Supply-Demand Forecast For Electric Utilities

2009-2019

Report to the West Virginia Legislature
West Virginia Code §24-1-1(d)(3)

201 Brooks Street
Charleston, WV 25323
1-800-344-5113 General
1-800-642-8544 Complaints
www.psc.state.wv.us

Michael A. Albert, Chairman
Jon W. McKinney, Commissioner
Edward H. Staats, Commissioner

REPORT TO THE WEST VIRGINIA LEGISLATURE

BY

THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

****

SUPPLY - DEMAND FORECAST FOR ELECTRIC UTILITIES

2010-2019

WEST VIRGINIA CODE 24-1-1(d)(3)

JANUARY 2010

TABLE OF CONTENTS

LISTS OF MAPS, TABLES, & CHARTS

I. EXECUTIVE SUMMARY

The Sixty-Fourth Legislature (1979) directed the Public Service Commission to make an annual report to the Legislature on the status of the supply and demand balance for the next ten years for the electric utilities in West Virginia (WVA. Code 24-1-1(d)(3)). Pursuant to this mandate, the Commission Staff conducts a yearly examination of major forecasting methodologies presently in use by each of the major electric utilities in West Virginia.

There are currently thirteen (13) regulated private electric utilities in the state. The four (4) largest collectively account for approximately 96% of total West Virginia residential sales and 98% of total West Virginia commercial and industrial sales. Further, the majority of the remaining ten (10) electric utilities are currently wholesale customers of one of these four largest. These companies purchase power from larger regulated utility generators then *resell* the purchased power, at approved retail rates, to residential and commercial customers in their service territories. Those companies are:

1) Wheeling Power Company (WPCO),
2) Harrison Rural Electrification Association,
3) Elk Power Company,
4) Union Power Company,
5) Black Diamond Power Company,
6) Shenandoah Valley Electric Cooperative,
7) Craig-Botetourt Electric Cooperative,

8) West Virginian Power,

9) New Martinsville Municipal Utilities,

10) Phillipi Municipal Electric.

The net demand of each of these reselling companies is included in this report.

The major electric utilities investigated, for this report, are considered to be the four largest companies in West Virginia which are known as: Appalachian Power Company (APCO), Monongahela Power Company (MPCO), the Potomac Edison Company (PECO), and Wheeling Power Company (WPCO). APCO and WPCO are sister companies of American Electric Power. MPCO and PECO are sister companies of Allegheny Power. Only three of these utilities (APCO, MPCO, and PECO) generate electric power. The rest are solely transmission/distribution or distribution only companies.

In addition to the major utilities' supply and demand forecasts, the Commission Staff also considers the utility forecasts conducted by Reliability First Corporation (RFC). RFC is a member of the North American Electric Reliability Corporation whose mission is "to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada."[1] RFC assesses the "future adequacy" of its region which includes the Pennsylvania, New Jersey, and Maryland Regional Transmission Organization (PJM) of which the Allegheny Power and American Electric Power are members. Please refer to the NERC Regional Reliability Councils map shown on page 16. The role of the PJM organization is to control each of the utilities' generation output such that it meets the current demand of the utilities' residential and commercial customers. PJM has an installed reserve generating capacity margin of approximately 16 percent. This reserve margin ensures that there is a sufficient amount of generating capacity installed, such that if a loss of a generating unit or transmission line occurs then the PJM system will have sufficient power to continue meeting the region's energy needs without interruption.

Data and other information for this forecast are provided by American Electric Power (AEP) and Allegheny Power (AP) to the Commission's Staff for review. The review is two-fold with the first step undertaking a review of the utilities' forecasted ten (10) year load growth and the second step was an examination of the utilities' capacity expansion plans and a computation of generation reserves to determine if adequate reserve installed capacity margins would be available to meet projected loads through the next decade.

The general conclusions of this report are for the forecast period of winter 2009/2010 through the winter of 2018/2019.

1) Overall, the average peak load forecasted for electricity demand in West

[1] See the NERC website at www.nerc.com.

Virginia are expected to average from 1.4% to 2.2% during the forecast period (2010-2019). With regard to electric supply, it is projected that generation capacity will be greater than the anticipated demands throughout the forecast period;

2) Based upon current demand projections and capacity plans, the utilities anticipate that installed capacity will exceed demand in the forecast period:

3) The utilities project that peak electric demand will continue to increase at a modest rate during the forecast period;

4) The average annual growth rate in peak load forecasted by the utilities is:

<u>Utility</u>	
AEP System (East Zone) (AEP-EAST)	1.4%
Appalachian Power - West Virginia (APWV)	1.4%
Allegheny Power (AP)	1.5%
Monongahela Power (MPCO)	1.7%
The Potomac Edison Company (PECO)	2.2%
Wheeling Power (WPCO)	1.5%

5) AEP has developed a generation expansion plan consisting of new generation sources that will be added within this forecast period. Starting in 2010, AEP could add up to 1,898 MW of new generation resources

through the year 2019. AEP's projections indicate that this will maintain a reserve margin that is expected to meet PJM requirements.

6) AP prepared an integrated resource plan for April 2007, which is based on the October 2006 Load Forecast. AP's integrated resource plan for 2007 reflects, for the first time, AP's generation fleet configuration for West Virginia following the implementation of the ownership restructuring which was approved by the Public Service Commission in its April 7 2006 Order in Case Nos. 00-0801-E-PC, 00-1246-E-PC, 00-1616-E-PC, and 03-0695-E-PC (AP Ownership Restructuring Order). The ownership restructuring, which among other things, enabled AP to utilize securitized financing to fund the construction of a planned flue gas desulphurization retrofit project at the Ft. Martin generating station, was completed by AP effective January 1, 2007. No changes in utility-owned capacity are indicated from 2008 through 2017. AP's projected capacity purchases continue to increase substantially during the forecast period. This is due to the anticipated reliance on the deregulated power market to maintain sufficient reserve margins as well as being a participating member of the Regional Transmission Organization. Continued reliance on power markets to provide firm capacity assumes that capacity will be available from a market source.

7) The impact of the Clean Air Act (CAA) and its Amendments, NOx

SIP Call, and Clean Air Interstate Rule (CAIR) on our utilities' supply and demand balance is significant. The Clean Air Mercury Rule (CAMR) was vacated in early 2008 removing the requirement for reduction of mercury emissions by 2010. AEP's fleet-wide environmental compliance plan for its generating units – which include APCO's units – requires extensive pollution control equipment retrofits through 2019. The market-based environmental control programs have allowed AEP and APCO to utilize a phase-in construction approach. This compliance program includes retrofitting flue gas desulfurization. selective catalytic reduction, and selective non-catalytic reduction technologies on a significant portion of the AEP coal-fired generating fleet.

8) As a result of the Energy Policy Act of 1992, the Federal Energy Regulatory Commission (FERC) has promoted continued competition in the natural gas market and greater competition in the electric market. In April, 1996, the FERC issued Order 888 concerning wholesale competition and stranded investments. Retail competition among electric utilities has not been a major issue among West Virginia consumers because of relatively low rates and the lack of price disparity within the state. West Virginia has retained a regulated electric utility system.

9) The North American Electric Reliability Corporation (NERC) has had the traditional role of maintaining electric reliability throughout North America using a non-mandatory system of compliance, certification, and enforcement. However, the Energy Policy Act of 2005 calls for an end to the former voluntary reliability regime by placing national reliability authority in FERC's hands with this authority to be implemented through a strong industry-based organization (the Electric Reliability Organization, or ERO). On July 20, 2006 FERC issued an order certifying NERC as the ERO for the United States.

II. Forecast Procedure

The examination procedure contains two steps. First, historical data are collected on electric peaks, coincident economic conditions, and coincident weather conditions. Additionally, the utilities are asked to provide forecasts of future electrical requirements and recommendations on the narrative parts of this report. Since all four companies use econometric forecasting models which require explicit economic and demographic assumptions about the future, an evaluation is made of the appropriateness of some of the models' assumed values. However, not all input variables could be independently verified because some of the companies' economic data were obtained from private forecasting services.

The second step of the analysis is an examination of the supply side resource plans of the utilities. These plans are developed to ensure that an adequate amount of resources exist to meet the forecasted peak demands and contingencies.

Since the reliability of an electric system, assuming an adequate supply of fuel, is a function of megawatts of demand rather than megawatt hours of energy, no energy supply data was incorporated in this study.[2]

Utility forecasts, aggregated by Reliability First Corporation (RFC), have been included in this report. The RFC study is regional in scope and provides an important overview of the area in which electric utilities in West Virginia and other participants might buy and sell electrical power. Average annual growth rates are provided throughout this report to permit comparisons to previous reports. These growth rates are compound growth rates and are very sensitive to the choice of starting and ending dates; therefore, they should be used with care.

It must be recognized that the projections and conclusions of this report are at a specific point in time. The analyses are subject to both known and unknown uncertainties which may influence the need for capacity by West Virginia electric utilities during the forecast period. The attempt by FERC to restructure the electric utility industry towards greater competition introduces a great deal of new uncertainties affecting peak demands and supply reliability. Therefore, the issuance of this report by the Public Service Commission does not preclude a determination of different capacity requirements either in future generic proceedings or on a case related basis.

[2] "Demand" is the average electrical energy required in any given interval of time (usually one hour) by a utility's customers, measured in megawatts. "Energy", on the other hand, is the total amount of electricity used, measured in megawatt hours.

III. REGIONAL PROJECTIONS

This section examines the ten year projections of the electric utilities that serve the Mid-Atlantic and East Central region of the United States.

Reliability First Corporation (RFC) Coordination Agreement

Reliability First Corporation's (RFC), goal is to preserve and enhance electric service reliability and security of infrastructure for the interconnected electric systems in its region. Appalachian Power Company, Monongahela Power Company, Potomac Edison Power Company, and Wheeling Power Company are members of RFC. RFC's forecast is the only regional demand forecast that has been considered in this report.

All RFC members are affiliated with either MISO or PJM for operations and reliability coordination with the exception of the Ohio Valley Electric Corporation (OVEC), a generation and transmission utility located in Kentucky and Ohio. The resource adequacy of RFC is determined via assessments of MISO and PJM against their individual adequacy standards. RFC compiles the long-term supply and demand projections of the member utilities to ensure a reliable supply of electrical energy. For this region the forecast average rate of demand growth from winter 2009/2010 to winter 2018/2019 is expected to be 1.1% per year. The winter reserve margin of the RFC is forecast to remain above 36 percent throughout the forecast period. The aggregate demand of the RFC region typically peaks in the summer. The forecasted average rate of demand growth from summer 2010 to summer 2018 is expected to be 1.4% per year. The summer reserve margin of the RFC region is forecast to decline to approximately 9.2%

by the end of the forecast period without the inclusion of announced Independent Power Producers (IPP).

A map of the RFC region and the ten-year supply and demand forecast of RFC's members for the summer and winter peaks are shown on pages 15-17.[3]

The bulk electric systems in the RFC footprint are expected to perform well in meeting the forecast obligations over a wide range of anticipated system conditions, as long as established operating limits and procedures are followed and proposed transmission projects are completed in a timely manner. AEP's Jacksons Ferry-Wyoming 765 kV transmission line in the southeastern portion of AEP's service area was energized in June 2006 and will guard against potential widespread power interruptions.

In 2009, the Commission issued a certificate of public convenience and necessity to construct a 500 kV line from Pennsylvania to Virginia through north central and eastern West Virginia.

Throughout the 2009-2018 forecast periods, the annual peak for total internal demand in the RFC region is expected to continue to occur during the summer. This peak demand growth is based on forecast economic factors and average summer weather conditions. Therefore, the actual peak demands may vary significantly from year to year. The 2009 forecast is 9.1% above the 2008 actual. Current resource projections developed by RFC members indicate that direct-controlled and interruptible load-management programs will provide 8,200 MW of supplemental resources during the 2009-2018

[3] Map is courtesy of the NERC Long Term Reliability Assessment 2007 published on October 2007 available at www.nerc.com.

forecast periods. With interruptible demand and loads under demand-side management removed, RFC's net internal demand is projected to be approximately 193,100 MW in 2018.

