Public Service Commission of West Virginia

Supply-Demand Forecast For Electric Utilities

2012-2021

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Executive Summary

The sixty-fourth Legislature (1979) directed the Public Service Commission of West Virginia (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 (W. Va. Code § 24-1-1(d)(3)). Pursuant to that requirement, the Commission Staff conducts a yearly examination of major forecasting methodologies presently in use by each of the major electric utilities in West Virginia.

The four largest regulated electric utilities in West Virginia are: Appalachian Power Company (APCo), Monongahela Power Company (Mon Power), The Potomac Edison Company (PE), and Wheeling Power Company (WPCo). APCo and WPCo are sister companies in American Electric Power (AEP). Mon Power and the PE Company are sister companies in FirstEnergy (FE). APCo and Mon Power are the State's only regulated electric distribution utilities that generate power. These four utilities account for approximately 96% of total West Virginia residential sales and 98% of total West Virginia commercial and industrial sales. Although WPCo and PE do not generate electricity, they are combined with their respective sister companies, APCo and Mon Power, for West Virginia ratemaking purposes. Thus, for purposes of this report, APCo/WPCo are paired and treated as generation companies, as are Mon Power/PE.

Currently, there are five independent non-generation electric utilities purchasing power at wholesale that distribute purchased power to local residential, commercial and industrial customers at retail rates subject to Commission jurisdiction. Those are:

1. Harrison Rural Electrification Association
2. Black Diamond Power Company
3. Craig-Botetourt Electric Cooperative
4. New Martinsville Municipal Utilities
5. Philippi Municipal Electric

The net demand of each reselling company is reflected in the demand projection of its wholesale power provider.

In addition to the major utilities' supply and demand forecasts, the Commission Staff also considers the regional utility forecasts conducted by Reliability First Corporation (RFC). RFC is a member of the North American Electric Reliability Corporation (NERC). One of NERC's many responsibilities is assessing future adequacy of North America's transmission grid and energy supply.[1] RFC assesses "future adequacy" of its region including the Pennsylvania, New Jersey, and Maryland Regional Transmission Organization (PJM-RTO or RTO) in which FirstEnergy and AEP are members.[2] The role of any RTO is controlling each regional utility generator's output (regional supply) such that it meets customer instantaneous power requirements (regional demand). If a sudden loss of one or more generators and/or transmission lines should occur, PJM relies on a "reserve generating capacity margin" (reserve capacity) of approximately sixteen percent.

The Commission's annual Supply-Demand Forecast for Electric Utilities consists of a ten year load growth forecast and customer demand data furnished by AEP, FE and the RFC.[3] AEP and FirstEnergy furnish additional information in the form of a capacity (supply) expansion plan also known as integrated resource planning (IRP). An IRP enables each utility to project future equipment upgrades, additional generating units and/or purchased generation needed to meet the State's increasing customer demand for the next ten years. The Commission Staff reviews the information to determine whether the State's peak load electric supply is sufficient to meet the State's peak customer demand plus an additional sixteen percent reserve capacity for the next ten years.

For the forecast period of winter 2011/2012 through the winter of 2020/2021, Staff concludes the following:

1. West Virginia's expected growth in peak electric demand could average 1.4% to 2.2%. Generation capacity will be greater than customer demand;

2. Capacity plans based on current demand projections indicate the State's electric supply will be sufficient to meet customer demand and provide a reasonable reserve margin;

3. Average annual peak load growth for each West Virginia electric distribution utility for which a separate forecast is performed and for the aggregate of the affiliated group within which they operate (AEP and FirstEnergy) is:

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

[2] Please refer to the NERC Regional Reliability Councils map shown on page 7.

[3] American Electric Power and FirstEnergy supply data for the State's project load growth and customer demand. Reliability First Corporation (RFC) projects load growth and customer demand for the region including West Virginia and surrounding states. RFC's regional forecast is the only regional forecast considered in the report.

Utility	
Appalachian Power Company	0.5%
Wheeling Power Company	0.3%
American Electric Power - aggregate	0.2%
Monongahela Power	1.7%
The Potomac Edison Company	2.2%
FirstEnergy – aggregate	1.5%

4. AEP developed a generation expansion plan consisting of new generation sources added within the forecast period. Additional new generation resources up to 1,419 MW may be possible for 2012 through 2021. Current projections indicate AEP's expansion plan will assist in maintaining PJM's reserve capacity margin;

5. Mon Power's 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 RTO. Continued reliance on power markets to provide firm capacity assumes that capacity will be available from a market source;

6. APCo has made significant investments in emission control equipment responding to requirements under the Clean Air Act (CAA), CAA Amendments, the United States Environmental Protection Agency's Nitrogen Oxides State Implementation Plan (NO_x SIP Call) and the Clean Air Interstate Rule (CAIR). Newly established and proposed environmental regulations continue to expand the scope and increase the stringency of applicable requirements. These programs will require AEP/APCo to make additional capital investments and operational changes to comply with more stringent air emissions, ash disposal, cooling water intake, and wastewater discharge requirements. The development and implementation of a comprehensive compliance plan is an iterative process that is driven by the stringency and implementation schedule of new regulatory programs, as well as by consideration of available compliance strategies such as the addition of emission controls, fuel-switching, and unit retirement options. Site-specific variables, such as the age, location, and type of unit, are also important factors considered in compliance planning. The impact of the emission control requirements on APCo's supply and demand balance has been, and will continue to be, significant.

Forecast Procedure

The procedure for determining a ten-year supply and demand forecast is comprised of two basic steps. Step one is collecting data on historical electric peaks, economic conditions and weather conditions. Additionally, utilities provide forecasts of future electrical requirements and recommendations for the narrative parts of this report. Since all four companies use econometric forecasting models requiring explicit economic and demographic assumptions, an evaluation of the appropriateness of some of the models' assumed values is also made. However, data provided by private forecasting services precluded independent verification of some input variables.

Step two of the forecast procedure involves 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 is incorporated in this study.[4]

Utility forecasts, aggregated by RFC, are included in this report (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. This Report provides average annual growth rates to permit comparisons to previous Reports. Use of compound growth rates sensitive to starting and ending dates requires caution.

Projections and conclusions of this Report are specific to a particular point in time. The analyses are subject to some level of uncertainty that may influence the need for capacity by West Virginia electric utilities during the forecast period. FERC's attempt to restructure the electric utility industry to provide greater competition introduces new uncertainties affecting peak supply and demand reliability. Therefore, the annual supply and demand report of the Commission does not preclude a determination of different capacity requirements in future proceedings or any other case related basis.

[4]"Demand" is the <u>average</u> 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 <u>total</u> amount of electricity used, measured in megawatt hours.

Regional Projections

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

All RFC members, with the exception of the Ohio Valley Electric Corporation (OVEC)[5], are affiliated with either the Midwest Independent Transmission System Operator, Inc**.** (MISO) or PJM Interconnections, LLC (PJM) for operations and reliability coordination. Resource adequacy of RFC is determined via assessments of MISO and PJM against their individual adequacy standards. RFC compiles long-term supply and demand projections of member utilities to ensure a reliable supply of electricity. Forecasted average rates of demand growth from winter 2011/2012 to winter 2020/2021 are expected to be 0.9% per year. RFC's winter reserve margin should remain 41 percent higher than customer demand throughout the forecast period. The aggregate demand of the RFC region typically peaks in the summer. Forecasted rates of demand growth, from summer 2012 to summer 2021, average 1.0% per year. RFC's summer Reserve Margin should decline to approximately 14.7% of customer demand by the end of the forecast period without the inclusion of additional capacity from Independent Power Producers (IPP).

