PRE-QUALIFICATION APPLICATION of AMERICAN ELECTRIC POWER COMPANY and CERTAIN AFFILIATES

Submitted to the PJM Office of Interconnection under
PJM Amended and Restated
Operating Agreement Section 1.5.8(a)
April 29, 2013

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1. Introduction

American Electric Power Company, Inc., for itself and certain of its subsidiaries, submits the following information to the PJM Office of Interconnection to address the pre-qualification criteria specified in section 1.5.8(a) of the PJM Amended and Restated Operating Agreement. AEP and the subsidiary companies listed herein seek Designated Entity status with respect to future transmission projects in PJM. In addition to the companies named and described in this document, AEP may form additional subsidiaries as the competitive marketplace for transmission projects within PJM develops. In this package, AEP is seeking pre-qualification for the following companies:

- American Electric Power Company, Inc. (AEP)
- Ohio Power Company, Inc. (AEP Ohio)
- Indiana Michigan Power Company, Inc. (I&M)
- Appalachian Power Company, Inc., Kingsport Power Company, Inc., and Wheeling Power Company, Inc. (APCo)
- Kentucky Power Company, Inc. (Kentucky Power)
- AEP Ohio Transmission Company, Inc. (Ohio Transco)
- AEP Indiana Michigan Transmission Company, Inc. (IM Transco)
- AEP Appalachian Transmission Company, Inc. (Virginia Transco)
- AEP West Virginia Transmission Company, Inc. (West Virginia Transco)
- AEP Kentucky Transmission Company, Inc. (Kentucky Transco)
- Transource Energy, LLC (Transource)

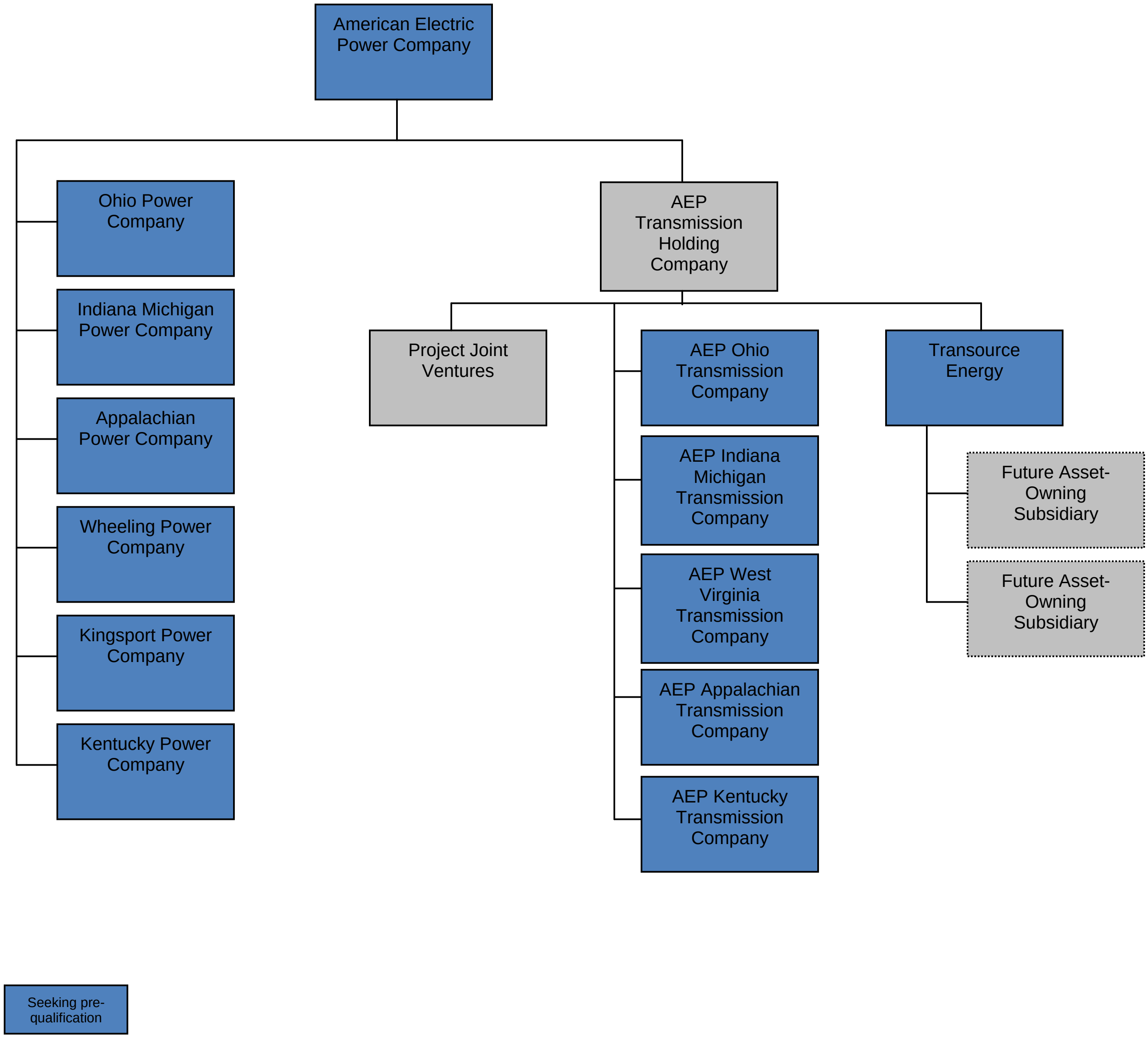
2. Overview of AEP Transmission

AEP is one of the largest electric utility holding companies in the United States, delivering electricity to more than 5 million customers in eleven states. Over the last 100 years AEP has developed, and now owns and operates the largest transmission system across the widest spectrum of voltage classes in the United States. AEP's 39,000-mile network includes more 765 kV extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves approximately 10% of the electricity demand in the Eastern Interconnection, and approximately 11% of the electricity demand in the Electric Reliability Council of Texas (ERCOT). AEP's operating utilities provide service to retail and wholesale customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. AEP's headquarters are in Columbus, Ohio.