Note: *The highlighted area between SPP and SERC denotes overlapping regional area boundaries: For example, some load serving entities participate in one region and transmission owner operators in another.*

ERCOT Electric Reliability Council of Texas, Inc.	RFC Reliability*First* Corp.
FRCC Florida Reliability Coordinating Council	SERC SERC Reliability Corp.
MRO Midwest Reliability Organization	SPP Southwest Power Pool, Inc.
NPCC Northeast Power Coordinating Council	WECC Western Electricity Coordinating Council

NERC Regional Reliability Councils

RFC REGIONAL COUNCIL
WINTER SUPPLY AND DEMAND
ANALYSIS

Winter of	Load (1) MW		Generation(2) MW		Reserve %	Annual Load Growth Rate %
2008/09	146,039	(3)	211,000	(4)	44.5	2.6
2009/10	145,800		215,800		48.0	0.3
2010/11	148,000		217,300		46.8	1.5
2011/12	151,800		220,100		45.0	2.6
2012/13	153,800		219,600		42.8	1.3
2013/14	155,100		219,600		41.6	0.8
2014/15	156,600		219,800		40.4	1.0
2015/16	157,900		219,800		39.2	0.8
2016/17	159,300		219,800		38.0	0.9
2017/18	160,700		219,800		36.8	0.9
2018/19	161,600		219,800		36.0	0.6

Source: 2009 Electricity Supply and Demand 2009-2018, September 2009, North American Electric Reliability Corporation, Princeton, N. J.

Notes:

(1) Includes both firm and interruptible demands.

(2) Represents capacity (market ratings) committed to the MISO and PJM markets.
Includes total installed generation capacity which is existing, presently under construction, or in various stages of planning; plus scheduled capacity purchases, less capacity sales. Does not include substantial amounts of independent (merchant) power projects that have been announced for the region.

(3) Actual.

(4) Estimated.

Table No. 1

RFC REGIONAL COUNCIL
SUMMER SUPPLY AND DEMAND
ANALYSIS

Summer of	Load(1) MW		Generation(2) MW		Reserve %	Annual Load Growth Rate %
2009	163,000	(3)	215,800	(4)	32.4	(3.6)
2010	180,400		217,300		20.5	10.7
2011	185,700		220,100		18.5	2.9
2012	189,700		219,600		15.8	2.2
2013	192,100		219,600		14.3	1.3
2014	194,100		219,800		13.2	1.0
2015	195,900		219,800		12.2	0.9
2016	197,700		219,800		11.2	0.9
2017	199,600		219,800		10.1	1.0
2018	201,300		219,800		9.2	0.9

Source: 2009 Electricity Supply and Demand 2009-2018, September 2009, North American Electric Reliability Corporation, Princeton, N. J.

Notes:

(1) Includes both firm and interruptible demands.

(2) Represents capacity (market ratings) committed to the MISO and PJM markets.
Includes total installed generation capacity which is existing, presently under construction, or in various stages of planning; plus scheduled capacity purchases, less capacity sales. Does not include substantial amounts of independent (merchant) power projects that have been announced for the region.

(3) Actual.

(4) Estimated.

Table No. 2

IV. APPALACHIAN AND WHEELING POWER COMPANY

Appalachian Power and Wheeling Power are members of the AEP System (East Zone). The generating companies of the AEP System (East Zone) continue to be parties to the AEP Interconnection Agreement. Under the AEP Interconnection Agreement (which represents the "pool agreement" among the five major AEP System (East Zone) operating companies), each member of the pool is responsible for a proportionate share of the aggregate AEP System (East Zone) pool generating capacity. The four AEP System (West Zone) operating companies are parties to a separate interconnection agreement. A system integration agreement ties the eastern and western AEP zones together. However, AEP states that there is relatively little effect on the AEP System (East Zone) companies' reserve outlook from the system integration agreement.

Appalachian Power Company (APCO) is one of the generating companies of the AEP System (East Zone). Wheeling Power (WPCO) is a non-generating AEP Company. However, each company remains a separate entity for regulatory purposes.

The focus of this report is the balance of electric supply and demand within West Virginia. Therefore, the Staff of the Public Service Commission undertook an examination of APCO's and WPCO's West Virginia jurisdictional peak demand and supply. Because APCo's and WPCO's forecasted demand and supply resources were modeled as part of the AEP System (East Zone), Staff's examination necessarily extended to that system's capacity capabilities and planning.

APPALACHIAN POWER COMPANY

Appalachian Power Company (APCO) is the largest AEP subsidiary in terms of population served, number of customers, and area of service territory of the operating companies which comprise the AEP System (East Zone). In 2008. APCO provided electric service to approximately 956,000 customers in the States of Virginia and West Virginia, with approximately 440,000 of those customers located in the southern 21 counties of West Virginia.

Appalachian Power Company's generation mix includes coal fired steam plants and hydroelectric facilities and one natural gas-fired combustion turbine plant as detailed on Chart No. 1 in the Appendix. Additionally, APCO has interconnections with other utilities as detailed on Chart No. 2 in the Appendix. These interconnections, which provide for reliability across a broad interconnected electrical network, also allow economic sales and purchases of power among the interconnected companies.

WHEELING POWER COMPANY

Wheeling Power Company (WPCO) provides electric service to approximately 41,000 customers (at year-ended 2008) primarily in Ohio and Marshall Counties of West Virginia's northern panhandle. Currently, Wheeling Power is strictly a transmission and distribution company that purchases all its power from Ohio Power Company.

AEP FORECASTING

The AEP System is a fully integrated system, with much of the engineering, accounting, purchasing and other functions accomplished through the use of a professional staff located at the system offices in Columbus, Ohio and Tulsa, Oklahoma.

All of the forecasting for Appalachian as well as other affiliated companies is done by the AEP Service Corporation (AEPSC) in Columbus and Tulsa in consultation with each of the AEP System operating companies. To evaluate APCO, then, one has to examine the technique employed by the AEP Service Corporation.

Generally, forecasts of electric load growth are prepared annually by AEPSC, and reviewed and revised as necessary in the interim between forecasts. In the third or fourth quarter of each year, short-term (up to two years) and long-term (two to twenty years) projections of the peak demand and energy requirements of each of the AEP System (East Zone) operating companies, as well as the aggregate AEP System, are usually issued. During the year the adequacy of the short-term forecast is reviewed in detail and, if judged necessary, this forecast is revised to reflect the most recent experience and changes in the short-term outlook. The current load forecast is the "5+7 Update" of the 2009 forecast, completed in May 2009.

The AEP System (East Zone) peak demand forecast is derived by summing the forecast for its operating companies, taking into account diversity effects. The listing which follows provides an overview of the more important considerations which have been taken into account in developing the current AEP Base Case forecast.

- Growth will continue in the number of residential customers served by the AEP System (East Zone) at the rate of 0.5% per year.
- During the 2010-2019 periods, electricity prices for the AEP System (East Zone) operating companies incorporate expectations concerning the need for

new generation, compliance with environmental laws, fuel costs and other factors that may affect price.

The forecast of peak internal demand for each of the individual operating companies is developed using a monthly peak electric demand forecasting model that simulates typical peak loads by jurisdiction. This model, in conjunction with monthly energy forecasts, is used to generate a preliminary weather-normalized peak load forecast for each month and season. The forecasted peak demands are then evaluated for reasonableness of both projected load factor and growth rate.

The projected seasonal peak demand requirements of the AEP System (East Zone) are obtained by aggregating the projected hourly peak demands of System's operating companies.[4] Currently, the AEP System (East Zone) annual load factor is forecast to be between 66% and 67% over the forecast period.

In addition to system records, the AEP forecast uses a large array of data from national, state and local sources, and consulting services. In particular, sources are used for obtaining historical and projected data relating to factors such as weather, demographics, economic activity, industrial productions, appliance saturation characteristics, and the technological outlook pertaining to the future.

[4] The internal demand reported for each of the operating companies in subsequent tables is a non-coincident peak. This means that not all operating companies experience their peaks on the same hour and, accordingly, the sum of the individual companies' peaks will exceed the reported peak AEP System internal demand.

AEP SYSTEM (EAST ZONE)

Projected Summer Peak Demand

This report focuses on the AEP System (East Zone) summer peak demand since the AEP System (East Zone) system is forecasted to be a summer peaking system over the forecast period. For example, the AEP System (East Zone) projected summer peak demand for 2010 is 4.0% greater than the winter 2009/2010 projected system peak, and by summer 2019 the projected summer peak is 4.5% greater than the 2018/2019 winter peak. The projected winter peak demands for AEP System (East Zone) system and most of its member companies are shown on Table 3. Average annual growth rates (AGR) are provided on this table and throughout this report. These growth rates are compound growth rates and are very sensitive to the choice of starting and ending dates; therefore, they should be used with care. For the AEP System (East Zone) as a whole, the ten year average annual growth rate in the summer peak internal demand is forecasted to be 1.4%. AEP predicts that over the forecast period, summer 2010 through summer 2019, demand will rise from a level of 21,160 MW to 23,999 MW. This represents a 2,839 MW increase in peak load. In terms of megawatt hours of electrical energy the long term growth rate of AEP System (East Zone) requirements over the same ten-year period is approximately 1.5% per year.

APCO Projected Winter Peak Demand

AEP's projection of APCO's winter peak demand is shown on Table 3, column (2). Further, the West Virginia jurisdictional projection, coincident with APCO's peak demand, is shown in column (1) as APWV. The major assumptions on which the APCO forecast is based are:

- Growth in the number of West Virginia residential customers is expected to increase at 0.2% annual rate.
- Energy conservation will continue to play a role in reducing the rate of growth in electrical demand from historical levels.
- The non-mining industrial load will continue to increase but at a rate that will lag economic advances by the nation as a whole.

Since the 1980's, the trend in coal mining employment has been a continuing decline primarily due to significant increases in productivity resulting from changes in mining techniques. The general outlook is for mining employment to decline, but at a much slower pace during the forecast period. The forecast also assumes increased output with continued productivity increases.

APCO's annual load factor in 2008 was 62% and is expected to be between 58% and 60% through 2019, based on normal weather. During the forecast period it is projected that APCO's West Virginia jurisdictional winter demand, APWV, will grow at an annual rate of 2.1%. However, after adjusting for economic recovery reflected in 2010, APWV winter demand grows at an average annual rate of 0.8%, which is slightly greater than the total company.

RESERVE MARGINS

Capacity Planning

To adequately serve the needs of its customers an electric utility must plan to have generating resources greater than its forecasted peak load. This margin above peak is necessary to allow for maintenance, forced outages, severe weather and other contingencies. The size of this planning margin will vary among utilities and is often a point of litigation between utilities and interveners before state Commissions.

Perhaps the two most widely used measures of adequate capacity are reserve margin and Loss of Load Expectation (LOLE). Reserve margin is defined as

$$R.M.\ \% = \frac{\text{Capacity - Load}}{\text{Load}} \times 100$$

LOLE can be defined in terms of the number of days when available generating capacity, including the effect of interconnections is not sufficient to meet the load demand during the peak hour. During such days it may be necessary to shed load. A typical LOLE criterion is one day in ten years.

Reserve margin is that portion of the generation resources which exceeds peak demand. Continuity of supply cannot be assured unless the utility has not only enough generating resources to supply its customers' peak demands, but also an additional amount of reserve margin to provide for contingencies. On October 1, 2004, AEP joined PJM Interconnection, LLC a Regional Transmission Organization (RTO). PJM determines the amount of reserve margin each of its member utilities is to provide to meet a LOLE of one day in ten years, considering load diversity among load serving entities in PJM and PJM and load serving entity forced outage rates. PJM reserve requirements, established for no more than four years into the future, generally are about 15% to 16% for PJM as a whole. Considering peak load diversity, the corresponding AEP reserve requirement is expected to be about 12%.

Appalachian Power Company Reserve Margin

Appalachian Power Company is projected to remain winter peaking over the next ten years, but APCO is part of the integrated AEP System (East Zone). In order to judge the adequacy of APCO's reserve margin, it is necessary to examine the reserve margins of the AEP System (East Zone). Since the system experiences a summer peak, the summer supply and demand projections for APCO were examined.

AEP Capacity Plan

The AEP System's (East Zone) operating companies jointly plan to meet their combined coincident peak. The five generating companies, Appalachian Power, Columbus Southern Power, Indiana-Michigan Power, Kentucky Power, and Ohio Power Company participate in a power supply pool agreement. Under this agreement, these companies share in their combined capacity resources.

Table 4 lists all of the AEP System – East Zone (system) generating additions planned for the forecast period (through 2019) and Table 5 shows the forecasted non-system or "off-system" capacity sales and purchases. These tables represent AEP's and APCO's current capacity addition plans. The Capacity changes noted in Table 4 are comprised of efficiency improvements, auxiliary power increases, generating unit retirements, wind generation additions, and generating unit additions. The efficiency improvements increase the megawatt availability of a generating unit by improvements of operating equipment such as turbine blades, steam valves, control equipment, etc. The auxiliary power increases are actually decreases in megawatt availability due to the addition of emission control equipment which consume additional power that is ultimately not available for market sales. For the years 2010, 2012, 2014, 2015, 2017, 2018, and 2019 several generating units are planned to be retired. However, generation unit retirements are subject to an ongoing review of system capacity needs. Therefore, retirements dates will vary from one forecast to another. Generating capacity is planned to be supplemented via wind energy generation for the forecasted years of 2010, 2011, 2012, 2015, and 2019. A total of one combined cycle, four combustion turbines, and two biomass generating units complete the forecasted generating capacity additions.