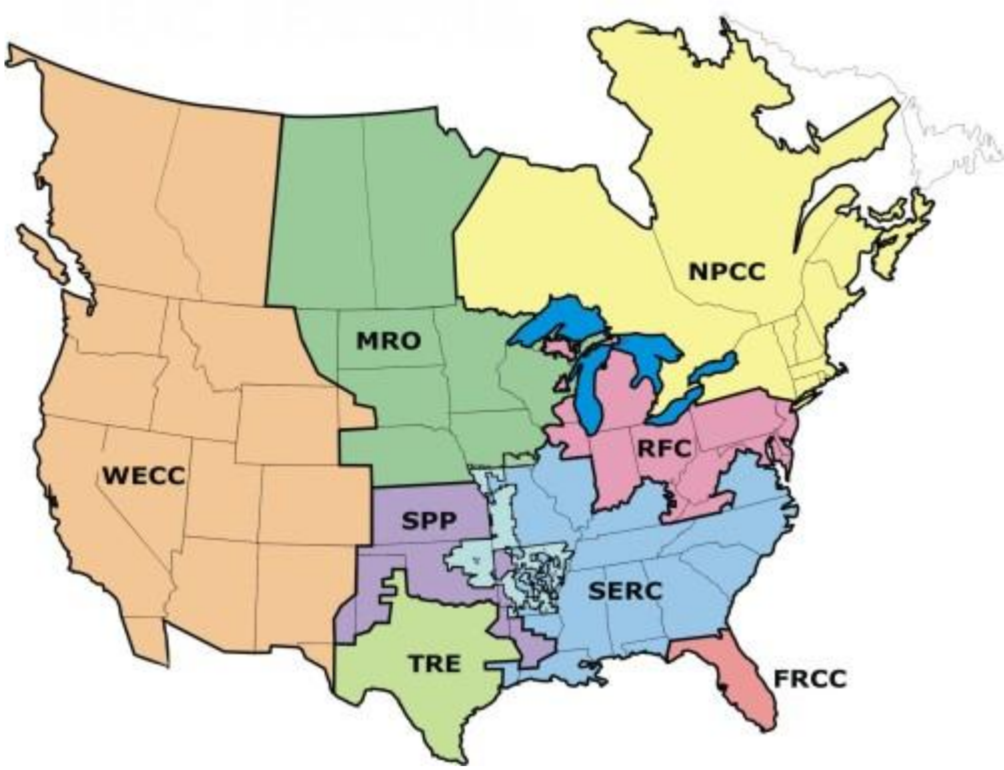
RFC's regional map is available in this report. NERC Regional Reliability Council's ten-year supply and demand forecast for summer and winter peaks is included in Tables 1 and 2.[6] The bulk electric system in the RFC region is expected to perform well during the forecast period.

RFC's annual peak total internal demand should continue to occur during the summer. Forecasted economic factors and average weather conditions will determine summer time growth of peak demand. Therefore, the actual peak demands may vary significantly from year to year. The 2011 forecast is 1.0% above the 2010 actual. RFC resource projections indicate direct-controlled and interruptible load-management programs will provide 5,614 MW of supplemental resources during the 2012-2021 forecast periods. RFC's net internal demand is approximately 190,850 MW in 2020 after removing interruptible demand and loads subject to demand-side management.

[5] OVEC is a generation and transmission utility located in Kentucky and Ohio
[6] Map is courtesy of the NERC Long Term Reliability Assessment 2007 published on October 2007 available at www.nerc.com.

Map No. 1

North American Electric Reliability Corporation (NERC) Regions



FRCC - Florida Reliability Coordinating Council
MRO - Midwest Reliability Organization
NPCC - Northeast Power Coordinating Council
RFC - Reliability*First* Corporation
SERC - SERC Reliability Corporation
SPP - Southwest Power Pool, RE
TRE - Texas Regional Entity
WECC - Western Electricity Coordinating Council

Note: The Alaska Systems Coordinating Council (ASCC) is an affiliate NERC member.

Source: North American Electric Reliability Corporation

Table No. 1

RFC REGIONAL COUNCIL

WINTER SUPPLY AND DEMAND ANALYSIS

Winter of	Load (1) MW	Generation (2) MW	Reserve %	Annual Load Growth Rate %
2010/11	144,317	216,800	50.2	--
2011/12	146,664	225,440	53.7	1.6
2012/13	149,691	225,440	50.6	2.1
2013/14	151,604	225,440	48.7	1.3
2014/15	152,771	225,440	47.6	0.8
2015/16	153,759	225,440	46.6	0.6
2016/17	154,865	225,440	45.6	0.7
2017/18	155,793	225,440	44.7	0.6
2018/19	156,943	225,440	43.6	0.7
2019/20	158,049	225,440	42.6	0.7
2020/21	159,261	225,440	41.6	0.8

Source: 2011 Electricity Supply and Demand 2011-2020, September 2011, 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 exists, presently under construction, or in various stages of planning; plus scheduled capacity purchases and less capacity sales. Does not include amounts of capacity for power projects that have been announced for the region but which are not at least in the planning stage.

Table No. 2

RFC REGIONAL COUNCIL
SUMMER SUPPLY AND DEMAND ANALYSIS

Summer of	Load (1) MW	Generation (2) MW	Reserve %	Annual Load Growth Rate %
2011	186,155	231,700	24.5	--
2012	181,282	225,440	24.4	-2.6
2013	185,555	225,440	21.5	2.4
2014	187,506	225,440	20.2	1.1
2015	189,079	225,440	19.2	0.8
2016	190,325	225,440	18.5	0.7
2017	191,740	225,440	17.6	0.7
2018	193,203	225,440	16.7	0.8
2019	194,895	225,440	15.7	0.9
2020	196,464	225,440	14.7	0.8

Source: 2011 Electricity Supply and Demand 2011-2020, September 2011, 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 exists, presently under construction, or in various stages of planning; plus scheduled capacity purchases and less capacity sales. Does not include amounts of capacity for power projects that have been announced for the region but which are not at least in the planning stage.

Companies

American Electric Power Company

Generating companies of the American Electric Power (AEP) East System (AEP East) continue to be parties to the AEP Interconnection Agreement (IA). AEP's interconnection "pool agreement" includes five other AEP System operating companies. Each member of the pool is responsible for a proportionate share of the aggregate AEP System pool generating capacity. Four AEP System (West Zone) operating companies are parties to a separate interconnection agreement. System integration agreements tie the eastern and western AEP zones together. However, AEP indicates there is relatively little effect on the AEP East companies' reserve outlook from the system integration agreement.

Appalachian Power Company (APCo) is one of the generating companies of the AEP East. Wheeling Power (WPCo) is a non-generating AEP Company. While each company remains a separate entity, they are combined for West Virginia regulatory purposes, such as for establishing rates.

The focus of this report is the balance of electric supply and demand within West Virginia. Therefore, the Commission Staff 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 East, Staff's examination necessarily extends to that system's capacity capabilities and planning.

Appalachian Power Company

Appalachian Power Company is the largest AEP subsidiary in terms of population served, number of customers and area of service territory of the operating companies that comprise the AEP East. In 2010, APCo provided electric service to approximately 961,000 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.

APCo's generation mix includes coal-fired steam plants and hydroelectric facilities and one natural gas-fired combustion turbine plant (detailed on Chart No. 1 in Appendix B). Additionally, APCo purchases wind power under various contracts and is constructing the Dresden natural gas plant that is scheduled for completion during the first quarter of 2012. APCo has interconnections with other utilities (detailed on Chart No. 2 in the Appendix). These interconnections provide for reliability across a broad interconnected electrical network and allow economic sales and purchases of power among the interconnected companies.

Wheeling Power Company

Wheeling Power Company provides electric service to approximately 41,000 customers (at year-end 2010) primarily in Ohio and Marshall Counties of West Virginia's northern panhandle. Currently, WPCo is solely a transmission and distribution company. WPCo has a purchased power contract with Ohio Power Company (OPCo). For rate and regulation purposes in West Virginia, the overall power supply costs of APCo and the WPCo purchased power contract are combined and shared among APCo and WPCo customers.

FirstEnergy Corporation

Monongahela Power Company (Mon Power) and Potomac Edison Company (PE) comprise the regulated operating companies of FirstEnergy Corp. (FE) in West Virginia. Each company remains a separate legal entity.

The FE projections include some estimated impact of the 1990 Clean Air Act Amendments (CAAA). The CAAA will affect both future demand and capacity. There is a flue gas desulfurization scrubber facility at the Harrison Power Station[7] in Harrison County, West Virginia (in compliance with Phase I of the CAAA, this facility was placed in service on January 1, 1995) and Mon Power also installed scrubbers at its Fort Marin generation facilities during 2009.