Today, AEP transmission facilities are primarily owned by two different types of AEP subsidiary companies: 1) AEP's vertically integrated operating companies that provide electric service within AEP's eleven-state retail territory and; 2) transmission-only subsidiaries held under AEP Transmission Holding Company, LLC (AEPHoldco). The transmission-only subsidiaries held under AEPHoldco can be further classified as follows: 1) state transmission-only companies (Transcos); 2) Transource; and 3) project joint ventures (JVs)[1].

The figure below depicts the structure of AEP's transmission companies in the PJM region:

[1] AEPHoldco's project JVs within PJM include Pioneer Transmission, LLC, and RITELine Indiana, LLC. It is AEP's understanding that as entities owned 50% each by two PJM Transmission Owners, these companies do not need to qualify individually for Designated Entity status at this time.


American Electric Power Company
Ohio Power Company
Indiana Michigan Power Company
Appalachian Power Company
Wheeling Power Company
Kingsport Power Company
Kentucky Power Company
AEP Transmission Holding Company
Project Joint Ventures
AEP Ohio Transmission Company
AEP Indiana Michigan Transmission Company
AEP West Virginia Transmission Company
AEP Appalachian Transmission Company
AEP Kentucky Transmission Company
Transource Energy
Future Asset-Owning Subsidiary
Future Asset-Owning Subsidiary
Seeking pre-qualification

Although the transmission facilities are organized as described above, the entire AEP transmission system is planned and operated on an integrated basis through the coordinated efforts of the AEP Transmission Department (AEP Transmission), a business unit of American Electric Power Service Corporation (AEPSC). AEP Transmission coordinates all development and operations aspects of AEP's transmission business[2], including engineering, design, development, ROW acquisition, construction, operations and maintenance. AEP Transmission provides these services to AEP's transmission-focused subsidiaries under the terms of service agreements between each subsidiary company and AEPSC. The operational capabilities and experience of AEP Transmission are described in greater detail below. AEP provides the following information as requested in PJM Operating Agreement section 1.5.8(a), subparts (i) through (x).

a. AEP Operating Companies

AEP Ohio, I&M, APCo and Kentucky Power seek pre-qualification under section 1.5.8(a) of the PJM Operating Agreement. These AEP Operating Companies are each Transmission Owners within PJM. AEP Ohio owns and operates approximately 9,281 circuit miles of transmission; I&M owns and operates 5,293 miles; APCO owns and operates 5,357 circuit miles, and Kentucky Power owns and operates 1,233 circuit miles of transmission.

The AEP Operating Companies rely on the resources of the centralized AEP Transmission organization to support their transmission functions, managed through a services agreement with AEPSC. The financial strength of the AEP Operating Companies is

[2] For JVs, AEP transmission or AEP's partner(s) may provide the operational services described.

evidenced by the financial statements of its ultimate parent company, AEP, attached at Appendix D. AEP and Operating Company credit ratings as of September 30, 2012 are below.

Company	Moody's	S&P	Fitch
American Electric Power Company Inc.	Baa2	BBB	BBB
Appalachian Power Company	Baa2	BBB	BBB
Indiana Michigan Power Company	Baa2	BBB	BBB
Kentucky Power Company	Baa2	BBB	BBB
Ohio Power Company	Baa1	BBB	A-

b. AEP Transcos

Over the last several years, AEP has obtained regulatory approval to form and operate transmission-only companies in several states. The Transcos complement the AEP Operating Companies by owning and operating larger, new projects on AEP's transmission system. The Transcos are wholly-owned subsidiaries of AEP. Ohio Transco, IM Transco, Virginia Transco, West Virginia Transco and Kentucky Transco seek pre-qualification under section 1.5.8(a) of the PJM Operating Agreement.

The transmission operation capabilities of the AEP Transcos are supported by the resources of the centralized AEP Transmission organization, described herein. The financial strength of the AEP Transcos is reflected in the financial statements of AEP, attached at Appendix D. The AEP Transcos further benefit from the coordinated financing activities of AEPHoldco, discussed below.

Ohio Transco and IM Transco currently own transmission assets within PJM, and will sign the PJM Consolidated Transmission Owners Agreement (CTOA) when authorized. Ohio Transco owns and operates approximately 72 circuit miles of transmission; IM

Transco currently owns one (1) circuit mile. Virginia, West Virginia and Kentucky Transcos do not currently own transmission assets, but will sign the CTOA when eligible.

c. Transource Energy

In response to changes in the electric transmission marketplace over the past decade and the prospect of increased competition for regional transmission projects following FERC Order No. 1000, AEP and Great Plains Energy Incorporated (GPE) formed Transource to pursue competitive transmission projects. AEPHoldco owns 86.5% of Transource, and GPE Transmission Holding Company, LLC (GPEHoldco) owns 13.5%.

Transource is seeking pre-qualification under section 1.5.8 (a) of the PJM Operating Agreement. In the future, we expect that Transource will form state- or project-specific subsidiary companies to construct, finance, own, operate, and maintain transmission projects. To date, Transource has formed one such subsidiary, Transource Missouri, LLC (Transource Missouri), for two Southwest Power Pool (SPP) transmission projects located in Missouri.

Transource and its existing subsidiaries have services agreements with both AEP and GPE, providing access to the transmission resources of both companies. Transource is not currently a Transmission Owner in PJM, but will sign the PJM Consolidated Transmission Owners Agreement when eligible. AEP's transmission capabilities are described elsewhere in this document and GPE is also a significant transmission-owning company. GPE is the holding company of Kansas City Power & Light (KCP&L) and Greater Missouri Operations (GMO), operating utilities that deliver electricity to more than 823,000 customers in Kansas and Missouri. GPE is headquartered in Kansas City, Missouri. GPE's operating companies own over 2,600 miles of transmission lines operating at voltages up to 345kV. KCP&L and GMO are SPP members and have transferred functional control of their transmission facilities to SPP.