On September 19, 2007, AEP completed the purchase of a natural gas-fired power plant under construction near Dresden, Ohio, from Dresden Energy LLC, a subsidiary of Dominion. When completed, Dresden will be a nominal 580 MW natural gas-fired combined-cycle plant assigned to APCo. In addition, several formal agreements that AEP System (East Zone) operating companies have entered into are discussed briefly below.

Four AEP companies (Appalachian Power, Columbus Southern Power, Indiana-Michigan Power, and Ohio Power Company) are among the fifteen investor-owned electric utilities in the Ohio Valley region which sponsored the formation in 1952 of the

Ohio Valley Electric Corporation (OVEC) and its subsidiary Indiana-Kentucky Electric Corporation (IKEC) for the purpose of supplying the electrical power of the Federal Government's Portsmouth Area Project, which was originally under the responsibility of the Atomic Energy Commission. and later the Department of Energy (DOE). Effective April 2003, the Sponsoring Companies are entitled to purchase from OVEC their participation share of any available power from the eleven OVEC units. As of April 2004, the sponsors have agreed to extend the OVEC operating agreement for an additional twenty years.

Ohio Power Company (OPCO) owns Unit 1, and Buckeye Power, Inc. owns Units 2 and 3. of the three-unit Cardinal Plant, located in Brilliant, Ohio. Buckeye supplies the power requirements of the Ohio rural electric cooperatives from its Cardinal units under terms of an agreement with Ohio's investor-owned electric utilities, whereby power is transmitted over their transmission systems to the cooperatives. Ohio Power provides Buckeye with backup power when Buckeye's Cardinal units are out of service for planned or emergency maintenance and, in turn, Ohio Power is entitled to utilize any capacity from the Cardinal units not needed for Buckeye's load. OPCO also has an agreement with Buckeye Power in connection with Buckeye Power's Robert P. Mone Plant (three 182 MW combustion turbines). OPCO is entitled to 20% of the capacity of the Mone Plant.

In early 2007, AEP committed to the acquisition of energy from 1,000 MW (nameplate) of additional wind generation projects by the end of 2010 via long-term purchase power agreements. The goal was expanded in early 2009 to 2,000 MW by the end of 2011. The AEP operating companies I&M and APCo are already receiving energy from two wind projects with total nameplate ratings of 275 MW and six additional contracts have been executed for APCo, CSP, OPCo and I&M for an additional 351 MW to be placed in service in 2009 and 2010.

Currently, APCo is receiving power related to the long-term purchase agreements of 75-MW and 100-MW (nameplate) of wind energy from the Camp Grove Wind Farm in Illinois and Fowler Ridge Wind Farm in Indiana, respectively. On August 12, 2008, APCo signed a 100.5-MW (nameplate) long-term purchase agreement with Beech Ridge Wind Farm that is under development in Greenbrier County, West Virginia. More recently, on February 5, 2009, APCo entered into two long-term purchase agreements for 51 MW (nameplate) from the Grand Ridge II Wind Farm and 49.5 MW from the Grand Ridge III Wind Farm, both expected to be constructed in LaSalle County, Illinois.

The capacity purchases shown in Table 5 represent new AEP capacity. The listed resources indicate the types and amounts of capacity that may be required. They do not represent a rigid plan.

AEP System (East Zone) Reserve Margin Projections

The forecasted summer reserve margin for AEP System (East Zone) based on AEP System (East Zone) own supply and demand projections, is shown on line 11 of Table 6. In the calculations of reserve margins, the interruptible loads are subtracted from the projected peak. However, these interruptible customers are expected to be served during the peak if possible.

As can be seen, AEP System (East Zone) expects to maintain a minimum reserve margin of about 14 percent. AEP System (East Zone) is projecting that it will need additional supply side resources to maintain reliability.

No capacity deficiency is projected for the AEP System (East Zone). Therefore, even though APCO might be capacity deficient on a stand-alone basis during the forecast period, its capacity requirements are expected to be met by capacity available from the other AEP System (East Zone) operating companies in accordance with the provisions of the AEP Interconnection Agreement.

POTENTIAL THREATS TO RELIABILITY FOR AEP

Restructuring of the Electric Industry

The movement to a competitive electric market will have a very profound impact on the electric supply and demand balance throughout the country as well as other reliability issues.

Power station maintenance staff is being reduced across the country. The general industry trend is to provide these services through contractors. The impact on the reliability of the plants as a result of staffing reductions is uncertain.

Utilities have historically provided neighboring utilities with much cooperation in sharing equipment, manpower, information and other types of emergency assistance. Now that neighboring utilities are competitors, such cooperation is diminishing.

Transmission line loadings may increase as a result of more transactions between distant buyers and sellers. Higher loading levels could result in more voltage or outage events.

Utilities are stockpiling less fuel than historical levels. Lower stockpiles increase the risk of fuel shortages if a disruption in fuel supply occurs.

Competition may increase local opposition to transmission line construction. Residents may view new construction as a way to accommodate sales between distant buyers and sellers and not as necessary to support their local distribution company.

Environmental Issues

AEP and its operating companies (such as APCO) have historically developed compliance strategies to meet the requirements of the Clean Air Act (CAA) and its Amendments (CAAA) as each rule became known. In addition to the CAAA Title IV (Acid Rain Program) Phase I and II emission requirements for SO_2 and NO_X, these rules include the NO_X State Implementation Plan (SIP) Call, Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR). Compliance with Title IV SO_2 requirements involved continually evaluating alternative fuel strategies, exercising opportunities to purchase sulfur dioxide allowances, and retrofit of post-combustion technologies in order to lower the overall cost of compliance. For Title IV NO_X compliance, AEP's strategy included installing low-NO_X burner technologies on its Phase II NO_X units and using an averaging plan for its remaining generating units.

In 2000 the level of allowable NO_X emissions was further reduced when the federal court of Appeals for the District of Columbia upheld an EPA rule requiring 19 states, including West Virginia, to revise their air quality regulations to substantially reduce NO_X emissions (the NO_x SIP call) during the five-month Ozone Season (May-September). In response to the Federal requirements, West Virginia promulgated state NO_X SIP Call regulations for electric generating units in 45 CSR 26 during the spring of 2003. As a result of these regulations, AEP committed significant resources to install and operate Selective Catalytic Reduction (SCR) systems (supplemented by allowance trading) to meet these new restrictions by the initial compliance deadline of May 31, 2004. AEP's continuing compliance strategy for compliance with the NO_X SIP Call involved a phased-in construction program for installation of additional NO_X control equipment beyond the initial compliance date.

On January 30, 2004, the United States Environmental Protection Agency (USEPA) proposed the Interstate Air Quality Rule (IAQR), renamed as the CAIR. On May 12, 2005, the USEPA published in the Federal Register the final CAIR that became effective 60 days later on July 11, 2005. As originally promulgated, the CAIR was a two-phase program, which called for significant reductions of NO_X and SO_2; it incorporated the following three subprograms:

1) An Ozone Season NO_X reduction program that would replace the NO_X SIP Call program;
2) An annual NO_X reduction program;

3) An annual SO_2 reduction program that would be administered through the Title IV Acid Rain Program.

As discussed later in this section, the CAIR was vacated by the States Court of Appeals for the District of Columbia Circuit on July 11, 2008.

The two CAIR NO_X programs were to be implemented with a two-phase process in 2009 and 2015. In 2009, the CAIR would reduce NO_X emissions by 1.7 million tons, or 53% from 2003 levels, across states covered by the rule. In 2015, the CAIR would reduce NO_X emissions by 2 million tons, achieving a regional emissions level of 1.3 million tons, a 61% reduction from 2003 levels.

The CAIR SO_2 program was to be implemented in a two-phase process in 2010 and 2015. In 2010, the CAIR would reduce SO_2 emissions by 4.3 million tons or 55% lower than 2003 levels, across states covered by the rule. By 2015, the CAIR would reduce SO_2 emissions by 5.4 million tons, or 69%, from 2003 levels in these states.

On March 15, 2005 the USEPA issued the CAMR which became effective on July 18, 2005. Similar to the CAIR, the CAMR program was also a two-phase program, to be implemented in 2010 and 2018. The CAMR applied nationwide, requiring a 20% reduction in mercury emissions by 2010 and a 70% reduction by 2018. As discussed later in this section, the CAMR program was vacated by the States Court of Appeals for the District of Columbia Circuit on February 8, 2008.

States within the AEP service territory were required to modify their State Implementation Plans to incorporate rules equivalent to the federal CAIR and CAMR programs. These rules were then submitted to and approved by USEPA as part of the State's Implementation Plan (SIP). The West Virginia Department of Environmental Protection (WVDEP), Division of Air Quality developed and finalized CAIR and CAMR implementation rules in the spring of 2006. The annual CAIR NO_X program rule (45 CSR 39), the ozone-season CAIR NO_X program rule (45 CSR 40), the annual CAIR SO_2 program rule (45 CSR 41), and CAMR mercury budget program (45 CSR 37) were each promulgated by the WVDEP and issued with an effective date of May 1, 2006. The WVDEP CAIR and CAMR implementation rules are patterned primarily after the federal model rules for the CAIR and CAMR.

The economic/compliance analysis conducted by AEP indicated that the flue gas desulfurization (FGD) scrubbers and SCRs being installed on its system, including at APCO generating facilities, were all part of a least-cost compliance plan to meet EPA regulations, including the CAIR and CAMR. The analysis also indicated that all the SCR investments needed to meet the NO_X SIP Call requirements were also needed to comply with the annual NO_X reductions required under the CAIR rule. The requirements of the CAMR also required installation of activated carbon injection at several units with the injected carbon captured by the existing electrostatic precipitator and disposed of with the unit's fly ash.

Subsequent to AEP and APCO initiating retrofitting of pollution control technologies to meet the requirements of the CAIR and CAMR, on October 9, 2007, AEP entered into a consent decree with the Department of Justice to settle all complaints filed against AEP and its affiliates of which APCO and Ohio Power (OPCO) are included. With respect to generating facilities in West Virginia, these companies are bound by the decree to install and continuously operate an SCR on Mountaineer Unit 1 and Amos Units 1 and 3 by January 1, 2008, and on Amos Unit 2 and Mitchell Units 1 and 2 by January 1, 2009. The companies are also required to install an FGD on Mountaineer Unit 1 and Mitchell Units 1 and 2 by December 31, 2007; on Amos Units 1 and 3 by December 31, 2009; and on Amos Unit 2 by December 31, 2010.

In addition, OPCO and APCO are required to continuously operate overfire air on Kammer Units 1-3 and low NO_X burners on Kanawha River Units 1 and 2 beginning on October 9, 2007. As well, beginning on the same date Kanawha River Units 1 and 2 can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis. Finally, OPCO is required to retire, repower, or retrofit BACT environmental controls on Sporn Unit 5 by December 31, 2013.

As AEP continued implementation of its least-cost environmental compliance strategy, the United States Court of Appeals for the District of Columbia Circuit vacated the CAMR on February 8, 2008. The court remanded the rule back to EPA for further rulemaking under the Maximum Achievable Control Technology (MACT) provisions of Section 112 of the Clean Air Act. On March 14, 2008, the three-judge panel granted a motion mandating immediate implementation of its February 8, 2008 decision. In response to this court decision, AEP and APCO cancelled the scheduled retrofits of activated carbon injection technology on all units except for two outside of APCO.

Similarly, on July 11, 2008, the same Court issued an opinion to vacate and remand the CAIR. The Court granted rehearing on its initial decision before the mandate was issued based on petitions from multiple parties. In the interim between the initial decision and the decision on rehearing, APCO and AEP continued to plan for compliance with the CAIR, pending final resolution of the petitions by the Court. On December 23, 2008, the District of Columbia Circuit Court of Appeals issued an order remanding the CAIR back to the EPA for new rulemaking without vacating the CAIR rule.

While EPA is required to rewrite the CAIR rule to address the deficiencies identified by the Court, the CAIR rule remains in effect until that new rule is promulgated. Therefore, as of January 1, 2009, AEP is required to meet the emission reduction requirements set forth under the CAIR.

With respect to a carbon constrained future, AEP has been proactively planning for the potential of federal carbon-related emission legislation which includes:

(1) Being proactive and engaged in the development of climate policy including support for sensible cost effective climate policy, including support for The American Clean Energy and Security Act of 2009;

(2) Investing in science/technology research and development through the Electric Power Research Institute and the Asia Pacific Partnership;

(3) Taking voluntary, proactive action in making real reductions and setting policy precedents through the Chicago Climate Exchange and EPA Climate leaders;

(4) Reducing its carbon dioxide emissions by about 51 million cumulative tons during 2003 through 2008;

(5) Investing in longer term technology solutions such as Integrated Gasification Combined Cycle generation with carbon sequestration/storage, ultra-supercritical pulverized coal generation, chilled ammonia technology for post-combustion carbon capture and storage for existing pulverized coal-fired generating units, wind, and biomass.