Monongahela Power Company

In 2011, Monongahela Power provided electric service to approximately 387,000 customers in West Virginia. Mon Power's present generation is largely coal-fired steam plants as detailed on Chart No. 4 in Appendix B, but includes some pumped storage and PURPA capacity. As of April 2009, Mon Power has approximately 41% equity ownership in the Allegheny Generating Company (AGC). AGC is a subsidiary of Mon Power and Allegheny Energy Supply Co., LLC. AGC owns 40% of the Bath County (2,773 MW as of March 2009) pumped storage facility located in Bath County, VA. The Bath County facility was placed in service in 1985. Mon Power also has three PURPA contracts for a total of approximately 160MW. Mon Power is a member of PJM, giving it access to liquid competitive wholesale energy and capacity markets.

[7] The Harrison Power Station is jointly owned by Monongahela Power and AE Supply, Inc.

Potomac Edison Company

Potomac Edison Company provided electric service to approximately 389,000 customers in 2011 in the States of West Virginia and Maryland, with approximately 136,000 of those customers located in the Eastern counties of West Virginia.[8] On December 31, 2010, PE purchased the Shenandoah Valley Electric Cooperative territory in West Virginia.

PE 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 PE's retail load responsibilities in West Virginia, PE previously entered into a power supply arrangement with its affiliate Allegheny Energy Supply. This supply arrangement terminated with implementation of generation transfers between Mon Power and Allegheny Energy Supply. This process transferred generation capacity to Mon Power so that PE could serve its West Virginia retail load responsibilities through generation assets owned by Mon Power.

[8] PE sold its Virginia jurisdictional service territory to Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative effective June 1, 2010. The sale resulted in about 102,000 less distribution customers in the Potomac Edison Company operating company service territory. The transmission assets were retained.

Forecasting

AEP Forecasting

The AEP System is comprised of two fully integrated zones. These are referred to as AEP East and AEP West. APCo is located in the AEP East zone, along with generating affiliates OPCo, Columbus and Southern Power Company (CSPC), Kentucky Power Company (KPCo), and Indiana and Michigan Power Company (I & M). Two non-generating distribution AEP Companies in the East zone are WPCo and Kingsport Power Company (KP). Much of the engineering, accounting, purchasing and other functions for both zones is accomplished using a professional staff located at the system offices in Columbus, Ohio and Tulsa, Oklahoma. The Service Corporation (AEPSC) in Columbus and Tulsa, in consultation with each of the AEP System operating companies, do all of the forecasting for APCo as well as other affiliated companies. To evaluate APCo, then, one has to review the technique employed by AEPSC.

Generally, AEPSC reviews, prepares and revises all forecasts as necessary. 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 East operating companies, as well as the aggregate AEP System zones, are usually issued. AEPSC reviews each short-term forecast, in detail, during the year. If necessary, each forecast is revised reflecting recent experiences and changes in short-term outlook.

1. AEP East peak demand forecast is calculated by summing the forecast for its operating companies, taking into account diversity effects. The following provides an overview of more important considerations in developing the current AEP Base Case forecast.

2. Growth will continue in the number of residential customers served by AEP East at the rate of 0.4% per year.

3. Electricity prices for AEP East operating companies incorporate expectations concerning the need for new generation, compliance with environmental laws, fuel costs and other factors that may affect price during the 2012-2021 period.

4. The forecast of peak internal demand for each individual operating company is determined by developing a monthly peak electric demand forecast model that simulates typical peak loads by jurisdiction. This model, in conjunction with monthly energy forecasts, produces a preliminary weather-normalized peak load forecast for each month and season. Forecasted peak demands are evaluated for reasonableness of both projected load factor and growth rate.

5. The projected seasonal peak demand requirements of AEP System utilize aggregate projected hourly peak demands of System's operating companies.[9] Currently, the AEP East annual load factor forecast is between 66% and 67% over the forecast period.

6. 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, historical and projected data relating to factors such as weather, demographics, economic activity, industrial production, appliance saturation characteristics and future technological outlook are sources of interest.

<u>AEP Projected Summer Peak Demand</u>

This report focuses on AEP East summer peak demand since AEP East is forecasting a summer peaking system over the forecast period. For example, AEP East projected summer peak demand for 2012 is 1.8% greater than the winter 2011/2012 projected system peak, and by summer 2021 the projected summer peak is 3.2% greater than the 2020/2021 winter peak. The projected winter peak demands for AEP East and most of its member companies are shown on Table 3(a). Average annual growth rates (AGR) are provided on this table and throughout this report. These growth rates are compound growth rates and are sensitive to the choice of starting and ending dates and should be used with care. For AEP East as a whole, the ten-year average annual growth rate in the summer peak internal demand is forecasted to be 0.4%. AEP predicts that over the forecast period, summer 2012 through summer 2021, demand will rise from a level of 21,264 MW to 21,949 MW. This represents a 685 MW increase in peak load. In terms of megawatt hours of electrical energy the long term growth rate of AEP East requirements over the same ten-year period is approximately 0.2% per year.

<u>APCo Projected Winter Peak Demand</u>

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

1. Growth in the number of West Virginia residential customers is expected to be 0.2% per year. Energy conservation will continue to play a role in reducing the rate of

[9]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.

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.

2. Since the 1980's, coal mining employment continues to decline primarily because of significant increases in productivity resulting from changes in mining techniques. Mining employment should continue to decline, during the forecast period, but at a much slower pace. The forecast also assumes increased output with continued productivity increasing.

In summary, APCo's annual load factor in 2010 was 58% and is expected to be near 58% through 2021, 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 0.5%.

FirstEnergy Forecasting

Mon Power and PE are part of a fully integrated electrical system within the Allegheny Power subsidiary of FirstEnergy (FE). Much of the engineering, accounting, purchasing and other functions are accomplished through the use of a consolidated professional staff located at the corporate offices in West Virginia (Fairmont), Ohio (Akron) and Pennsylvania (Greensburg). A discussion of the load forecasting techniques of Mon Power and PE involves a discussion of the techniques used by FE.

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

2. The Mon Power and PE forecasting methodology employs both econometric and end-use models. The residential kilowatt-hour use per customer model is a statistically adjusted end-use model that 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 also blends both econometric and end-use modeling methodologies. The commercial statistically adjusted end use model combines econometric techniques driven by weather, price of electricity, number

of customers, and service area state non-manufacturing employment along with the end-use structure that captures equipment efficiency trends and saturations over time.

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

4. Peak load forecasts are based on a model that considers end-use estimates and class load diversity based on projected residential, commercial and industrial sales. These are derived from the energy sales models.[10]

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

Mon Power and PE Projected Winter Peak Demand

Table 5 shows the Mon Power and PE winter peak demand for the forecast period of the Winter of 2011/12 through the Winter of 2020/21. Table 5 also reflects the projected Winter peak demands of each of the West Virginia Mon Power and PE operating companies. Table 5 represents the Allegheny Power zone Control Area (AP zone Control Area) load as well as the demand for West Virginia Power (WVP).

The average annual growth rate in the winter peak demand for the entire AP zone Control Area is projected to be 1.0% over the forecast period of Winter 2011/12 to Winter 2020/21. Mon Power and PE project an 800 MW increase over the forecast period from 8,393 MW to 9,193 MW. These forecasts are based upon the Mon Power and PE September 2011 Load Forecast.

Table 5 results from an RFC requirement to provide forecasts of the connected load delivered by each operating company without regard to the actual generation supplier.

[10] Major economic features of WV forecast in the interval 2012 through 2021 are: West Virginia population growth will occur at an average rate of 0.13% per year. West Virginia personal income is expected to increase by 3.8% per year from 2012 to 2013 and increase by 1.9% between 2012 and 2021. West Virginia non-farm employment will increase at 1.1% per year from 2012 through 2021. The real (inflation adjusted) price of electricity, in general, declines.

Mon Power Projected Winter Peak Demand

Projection of Mon Power's winter peak demand is shown on Table 5, Column (2). The West Virginia jurisdictional projection is shown in Column (1) as MPWV.