GPE is currently seeking regulatory approval to transfer ownership of the following SPP-approved regional transmission projects to Transource Missouri:

- The Sibley-Nebraska City line is a 175-mile, 345kV line linking the Nebraska City substation (owned by Omaha Public Power District) near Nebraska City, NE, with the Sibley substation near Sibley, MO. Transource Missouri will construct and own approximately 170 miles of the project in Missouri. Omaha Public Power District will construct the remainder of the transmission line. The project has an anticipated in-service date of 2017.

- The Iatan-Nashua line is a 30-mile, 345kV line from the Iatan substation near Weston, MO, to the Nashua substation near Smithville, MO. The Iatan-Nashua project has an anticipated in-service date of 2015.

The financial strength of Transource is evidenced by the most recent financial statements of its ultimate parent companies, AEP and GPE, attached at Appendix D and E. GPE, KCP&L and GMO credit ratings as of February 15, 2013, are as follows:

Company	**Moody's**	**S&P**
GPE	Baa3	BBB-
KCP&L	Baa2	BBB
GMO	Baa3	BBB

In addition, Transource benefits from the coordinated financing activities under AEPHoldco described herein.

d. Financing Activities Under AEPHoldco

One of the benefits of the AEPHoldco structure is the ability to coordinate financing activities to support the capital requirements for all of AEP's transmission-only subsidiaries. For example, in the third quarter of 2012, AEPHoldco issued $350 million of debt capital on highly competitive terms, which it will distribute on an as-needed basis, allowing the transmission-only companies to efficiently raise capital without incurring the cost of individually accessing capital markets. In addition to the AEPHoldco issuance last year, two project JVs successfully raised debt capital in the last two years with the support of the AEPSC finance and legal groups. This unique level of experience in raising capital for transmission-only companies, together with the ability to coordinate financing activities across the AEP platform is further evidence of the financial strength of each of AEP's transmission-owning subsidiaries.

3. Summary of AEP Transmission Capabilities

AEP is one of the largest transmission owners and operators in the country, with $8.6 billion in transmission assets in 2012 forecasted to grow to more than $11 billion by 2015. At the December, 2012 PJM Board of Managers meeting alone, PJM approved more than $100 million of AEP transmission projects in the Regional Transmission Expansion Plan (RTEP). Currently, AEP has more than 600 PJM-approved baseline projects, supplemental projects and network upgrades in various stages of planning and construction.

AEP's approach to transmission planning, project management, siting, engineering, construction, procurement, maintenance, operations and health and safety is set out in more detail below.

a. Transmission Planning

AEP has a large internal planning organization which allows the AEP transmission system to be planned and operated on an integrated basis. AEP Transmission works closely with neighboring utilities, other interconnected entities and the Regional Transmission Organizations (RTOs) to plan and operate the transmission grid in alignment with RTO protocols and North American Electric Reliability Corporation (NERC) requirements.

b. Project Management

AEP currently employs more than 100 professionals in its transmission project and construction management organizations. These organizations annually manage more than 100 large projects (>$1 million) with a combined value of over $1 billion. AEP's station and line project managers are capable of executing projects varying in complexity from small projects such as circuit breakers, to large projects such as the construction of over 280 miles of 765 kV line in mountainous terrain.

The Project Management team has established relationships with construction contractors who provide the qualified labor to build station and line projects. The team is supported by an extensive construction management group capable of overseeing any size project in the field.

Depending on the project specifications, AEP utilizes one of several approaches to project delivery: under the self-perform method, AEP engineers, designs and procures the project using internal resources. While AEP typically self-performs, accepting the accompanying risk, we have also utilized external Engineering, Procurement and Construction (EPC) contracts, External Program Manager (EPM) and open book EPC contract methods when appropriate. AEP project managers have the experience and flexibility to deliver each project on time and within budget.

c. Project Estimation

Quality project estimation is critical to the success of transmission developers in a competitive market. AEP has extensive experience in transmission project delivery including planning, siting, engineering, design and construction of station and line projects. This experience provides a foundation for scoping and estimating projects of any size. AEP's recent experience in siting and construction of the Jacksons Ferry – Wyoming 765 kV project, the 345 kV systems build out in Texas (including the CREZ projects) as well as the 765 kV Pioneer and PATH projects provide a basis for future EHV project scoping and estimating.

Established relationships with equipment and material suppliers facilitate the development of project cost estimates. AEP has established equipment and material blankets, with competitive pricing for such items as circuit breakers, transformers, reactors and steel for station and line structures. AEP's relationships with construction contractors provide certainty when estimating project costs.

d. Transmission Engineering, Procurement and Construction

The AEP Transmission engineering, procurement and construction groups are among the largest and most sophisticated in the country, equally or exceeding the capabilities of most outside firms. AEP currently employs nearly 450 people in its line, station, and protection and control engineering organizations. In addition to 200 construction management employees, AEP relies on an extensive network of construction contractors to build large projects.

In-house engineering and construction management expertise allows AEP to deliver consistently high-quality results, as well as advanced technical innovations that improve the transmission system and add value to customers. AEP has multiple existing and pending patents for technologies developed throughout our history. In addition to formal patents, AEP is also a leader in developing technical standards for the industry. For example, the International Electrotechnical Commission's 61850 protocols for the design of electrical substation automation, which were first accepted in 2001, resulted from significant work by AEP to ensure that consistent communications standards are used by multiple vendors of electronic devices throughout the industry. AEP is also an industry leader in technical areas such as station security, cyber security, and new transmission technology, and many longtime AEP employees are recognized as experts in their fields.