Aging Generating Units

Currently, there are 44 coal-fired units on the AEP System (East Zone) that are 30 years of age or older. These units represent 16,343 MW or 62 percent of AEP System (East Zone) total capability. Assuming no retirements, by 2019 the number of coal-fired units over 30 years in age would increase to 46 representing 18,983 MW, or 72 percent of total existing system capability. The availability of units may deteriorate as a result of the aging process unless appropriate measures are taken. A utility with a given level of unit availability would need a larger reserve margin than an identical utility with more available units for the same level of system reliability.

Loss of Interruptible Load

In 2009, the AEP System (East Zone) served a significant amount of interruptible load (1,019 MW based on contract demands). However, after reflecting diversity of the various customer loads plus an allowance for customer curtailments due to economic price signals, the estimated load available for interruption is 614 MW at time of summer peak and 590 MW at time of winter peak. As AEP System (East Zone) reserve margins decline, the threat of increased interruptions may lead some interruptible customers to seek to become firm customers.

Lack of Participation in Load Modification Programs

Customer participation in possible future load modification programs is beyond the control of AEP. Therefore, there is the potential to achieve lower than expected peak reductions.

Transmission Issues

On June 22, 2007, the PJM Interconnection LLC (PJM) Board approved a transmission project, now known as the Potomac-Appalachian Transmission Highline (PATH) project, with an expected in-service date of June 2012, for inclusion in PJM's Regional Transmission Expansion Plan (RTEP). The PATH project was approved by the PJM Board for the purpose of maintaining the reliability of the power supply system in the PJM Regional Transmission Organization (RTO). In 2007, American Electric Power Company, Inc. (AEP) and Allegheny Energy (AYE) formed a joint venture to build the PATH project (Joint Venture).

On October 2, 2007, the Department of Energy (DOE), pursuant to the Energy Policy Act of 2005, issued an order for two National Transmission Corridor designations: the Mid-Atlantic Area National Transmission Corridor (includes some or all counties in DE, OH, MD, NJ, NY, PA, VA, WV, and DC); and the Southwest Area National

Transmission Corridor (seven counties in Southern California and three counties in western Arizona). The PATH project falls within the Mid-Atlantic Area National Transmission Corridor.

On November 4, 2008, the Joint Venture announced that updated PJM reliability studies had identified June 2013 as the revised in-service date for the PATH project and that the PATH project will consist of a single 765-kilovolt (kV) transmission line from AEP's Amos substation near St. Albans, West Virginia, to a new substation near Kemptown, southeast of Frederick, Maryland. The project also will include a new mid-point substation, Welton Spring, in the vicinity of northern Hardy County in West Virginia.

On April 14, 2009, the Joint Venture announced that updated PJM reliability studies had identified June 2014 as the latest in-service date for the PATH project.

PJM asserts the PATH project will relieve significant overloads and voltage problems that it projects as early as 2014 on several existing 500 kV transmission facilities in Maryland, Pennsylvania, Virginia, and West Virginia. According to PJM, these overloads threaten the system's ability to keep power flowing to consumers, and thus the need to address these reliability concerns through the construction of the PATH project.

On May 15, 2009, the PATH West Virginia Transmission Company, LLC, PATH Allegheny Transmission Company, LLC ("PATH-Allegheny"), the PATH-WV Land Acquisition Company and the PATH-Allegheny Land Acquisition Company filed a joint application for certificates of public convenience and necessity and for related relief pursuant to W.Va. Code 24-2-11 and 24-2-11a. The PATH Project is approximately 225 miles of 765 kV electric transmission line and related facilities in the fourteen counties of Putnam, Kanawha, Roane, Calhoun, Braxton, Lewis, Upshur, Barbour, Tucker, Preston, Grant, Hardy, Hampshire, and Jefferson. The Applicants also seek a certificate of public convenience and necessity (i) to jointly construct, own, operate, and maintain the new Welton Spring Substation, as another part of the PATH Project in West Virginia to be constructed two miles north of Old Fields in Hardy County, and (ii) to construct, own, operate, and maintain certain modifications to the Amos Substation owned by Appalachian Power Company and Ohio Power Company.

On November 17, 2009, the Applicants filed a Revised Proposal to Toll Statutory Decision Due Date and Extend Procedural Schedule. The Applicants (i) stated that the Potomac Edison Company plans to re-file an application seeking certification of those portions of the PATH Project in Maryland, including a terminus at the Kemptown Substation, (ii) proposed tolling the statutory due date until February 24, 2011, and (iii) submitted a revised procedural schedule that did not require multiple hearings and testimony filings to address need and non-need issues. In response to this motion, on November 24, 2009 the Commission tolled the statutory due date and established a new procedural schedule which provides for discovery and evidentiary processes throughout 2010 and an expected Commission order by early 2011.The Joint Venture filed for regulatory approvals in Maryland, Virginia, and West Virginia.

During 2009, the most significant development impacting the AEP transmission system in West Virginia was attributed to end-use customers. While there were positive signs in the coal industry with the addition of three new transmission level customers, the overall result was a decrease in customer load due to the closing of the Century Aluminum plant in Ravenswood, which was the largest customer load on the Appalachian Power system in West Virginia. Consequently, a project to install a new 345/138 kV transformer at Sporn Station was postponed.

CONCLUSION

The AEP System's current resource plans assume that up to 1,898 MW of new generation resources are to be acquired during the forecast period on the AEP System, from 2010 through 2019. After taking into account the unit capacity changes of efficiency improvements, auxiliary power increases and retirements, the new generation resources result in a net decrease of 1,388 MW over the forecast period. AEP has developed a plan of capacity additions for the long term.

The effects of the CAA on the economic and demographic conditions of West Virginia are potentially extensive. To the extent that affected utilities to use both low and high sulfur coal along with pollution control equipment to meet the SO_2 emission requirements of the CAA, this scenario may result in greater mining employment, greater personal income, and greater population than would have occurred otherwise in the coal regions within APCO's service territory. An extensive FGD retrofit program was completed for AEP to meet the requirements of the CAA Title IV Acid Rain program.

Newer programs such as the NO_X SIP Call and the CAIR require significantly greater reductions of SO_2 and NO_X emissions at coal-fired generating plants, requiring AEP to undertake an extensive SCR-retrofit program supplemented by the retrofit of additional FGDs. Over the ten-year forecast period considered in this report we expect moderate to slow growth in the internal economic and demographic factors affecting electric demand within APCo's and WPCo's West Virginia Service areas.

AEP SYSTEM – EAST ZONE
PROJECTED WINTER PEAK INTERNAL DEMANDS
(MW)

AFTER FILED DSM ADJUSTMENTS

WINTER		COINCIDENT APWV(B)	APCO	CSP	I&M	KPCP	OPCO(	COINCIDENT WPCO(D)	WPCO (E)	SUM OF INTERNAL PEAK DEMANDS	AEP SYSTEM (EAST ZONE) PEAK	DIVERSITY
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(2)+(3)+(4)+(5)+(6)	(10)	(11)=(9)-(1(
08/09 (A)		3,651	8,308	3,934	3,729	1,673	4,972	332	337	-	22,273	-
09/10		3,172	7,474	3,214	3,803	1,639	4,590	322	329	20,720	20,338	382
10/11		3,577	7,973	3,537	3,939	1,668	4,950	328	335	22,067	21,726	341
11/12		3,575	8,005	3,557	3,978	1,672	4,982	331	337	22,194	21,864	33C
12/13		3,614	8,101	3,601	4,022	1,689	5,036	335	341	22,449	22,130	319
13/14		3,723	8,162	3,633	4,055	1,700	5,063	336	343	22,613	22,297	316
14/15		3,749	8,222	3,670	4,087	1,711	5,087	338	345	22,777	22,456	321
15/16		3,764	8,262	3,697	4,106	1,717	5,095	339	346	22,877	22,550	327
16/17		3,777	8,320	3,722	4,140	1,728	5,124	342	347	23,034	22,702	332
17/18		3,798	8,375	3,751	4,171	1,739	5,140	343	349	23,176	22,840	336
18/19		3,822	8,435	3,781	4,200	1,750	5,153	344	350	23,319	22,976	343
AGR 09/19	(%)	0.5	0.2	-0.4	1.2	0.4	0.4	0.4	0.4	-	0.3	-
AGR 10/19	(%)	2.1	1.4	1.8	1.1	0.7	1.3	0.7	0.7	-	1.4	-

NOTES:
(A) ACTUAL
(B) WEST VIRGINIA'S PORTION OF APCO'S PEAK INTERNAL DEMAND.
(C) INCLUDES O'CO'S CALE TO WPCO.
(D) AMOUNT OF SALE TO WPCO INCLUDED IN OPCO'S PEAK INTERNAL DEMAND.
(E) W'CO'S NON-COINCIDENTAL PEAK INTERNAL DEMAND.

Table 3

Company Projected Capacity Changes
AEP System - East Zone

Existing Company-Owned Capacity (M–) - Year end 2009	
Active Capacity	26,495
Cold Reserve Capacity	0
Total	**26,495**
Existing Company-Total (PJM) Equivalent Installed Capacity (ICAP)	
Total Equivalent ICAP	28,796
Existing Non-Utility Capacity (MW)	
Total	See Table 5

Capacity Changes

Date	Description	Megawatt Increase Winter	Megawatt Increase Summer
2011	Efficiency Improvement (1)	14	14
2012	Efficiency Improvement (1)	0	12
2013	Efficiency Improvement (1)	24	12
2014	Efficiency Improvement (1)	45	45
2015	Efficiency Improvement (1)	100	168
2016	Efficiency Improvement (1)	68	68
2017	Efficiency Improvement (1)	136	103
2018	Efficiency Improvement (1)	103	68
2019	Efficiency Improvement (1)	0	35
2010	Auxiliary Power Increase (1)	-2	-17
2011	Auxiliary Power Increase (1)	-20	-6
2012	Auxiliary Power Increase (1)	-16	-44
2013	Auxiliary Power Increase (1)	-50	-22
2014	Auxiliary Power Increase (1)	0	-30
2015	Auxiliary Power Increase (1)	-73	-83
2016	Auxiliary Power Increase (1)	-58	-18
2017	Auxiliary Power Increase (1)	0	-35
2018	Auxiliary Power Increase (1)	-35	0
2019	Auxiliary Power Increase (1)	-41	-76
2010	Retirements	-450	-440
2012	Retirements	-585	-560
2014	Retirements	-420	-395
2015	Retirements	-435	-420
2017	Retirements	-630	-600
2018	Retirements	-600	-580
2019	Retirements	-495	-485
2010	Unit Power Return (2)	250	250
2010	Wind Addition (3)	91	46
2011	Wind Addition (3)	91	78
2012	Biomass and Wind Addition (3)	125	151
2013	Dresden CC & Wind (Summer) Addition (3)	625	605
2015	Wind Addition (Winter) (3)	13	0
2016	Wind (Summer) Addition (3)	0	13
2018	4 CT & Biomass	810	755
2019	Wind (Winter) Addition (3)	26	0

Note:

(1) Assumed for forecast purposes only.

(2) Return of capability associated with 250 MW unit power sale of CP&L through 2009.

(3) Estimated value of wind is 13% of nameplate capacity. Wind capacity is assumed to enter service in December.