Two of the principle assumptions regarding Mon Power's service territory embedded in these September 2011 demand forecasts are:

1. Mon Power residential customers are projected to increase at an annual 0.5% rate.

2. The residential electric heat saturation is expected to increase from 23.2% in 2011 to about 29.7% in 2021.

Reference to Table 5, Column (2) projects that Mon Power's peak winter demand will increase from 1,853 MW to 2,037 MW at an annual growth rate of 1.1% over the Winter 2011/12 to Winter 2020/21 period. While West Virginia Power (WVP) is now a division of Mon Power, WVP's service territory is not part of AP's Control Area. Therefore, Mon Power has not included WVP peak demand forecasts in the forecasts for Mon Power or MPWV on Table 5. West Virginia Power's peak demand is expected to increase from 131 MW to 141 MW, at an annual growth of 0.9% over the forecast period as shown in Column (9) on Table 5.

PE Projected Winter Peak

Projections of PE winter peak demands are shown on Table 5, Column (4). The West Virginia jurisdictional demand projections for PE are shown on Table 5, Column (3) as PEWV. Some of the assumptions regarding PE's service territory embedded in these September 2011 demand forecasts are:

1. PE residential customers are projected to increase at an annual 1.2% rate.

2. Residential electric heat saturation is expected to increase from 57.1% in 2011 to 62.2% in 2021.

3. The costs associated with the AES Warrior Run project will not be reflected in the rates of PE customers in West Virginia.

Table 5, Column (4) projects the gross winter peaks for PE increasing from 3,084 MW in Winter 2011/12 to 3,317 MW in Winter 2020/21, at an annual growth rate of 0.8%. PEWV, the PE West Virginia jurisdictional demand, is forecast to grow at an average annual rate of 1.2% over the same period.

Reserve Margins Planning and Projections

AEP 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 contention.

Perhaps the two most widely-used measures of adequate capacity are Reserve Margin and Loss of Load Expectation (LOLE). Reserve Margin (R.M.) is described as:

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

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 sufficient generating resources to supply peak summer and winter demands, but also an additional Reserve Margin to provide for contingencies. On October 1, 2004, AEP joined PJM 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%.

APCo Reserve Margin

APCo is projected to remain winter peaking over the next ten years, but APCo is part of the integrated AEP East. In order to assess the adequacy of APCo's Reserve Margin, it is necessary to examine the Reserve Margins of AEP East. Because the system experiences a summer peak, the summer supply and demand projections for APCo are important considerations.

AEP Capacity Plan

The AEP East operating companies jointly plan to meet their combined coincident peak. The five generating companies, APCo, Columbus Southern Power, Indiana-Michigan Power, Kentucky Power, and OPCo participate in a power supply pool agreement. Under this agreement, these companies share in their combined capacity resources.

The capacity changes, either upward or downward, are comprised of efficiency improvements, generating unit additions, purchased solar or wind generation additions, auxiliary power increases and generating unit retirements. 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. Auxiliary power increases are actually decreases in available capacity because of additional emission control equipment consuming power that would otherwise be available for market sales. During the years 2012 to 2016, AEP is planning to retire several generating units. However, generation unit retirements are subject to an ongoing review based, in part, on environmental considerations, and therefore, retirement dates will vary from one forecast to another. Generating capacity is planned to be supplemented via firm purchase of solar and wind energy generation for the entire forecast period of 2012 through 2021. In addition, one new gas fired combined cycle generation unit is included in the forecasted generating capacity additions.

On August 31, 2011, APCo completed the purchase of a natural gas-fired power plant under construction near Dresden, Ohio, from AEGCo, a subsidiary of AEP. When completed during the first quarter of 2012, Dresden will be a nominal 580 MW natural gas-fired combined-cycle plant.

Four AEP companies (APCo, Columbus Southern Power, Indiana-Michigan Power, and OPCo) 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 for the Federal Government's Portsmouth Area Project, that 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 February 2011, the sponsors have agreed to extend the OVEC operating agreement through June 2040.

OPCo owns Unit 1 of the three-unit Cardinal Plant, located in Brilliant, Ohio. Buckeye Power, Inc. owns Units 2 and 3. Buckeye Power supplies the power requirements of Ohio's rural electric cooperatives under terms of an agreement with Ohio's investor-owned electric utilities, whereby power is transmitted over investor-owned transmission systems to each cooperative. OPCo provides Buckeye Power with an alternate source of power when Cardinal Units 2 and 3 are out of service. OPCo is entitled to utilize generating capacity from either Cardinal unit not needed for Buckeye Power's load. OPCo has an agreement with Buckeye Power entitling OPCo to 20% of Buckeye Power's Robert P. Mone Plant (three 182 MW combustion turbines) generating capacity.

Currently, AEP East operating companies are receiving energy from nine wind contracts and one solar project, with total nameplate capacity ratings of 636 MW. Of that total, APCo receives wind power related to five long-term purchase agreements for 376 MW (nameplate capacity). Also, CSP and OPCo are purchasing all of the output from the Public Service Electric and Gas Wyandot Solar project (10 MW, nameplate capacity), which went into commercial operation in May 2010.

AEP East Reserve Margin Projections

The forecasted summer and winter Reserve Margins for AEP East based on AEP supply and demand projections are shown on line 11 of Tables 4(a) and 4(b). 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.

AEP East expects to maintain a minimum Reserve Margin of about 12 percent. AEP East is projecting that it will need additional supply resources to maintain reliability.

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

On December 17, 2010, pursuant to Article 13 of the FERC-approved AEP Interconnection Agreement (IA, Interconnection Agreement or AEP Pool), each of the AEP Pool members gave written notice to the other members, and to American Electric Power Service Corporation (AEPSC), the AEP Pool's agent, of its intent to terminate the Interconnection Agreement, effective January 1, 2014 or such other date as approved by FERC. Because the IA is a rate schedule on file at FERC, its termination will not be effective until accepted for filing by FERC.

The Interim Allowance Agreement among the AEP companies (IAA), which was most recently modified in 1996 and deals with sulfur dioxide (SO_2) emissions and allowances, would also likely be terminated by the FERC during that time frame. Environmental regulations have expanded beyond those covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of nitrogen oxides (NO_x). In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions.

Termination of the Interconnection Agreement will have a significant impact on the sources of capacity and energy available to APCo. It is expected that alternative sources and the impact of the termination of the Interconnection Agreement will be the subject of discussions among the parties prior to and during FERC consideration of a formal filing to terminate the agreement.

This FERC process will provide interested stakeholders an opportunity to participate in the determination of how the AEP East operating companies should operate prospectively. Because the Interconnection Agreement is still in effect, and it is not known how the AEP East operating companies, including APCo, will operate prospectively, this report assumes the existence of the AEP Pool through the forecast period.

FE Capacity Planning

The FE 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 consideration of supplemental capacity needed to meet the reliability standards of PJM and Reliability First over the forecast period and Interruptible Load Resources (ILR). FE Pennsylvania and Maryland affiliates (West Penn and PE) operate in competitive retail markets. As a result, this IRP represents one of many possible scenarios that might be impacted by customer choice in power suppliers.

FE Planning Philosophy

Mon Power and PE are wholly within the PJM Regional Transmission Operation footprint. Numerous system planning benefits are realized as a member and participant of PJM. These benefits include 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 Regional Transmission Expansion Planning (RTEP) process with system planning solutions being effectuated through the energy market and the Reliability Pricing Model (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 15.5% for the 2012 / 2013 delivery year and 15.3% for the 2013 / 2014 and 2014 / 2015 delivery years. Further, PJM's study currently estimates an RTO average forecasted 11-year Reserve Margin of 20.6% for the period 2010 through 2020.[11]

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 provide a basis for build or buy decisions.

FE Projected Supply Side Resources

Table 6 assumes no planned retirements of generating units in the next ten years. Currently, Mon Power plans to meet its RPM capacity obligations using its owned assets and through participation in the PJM RPM capacity market. Currently, Mon Power has a total of 332 customers with interruptible loads under the PJM and the Interruptible Load Resource (ILR) program.[12]

FE Projected Demand Side Resources

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. The most recent 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. For the present time, Mon Power and PE have determined that because the load reductions from current programs are either voluntary or have not yet been material and predictable, it is not prudent to include any load and energy reduction assumptions based on those programs. Any actual impacts from DSM programs will be reflected in the projections as they are included in the historical load data used to develop the load forecast models.

All Mon Power and PE commercial and industrial customers have the opportunity to participate in PJM demand response programs. Mon Power and PE 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 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 resources to reduce peak demand.