Just in the last ten years, AEP engineering and construction groups have:

- designed and deployed six-bundle 765 kV lines minimizing noise impacts in high altitudes;
- developed the next generation of 765 kV circuit breaker;
- installed the first commercially operated Variable Frequency Transformer developed by GE and connecting Texas and Mexico;
- provided consulting services to Sharyland Utilities to install a back-to-back DC converter station to connect Texas and Mexico;
- installed and are currently specifying and constructing several Flexible Alternating Current Transmission System (FACTS) devices such as series capacitors and Static Var Systems (SVS) for power flow and voltage control as part of the Texas CREZ projects.

Other innovations include the development of drop-in control modules - a control house on a flatbed built in a factory for half the price of retrofitting an old control building that standardizes control room configuration and reduces installation time – and skid stations, which enable us to provide service to new delivery points quickly and safely.

The work of AEP's engineering and construction teams is supported by carefully designed and implemented procurement and material management policies. AEP Transmission's procurement group collaborates with AEP Legal, Risk Management, and Environment and Safety teams to establish overall corporate procurement policies. The highest standards of personal conduct and business ethics are required of each AEP employee involved in the procurement of equipment, material and services and those who are in a position to influence purchase decisions or business relationships with contractors or suppliers.

AEP Procurement is involved in all phases of material and service management: planning, sourcing, negotiations, evaluations, contract awards and contract administration. In the process, AEP Procurement interfaces with project management, project controls, transmission engineering and standards, construction site management, stores and suppliers to achieve timely and cost-effective delivery of needed project materials.

Certain oversight and approval criteria have been established for special expenditure amounts as follows:

- Acquisitions of material and equipment valued above $10,000.00 must be made through competitive bidding or have documented sole source justification.
- Acquisitions for services valued above $50,000 are made through competitive bidding unless they have documented justification for sole source.
- Procurement personnel processing material requisitions, purchase requisitions, contract requisitions have discretion to competitively bid any dollar value in order to obtain the best value and delivery to AEP.

If an award is to be made based on criteria other than the lowest evaluated, technically and commercially qualified bid, evaluation criteria must be documented and approved similarly to the sole source process described above.

AEP's purchasing power gives us the unique ability to reserve shop space in advance of actual purchase to meet project needs, and we have relationships and contracts with most major vendors that meet our exacting engineering and manufacturing standards. Strategic master agreements with many of the largest equipment manufacturers internationally, nationally and regionally – are utilized as necessary, particularly to respond to emergencies such as storm damage, equipment or structure failures. In a survey of AEP's equipment vendors and manufacturers conducted in May 2012, 85% of the 60 respondents indicated that our manufacturing standards are better in terms of quality, depth and detail, and that AEP outperforms our peers in system-wide application of our standards.

AEP supports supplier diversity in selecting services and materials in accordance with AEP corporate diversity expectations. AEP makes every effort to extend opportunities to qualified diversity suppliers.

e. Routing and Siting

Over the course of the past century, AEP and its affiliates have acquired right of way (ROW) and sited transmission lines and stations in more than 12 states. This experience has led AEP to develop standard procedures and best practices for routing, siting and ROW acquisition described below. AEP's siting methods vary due to unique elements of each project including line length, line voltage, project location, environmental issues and federal, state and local requirements. AEP employs a siting methodology to create and analyze several possible routes that includes:

- Identification of the study area

- Siting criteria development
- Data collection
- Development of alternative routes
- Evaluation of alternative routes and preferred alternative route selection.

Once project end points are determined, AEP evaluates data from maps and aerial photography to establish area boundaries for data collection to establish the study corridor. AEP's siting criteria are designed to:

- Avoid or minimize impact upon human, natural, visual and cultural resources
- Avoid or minimize visibility from populated areas, scenic roadways and designated scenic resources
- Avoid or minimize conflict with existing and proposed future land uses
- Avoid habitat fragmentation and designated areas of biodiversity concern
- Maximize the separation distance from dwellings, schools, daycare facilities, hospitals and other community facilities
- Maximize stakeholder input
- Use or parallel existing rights-of-way where possible
- Minimize environmental impact and construction/maintenance costs by selecting shorter, more direct routes
- Route corridors through terrain where economical construction and environmental mitigation techniques can be employed while enabling feasible line operation and maintenance
- Maintain consistency with transmission needs, project schedules, regulatory agency oversight requirements and environmental regulations
- Adhere to FERC and state regulatory guidelines

AEP develops a database of information for the search area, which is described in detail in the route selection study documents filed with the application. Numerous sources are reviewed for the relevant information compiled in the development of this database, including:

- Literature review and data collection from published data, aerial photographs, USGS maps, and GIS data repositories
- Discussions with public officials and land owners concerning present and future land use and other community values and concerns
- Ground level surveys
- Apparent property boundaries

- Discussions with state and federal officials regarding natural resources such as endangered or threatened species, cultural resources and protected areas such as national parks, state parks, or various protected areas
- Input from public workshops and submitted comments

The data is summarized into a GIS constraints map that includes any exclusion and sensitive/avoidance areas present in the area. A preferred route is ultimately selected based on the evaluation of all potential routes using the siting criteria, evaluation of potential impacts to sensitive areas, field evaluations and the professional judgment of the siting team. This process ensures that the final route reasonably minimizes adverse impacts to both landowners and sensitive resources and is consistent with the siting criteria of the jurisdictional agency.

Siting Support

Early in the siting process, AEP ROW agents identify landowners affected by proposed routes and research property deeds to identify affected property owners. ROW agents work with AEP environmental experts and project engineers to determine the location of sensitive areas, such as a family farm, property owned by federal, state or local governments, a cemetery, monument or a 200-acre nature preserve.

Once the preferred route is identified, ROW agents notify property owners of the public meetings to be held in their area. The project team, which consists of AEP and consulting engineering and environmental specialists, hosts public information meetings at which residents are invited to review and discuss project plans and to express their concerns. Several meetings may be conducted in different counties depending on state requirements and project size. These meetings also allow ROW agents to communicate additional information about easements to property owners.

