based on 1995 revenues. Of that total, about $6.4 million came from the electric cooperatives and $92.9 million came from investor-owned utilities. Virginia Power's 1996 gross receipts tax was $77.4 million. These 1996 totals are net of $13.7 million in Virginia coal tax credits received from buying coal produced in Virginia mines. Currently the Virginia coal tax credit stands at $3.00 per ton of coal. In order to qualify for the credit, the coal must be purchased from Virginia mines, not necessarily burned in Virginia. In fact, Delmarva reduced its Virginia tax burden by over 66% in 1996 by purchasing Virginia coal which was burned in out-of-state plants.

There can be two effects in Virginia related to the gross receipts tax and a competitive electric industry.

First, there may be a reduction in the amount of GRT collected and a corresponding reduction of funds available to the Commonwealth. If retail wheeling is allowed, sales to Virginia customers may come from out-of-state generators. In such a case, Virginia would not collect a gross receipts tax on the generation portion of an electric bill, only upon the wires charge of the distribution company.

In addition, the GRT may have an effect upon competition by providing out-of-state competitors an advantage over Virginia utilities on sales to Virginia customers. The Virginia utility will be assessed a 2% GRT on any in-state sale while the out-of-state competitor pays a Virginia state income tax.