[11] 2010 PJM Reserve Requirement Study with an 11-year Planning Horizon: 2010-2020. http://www.pjm.com/~/media/committees-groups/committees/pc/20101006/20101006-item-08-2010-pjm-reserve-requirement-study.ashx

[12] Mon Power and PE act as the Curtailment Service Provider for 4 of the customers.

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. Because of 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, Mon Power and PE have 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 participating customers if they are called upon 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 been used twice in the AP zone on September 23 and 24, 2010. The impact on Mon Power and PE's load demand, from each emergency event, has not been quantified. For the present time, Mon Power and PE determined that load reductions from this program are currently not material or predictable. Therefore, it is not prudent to include load and energy reduction assumptions based on the ILR program. Additionally, the ILR program is being sunset by PJM as of May 31, 2012.

On March 31, 2011, Mon Power and PE filed a Phase I Energy Efficiency and Conservation Plan for Commission approval (Case No. 11-0452-E-P-T) in accordance with commitments made in Cases No. 09-0352-E-42T and 10-0713-E-PC. The Plan is designed to reduce both energy and peak demands by at least 0.5%. The Plan includes home energy audits and appliance replacement programs for low income residential users and rebates for non-residential users who install high efficiency lighting. The Plan is estimated to result in 64,437 megawatt-hours of net energy savings and 13.8 megawatts of demand reduction over the initial five year period. The Companies requested a surcharge be implemented to pay for the cost of these programs. The impact of the surcharge to customers would vary given usage, but under the Companies' proposal, a residential customer that uses 1,000 Kwh of electricity each month would see a $.10 increase in the monthly bill.

The Commission held a hearing on this matter on December 1, 2011. On December 30, 2011, the Commission approved the first phase of the Energy Efficiency and Conservation programs, authorizing the Companies to recover the estimated annual program costs of $1.7 million.

FE Reserve Margin Projections

Mon Power and PE expect 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 2010/2011 planning period is 15.6%.

Comments Received from AEP and FE Regarding Potential Threats to Reliability

AEP Restructuring of the Electric Industry

The movement to a competitive electric market, as well as other reliability issues, will have a profound impact on the electric supply and demand balance throughout the country. 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. Because neighboring utilities are now competitors, that 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 drops or outage events.

Utilities may stockpile 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. Many residents may view new transmission line construction as a way to accommodate sales between distant buyers and sellers, and not as necessary to support their local distribution company.

AEP Environmental Issues

Newly established and proposed environmental regulations continue to expand the scope and increase the stringency of applicable requirements. These programs will require AEP to make additional capital investments and operational changes to comply with more stringent air emissions, ash disposal, cooling water intake, and wastewater discharge requirements. The development and implementation of a comprehensive compliance plan is an iterative process that is driven by the stringency and implementation schedule of new regulatory programs, as well as by consideration of available compliance strategies such as the addition of emission controls, fuel-switching, and unit retirement options. Site-specific variables, such as the age, location, and type of unit, are also important factors considered in compliance planning. Key environmental programs impacting the decision-making regarding the disposition of the APCO and AEP generation fleet are summarized below.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR), which is designed to reduce the impacts from interstate transport of NO_x and SO_2 emissions across the eastern United States. CSAPR is a replacement to the Clean Air Interstate Rule (CAIR) and the previously proposed Transport Rule. The Final Rule applies to facilities in all AEP states and will be implemented in two phases: Phase I in 2012 and Phase II in 2014. The Final Rule is more stringent than proposed resulting in increased and accelerated SO_2 and NO_x reductions across the AEP fleet. Compliance options include installing flue gas desulfurization (FGD) and selective catalytic reduction (SCR) emission controls, fuel-switching, and unit retirements. The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns. The more stringent requirements included in the CSAPR could cause unit curtailments, increased capital requirements, constrained operations and decreased reliability.

On March 16, 2011, the EPA issued a Proposed Rule to reduce the emissions of hazardous air pollutants (HAPs) from coal-and oil-fired electric generating units. The proposal, which is referred to as the Utility MACT (Maximum Achievable Control Technology) Rule, will require additional emission controls to be constructed, will force the premature retirement of some units, and will impair the potential for future new coal generation development. The Rule was finalized in December 2011 and will have a three to four year implementation schedule. Compliance options include installation of additional emission controls, fuel-switching, or unit retirements. The short implementation timeline coupled with the scope of unit outages and retirements required to implement compliance strategies across the U.S. coal-based generation fleet will create challenges with respect to grid reliability and compliance costs.

The Clean Air Act requires the EPA to periodically review national ambient air quality standards (NAAQS). On July 12, 2011, the EPA proposed secondary NO_x and SO_2 standards. AEP is currently evaluating the potential impacts of this proposal. Revised ozone standards had been expected in 2011, but on September 2, 2011, it was announced that reconsideration of the ozone standards would not occur until 2013 in order to coincide with the EPA's current review of the science. After NAAQS are revised, States are required to designate areas that do not meet those standards (non-attainment areas) and must implement plans to bring those non-attainment areas into compliance. Because of the expected stringency of each of the revised standards, additional NO_x and SO_2 reductions are likely to be required for the AEP coal-fleet.

Although federal greenhouse gas regulation (GHG) legislation is unlikely in the near future, the EPA has initiated and intends to broaden the regulation of GHG emissions by expanding the applicability of existing Clean Air Act programs. For example, in 2010, the

EPA finalized the GHG Tailoring Rule, which establishes thresholds for when new emission sources or modifications to existing sources are required to obtain permits that regulate GHG emissions. The EPA is also currently developing New Source Performance Standards (NSPS) for GHG emissions from power plants, which at the earliest are expected to be proposed in 2012. Given that cost-effective post combustion control technologies for power plants have yet to be commercialized, the compliance will likely focus on generation efficiency and alternative fuel.

In June 2010, the EPA published a Proposed Rule to regulate the disposal and beneficial reuse of coal combustion residuals, including fly ash and bottom ash from coal-fired electric generating units. The Rule contains two alternative proposals: one would impose federal hazardous waste disposal and management standards on these materials; and the other would allow States to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills. In either case, the EPA is either requiring or strongly encouraging phase-out of wet disposal of these materials by requiring existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final Rule. The proposed schedule for implementation is short, within five years of final adoption of the program. Regulation of these materials as hazardous wastes would significantly increase costs of coal-fired generation. A Final Rule is expected in 2013.

In April 2011, the EPA issued a Proposed Rule under Section 316(b) of the Clean Water Act that would establish standards for existing power plants that reduce impacts to aquatic organisms related to cooling water intake processes. The Proposed Rule establishes both impingement and entrainment standards. Impingement refers to impacts from being pinned against the cooling water intake screen, while entrainment refers to impacts when small fish, eggs or larvae are drawn into the cooling water system. The proposed rule would drive additional capital investments that could require upgrades to the existing cooling water intake structures or installation of cooling towers. A Final Rule is expected in July 2012.

The EPA is moving forward to update guidelines that will result in more stringent limits for water discharges from power plants. More stringent limits would drive additional capital investments to upgrade or install new wastewater treatment systems. The EPA is expected to issue a Proposed Rule in July 2012 with a Final Rule is expected in January 2014.

AEP Aging Generating Units

Currently, there are 45 coal-fired units on the AEP East System that are 30 or more years old. These units represent 17,026 MW, or 65 percent of AEP East total capability. Assuming no retirements, by 2021 the number of coal-fired units more than 30 years old would increase to 48 units representing 19,976 MW, or 76 percent of total existing system capability. Depending upon new and proposed environmental regulations, it is possible that a number of AEP East coal-fired plants will be retired prior to 2021. The availability of units may also deteriorate as a result of the aging process unless appropriate measures are taken.

AEP Loss of Interruptible Load

In 2011, the AEP East System served a significant amount of interruptible load (1,071 MW based on contract demands). However, after reflecting diversity of the various customer loads plus an allowance for customer curtailments because of economic price signals, the estimated load available for interruption is 565 MW at summer peak and 579 MW at winter peak. It should be noted that this interruptible load does not reflect customers participating in PJM’s demand response programs. As AEP East Reserve Margins decline, the threat of increased interruptions may lead some interruptible customers to seek to become firm customers.