Table 4

COMPANY PROJECTED CAPACITY
SALES AND PURCHASES

AMERICAN ELECTRIC POWER SYSTEM
EAST ZONE

CAPACITY SALES

TERM	BUYER	MEGAWATT WINTER	MEGAWATT SUMMER
Through May 2010	MISO	25	0
Through May 2010	Wolverine	100	0
Jan 20–0 - Dec 2011	Buckeye Cardinal (UCAP)	1,052	1,052
Jan 20–2 - Dec 2019	Buckeye Cardinal (UCAP)	1,043	1,043
Through Dec 2010	North Carolina Electric Membership Corp.	220	220
June 20–0 - Dec 2011	Dowagiac (from Tanners Creek Unit 4)	22	22
Jan 20–2 - Dec 2012	Dowagiac (from Tanners Creek Unit 4)	22	30
Jan 20–3 - Sept 2014	Dowagiac (from Tanners Creek Unit 4)	30	30
Jan 20–0 - Dec 2010	RPM Auction	1,379	1,404
Jan 20–1 - Dec 2011	RPM Auction	1,404	1,396
Jan 20–2 - May 2012	RPM Auction	1,391	0

CAPACITY PURCHASES

TERM	SELLER	MEGAWATT WINTER	MEGAWATT SUMMER
Through Aug 2027	Non-Utility Generator: Summersville Hydro Project (QF)	80	80
Through Jan 2028	Non-Utility Generator: Camp Grove Wind Power Project	75	75
Through Dec 2028	Non-Utility Generator: Fowler Ridge Wind Power Project	200	200
Apr 20–0 - Mar 2030	Non-Utility Generator: Beech Ridge Wind Power Project	100.5	100.5
Jan 20–0 - Dec 2030	Non-Utility Generator: Grand Ridge Wind Power Project	100.5	100.5
Jan 20–0 - Dec 2030	Non-Utility Generator: Fowler Ridge Wind Power Project	150	150
Through May 2010	West Virginia Power (PJM Market)	267	0
Jan 20–0 - Dec 2019	National Power Corp: Mone Project (ICAP)	145-153	43-65
Jan 20–0 - Dec 2010	Ohio Valley Electric Corp.	980	938
Jan 20–1 - Dec 2011	Ohio Valley Electric Corp.	965	932
Jan 20–2 - Dec 2012	Ohio Valley Electric Corp.	959	920
Jan 20–3 - Dec 2019	Ohio Valley Electric Corp.	953	920
Jan 20–0 - Dec 2011	Constellation (UCAP)	315	315
Jan 20–2 - May 2012	Constellation (UCAP)	315	0
Jan 20–7 - NA	SEPA (via Blue Ridge contract, capacity credit)	3.6	3.6

CAPACITY EXCHANGES

TERM	SELLER/BUYER	MEGAWATTS
-	None	-

Table 5

COMPANY'S
PROJECTED CAPACITY AND DEMAND
SUMMER SEASON

AMERICAN ELECTRIC POWER SYSTEM
EAST ZONE

Line	Peak Demand (MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Gross Internal Demand	21,308	22,640	22,869	23,149	23,354	23,551	23,698	23,926	24,103	24,274
(2)	Load Modification	326	629	816	1,007	1,196	1,386	1,396	1,405	1,417	1,429
(3)	Load Sales	1,274	1,052	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043
(4)	Interruptible Demand	614	614	614	614	614	614	614	614	614	614
(5)	Net Internal Demand (1-2+3-4)	21,641	22,448	22,481	22,570	22,586	22,593	22,730	22,949	23,114	23,273
	Capacity (MW)										
(6)	Total Installed Capacity	27,712	27,798	27,392	27,987	27,607	27,272	27,335	26,813	27,056	26,530
(7)	Capacity Purchases	0	0	0	0	0	0	0	0	0	0
(8)	Capacity Sales	1,123	1,052	-33	-35	-33	-64	-64	-64	-66	-69
(9)	Net Capacity Resources (6+7-8)	26,589	26,746	27,425	28,022	27,640	27,336	27,399	26,877	27,122	26,599
	Reserve Margin										
(10)	Margin In Megawatts (9-5)	4,947	4,297	4,943	5,451	5,053	4,742	4,668	3,927	4,007	3,325
(11)	Margin in Percent of Demand (10/5) * 100%	22.9	19.1	22.0	24.1	22.4	21.0	20.5	17.1	17.3	14.3

Table 6

ALLEGHENY POWER

MPCO AND PECO

Monongahela Power Company (MPCO) and The Potomac Edison Company (PECO) comprise the regulated operating companies of Allegheny Energy, Inc. in West Virginia. These companies are now doing business as Allegheny Power (AP). However, for regulatory purposes each company remains a separate legal entity.

The concern of this report is the balance of electric supply and demand within West Virginia. Therefore, AP undertook an examination of MPCO's and PECO's jurisdictional peak demand and supply.

The projections of AP include some estimated impact of the 1990 Clean Air Act Amendments (CAAA). This act will affect both future demand and capacity. The AP operating companies have completed a flue gas desulfurization facility at the Harrison Power Station in Harrison County. West Virginia (in compliance with Phase I of the CAAA, this facility was placed in service on January 1, 1995) and has installed scrubbers at its Fort Marin generation facilities during 2009.

It should be noted that the AP response to Staff's data request for information to produce this report included its October 2009 Forecast for the System and individual operating companies, suggested text changes, and many useful comments to help make this report possible. The supply side resource information provided by AP, in Table 8, is based upon the November 2009 Integrated Resource Plan.

MONONGAHELA POWER COMPANY

In 2009, MPCO is providing electric service to approximately 384,000 customers in the State of West Virginia. MPCO's present generation is nearly exclusively coal-fired steam plants as detailed on Chart No. 4 in the Appendix, but also includes pumped storage and PURPA capacity. As of April, 2009, MPCO has approximately 41% equity ownership in the Allegheny Generating Company (AGC). AGC is a subsidiary of MPCO and Allegheny Energy Supply Co., LLC. AGC owns 40% of the Bath County facility (2,587 MW on 1/1/2007) pumped storage facility located in Bath County, VA. The Bath County facility was placed in service in 1985. MPCO also has three PURPA contracts for a total of approximately 160MW. MPCO is also a member of PJM, giving it access to very liquid competitive wholesale energy and capacity markets.

POTOMAC EDISON COMPANY

The Potomac Edison Company (PECO) provided electric service to approximately 480,000 customers in 2007 in the States of West Virginia, Virginia and Maryland, with approximately 130,000 of those customers located in the Eastern Panhandle counties of West Virginia.

PECO transferred approximately 2,100 MW of its Maryland, Virginia, and West Virginia jurisdictional generating assets to Allegheny Energy Supply on August 1, 2000. To serve PECO's retail load responsibilities in West Virginia, PECO previously entered into a power supply arrangement with its affiliate Allegheny Energy Supply. This supply arrangement has terminated with AP's implementation of its generation ownership restructuring in West Virginia and PECO will serve its retail load responsibilities through generation assets owned in whole and in part by MPCO.

AP FORECASTING

Allegheny Power (AP) is a fully integrated electrical system with much of the engineering, accounting, purchasing and other functions accomplished through the use of a consolidated professional staff located at the corporate office in Fairmont, West Virginia, and Greensburg, Pennsylvania. Therefore, a discussion of the load forecasting techniques of MPCO and PECO is inherently a discussion of the techniques used by AP.

A comprehensive load forecast report is prepared annually for AP. In that report, peak loads, kilowatt-hour energy use and load factors are projected for a 20-year period. The forecast is monitored on a monthly basis. New forecasts are made periodically, but an update to the forecast might be done at any time if economic events indicate a significant variation in the long run.

The AP forecasting methodology employs both econometric and end use models. The residential kilowatt-hour use per customer model is a statistically adjusted end use model which blends econometric methodology driven by weather, price of electricity, and economic conditions with end use methodology to capture equipment efficiency trends and saturations. The number of residential customers' model uses econometric techniques based on the projected service area state population. Residential energy sales are the product of the forecast of use per customer and total residential customers. The commercial energy sales forecast uses the econometric model driven by weather, price of electricity, number of residential customers, and service area state non-manufacturing employment.

The industrial energy sales sector is disaggregated into the major two-digit Standard Industrial Classification (SIC) groups served by AP. Econometric models are used to estimate the forecasting equation for each SIC driven by employment, production and industrial electric prices. Total industrial energy sales are the sum of the SIC's forecasted. Adjustments to the forecast are made for large load additions or losses.

Peak load forecasts are based on a model that considers end-use stock estimates and class load diversity based on projected residential, commercial and industrial sales. These are derived from the energy sales models. Major economic features of AP WV forecast in the interval 2010 through 2019 are:

- WV population growth will occur at an average rate of 0.08% per year.
- WV personal income is expected to decline at the rate of 0.5% per year from 2010 to 20011 and increase by 0.1.5% per year by 2019.
- WV non-farm employment will increase at 1.4% per year from 2010 through 2019.
- The real (inflation adjusted) price of electricity, in general, declines.

The principal sources of demographic data for AP analyses and forecasts are company records, state agencies and local agencies. National economic data and service area economic data are supplied to AP by Moody's Economy.com . These data are employed in the various models used to make the AP forecasts.

AP Projected Winter Peak Demand

Table 7 shows the AP winter peak demand for the forecast period of the winter of 2009/10 through the winter of 2018/19. Also shown on this Table are the projected winter peak demands of each of the AP operating companies including MPCO, PECO and West Penn Power. Table 7 represents AP Control Area load as well as the demand for West Virginia Power.

The average annual growth rate in the winter peak demand for the entire AP Control Area is projected to be 1.5% over the forecast period of winter 20098/10 to winter 2018/19. AP projected a 1,137 MW increase over the forecast period from 8,010 MW to 9,147 MW. These forecasts are based upon the AP October 2009 Forecast reports.

This year's Table 7 results from an RFC requirement to provide forecasts of the connected load delivered by each operating company without regard to the actual generation supplier.

MPCO Projected Winter Peak Demand

AP's projection of MPCO's winter peak demand is shown on Table 7, column (2). Further, the West Virginia jurisdictional projection is shown in column (1) as MPWV. Due to the sale of MPCO's Ohio territory on January 1, 2006, these values are equivalent.

Some of the assumptions regarding MPCO's service territory embedded in these October 2009 demand forecasts are:

- MPCO residential customers are projected to increase at an annual 0.7% rate.
- The residential electric heat saturation is expected to increase from 22.3% in 2009 to about 22.9% in 2019.

Reference to Table 7, column (2) shows that AP projects that MPCO's peak winter demand will increase from 1,695 MW to 1,981 MW at an annual growth rate of 1.7% over the winter 2009/10 to winter 2018/19 period. While West Virginia Power (WVP) is now a division of MPCO, WVP's service territory is not part of AP's Control Area. Therefore, AP has not included WVP peak demand forecasts in the forecasts for MPCO or MPWV on Table 7. West Virginia Power's peak demand is expected to increase from 118 MW to 131 MW, at an annual growth of 1.1% over the forecast period and is also provided in column (1) on Table 7.

PECO Projected Winter Peak

The AP projections of PECO winter peak demands are shown on Table 7, column (4). The West Virginia jurisdictional demand projections for PECO are shown in column (3) as PEWV.

Some of the assumptions regarding PECO's service territory embedded in these October 2009 demand forecasts are:

- PECO residential customers are projected to increase at an annual 2.2% rate.

- Residential electric heat saturation is expected to increase from 57.2% in 2009 to 57.5% in 2019.
- The costs associated with the AES Warrior Run project will not be reflected in the rates of PECO customers in West Virginia.

Table 7, column (4) shows the AP projected gross winter peaks for PECO increasing from 2,965 MW in winter 2009/10 to 3,376 MW in winter 2018/19 at an annual growth rate of 1.5%. PEWV, the PECO West Virginia jurisdictional demand, is forecast to grow at an average annual rate of 2.2% over the same period.

RESERVE MARGINS PLANNING AND PROJECTIONS

Capacity Planning

The November 2009 Integrated Resource Plan (IRP) reflects generation and load projections as they were expected to occur at the time of preparation of the IRP and load forecast, including any supplemental capacity needed to meet the reliability standards of PJM and Reliability First over the forecast period and any Interruptible Load Resources (ILR). AP is in the midst of transition to competitive retail markets in Pennsylvania and Maryland. As a result, this IRP represents one of many possible futures, based on current statutory and regulatory requirements.

The AP IRP reflects all West Penn Power customers eligible to select an alternative generation supplier as of January 2, 2000, all Potomac Edison's Maryland customers eligible to select an alternate generation supplies as of July 1, 2000. In 2007, the Virginia legislature amended the restructuring act, terminating Virginia's transition to competitive markets, except for customers of 5 MWs or greater and aggregated residential load. West Virginia is not expected to enact retail access (Customer Choice) in the foreseeable future.

Allegheny Power Planning Philosophy

Mon Power is part of the greater PJM footprint. Numerous system planning benefits are realized as a member and participant of PJM. These benefits include numerous cost savings and efficiencies gained through coordinated regionalized markets and system planning for reliability. The PJM regional transmission organization operates and monitors the markets to effectuate market based solutions for reliability including the RTEP process with system planning solutions being effectuated through the energy market and the RPM capacity market.

The Reserve Requirement Study, which is performed on an annual basis by PJM to support an average loss of load expectation of once every ten years, is the criteria used to determine the planning parameters for the RPM capacity market. This study provides a ten-year projection consistent with RFC and NERC standards for resource planning reserve requirements for all PJM shared reserve group members. PJM's study currently recommends an RTO average installed reserve margin of 15.4% for the 2012 / 2013 delivery year and 15.3% for 2013 / 2014 delivery year. Further, PJM's study currently estimates an RTO average forecasted 11-year reserve margin of 20.5% for the period 2009 through 2019.[5]

[5] 2009 PJM Reserve Requirement Study with a 11-year Planning Horizon: June 1st 2009 - May 31st 2020. http://www.pjm.com/committees-and-groups/working-groups/~/media/committees-

The annual RPM capacity auction provides market signals to participants three years from the auction date. The prices are determined on a regional basis taking into consideration transmission limitations of the various PJM regions. The forward capacity prices developed from these capacity auctions provides a basis for system planning build or buy decisions of the market participants and PJM.