ROW agents also assist with consistency of information for project estimates during the estimation process. AEP estimation guidelines require multiple project estimates before a project is funded, and accurate estimates depend heavily on accurate historical information about property owners, parcels, surveys, and terrain type. Including this information in the estimate helps AEP achieve consistent, accurate estimates at the earliest possible point in the process.

Acquisition of Right-of-Way

Acquisition time varies depending on the size and scope of the project. ROW agents may retain local surveyors and real estate companies to assist with land acquisitions. Surveyors prepare line and property boundaries and document obstacles like gas pipelines and railroads relative to the path of the line.

Land values vary depending on factors such as land use, for example, line versus station. Every effort is made to reach a consensus with property owners before resorting to the condemnation process. If a consensus cannot be obtained, ROW agents work with AEP legal to arrive at an appraisal that is fair to both parties. AEP's 'good neighbor' policy resulted in successful ROW negotiations for the Turk Plant in Arkansas. Condemnation rates were less than 1%, a result which both minimizes delay and ensures good relationships for the future.

AEP seeks to maintain a good relationship with property owners by ensuring that the same ROW agent that worked with them during negotiations stays with them throughout the construction process. Agents inform landowners of the likelihood of damage to their property and of the efforts AEP will make to mitigate and repair any damage, and if issues arise during construction, the ROW agent continues to be the face of AEP with the landowners.

f. Vegetation Management and Environmental Stewardship

In August 2003, a major power outage crippled much of the northeastern United States and southeastern Canada, leading to new national standards governing vegetation management practices for power lines identified as part of the national transmission grid. To comply with federal guidelines and maintain system reliability, AEP routinely removes all trees and vegetation within the ROW corridor for all such lines having conductor less than 100 feet above the ground. AEP also works to accommodate landowners and preserve public areas within the constraints of safe line operation. AEP may allow compatible, low-growing species to remain in the ROW in certain topographically or environmentally-sensitive areas.

AEP has developed a vegetation management program to control the growth of trees and other vegetation around our transmission facilities and rights of way. The program balances the customers' need for reliable energy with respect for the natural environment that surrounds our facilities. This program enables AEP to:

- Protect the transmission and distribution systems to minimize outages
- Minimize adverse environmental impacts
- Ensure compliance with all applicable laws and regulations
- Perform work safely and economically
- Maintain a positive relationship with land owners and the public

AEP achieves the balance between service reliability and respect for the natural landscape by investing time and resources into public education concerning proper tree care and sound environmental practices. AEP is an active participant in many organizations that support responsible vegetation management practices that include the National Arbor Day Foundation, the Utility Arborist Association, the International Society of Arboriculture and several state and local vegetation management organizations.

Mindful of the impact a project has on neighboring landowners, AEP strives to mitigate these impacts through innovative technologies that include non-specular coatings for conductors, painted structures, special landscaping, avoidance of sensitive areas and underground construction.

g. System Maintenance

AEP's comprehensive experience in the design, construction and restoration of high-voltage power equipment contributes to its ability to maintain the system reliably. AEP transmission field employees seamlessly maintain facilities across our five transmission regions according to a uniform set of standards and practices that meet or exceed applicable regulations and codes to ensure high service quality, reliability, and cost-effective maintenance.

AEP Transmission crews, stores and equipment are strategically located throughout the AEP service territory to ensure that inspection and maintenance requirements are met and to provide the optimum response time for all of the equipment under each crew's responsibility. AEP maintains reciprocal maintenance assistance agreements with other utilities to assist in restoration efforts after major storms.

Capabilities

AEP's maintenance capabilities include the following:

- Inspection & maintenance of all substation and transmission line facilities
- Live-line maintenance of EHV transmission lines
- Equipment testing and repair
- Vegetation management
- Emergency restoration of lines and stations using permanent and portable equipment
- Spares for certain long-lead time and other specialized equipment

AEP maintains relationships with several engineering firms to provide skilled labor as needed. These firms are already familiar with AEP standards and practices such that there is no learning curve for contractors.

Inspection

AEP is dedicated to providing a safe environment for the public and company personnel and to maintaining system reliability. Inspection and maintenance programs for AEP's transmission system ensure that AEP equipment functions safely and provides optimum service and reliability to AEP customers. AEP schedules regular inspections to evaluate the physical and operational condition of transmission lines, ROW clearances and station equipment. AEP focuses on evaluating the general condition of the transmission system and determining equipment or areas requiring immediate corrective action. Items found to require urgent attention are scheduled for repair or replacement immediately.

Inspections can also reveal certain trends, such as increasing structure deterioration or excessive compressor run times. This data allows for future planning, budgeting and scheduling of resources to forestall critical situations. AEP also uses electronic information systems to gather, record and analyze information on the condition of the transmission system. These systems include the following abilities:

- Electronic reporting and recording of conditions found on transmission lines and equipment
- Condition based maintenance reporting system
- Maintenance data records
- Tracking cost of maintenance on assets
- Inspection scheduling and tracking
- Reporting of forestry issues on transmission lines

Training

AEP personnel involved in line engineering, design, construction and maintenance are among the most highly trained and skilled in the industry. AEP maintains a state-of-the-art transmission training facility staffed with experienced training coordinators to provide the required technical training for all transmission line, station and P&C maintenance personnel. The A. Ray King Transmission Training Center in Pataskala, Ohio is the only dedicated transmission training center in the eastern United States with a functioning indoor transmission substation training facility. The center features an outdoor transmission line training area where classes train on same structures found on the live AEP system.

h. Operations and Compliance

AEP Transmission Operations (TOPS) staffs five state-of-the-art control centers around the clock, and maintains one hot back-up site used for training. TOPS manages system control desks, balancing authority with SPP, and several dispatching desks. In 2011, TOPS completed 250,000 switching steps with an accuracy rate of approximately 99.99%.