AEP Transmission Issues

On June 22, 2007, the PJM Board approved a transmission project, known as the Potomac-Appalachian Transmission Highline (PATH) Project, for inclusion in PJM's Regional Transmission Expansion Plan. The PATH Project, which was approved by the PJM Board for the purpose of maintaining the reliability of the PJM transmission system, was a joint venture of subsidiaries of AEP and Allegheny Energy, Inc., now FirstEnergy, Inc. (FE).

In February 2011, PJM announced its decision to hold the PATH Project in abeyance in its 2011 Regional Transmission Expansion Plan (RTEP). PJM directed AEP and FE to suspend current development efforts on the PATH Project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the potential need for the PATH Project as part of its continuing RTEP process. PJM’s announcement specifically indicated that PJM was not directing AEP and FE to cancel or abandon the PATH Project.

In February 2011, PATH-WV filed a motion to withdraw its pending certificate of public convenience and necessity application in West Virginia based on PJM’s directive and the motion was granted by the Commission in March 2011. Applications for certificate and siting of PATH in Maryland and Virginia have also been withdrawn.

FE Environmental Issues

The operations of FE'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 Mon Power and PE to incur substantial additional costs to modify or replace existing and proposed equipment and facilities. These costs may adversely affect the cost of Mon Power and PE's future operations.

FE Global Climate Change

In response to a potentially carbon constrained future, Mon Power is running its generation assets as efficiently as possible to reduce carbon emissions. Mon Power and PE are educating customers to consume less and to be conservation minded with respect to energy use. To promote the lowest possible cost to customers, the cost of carbon would be reflected in future dispatch costs to assure that the lowest carbon emitting generation facilities would run first. Finally, Mon Power would actively engage in various ways to reduce carbon emissions from its generation assets including new additive controls, carbon sequestration technologies, and the development and implementation of alternative, non-carbon based generation.

Mon Power and PE's current strategy in response to carbon-constraining regulatory or legislative initiatives focuses on six tasks:

- Maintaining an accurate carbon dioxide emissions inventory;
- Improving the efficiency of the existing coal-burning fleet;
- Following developing technologies for clean-coal energy and for carbon dioxide emission controls, including carbon sequestration;
- Participatory in carbon dioxide offset projects (e.g. reforestation projects) both domestically and abroad;
- Analyzing options for future energy investments (e.g. renewable energy, clean-coal, etc.); and,
- Improving demand-side efficiency programs through various customer energy conservation outreach programs.

FE Clean Air Act Compliance

Mon Power's generation complies with the Clean Air Act Amendments of 1990 (CAAA) through the use of various emission controls installed at its stations and/or operational constraints in accordance with all applicable state and federal regulations to primarily control emission of particulate matter (PM), nitrogen oxides (NO_x) and sulfur dioxide (SO2). Currently, Mon Power has requirements for compliance under the Acid Rain Program (ARP), Title V permit program and Clean Air Interstate Rule (CAIR) relative to the Clean Air Act Amendments of 1990. The CAIR rule will be replaced by the Cross State Air Pollution Rule (CSAPR), beginning on January 1, 2012.

Mon Power's generation assets meet the existing APR, CAIR and Title V requirements by utilizing Electrostatic Precipitators (ESP), Flue Gas Desulfurization (FGD) scrubbers, low-sulfur coal, low- NO_x burners, Selective Catalytic Reduction (SCR), Selective Non-Selective Catalytic Reduction (SNCR-trim), over-fired air and optimization software. The same equipment will be utilized to meet the requirements of the CSPAR rule in 2012.

Compliance with the NO_x and SO2 trading programs (APR, CAIR, CSPAR) is achieved by surrender of allowances to the USEPA equivalent to the emissions (SO2 & NO_x) for each ozone season and each calendar year. A combination of SO2 & NO_x allocations received from USEPA and SO2 & NO_x allowances traded and/or purchased are used for allowance surrenders for each compliance period. Additional ARP NO_x requirements are met by a NO_x averaging plan that has been filed with both the West Virginia Department of Environmental Protection (WVDEP) and the United States Environmental Protection Agency (USEPA).

Mon Power is currently evaluating options for compliance with a new Rule under the CAAA that has been proposed for Maximum Achievable Control Technology (MACT) for Electric Generating Units. The final MACT Rule was issued in late December 2011 and compliance with this rule will be required within 3-4 years.

FE Aging Generation Units

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

Table No. 3 (a)

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

AFTER DSM ADJUSTMENTS

WINTER	COINCIDENT APWV(B)	TOTAL APCo	CSP	I&M	KPCo	OPCo(C)	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)-(10)
10/11 (A)	3,195	7,623	3,564	3,785	1,596	4,666	308	356	-	20,605	-
11/12	3,105	7,404	3,556	3,932	1,550	4,933	416	451	21,375	20,895	479
12/13	3,116	7,457	3,627	4,007	1,563	5,014	420	457	21,667	21,172	495
13/14	3,130	7,503	3,625	3,988	1,564	4,985	422	458	21,665	21,172	492
14/15	3,154	7,548	3,616	3,963	1,563	4,953	424	460	21,642	21,151	492
15/16	3,168	7,563	3,603	3,930	1,557	4,926	426	461	21,579	21,083	496
16/17	3,171	7,578	3,598	3,915	1,554	4,930	428	462	21,575	21,065	509
17/18	3,179	7,611	3,604	3,894	1,556	4,935	428	460	21,599	21,096	503
18/19	3,194	7,656	3,604	3,878	1,560	4,927	428	460	21,625	21,136	489
19/20	3,200	7,682	3,587	3,856	1,561	4,900	427	459	21,585	21,082	503
20/21	3,237	7,777	3,607	3,874	1,575	4,923	431	462	21,756	21,275	481
AGR 11/21	0.1	0.2	0.1	0.2	-0.1	0.5	3.4	2.6	-	0.3	-
AGR 12/21	0.5	0.5	0.2	-0.2	0.2	0.0	0.4	0.3	-	0.2	-

NOTES: (A) ACTUAL.
(B) WEST VIRGINIA'S PORTION OF APCo'S PEAK INTERNAL DEMAND.
(C) INCLUDES OPCo'S SALE TO WPCo.
(D) AMOUNT OF SALE TO WPCo INCLUDED IN OPCo'S PEAK INTERNAL DEMAND.
(E) WPCo'S NON-COINCIDENTAL PEAK INTERNAL DEMAND.

1. Appalachian Power West Virginia (APWV)
2. Appalachian Power Company (APCo)
3. Columbus Southern Power Company (CSP)
4. Indiana Michigan Power (I&M)
5. Kentucky Power Company (KPCo)
6. Ohio Power Company (OPCo)
7. Wheeling Power Company (WPCo)

Table No. 3 (b)

AEP SYSTEM - EAST ZONE
PROJECTED SUMMER PEAK INTERNAL DEMANDS
(MW)
AFTER DSM ADJUSTMENTS

SUMMER	COINCIDENT APWV(B)	TOTAL APCo	CSP	I&M	KPCo	OPCo (C)	COINCIDENT WPCo(D)	WPCo (E)	SUM OF INTERNAL PEAK DEMANDS	AEP SYSTEM (EASTERN PORTION) PEAK	DIVERSITY
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(2)+(3)+(4)+(5)+(6)	(10)	(11)=(9)-(10)
2011 (A)	2,718	6,214	4,669	4,837	1,240	5,544	322	358	-	22,200	-
2012	2,621	6,177	4,322	4,527	1,271	5,272	454	457	21,570	21,264	305
2013	2,637	6,231	4,363	4,613	1,285	5,303	458	462	21,794	21,474	321
2014	2,656	6,280	4,381	4,597	1,288	5,279	461	465	21,825	21,508	317
2015	2,687	6,337	4,387	4,579	1,291	5,251	464	468	21,845	21,531	314
2016	2,709	6,372	4,382	4,558	1,290	5,235	466	470	21,837	21,521	316
2017	2,726	6,412	4,398	4,560	1,292	5,250	468	472	21,912	21,585	326
2018	2,744	6,462	4,425	4,550	1,297	5,262	468	472	21,996	21,668	328
2019	2,763	6,517	4,448	4,545	1,303	5,260	469	473	22,074	21,750	324
2020	2,780	6,566	4,453	4,536	1,308	5,242	469	473	22,105	21,780	324
2021	2,817	6,655	4,473	4,563	1,321	5,267	473	477	22,279	21,949	330
AGR 11/21	0.4	0.7	-0.4	-0.6	0.6	-0.5	3.9	2.9	-	-0.1	-
AGR 12/21	0.8	0.8	0.4	0.1	0.4	0.0	0.5	0.5	-	0.4	-