Company Projected Supply Side Resources for AP

Table 8 assumes no planned retirements of generating units by AP in the next ten years. Currently, MPCO plans to meet its RPM capacity obligations using its owned assets and through participation in the PJM RPM capacity market. Currently, Allegheny Power has a total of 130 customers with interruptible loads under the PJM ILR program.[6]

Projected Demand Side Resources for AP

The most recent Allegheny Power load forecast for the West Virginia service territory does not contain any specific estimates of future peak demand or energy impacts from current demand side management (DSM) programs. Any actual impacts from DSM programs are included in the historical load data used to develop the load forecast models. Current PJM programs, which are described below, are reviewed each year in order to determine if a material and predictable amount of load impact is expected in the future from these programs. For the present time, Allegheny Power has determined that because the load reductions from current programs are either voluntary or have not yet

groups/working-groups/rrawg/20091012/20091012-item-03a-2009-pjm-reserve-requirement-study-final-draft.ashx

[6] Allegheny Power acts as the Curtailment Service Provider for 3 of the customers.

been material and predictable, it is not prudent to include any load and energy reduction assumptions based on such programs.

In April of 2002, Allegheny Power turned over functional control of its transmission facilities to PJM and became a member of PJM. Since June 2002, all Allegheny Power commercial and industrial customers have had the opportunity to participate in PJM demand side programs. Allegheny Power commercial and industrial customers currently have the opportunity to participate in two demand response programs through PJM: the Economic Load Response Program (ELRP) and the Interruptible Load Resource (ILR) program, as described below. The purpose of these programs is to provide customers options to aid in reducing their electricity costs through flexibility in their operations while benefiting the PJM generation market with additional load resources.

The PJM Economic Load Response Program (ELRP) is a voluntary peak load reduction plan that offers financial compensation to customers who can reduce their power consumption during periods of high electrical demand or prices. Participating businesses are paid a percentage of the wholesale cost of power in return for reducing energy consumption, which will lower their overall energy costs. To qualify, customers must have the ability to reduce their electric demand by a minimum of 100 kilowatts (kW) per hour. Enrolled customers may choose to not participate during each event, making participation, and the impact on the load forecast, unpredictable. Due to the voluntary nature of the program, PJM does not include any load reductions from the

ELRP program in its load forecast. Similarly, for the present time, Allegheny Power has determined that because the load reductions from this program are voluntary, it is not prudent to include any load and energy reduction assumptions based on the ELRP program.

The PJM Interruptible Load Resource (ILR) Program pays customers if they are called to reduce electrical usage during system emergencies. To participate, customers must agree to be available for up to 10 reductions per year and have the ability to reduce demand by a minimum of 100 kW per hour. These customers must have the ability to reduce metered load when an emergency event is called by PJM. To date, the ILR program has not been called in the Allegheny Power zone. Therefore, no impact has been seen from this program in Allegheny's load. For the present time, Allegheny Power has determined that because the load reductions from this program has not yet been material or predictable, it is not prudent to include any load and energy reduction assumptions based on such a program.

Allegheny Power has also filed and received commission approval to implement new energy efficiency and conservation programs, as well as demand response programs, in the Maryland and Pennsylvania portions of its service territory. As these programs are implemented, the impacts are being included in future load forecasts.

AP Reserve Margin Projections

AP expects to purchase any needed supplemental capacity from the wholesale market to meet the required PJM RPM capacity requirement. The required PJM Installed Reserve Margin requirement for the 2009/2010 planning period is 115%.

POTENTIAL THREATS TO RELIABILITY FOR AP

Restructuring of the Electric Industry

The movement to a competitive electric market will have a profound impact on the electric supply and demand balance throughout the country as well as other reliability issues.

Utility transmission systems were designed to deliver native generation to native load. As deregulation increases and the competitive market develops, utilities and LSEs may increasingly rely on the wholesale market for capacity and energy resources and as such, the bulk power transfers on the utility transmission systems will continue to be stressed as never before. As residents may view new construction as a way to accommodate sales between distant buyers and sellers and not as necessary to support their local distribution company, competition may increase local opposition to transmission line constriction.

Additionally, potential market price volatility in the unregulated power supply industry will foster price uncertainty, in additional to regulatory uncertainty presenting market confusion on the development and purchase of capacity and energy resources.

ENVIRONMENTAL ISSUES

The operations of Allegheny's owned facilities, including its generation facilities, are subject to various federal, state and local laws, regulations and uncertainties as to air and water quality, hazardous and solid waste disposal and other environmental matters. Compliance may require Allegheny to incur substantial additional costs to modify or replace existing and proposed equipment and facilities. These costs may adversely affect the cost of Allegheny's future operations.

Global Climate Change

The United States relies on coal-fired power plants for more than 50 percent of its energy. However, coal-fired power plants have come under scrutiny due to their emission of gases implicated in climate change, primarily carbon dioxide, or "CO_2."

Allegheny produces more than 90 percent of its electricity at coal-fired facilities and currently produces approximately 45 million tons of CO_2 annually through its energy production. While there are many unknowns concerning the final regulation of greenhouse gases in the United States, federal and/or state legislation and implementing regulations addressing climate change likely will be adopted some time in the future, and may include limits on emissions of CO_2. Thus, CO_2 legislation and regulation, if not reasonably designed, could have a significant impact on Allegheny's operations. Allegheny can provide no assurance that limits on CO_2 emissions, if imposed, will be set at levels that can accommodate its generation facilities absent the installation of controls.

Moreover, there is a gap between desired reduction levels in the current proposed legislation and the current capabilities of technology; no current commercial-scale technology exists to enable many of the reduction levels being proposed in national, regional and state proposals. Such technology may not become available within a timeframe consistent with the implementation of any future climate control legislation or at all. To the extent that such technology does become available, Allegheny can provide no assurance that it will be suitable for installation at Allegheny's generation facilities on a cost effective basis or at all. Based on estimates from a 2007 U.S. Department of Energy (DOE) National Electric Technology Laboratory report, it could cost more than $3,000 per kW to replace existing coal-based power generation with fossil fuel stations capable of capturing and sequestering CO_2 emissions, and recent project announcements suggest that these costs could be substantially higher. However, exact estimates are difficult because of the variance in the legislative proposals and the current lack of deployable technology.

Allegheny supports federal legislation and believes that the United States must commit to a response to climate change that both encourages the development of technology and creates a workable control system. Regardless of the eventual mechanism for limiting CO_2 emissions, however, compliance will be a major and costly challenge for Allegheny, its customers and the region in which it operates. Most notable will be the potential impact on customer bills and disproportionate increases in energy cost in areas that have built their energy and industrial infrastructure over the past century based on coal-fired electric generation.

Because the legislative process and applicable technology each is in its infancy, it is difficult for Allegheny to aggressively implement greenhouse gas emission expenditures until the exact nature and requirements of any regulation are known and the capabilities of control or reduction technologies are more fully understood. Allegheny's current strategy in response to climate change initiatives focuses on seven tasks:

- maintaining an accurate CO_2 emissions data base;
- improving the efficiency of its existing coal-burning generation fleet;
- following developing technologies for clean-coal energy and for CO_2 emission controls at coal-fired power plants;
- following developing technologies for carbon sequestration;
- participating in CO_2 sequestration efforts (e.g. reforestation projects) both domestically and abroad;
- analyzing options for future energy investment (e.g. renewables, clean-coal, etc.); and
- improving demand-side efficiency programs, as evidenced by customer conservation outreach plans and Allegheny's Watt Watchers initiatives.

Allegheny's energy portfolio also includes more than 1,090 MWs of renewable hydroelectric and pumped storage power generation. Allegheny is also pursuing permits to allow for a limited use of bio-mass (wood chips and saw dust) and waste-tire derived fuel at two of its coal-based power stations in West Virginia, and is exploring the economics of installing additional renewable generation capacity.

Allegheny intends to engage in the dialogue that will shape the regulatory landscape surrounding CO_2 emissions. Additionally, Allegheny intends to pursue proven and cost-effective measures to manage its emissions while maintaining an affordable and reliable supply of electricity for its customers.

Clean Air Act Compliance

Allegheny currently meets applicable standards for particulate matter emissions at its generation facilities through the use of high-efficiency electrostatic precipitators, cleaned coal, flue-gas conditioning, optimization software, fuel combustion modifications and, at times, through other means. From time to time, minor excursions of stack emission opacity that are normal to fossil fuel operations are experienced and are accommodated by the regulatory process. Allegheny meets current emission standards for sulfur dioxide (SO_2) by using emission controls, burning low-sulfur coal, purchasing cleaned coal (which has lower sulfur content), and blending low-sulfur coal with higher sulfur coal and utilizing emission allowances.

Allegheny's compliance with the Clean Air Act of 1990 (Clean Air Act) has required, and may require in the future, that Allegheny install control technologies on many of its generation facilities. The Clean Air Interstate Rule (CAIR) promulgated by the U.S. Environmental Protection Agency (EPA) on March 10, 2005 was overturned by the U.S. Court of Appeals for the District of Columbia Circuit on July 11, 2008. The

Court issued a unanimous decision overturning the entire CAIR and the associated Federal Implementation Plan and remanded both to the EPA. EPA requested a rehearing by the full court (en banc) arguing that remand for certain issues within the rule were well founded, but full vacatur of the rule was an error. On December 23, 2008, the D.C. Circuit court remanded CAIR, without vacatur, ordering EPA to redraft certain parts of the rule. The EPA has since indicated that rule re-issuance will be in the March – April 2010 timeframe. Allegheny compliance is currently based on the requirements of the existing CAIR rule and will remain so until EPA re-issues a new CAIR rule.

The Clean Air Act Acid Rain Program mandates annual reductions of SO_2 and created a SO_2 emission allowance trading program. AE Supply and Monongahela comply with current SO_2 emission standards through a system-wide plan combining the use of emission controls, low sulfur fuel and emission allowances. Allegheny's SO_2 allowance needs, to a large extent, are affected at any given time by the amount of output produced and the types of fuel used by its generation facilities, as well as the implementation of environmental controls. Allegheny continues to evaluate and implement options for compliance; it completed the elimination of a partial bypass of flue-gas desulfurization equipment (Scrubbers) at its Pleasants generation facility in December 2007, and has installed scrubbers at its Fort Martin generation facilities during 2009. The Acid Rain Program ends in 2009 and the existing CAIR rule will begin controlling SO_2 reductions in 2010.

The CAIR rule requires ozone season (May 1 through September 30) and annual NOx reductions equivalent to a 0.15 lb/MMBtu emission rate, beginning in 2009.

Allegheny meets current emission standards for NOx by using low NOx burners, Selective Catalytic Reduction, Selective Non-Catalytic Reduction and over-fire air and optimization software, as well as through the use of emission allowances. Allegheny is currently complying with the existing CAIR rule, beginning with the ozone season allowance reconciliation due November 30, 2009.

Allegheny's NOx compliance plan functions on a system-wide basis, similar to its SO_2 compliance plan. Monongahela also has the option, in some cases, to purchase alternate fuels or NOx allowances, if needed, to supplement their compliance strategies. Allegheny's NOx allowance needs, to a large extent, are affected at any given time by the amount of output produced and the types of fuel used by its generation facilities.

The majority of Allegheny's emission allowances were allocated to Allegheny by the EPA at zero cost. Excess can be sold and shortages can be bought on the very fluid emission allowance market. The recorded value of Allegheny's annual NOx allowances was approximately $3.1 million at September 30, 2008.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule (CAMR), establishing a cap and trade system designed to reduce mercury emissions from coal-fired power plants in two phases during 2010 and 2018. This rule was to be implemented through state implementation plans. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the rule in its entirety. The State of West Virginia subsequently suspended its rule for implementing CAMR. Pennsylvania and Maryland, however, have taken the position that their mercury rules survive this ruling. A new Hazardous Air Pollutant (HAP) Maximum Achievable Control Technology (MACT) rule, including limits for mercury, is to be issued in draft form by EPA in early 2010.

Clean Air Act Litigation

In August 2000, AE received a letter from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten electric generation facilities, which collectively include 22 generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island. AE Supply and/or Monongahela own these generation facilities. The letter requested information under Section 114 of the Clean Air Act to determine compliance with the Clean Air Act and related requirements, including potential application of the New Source Review (NSR) standards of the Clean Air Act, which can require the installation of additional air emission control equipment when the major modification of an existing facility results in an increase in emissions. AE has provided responsive information to this and a subsequent request.