AEP Transmission field operations includes approximately 950 employees covering 250,000 square miles of territory, 39,000 miles of transmission and over 3,500 switching stations. These employees have specialized skills qualifying them to safely work in the complex environment of high voltage transmission lines and substations. The technical expertise necessary to commission large station equipment and relay protection schemes is one of this group's strengths. The ability to oversee and coordinate commissioning activities is scarce and in high demand, making our internal capability to commission AEP assets critically important.

TOPS includes AEP's system reliability compliance functions as well. Field operations performs periodic station protection inspections of batteries, current and potential transformers and relays. Relays must be trip tested and calibrated on a fixed schedule to be compliant with NERC guidelines.

The transmission reliability compliance group monitors the ever-changing landscape of NERC compliance, identifying potential issues internally before they become external problems. Along with an annual schedule of NERC and RFC audits, the group participates in two internal spot audits every year, designed for continuous improvement of AEP's reporting of NERC compliance standards. AEP successfully completed an exhaustive NERC audit last June.

i. Safety and Health

Mutual Care – protecting ourselves and the public - is a key element of AEP Transmission's safety and health culture. AEP Transmission employees and contractors embrace the safety and health culture on a daily basis. Ongoing training teaches both technical excellence and safe job performance. Employees are held accountable for applying the AEP Safety & Health Manual to their daily work. Employee input is encouraged and helps to strengthen the documented AEP safety and health policies and procedures that employees are trained to know, understand, and execute.

Striving for Zero Harm pays dividends in all facets of AEP Transmission operations. AEP Transmission's safety performance measured in Lost Time Rate (LTR) and Total Recordable Rate (TRR) has been good, with two of the last three years below 1.0 in TRR. We continually strive to further improve our safety performance and protect our employees from injury. Two safety practices place emphasis on hazard recognition and mitigation: 1) if the job scope changes before critical job steps are performed, the safety briefing must be reviewed and revised as necessary; 2) at any time, an employee is expected to stop the job if there is question as to how to proceed. These expectations are identified and addressed in a mandatory job briefing and hazard analysis performed before the start of each job to ensure that each person at the site has a complete understanding of how to perform the work safely.

Contractor Oversight Program

The AEP Transmission safety culture extends to contractors because they represent AEP to the public. The AEP Transmission Contractor Safety Management System both qualifies contractors and monitors contractor field performance from the standpoint of safety and health. Contractors are qualified by an assessment of the contractor's commitment to safety and health via a thorough review of their safety program, past experiences, policies and procedures. Execution of their policies and procedures is verified by observation in the field.

AEP Transmission uses the following methods to ensure contractors maintain standards consistent with AEP safety culture values:

- Training requirements
- Drug and Alcohol Testing
- Firearms, alcohol and drug policies
- Station entry and switchyard entry restrictions
- Personal Protective Equipment (PPE) standards
- Task Hazard/Job briefing requirements
- Monthly safety reporting requirements
- Contractor safety representative requirements

Each contractor employed by AEP Transmission must abide by specific Supplemental Safety Terms and Conditions, which specify the particulars of these methods, in addition to the General Terms and Conditions of their contract. AEP Transmission requires contractors to report any safety and health related event within 48 hours through a web-based portal. These events include the following:

- OSHA recordable injuries
- First aid injury
- Interruption of service (outage)
- Vehicle accident
- Equipment event
- Material handling event
- Environmental issues, spills
- Dig-in
- Near miss

The contractor is also expected to perform an appropriate investigation and analysis of each reported event, determine how to address such events and implement a plan to eliminate or mitigate the situation from recurring. AEP Transmission shares this information more broadly internally and among other contractors, ensuring continuous improvement.

j. Regulatory

AEP Transmission actively participates in the regulatory process at both the federal and state levels, providing input in shaping transmission policy, and seeking approvals and cost recovery as necessary to improve the transmission system. Our experience at FERC and in 14 state jurisdictions extends from basic rate and transmission tracker cases to novation proceedings to seeking utility status for transmission siting, often as the first transmission-only utility in a given state. Through a 50/50 joint venture with Westar, AEP has formed new regulated entities to build, own and operate transmission outside of its traditional footprint in Kansas, and is currently in the process of obtaining regulatory approval for Transource Missouri to build and own projects in Missouri.

In each of AEP's eleven operating company states, we have an established team led by a company vice president for external affairs, exclusively dedicated to maintaining a collaborative relationship with state and local government, regulatory agencies, elected officials and consumer groups. This AEP presence across the country enables AEP Transmission to be aware of shifting priorities in different states and to address concerns quickly on a local level. Similar staff in Washington D.C. allows AEP Transmission to follow developments at FERC and the Department of Energy as well. AEP's regulatory case managers and attorneys represent AEP Transmission's interests in regulatory and siting proceedings and on an ongoing basis, manage reporting and disclosure requirements and ensure compliance with local laws and regulations.

4. AEP Recent Transmission Experience and System Restoration Capabilities

Provided in Appendix A are lists of selected active transmission projects in PJM, and several narrative descriptions of line and station projects that AEP and its affiliates have built in recent years, demonstrating the experience of AEP Transmission to develop, construct, maintain and operate transmission facilities. Appendix B is a report prepared following the restoration of a five-mile section of the 500 kV Broadford-Sullivan line following an F3 tornado in April, 2011, demonstrating the capability of AEP to remedy the failure of facilities.

5. Contact Information

The business address for each of the companies listed herein is 1 Riverside Plaza, Columbus Ohio, 43215. Please contact Raja Sundararajan (rsundararajan@aep.com, 614-716-2843), Antonio Smyth (apsmyth@aep.com, 614-716-2839), Robert Bradish (rwbradish@aep.com, 614- 552-1600), or Takis Laois (tlaios@aep.com, 614-716-3642) with any questions about the materials contained herein.