NOTES: (A) ACTUAL
(B) WEST VIRGINIA'S PORTION OF APCo'S PEAK INTERNAL DEMAND
(C) INCLUDES OPCo'S SALE TO WPCo
(D) AMOUNT OF SALE TO WPCo INCLUDED IN OPCo'S PEAK INTERNAL DEMAND
(E) WPCo'S NON-COINCIDENTAL PEAK INTERNAL DEMAND

1. Appalachian Power West Virginia (APWV)
2. Appalachian Power Company (APCo)
3. Columbus Southern Power Company (CSP)
4. Indiana Michigan Power (I&M)
5. Kentucky Power Company (KPCo)
6. Ohio Power Company (OPCo)
7. Wheeling Power Company (WPCo)

Table No. 4 (a)

AMERICAN ELECTRIC POWER SYSTEM EAST ZONE
SUMMER SEASON PROJECTED CAPACITY AND DEMAND

Line	Peak Demand (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Gross Internal Demand	21,413	21,726	21,898	22,054	22,171	22,350	22,534	22,743	22,908	23,170
(2)	Load Modification	149	252	390	523	650	765	866	993	1,128	1,221
(3)	Load Sales	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048
(4)	Interruptible Demand	569	569	699	819	969	1,119	1,131	1,143	1,156	1,168
(5)	Net Internal Demand (1-2+3-4)	21,743	21,953	21,857	21,760	21,600	21,514	21,585	21,655	21,672	21,829
	Capacity (MW)										
(6)	Total Installed Capacity	27,649	27,657	27,315	23,844	24,190	24,209	24,229	24,242	24,317	24,330
(7)	Capacity Purchases	0	0	1,776	1,643	843	757	823	888	885	1,052
(8)	Capacity Sales	838	707	-63	-63	-63	-63	-63	-63	-63	-63
(9)	Net Capacity Resources (6+7-8)	26,811	26,950	29,154	25,550	25,096	25,029	25,115	25,193	25,265	25,445
	Reserve Margin										
(10)	Margin in Megawatts (9-5)	5,068	4,997	7,297	3,790	3,496	3,515	3,530	3,538	3,593	3,616
(11)	Margin in Percent of Demand (10/5) * 100%	23.3	22.8	33.4	17.4	16.2	16.3	16.4	16.3	16.6	16.6

Table No. 4 (b)

AMERICAN ELECTRIC POWER SYSTEM EAST ZONE
WINTER SEASON PROJECTED CAPACITY AND DEMAND

Line	Peak Demand (MW)	2011/12	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
(1)	Gross Internal Demand	21,038	21,516	21,610	21,658	21,737	21,859	22,012	22,074	22,348
(2)	Load Modification	143	344	459	575	672	763	876	992	1,073
(3)	Load Sales	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057	1,057
(4)	Interruptible Demand	554	555	586	608	636	663	665	667	670
(5)	Net Internal Demand (1-2+3-4)	21,398	21,674	21,622	21,532	21,486	21,490	21,528	21,472	21,662
	Capacity (MW)									
(6)	Total Installed Capacity	28,291	28,356	24,389	24,122	24,826	24,840	24,853	24,887	24,935
(7)	Capacity Purchases	0	0	1,776	1,643	843	757	823	888	885
(8)	Capacity Sales	1,379	617	-153	-153	-153	-153	-153	-153	-153
(9)	Net Capacity Resources (6+7-8)	26,912	27,739	26,318	25,918	25,822	25,750	25,829	25,928	25,973
	Reserve Margin									
(10)	Margin in Megawatts (9-5)	5,514	6,065	4,696	4,386	4,336	4,260	4,301	4,456	4,311
(11)	Margin in Percent of Demand (10/5) * 100%	25.8	28.0	21.7	20.4	20.2	19.8	20.0	20.8	19.9

Table No. 5

MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
PROJECTED WINTER PEAK INTERNAL DEMANDS (A)
FROM DATA PROVIDED BY
FirstEnergy
(MW)

WINTER PEAK OF		MPWV (C) (1)	TOTAL MPCO(D) (2)	PEWV (E) (3)	TOTAL PE (F) (4)	WEST PENN (G) (5)	SUM OF INTERNAL PEAK DEMANDS (6) = (2) + (4) + (5)	AP SYSTEM PEAK (H) (7)	DIVERSITY (8) = (6) - (7)	WEST VIRGINIA POWER (I) (9)
10/11	(B)	1,748	1,748	852	3,176	3,988	8,911	8,643	268	133
11/12		1,853	1,853	814	3,084	3,609	8,547	8,393	153	131
12/13		1,885	1,885	824	3,105	3,621	8,611	8,456	155	132
13/14		1,914	1,914	838	3,126	3,721	8,760	8,604	157	133
14/15		1,936	1,936	849	3,142	3,789	8,868	8,710	158	134
15/16		1,955	1,955	861	3,164	3,831	8,950	8,790	160	136
16/17		1,968	1,968	870	3,193	3,863	9,024	8,863	161	137
17/18		1,984	1,984	880	3,221	3,901	9,107	8,944	162	138
18/19		2,003	2,003	890	3,253	3,941	9,197	9,033	164	139
19/20		2,022	2,022	900	3,287	3,979	9,288	9,123	165	140
20/21		2,037	2,037	909	3,317	4,006	9,360	9,193	167	141
AGR 10/11 - 20/21(%)		1.5	1.5	0.7	0.4	0.0		0.6		0.6
AGR 11/12 - 20/21(%)		1.1	1.1	1.2	0.8	1.2		1.0		0.9

NOTES:

(A) THESE VALUES REPRESENT CONNECTED LOAD DELIVERED BY EACH OPERATING COMPANY WITHOUT REGARD TO GENERATION SUPPLIER.
(B) ACTUAL.
(C) BASED UPON SEPTEMBER 2011 CONNECTED LOAD FORECAST.
(D) BASED UPON SEPTEMBER 2011 CONNECTED LOAD FORECAST.
(E) BASED UPON SEPTEMBER 2011 CONNECTED LOAD FORECAST.
(F) BASED UPON SEPTEMBER 2011 CONNECTED LOAD FORECAST.
(G) BASED UPON SEPTEMBER 2011 CONNECTED LOAD FORECAST.
(H) BASED UPON SEPTEMBER 2011 CONNECTED LOAD FORECAST.
(I) AT THIS TIME, WEST VIRGINIA POWER TERRITORY IS NOT PART OF AP'S CONTROL AREA.

1. Mon Power West Virginia (MPWV)
2. Mon Power Company (MPCO)
3. Potomac Edison West Virginia (PEWV)
4. Potomac Edison Company (PE)
5. West Penn Power Company (West Penn)

* 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. 6

Allegheny Power - West Virginia
2010 Integrated Resource Plan

Based Upon 2009/2010 PJM RTO AP Peak Forecast
Mean-Value Forecast for Seasonal Peak Periods

Bundled Service (Regulated)										
Summer		2010	2011	2012	2013	2014	2015	2016	2017	2018
Demand-Side (MW)										
	Monongahela Power	1,944	2,087	2,144	2,174	2,202	2,228	2,251	2,276	2,298
	Potomac Edison	636	683	702	712	721	729	737	745	752
	West Virginia Power	100	103	106	108	109	110	110	111	112
Total [a] [b]		2,680	2,873	2,952	2,993	3,032	3,067	3,098	3,132	3,162
Supply-Side (MW)										
	Owned Capacity [c]	2,469	2,469	2,469	2,469	2,469	2,469	2,469	2,469	2,469
	PURPA Capacity [d]	139	139	139	139	139	139	139	139	139
	Purchased (Excess) Capacity [e]	72	265	343	384	424	459	490	524	554
Total		2,680	2,873	2,952	2,993	3,032	3,068	3,098	3,132	3,163
Winter		2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Demand-Side (MW)										
	Monongahela Power	1,944	2,087	2,144	2,174	2,202	2,228	2,251	2,276	2,298
	Potomac Edison	636	683	702	712	721	729	737	745	752
	West Virginia Power	100	103	106	108	109	110	110	111	112
Total [a] [b]		2,680	2,873	2,952	2,993	3,032	3,068	3,098	3,132	3,162
Supply-Side (MW)										
	Owned Capacity [c]	2,498	2,498	2,498	2,498	2,498	2,498	2,498	2,498	2,498
	PURPA Capacity [d]	149	149	149	149	149	149	149	149	149
	Purchased (Excess) Capacity [e]	33	226	305	347	385	420	451	485	515
Total		2,680	2,873	2,952	2,993	3,032	3,068	3,098	3,132	3,162