If NSR requirements are imposed on Allegheny's generation facilities, in addition to the possible imposition of fines, compliance would entail significant capital investments in emission control technology.

On May 20, 2004, AE, AE Supply, Monongahela and West Penn received a Notice of Intent to Sue Pursuant to Clean Air Act §7604 (Notice) from the Attorneys General of New York, New Jersey and Connecticut and from the PA DEP. The Notice alleged that Allegheny made major modifications to some of its West Virginia facilities in violation of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at the following coal-fired facilities: Albright Unit No. 3; Fort Martin Units No. 1 and 2; Harrison Units No. 1, 2 and 3; Pleasants Units No. 1 and 2 and Willow Island Unit No. 2. The Notice also alleged PSD violations at the Armstrong, Hatfield's Ferry and Mitchell generation facilities in Pennsylvania and identifies PA DEP as the lead agency regarding those facilities. On September 8, 2004, AE, AE Supply, Monongahela and West Penn received a separate Notice of Intent to Sue from the Maryland Attorney General that essentially mirrored the previous Notice.

On January 6, 2005, AE Supply and Monongahela filed a declaratory judgment action against the Attorneys General of New York, Connecticut and New Jersey in federal District Court in West Virginia (West Virginia DJ Action). This action requests that the court declare that AE Supply's and Monongahela's coal-fired generation facilities in Pennsylvania and West Virginia comply with the Clean Air Act. The Attorneys General filed a motion to dismiss the West Virginia DJ Action. It is possible that the EPA and other state authorities may join or move to transfer the West Virginia DJ Action.

On June 28, 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Distribution Companies in the United States District Court for the Western District of Pennsylvania (PA Enforcement Action). This action alleges NSR violations under the federal Clean Air Act and the Pennsylvania Air Pollution Control Act at the Hatfield's Ferry, Armstrong and Mitchell facilities in Pennsylvania. The PA Enforcement Action appears to raise the same issues regarding Allegheny's Pennsylvania generation facilities that are before the federal District Court in the West Virginia DJ Action, except that the PA Enforcement Action also includes the PA DEP and the Maryland Attorney General. On January 17. 2006, the PA DEP and the Attorneys General filed an amended complaint. On May 30, 2006, the District Court denied Allegheny's motion to dismiss the amended complaint. On July 26, 2006, at a status conference, the Court determined that discovery would proceed regarding liability issues, but not remedies. Discovery on the liability phase closed on December 31, 2007, and summary judgment briefing was completed during the first quarter of 2008. On September 2, 2008, the Magistrate Judge issued a Report and Recommendation that all parties' motions for summary judgment be denied. Objections to this report and responses to those objections have been filed by all parties. The District Court Judge will hear oral argument and then decide whether to accept, reject or modify the Report and Recommendation. A trial date has yet to be scheduled.

In addition to this lawsuit, on September 21, 2007, Allegheny received a Notice of Violation (NOV) from the EPA alleging NSR and PSD violations under the federal Clean Air Act, as well as Pennsylvania and West Virginia state laws. The NOV was directed to AE, Monongahela and West Penn and alleges violations at the Hatfield's Ferry and Armstrong generation facilities in Pennsylvania and the Fort Martin and Willow Island generation facilities in West Virginia. The projects identified in the NOV are essentially the same as the projects at issue for these four facilities in the May 20, 2004 Notice, the West Virginia DJ Action and the PA Enforcement Action.

On April 2, 2007. the United States Supreme Court issued a decision in the Duke Energy case vacating the Fourth Circuit's decision that had supported the industry's understanding of NSR requirements and remanded the case to the lower court. The Supreme Court rejected the industry's position on an hourly emissions standard and adopted an annual emissions standard favored by environmental groups. However, the Supreme Court did not specify a testing standard for how to calculate annual emissions and otherwise provided little clarity on whether the industry's or the government's interpretation of other aspects of the NSR regulations will prevail.

Allegheny intends to vigorously pursue and defend against the Clean Air Act matters described above but cannot predict their outcomes.

Canadian Toxic-Tort Class Action

On June 30, 2005. AE Supply, Monongahela and AGC, along with 18 other companies with coal-fired generation facilities, were named as defendants in a toxic-tort, purported class action lawsuit filed in the Ontario Superior Court of Justice. On behalf of a purported class comprised of all persons residing in Ontario within the past six years (and/or their family members or heirs), the named plaintiffs allege that the defendants negligently failed to prevent their generation facilities from emitting air pollutants in such a manner as to cause death and multiple adverse health effects, as well as economic damages, to the plaintiff class. The plaintiffs seek damages in the approximate amount of

Canadian $49.1 billion (approximately US $47.05 billion, assuming an exchange rate of 1.0435 Canadian dollars per US dollar), along with continuing damages in the amount of Canadian $4.1 billion per year and punitive damages of Canadian $1.0 billion (approximately US $3.9 billion and US $958 million, respectively, assuming an exchange rate of 1.0435 Canadian dollars per US dollar) along with such other relief as the court deems just. Allegheny has not yet been served with this lawsuit, and the time for service of the original lawsuit has expired. Allegheny intends to vigorously defend against this action but cannot predict its outcome.

Global Warming Class Action

On April 9, 2006, AE, along with numerous other companies with coal-fired generation facilities and companies in other industries, was named as a defendant in a class action lawsuit in the United States District Court for the Southern District of Mississippi. On behalf of a purported class of residents and property owners in Mississippi who were harmed by Hurricane Katrina, the named plaintiffs allege that the emission of greenhouse gases by the defendants contributed to global warming, thereby causing Hurricane Katrina and plaintiffs' damages. The plaintiffs seek unspecified damages. On December 6, 2006, AE filed a motion to dismiss plaintiffs' complaint on jurisdictional grounds and then joined a motion filed by other defendants to dismiss the complaint for failure to state a claim. At a hearing on August 30, 2007, the Court granted the motion to dismiss that AE had joined and dismissed all of the plaintiffs' claims against all defendants. Plaintiffs filed a notice of appeal of that ruling on September 17,

2007. The case has been fully briefed to the United States Court of Appeals for the Fifth Circuit, and oral argument took place on August 6, 2008. Before a decision was issued, the parties were notified that one of the presiding judges had disqualified himself from participating in the decision. Oral argument before a new panel took place on November 3, 2008, but no decision was recorded at that time. AE intends to vigorously defend against this action but cannot predict its outcome.

Claims Related to Alleged Asbestos Exposure

The Distribution Companies have been named as defendants, along with multiple other defendants, in pending asbestos cases alleging bodily injury involving multiple plaintiffs and multiple sites. These suits have been brought mostly by seasonal contractors' employees and do not involve allegations of the manufacture, sale or distribution of asbestos-containing products by Allegheny. These asbestos suits arise out of historical operations and are related to the installation and removal of asbestos-containing materials at Allegheny's generation facilities. Allegheny's historical operations were insured by various foreign and domestic insurers, including Lloyd's of London. Asbestos-related litigation expenses have to date been reimbursed in full by recoveries from these historical insurers, and Allegheny believes that it has sufficient insurance to respond fully to the asbestos suits. Certain insurers, however, have contested their obligations to pay for the future defense and settlement costs relating to the asbestos suits. Allegheny is currently involved in three asbestos and/or environmental insurance-related actions, Certain Underwriters at Lloyd's, London et al. v. Allegheny Energy, Inc.

et al., Case No. 21-C-03-16733 (Washington County, Md.), Monongahela Power Company et al. v. Certain Underwriters at Lloyd's London and London Market Companies, et al., Civil Action No. 03-C-281 (Monongalia County, W.Va.) and Allegheny Energy, Inc. et al. v. Liberty Mutual Insurance Company, Civil Action No. 07-3168-BLS (Suffolk Superior Court, MA). The parties in these actions are seeking a declaration of coverage under the policies for asbestos-related and environmental claims.

Allegheny does not believe that the existence or pendency of either the asbestos suits or the actions involving its insurance will have a material impact on its consolidated financial position, results of operations or cash flows. As of September 30, 2008, Allegheny's total number of claims alleging exposure to asbestos was 845 in West Virginia and five in Pennsylvania.

Allegheny intends to vigorously pursue these matters but cannot predict their outcomes.

AGING GENERATION UNITS

By the end of 2011 all of the active steam units will be over 30 years of age.

CONCLUSION

Over the ten year forecast period considered in this report we expect moderate growth in the internal economic and demographic factors affecting electric demand within AP's and MPCO's West Virginia service areas. The major uncertainties are related to the external factors.

Both the utilities and Staff foresee a need for generation additions on the AP system in the foreseeable future. The System is planning to satisfy that need through a least cost approach.

Additional uncertainty related to environmental issues concerns nitrous oxide and carbon dioxide emissions of coal-fired generating plants. New standards are being proposed at both the national and international level. Adoption of more stringent standards would most likely increase electric generating costs. As noted in the prior report, in 2005, AP filed an application with the Public Service Commission for (i) a Certificate of Public Convenience and Necessity (CPCN) to install emissions controls on its Fort Martin Generating Station, and (ii) an order (Financing Order) authorizing AP to utilize securitization financing pursuant to the provisions of W. Va. Code §24-2-4e (Section 4e). On April 7, 2006, and in conjunction with its issuance of the AP Ownership Restructuring Order, the Public Service issued a Financing Order granting AP's request for a CPCN to retrofit the emissions controls technology planned for Ft. Martin and authorizing AP to utilized securitization financing. The installation of emissions controls at Ft. Martin will significantly reduce SO_2 emissions at Ft. Martin while enabling AP to utilize West Virginia coal supplies. AP's ownership restructuring also brings AP's generation fleet for its West Virginia retail electric load responsibilities fully under the regulatory authority of the Public Service Commission.

ALLEGHENY POWER
PROJECTED WINTER PEAK INTERNAL DEMANDS (A)
FROM DATA PROVIDED BY
ALLEGHENY POWER
(MW)

WINTER PEAK OF	MPWV (C) (1)	MP CO (D) (2)	PEWV (E) (3)	PE CO (F) (4)	WEST PENN (G) (5)	SUM OF INTERNAL PEAK DEMANDS (6) = (2) + (4) + (5)	AP SYSTEM PEAK (H) (7)	DIVERSITY ADJUSTMENT (8) = (6) - (7)	WEST VIRGINIA POWER (I)
08/09 (B)	1,799	1,799	836	3,191	3,671	8,661	8,527	134	137
09/10	1,695	1,695	771	2,965	3,498	8,157	8,010	148	118
10/11	1,713	1,713	797	3,008	3,496	8,217	8,067	149	119
11/12	1,761	1,761	820	3,057	3,492	8,310	8,158	152	121
12/13	1,802	1,802	837	3,100	3,512	8,414	8,260	154	122
13/14	1,834	1,834	854	3,137	3,627	8,597	8,441	157	123
14/15	1,867	1,867	872	3,173	3,711	8,751	8,592	159	125
15/16	1,898	1,898	891	3,217	3,775	8,890	8,728	162	127
16/17	1,924	1,924	908	3,270	3,835	9,030	8,865	164	128
17/18	1,953	1,953	926	3,325	3,901	9,180	9,013	167	130
18/19	1,981	1,981	942	3,376	3,959	9,316	9,147	170	131
AGR 08/09 - 19/19(%)	1.0	1.0	1.2	0.6	0.8		0.7		-0.4
AGR 09/10 - 18/19(%)	1.7	1.7	2.2	1.5	1.4		1.6		1.1

1,137

NOTES:

(A) THESE VALUES REPRESENT CONNECTED LOAD DELIVERED BY EACH OPERATING COMPANY WITHOUT REGARD TO GENERATION SUPPLIER.
(B) ACTUAL.
(C) BASED UPON OCTOBER 2009 CONNECTED LOAD FORECAST.
(D) BASED UPON OCTOBER 2009 CONNECTED LOAD FORECAST.
(E) BASED UPON OCTOBER 2009 CONNECTED LOAD FORECAST.
(F) BASED UPON OCTOBER 2009 CONNECTED LOAD FORECAST.
(G) BASED UPON OCTOBER 2009 CONNECTED LOAD FORECAST.
(H) BASED UPON OCTOBER 2009 CONNECTED LOAD FORECAST
(I) AT THIS TIME, WEST VIRGINIA POWER TERRITORY IS NOT PART OF AP'S CONTROL AREA, BUT RATHER IS SERVED THROUGH A SUPPLY CONTRACT WITH A THIRD-PARTY SUPPLIER.

* These values represent the connected load delivered by each operating company. ECAR defines connected load as the load served by a transmission provider, including losses and without regard to generation supplier.