APPENDIX

A. Representative Sample of Transmission Projects built by AEP and affiliates (lists and narrative descriptions)

B. System Restoration Capabilities (500kV Broadford – Sullivan line restoration)

C. AEP Transmission Organization Chart

D. American Electric Power Company, Inc. 2009-2012 Financial Statements

E. Great Plains Energy, Inc. 2009-2012 Financial Statements

APPENDIX A:
Selected PJM-Approved Transmission Projects

Virginia and West Virginia

Project	Purpose	In-Service Date
1 **Cloverdale System Improvement Project** Install new 765/500-kV transformer at Cloverdale.	Reliability enhancement - NERC	2015
2 **Bland System Improvement Project** Install second 765/138-kV transformer at Jackson's Ferry Station; build 138-kV double circuit from Jackson's Ferry to Wythe station.	Reliability enhancement - NERC	2015
3 **South Christiansburg Area Improvements** Build new 138-kV line from Falling Branch Station to Merrimac Station. Install new 138/69-kV transformer at Merrimac.	Reliability enhancement - NERC/local	2016
4 **Roanoke Area Improvements** Install a 345/138-kV transformer at Matt Funk Station and 138-kV line exits to intersect Hancock-Tech Drive 138-kV circuit. A new 138-kV line will be constructed from Huntington Court to Roanoke stations.	Reliability enhancement - NERC	2012
5 **McDowell System Improvement** Convert the 88-kV system to 138-kV; retire stations; add 138-kV source into Richlands Station; install new capacitor bank at Faraday Station.	Reliability enhancement - NERC Operational performance	2017
6 **Cherry Creek-Pemberton System** Install a second 138-kV source into Cherry Creek Station and install breakers.	Reliability enhancement - NERC	2015
7 **Kanawha River Station** Add a 345/138-kV transformer at Kanawha River Station.	Reliability enhancement - Local	2015
8 **Wyoming Station** Add a 765-kV circuit breaker between the 765/138-kV transformers.	Operational performance	2014
9 **Baker Station** Construct second 765/345-kV transformer at Baker Station.	Reliability enhancement - NERC	2015
10 **Hazard KY Improvement Project** Build new 138-kV line Beaver Creek Station to Hazard area; build new 20-mile line from Soft Shell Station to Bonnyman Station 138-kV source into Hazard.	Reliability enhancement - NERC	2014

Indiana and Michigan

	Project	Purpose	In-Service Date
1	**Cook 765/345-kV Transformer Replacement** Replace existing 765/345-kV transformer at Cook Station; rehab existing 765-kV circuit breakers; move Cook Unit 1 to a dedicated 345-kV string.	Operational performance; System renewal	2013
2	**Michiana Area Improvements** Establish a 138/69-kV station; build a new 138/12-kV station to retire 34.5-kV Galien Station and 34.5-kV line between New Carlisle and Buchanan Hydro 34.5-kV stations.	Reliability enhancement - Local; Operational performance	2015
3	**Sister Lake Tap Upgrades** Construct a new 34.5-kV line (designed for 69-kV) between Hartford and Sister Lake tap stations; rebuild existing 34.5-kV Sister Lake tap for connection to Colby Station.	Reliability enhancement - NERC; Operational performance	2015
4	**Mishawaka Area Improvements** Build new circuit on existing double circuit tower-line between Twin Branch and East Elkhart 138-kV stations; reconfigure existing distribution stations and add a new 138/34.5-kV station.	Reliability enhancement - NERC	2014
5	**Corey Station 138-kV Integration** Add new 138-kV source into Corey Station by utilizing the vacant circuit on the planned rebuild of the Corey-Pokagon 69-kV line.	Reliability enhancement - Local	2016-20
6	**Sorenson Station** Add new source by establishing Sorenson Station as 765/345/138-kV station by looping the nearby 765-kV line in and out; improve the 345-kV switching configuration; rebuild Sorenson – Rob Park 138-kV line as double circuit 345-kV line with one side operating at 138-kV.	Reliability enhancement - NERC	2016
7	**Northern Fort Wayne Area Improvements** Establish new 138/69-kV station; construct new double circuit 138-kV line between Woods Road and Auburn stations.	Reliability enhancement - NERC	2015
8	**Southern Fort Wayne Improvements** Convert Decatur – Lincoln 34.5-kV line and associated station to 69-kV.	Reliability enhancement - Local	2015
9	**City of Fort Wayne Improvements** Establish a 138-kV circuit between Robison Park and Spy Run stations; convert IU Purdue station to 138-kV.	Reliability enhancement - Local	2015
10	**Alexandria Area Improvements** Complete conversion of 34.5-kV line between Jones Creek and Mullin 138-kV stations; consolidate 34.5-kV lines between Mullin and Deer Creek stations into 69-kV circuit.	Reliability enhancement - Local	2015

Ohio

	Project	Purpose	In-Service Date
1	**Vassell Station** New 765/345-kV station in Columbus District; additional 138-kV line into Delaware County.	Reliability enhancement - NERC	2014
2	**Amlin Station** New 138-kV station radially from Hyatt Station; construct 9.8 miles of 345-kV line on vacant position of the Hayden-Hyatt 345-kV line.	Reliability enhancement - Local	2014
3	**Cole Station** Build new 345/138/69-kV station in southwest Franklin County for looping Hyatt - Amlin 138-kV line.	Reliability enhancement - Local	2015
4	**Berrywood-Lincoln Line** Construct 15 miles of 69-kV line from Lincoln Station to new Berrywood Station; install 138/69-kV transformer at new station.	Reliability enhancement - Local	2015
5	**Melmore Station** Build new nine-breaker, 138-kV station at Melmore Station; add 138-kV circuit breakers to Tiffin and Fremont Center stations; add new double-circuit 138-kV line between Fremont Center and Melmore stations.	Reliability enhancement - NERC	2015
6	**Findlay Station** Build new nine-breaker, 138-kV station in Findlay; station upgrades at Northeast Findlay Station.	Reliability enhancement - NERC	2015
7	**Biers Run Station** Construct new 345/138/69-kV station at Biers Run with two 138-kV outlets and two 69-kV outlets to Circleville and Delano; build 138/12-kV Hopetown Station; retire Camp Sherman Station.	Reliability enhancement - NERC/Local	2016
8	**Highland-Seaman Improvements** Construct new Hillsboro-Highland 138-kV circuit; 138-kV improvements at Hillsboro, Highland, Seaman, and Adams stations; convert Highland-Seaman 69-kV circuit to 138-kV; and various area upgrades.	Reliability enhancement - NERC/Local	2014
9	**Canton Area Improvements** Install second 345/138-kV transformer at Canton Central station; build 138-kV circuits between South Canton and West Canton stations and between Wagenhals and West Canton stations; other area substation improvements.	Reliability enhancement - NERC/Local	2014
10	**Kammer Station** Improvements to prepare the area for retirement of 138-kV generating units include new 345/138-kV transformers; new 345-kV breakers and second 138-kV outlet.	Reliability enhancement - NERC	2014