	Load Management	2010	2011	2012	2013	2014	2015	2016	2017	2018
PJM Interruptible Load Response (ILR) [f]		4	4	4	4	4	5	5	5	5
Emergency Load Response Program (ELRP) [g]		5	5	5	5	5	5	5	5	5

Notes for Table No. 6

a. Demands are based on AP's share of the 2009/20010 PJM RTO peak (summer) forecast and latest available AP state PLC data and multiplying the PLC by forecasted and actual zonal and FPRs from ERPM.
Actual peak hour demands have an equal probability of being over or under the forecast values due to weather variations.
Bundled Service load consists of WV electric customers who do not have retail choice.

b. Total loads include the PJM Forecast Pool Requirement (FPR) and Base Residual Auction (BRA) Scaling Factor. These load values, in conjunction with PJM UCAP values for capacity, comprise the PJM Installed Reserve Margin (IRM) requirement of 15%.

c. Owned Capacity is generation owned by Allegheny Power and used to serve WV bundled service load. The summer capacity is based on the latest available and official PJM RPM UCAP (Unforced Capacity) values. The winter capacity is based on the latest available winter PJM UCAP values and is only shown as reference.

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 MP to serve bundled service load. Summer capacity is based on official PJM RPM UCAP values and winter capacity is based on the latest available winter PJM UCAP values and is only shown as reference.

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

f. Interruptible Load Response (ILR) program is a PJM reliability program that AP started participating in February 2008. The program pays customers to be ready to reduce load if called by PJM during system emergencies. The customer must be available for up to 10 reductions per year and have the ability to reduce a minimum of 100 kW per hour. Due to this program being voluntary, these values are shown as reference only and are not used in calculating PJM IRM requirements. This program expires effective May 31, 2012 and is replace by the Demand Response Program.

g. Emergency Load Response Program (ELRP) is a PJM voluntary peak load reduction program that AP started participating in April 2008. The program offers financial rewards to customers who can reduce their power consumption during periods of high demand or prices. In return for reducing load, the customer is paid a percentage of the wholesale market price for their reductions. Due to this program being 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.

j. Fort Martin scrubbers will reduce the ICAP for each unit by 20 MWs and are anticipated to be online by December 1, 2009.

k. All EFORd values are as of 11/30/2009. There is no degradation planned in the above generation capacity data. It is assumed outage rates will not change.

Appendix A: Lists of Maps, Tables and Charts

Appendix B: Existing Plants and Summaries of Interchanges

Chart 1 (Page 1 of 3)
Appalachian Power Company
Existing Plants

Plant Name	Location	Unit No.	Year in Service	Kind	Fuel	APCo % Ownership	APCo Share Unit Nameplate Capacity (kW)	APCo Share 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	St. Albans, WV	1	1971	Steam	Coal	100	816,300	790,000
John E. Amos	St. Albans, WV	2	1972	Steam	Coal	100	816,300	790,000
John E. Amos	St. 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	Graham Station, WV	1	1950	Steam	Coal	100	152,500	150,000
Philip Sporn	Graham 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	1,320,000
Ceredo	Ceredo, WV	1-6	2001	Comb. Turbine	Nat. Gas	100	519,000	516,000
Totals							**5,678,976**	**5,589,000**

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

Chart 1 (Page 2 of 3)

Appalachian Power Company
Existing Hydroelectric Plants

Plant Name	Location	Stream Name	Year in Service	Unit Nameplate Capacity (kW)	Unit Capability (kW)
Claytor	New Radford, VA	New River	1939	75,000	28,000
Leesville	Leesville, VA	Roanoke River	1964	40,000	9,000
Reusens	Lynchburg, VA	James River	1903	12,500	3,000
Bylesby	Bylesby, VA	New River	1912	21,600	8,000
Buck	Near Bylesby, 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**	**92,000**

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

Chart 1 (Page 3 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	Reversible	66,025	66,000
Smith Mountain 2	Penhook, VA	Roanoke River	1965	Non-Reversible	150,100	174,000
Smith Mountain 3	Penhook, VA	Roanoke River	1980	Reversible	115,344	106,000
Smith Mountain 4	Penhook, VA	Roanoke River	1966	Non-Reversible	150,100	174,000
Smith Mountain 5	Penhook, VA	Roanoke River	1966	Reversible	66,025	66,000
Totals					**547,594**	**586,000**

Chart 2 (Page 1 of 2)

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 Major Interconnection is at 765kV
Indiana Michigan Power Company		
Kentucky Power Company		
Columbus Southern Power Company		
Non-Associated Utilities		
Carolina Power & Light Company (Progress Energy)	Danville, VA	230kV
	Kingsport, TN	138kV
	Kingsport, TN	230kV
Duke Power Company (Duke Energy)	Ridgeway, VA	138kV
	Austinville, VA	500kV
Monongahela Power Company (First Energy)	Bentree, WV	138kV
	Quinwood, WV	138kV
	Belmont, WV	500kV

Chart 2 (Page 2 of 2)

Appalachian Power Company

Summary of Interchange Locations

Name of Company	**Points of Interchange**	**Voltage of Interchange**
Non-Associated Utilities Continued		
Virginia Power Company (Dominion)	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
Ohio Valley Electric Corporation	New Haven, WV	345kV
	Huntington, WV	345kV
Louisville Gas and Electric (Kentucky Utilities)	Clinch River, VA	138kV
Public Authorities		
Tennessee Valley Authority	Near Bristol, TN	138kV
	Kingsport, TN	138kV
	Kingsport, TN	500kV
	Near Bluff City, TN	500kV

*Serves local load or generation only

Chart 3

Wheeling Power Company

Summary of Interchange Locations

Name of Company	Points of Interchange	Voltage of Interchange
Associated Utilities		
Ohio Power Company (AEP)	Natrium, WV	138kV
	Near Moundsville, WV	138kV
	Benwood, WV	138kV
	Near Brilliant, OH	138kV
Non-Associated Utilities		
Monongahela Power Company (FirstEnergy)	Natrium, WV	138kV

Chart 4

Monongahela Power Company
Existing Plants

Plant Name	**Location**	**Unit No.**	**Year in Service**	**Kind**	**Fuel**	**MPCO Power % Ownership**	**MPCO Share of 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
Harrison	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**

*Mon Power's share of capacity is based on the percentage of ownership

Chart 5

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 Pennsylvania and West Virginia state line in Preston, Monongalia, Brooke, and Hancock Counties, WV	500kV, 138kV
The Potomac Edison Company	Various at or near the Maryland and West Virginia state line in Preston, Mineral and Grant Counties, WV	138kV
ATSI	Hancock, WV	345kV
Non-Associated Utilities		
PA, NJ, MD (PJM RTO Group)	*See note below	500kV, 230kV, 138kV, 115kV
Appalachian Power Company	Various in Greenbrier, Summers, Nicholas and Wood Counties, WV	765kV, 138kV
Wheeling Power Company	Near Marshall County, WV	138kV
Ohio Power Company	Various in Brooke, Hancock, and Pleasants Counties, WV	500kV, 345kV, 138kV
Virginia Power Company	Mount Storm Substation in Grant County, WV	500kV

*Note: As a member of the PJM RTO and through the development of the PJM West Region, AP is operated as a control zone within the PJM control area for coordination of market operations and market settlement.

Chart 5 (a)

Trans-Allegheny Interstate Line Company

Summary of Interchange Locations

Name of Company	**Points of Interchange**	**Voltage of Interchange**
Non-Associated Utilities		
Ohio Power Company	Marshall County, WV Kammer Substation (Transformer Only)	765kV, 500kV
Virginia Power Company	Mount Storm Substation Grant County, WV	500kV