Table No. 7

Allegheny Power System
Winter Season Projected
Megawatt Capacity and Demand

Bundled Service (Regulated)	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Demand-Side (MW)										
West Virginia										
Monongahela Power	1,693	1,702	1,702	1,712	1,727	1,743	1,751	1,758	1,768	1,813
Potomac Edison	681	691	700	712	725	740	748	761	773	799
West Virginia Power	105	105	105	106	107	107	108	108	108	111
Total	**2,467**	**2,485**	**2,494**	**2,517**	**2,546**	**2,576**	**2,594**	**2,613**	**2,635**	**2,708**
Total (Including 7.90% PJM FPR) [b]	**2,662**	**2,681**	**2,691**	**2,715**	**2,747**	**2,779**	**2,799**	**2,819**	**2,843**	**2,922**
Supply-Side (MW)										
Owned Capacity [c]	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600
PURPA Capacity [d]	155	155	155	155	155	155	155	155	155	155
Purchased (Excess) Capacity [e]	(93)	(74)	(63)	(39)	(8)	25	44	64	88	168
Active Load Management [f]	0	0	0	0	0	0	0	0	0	0
Total	**2,662**	**2,681**	**2,691**	**2,715**	**2,747**	**2,779**	**2,799**	**2,819**	**2,843**	**2,922**
Generation Buy-Back Program [g]	**(42)**	**(42)**	**(42)**	**(42)**	**(42)**	**(42)**	**(42)**	**(42)**	**(42)**	**(42)**
Default Service (De-Regulated)										
Demand-Side (MW)										
Maryland	1,152	1,171	1,201	1,217	1,241	1,257	1,268	1,280	1,293	1,333
Virginia	631	635	645	656	669	676	684	692	701	724
Total [a]	**5,027**	**5,059**	**5,130**	**5,110**	**4,866**	**4,797**	**4,817**	**4,842**	**4,870**	**4,996**
Total (Including 7.90% PJM FPR) [b]	**5,424**	**5,458**	**5,536**	**5,514**	**5,251**	**5,176**	**5,198**	**5,225**	**5,254**	**5,390**
Supply-Side (MW)										
Owned Capacity [c]	0	0	0	0	0	0	0	0	0	0
PURPA Capacity [d]	126	126	126	126	126	126	126	126	126	126
Purchased (Excess) Capacity [e]	5,289	5,323	5,401	5,379	5,116	5,041	5,063	5,090	5,120	5,256
Active Load Management [f]	9	9	9	9	9	9	9	9	9	9
Total	**5,424**	**5,458**	**5,536**	**5,514**	**5,251**	**5,176**	**5,198**	**5,225**	**5,254**	**5,390**
Generation Buy-Back Program [g]	**(18)**	**(18)**	**(18)**	**(18)**	**(18)**	**(18)**	**(18)**	**(18)**	**(18)**	**(18)**

Table 8

<u>Notes for Table 8</u>

a. Summer and winter peak demands are based on AP's share of the 2007/2008 PJM RTO peak forecast and the Allegheny Power (AP) Forecast of Peak Demand and Net Power Supply (LF06Q3 - October 2006). AP default service peak demands are derived from diversified state (PA, MD, VA) peak demands and AP bundled service (WV) peak demands are derived from diversified company (MP, PE, WVP) peak demands.
Actual peak hour demands have an equal probability of being over or under the forecast values due to weather variations. For the purposes of this report, the summer peak is assumed to occur in August and the winter peak is assumed to occur in January of the following year.
Bundled Service load consists of AP electric customers who do not have retail choice.
Default Service load consists of AP customers who have choice and are not taking service from an alternate generation supplier. The latest estimates of AP customers served by

b. Total loads include the PJM West Forecast Pool Requirement (FPR) of 7.90%. These load values, in conjunction with PJM UCAP values for capacity, comprise the PJM Installed Reserve Margin (IRM) requirement of 15%, which is in effect until May 31, 2008.

c. As of January 1, 2007, AP's generation capacity consists of MP generation, along with MP's share of Bath County and OVEC. The capacity values listed are January and August 2007 PJM UCAP values.

d. PURPA Capacity is generation purchased from small power production and cogeneration qualifying facilities pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA generation is currently used by AP to serve bundled service and default service load. This capacity is based on PJM UCAP (Unforced Capacity) values.

e. Purchased capacity is capacity purchases made by AP for bundled service and default service load requirements, including the PJM Installed Reserve Margin (IRM) requirement of 15%.

f. Active Load Management (ALM) program, which began on June 1, 2003, is based on PJM's requirement that a customer must be able to be interrupted within two hours for a minimum

g. The generation buy-back program is a voluntary program that enables AP to buy back electric generation capacity from retail customers during high cost periods. Due to this program being strictly voluntary, these values are shown as reference only and are not used in calculating PJM IRM requirements.

h. This plan represents one of many possible futures based on current legal requirements. While the plan is shown for an extended period of time because of filing requirements, any projection beyond the near term has a very low probability of occurrence due to uncertainties in the load forecast and in the regulatory environment.

i. Some values may not sum exactly due to rounding.

VI. APPENDIX

TO THE

REPORT OF THE WEST VIRGINIA LEGISLATURE

THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

ELECTRIC SUPPLY AND DEMAND BALANCE

Appalachian Power Company
Existing Plants

Plant Name	Location	Unit No.	Year In Service	Kind	Fuel	APCo Percent Ownership	Unit Nameplate Capacity (Kw)	Unit Capability Kw
Kanawha River	Glasgow, WV	1	1953	Steam	Coal	100	219,688	200,000
Kanawha River	Glasgow, WV	2	1953	Steam	Coal	100	219,688	200,000
John E. Amos	Saint Albans, WV	1	1971	Steam	Coal	100	816,300	800,000
John E. Amos	Saint Albans, WV	2	1972	Steam	Coal	100	816,300	800,000
John E. Amos	Saint Albans, WV	3	1973	Steam	Coal	33.33*	433,000	433,000
Glen Lyn	Glen Lyn, WV	5	1944	Steam	Coal	100	100,000	95,000
Glen Lyn	Glen Lyn, WV	6	1957	Steam	Coal	100	237,500	240,000
Philip Sporn	Ghaham Station, WV	1	1950	Steam	Coal	100	152,500	150,000
Philip Sporn	Ghaham Station, WV	3	1951	Steam	Coal	100	152,500	150,000
Clinch River	Carbo, VA	1	1958	Steam	Coal	100	237,500	235,000
Clinch River	Carbo, VA	2	1958	Steam	Coal	100	237,500	235,000
Clinch River	Carbo, VA	3	1961	Steam	Coal	100	237,500	235,000
Mountaineer	New Haven, WV	1	1980	Steam	Coal	100	1,300,000	1,300,000
Totals							5,159,976	5,073,000

* Ohio Power Company owns 66.67% of the 1,300,000 Kw unit

Appalachian Power Company
Existing Hydroelectric Plants

Plant Name	Location	Stream Name	Year In Service	Unit Nameplate Capacity (Kw)	Unit Capability Kw*
Claytor	New Radford, WV	New River	1939	75,000	28,000
Leesville	Leesville, WV	Roanoke River	1964	40,000	9,000
Reusens	Lynchburb, VA	James River	1903	12,500	6,000
Byllesby	Byllesby, VA	New River	1912	21,600	8,000
Buck	Near Byllesby, VA	New River	1912	8,505	5,000
Niagra	New Roanoke, VA	Roanoke River	1954	2,400	1,000
London	London, WV	Kanawha River	1935	14,400	12,000
Marmet	Marmet, WV	Kanawha River	1935	14,400	11,000
Winfield	Winfield, WV	Kanawha River	1938	14,760	15,000
Totals				203,565	95,000

* The revised hydroelectric capability values are based on average Kw output determined by using water flows and equipment manufacturer data.

Chart No. 1 (Page 2 of 3)

Appalachian Power Company
Existing Pumped Storage Plants

Plant Name	Location	River Name	Year In Service	Type of Pump	Unit Nameplate Capacity (Kw)	Unit Capability Kw*
Smith Mountain 1	Penhook, VA	Roanoke River	1965	Reversable	66,025	66,000
Smith Mountain 2	Penhook, VA	Roanoke River	1965	Non-Reversable	150,100	174,000
Smith Mountain 3	Penhook, VA	Roanoke River	1980	Reversable	115,344	106,000
Smith Mountain 4	Penhook, VA	Roanoke River	1966	Non-Reversable	150,100	174,000
Smith Mountain 5	Penhook, VA	Roanoke River	1966	Reversable	66,025	66,000
Totals					547,594	586,000

Chart 1 (Page 3 of 3)

Appalachian Power Company
Summary of Interchange Locations

Name of Company	Points of Interchange	Voltage of Interchange
Associated Utilities		
Ohio Power Company	Under Terms of the Interconnection Agreement (7/6/1951)	Various
Indiana Michigan Power Comopay		
Kentucky Power Company		
Columbus Southern Power Company*		
Non-Associated Utilities		
Carolina Power & Light Company	Danville, VA	230kV
	Kingsport, TN	138kV
	Kingsport, TN	230kV
Duke Power Company	Ridgeway, VA	138kV
	Austinville, VA	500kV
Monogahela Polwer Company	Bentree, WV	138kV
	Quinwood, WV	138kV
	Belmont, WV	765kV

* Formerly Columbus and Southern Ohio Electric Company which became a part of the AEP System in May, 1980

Appalachian Power Company
Summary of Interchange Locations

Non-Associated Utilities Continued

Name of Company	Points of Interchange	Voltage of Interchange
Virginia Power Company	Roanoke, VA	500kV
	Scottsville, VA	138kV
	Altavista, VA	138kV
	Ronceverte, WV	138kV
	Philpott, VA*	138kV
	Red Hill, VA*	115kV
	Bearskin, VA*	138kV
	Banister, VA	138kV
	Big Island, VA	115kV
	New Haven, WV	345kV
	Huntington, WV	345kV

Public Authorities

Tennesee Valley Authority	Near Bristol, TN	138kV
	Kingsport, TN	138kV
	Kingsport, TN	500kV
	Near Bluff City, TN	500kV

* Serves Local Load or Generation only

Chart No. 2 (Page 2 of 2)

Wheeling Power Company
Summary of Interchanges

Name of Company	Points of Interchange	Voltage of Interchange
Associated Utilities		
Ohio Power Company	Natruim, WV	138kV
	Near Moundsvilled, WV	138kV
	Benwood, WV	138kV
	Near Brilliant, WV	138kV
Non-Associated Utilities		
Monongahela Power Company	Natrium, WV	138kV

Chart 3

Monongahela Power Company
Existing Regulated Plants

Plant Name	Location	Unit No.	Year In Service	Kind	Fuel	MPCo Percent Ownership	MPCo Regulated Ownership Capacity (Kw)*
Albright	Albright, WV	1	1952	Steam	Coal	100	76,000
		2	1952	Steam	Coal	100	76,000
		3	1954	Steam	Coal	100	140,000
Fort Martin	Maidsville, WV	1	1967	Steam	Coal	100	552,000
		2	1968	Steam	Coal	100	555,000
Harrision	Haywood, WV	1	1972	Steam	Coal	21	135,769
		2	1973	Steam	Coal	21	135,769
		3	1974	Steam	Coal	21	135,769
Pleasants	Willow Island, WV	1	1979	Steam	Coal	8	49,985
		2	1980	Steam	Coal	8	49,985
Rivesville	Rivesville, WV	5	1943	Steam	Coal	100	48,000
		6	1951	Steam	Coal	100	94,000
Willow Island	Willow Island, WV	1	1949	Steam	Coal	100	55,000
		2	1960	Steam	Coal	100	188,000
Totals							2,291,277

* MPCo's regulated capacity is based on the percentage of ownership

Chart 4

Monongahela Power Company
Summary of Interchange Locations

Name of Company	Points of Interchange	Voltage of Interchange
Associated Utilities		
West Penn Power Company	Various at or near the Pennsylvannia and West Virginia	500kV
	State Line	138kV
The Potomac Edison Company	Near Lake Lynn, PA, Albright and Petersburg, WV	138kV
Non-Associated Utilities		
PA, NJ, MD (PJM RTO Group)	See note below	500kV, 230kV
		138kV, 115kV
Appalachian Power Company	Near Gilboa and Grassy Falls, WV	138kV
	Near Belmont, WV	735kV
Wheeling Power Company	Near Natrium, WV	138kV
	Near Chester, WV	765kV
Ohio Edison Company	Near Weirton, WV	345kV
Duquesne Light Company	No Direct Interconnection	
	Interchange occurs through West Penn Power Company	138kV
Ohio Power Company	Various near Beverly and East Liverpool, OH and near	
Monogahela Poiwer Company	Moundsville, Weirton, and Beech Bottom, WV	500kV, 138kV
		345kV
Virginia Power Company	Mount Storm, WV	500kV

Note: As a member of PJM and though the development of the PJM West RTO, AP is operated as a control zone within the PJM control area for coordinationg of market operations and market settlement

Chart 5