Representative Completed Projects

Jacksons Ferry – Wyoming 765kV Transmission Line

Project Summary

This $306 Million project was energized on June 20, 2006 after a 13-year effort. The 90-mile line crosses two states and completing it required AEP to overcome numerous cultural, legal, environmental and technological barriers.

Completion Date:
June, 2006
Services Provided:

- Siting
- Right-of-Way
- Engineering
- Procurement
- Construction Management
- Environmental Mitigation

Project Challenges

Siting approval was complicated by the line crossing Virginia and West Virginia borders, 11 miles of National Forest, the Appalachian National Scenic Trail and two Army Corps of Engineers jurisdictional rivers. The US Fish and Wildlife agency was also involved.

Technical challenges included reducing audible noise levels and corona losses experienced with traditional 4-conductor designs and routing the line through some of the most inaccessible mountainous terrain in AEP service territory. Spans between towers reached lengths of 3,500 feet in some cases, and the lack of soil depth greatly limited the choice of structure foundations.

The project required AEP to secure more than 90 miles of right-of-way.

Project Solutions

This project required the development of new steel structures, tower installation techniques, stringing hardware, equipment, 160 miles of service road construction and a new construction process.

AEP greatly reduced audible noise and corona discharge by engineering the first 765kV 6-conductor bundle arrangement in the US. The 6-bundle conductors were strung using new equipment and bundled together using a new 6-conductor spacer damper developed for this project.

A new family of guyed-vee structures was developed to both support the long spans and speed installation. This project allowed AEP to establish new standards for 765kV lines used throughout the AEP system, thus reducing cost and increasing quality and project constructability.

Consideration for area residents led AEP to mitigate the aesthetic impact of the project. Conductors and towers were treated in certain areas with a finish that reduced their visibility. AEP also used landscape-based mitigation techniques to preserve the natural beauty of the area.

The project improved reliability in AEP's WV and VA territory and enhanced power transfer capability from the Midwest to the east and southeast, thus allowing competitive markets to benefit.

Members of the project team were awarded the Southeastern Electric Exchange (SEE) Industry Excellence Award in 2007 for achievement in meeting challenges and solving problems, innovation in design, operations and processes, performance of the completed project, meeting the requirements of project customers and technical complexity.

Maliszewski 765kV/138kV Substation, Delaware Ohio

Project Summary

The Maliszewski 765/345/138kV station near Delaware, Ohio, was completed in 2001 to reinforce the company´s transmission network due to rapid growth and development in Central Ohio. The station includes notable industry firsts, including the first 800,000-volt SF6 dead-tank circuit breaker, and it is the first 765kV station to employ HMI (Human Machine Interface) technology, which allows equipment operation via a touch screen console. The station layout allows for station expansion as the needs of Central Ohio grow.

Completion Date:
2001
Services Provided:

- Planning
- Engineering
- Siting/Permitting/Right-of-Way
- Procurement
- Construction

Project Challenges

Construction required navigating both residential and commercial needs in the area, completing the Ohio Power Siting Board process, working with the local railroad company to develop a spur for large equipment deliveries and accommodating local government plans for future road development in the area.

AEP developed the station design and layout within a footprint constrained by railroad tracks and 138kV lines to the east, an existing 765kV line to the north and a 345kV double-circuit tower line to the south. This 345kV line also crosses the 765kV line.

Project Solutions

The completed station design and layout includes 765kV, 345kV and 138kV yards.

The 765kV yard is equipped with a four-breaker ring bus, two 765kV lines, a 765/138kV transformer and a 765/345kV or 765/138kV transformer. The 345kV yard has a five-breaker ring bus, three 345kV lines, a 765kV transformer connection and a 345/138kV transformer.

When fully-configured, the 138kV yard will consist of five 'breaker & a half' strings, ten 138kV lines, one 765kV transformer connection, a 765kV or 345kV transformer connection and five 138/34kV transformers to feed distribution load in the area.

Roberts-OSU 138kV Underground Line – Columbus Ohio

Completion Date:
December 2011
Services Provided:
- Siting and Permitting
- Right-of-Way
- Engineering
- Procurement
- Construction Management

Project Summary

AEP designed and constructed 5.55 miles of 138kV underground transmission line using a 2,500 KCM Prysmian XLPE© cable design in a heavily residential area. The project terminated into the Roberts Road substation, involving replacement of a 1970s era 138kV wood pole line with 1.1 miles of double circuit 1,272 KCM ACSR conductor suspended on new tubular steel monopoles.

Project Challenges

Close coordination with the Ohio State University was essential to avoid impacting campus activities like school breaks and when working near these locations. Coordination with municipalities was also essential to avoid interfering with services and utilities. The presence of existing underground facilities was a complicating factor when selecting locations to dig or drill. The path of the underground portion of the line involved two HDD river crossings of 1450 and 800 feet. The line also crossed over an 84-inch sanitary sewer.

Project Solutions

AEP selected 2500 MCM segmental copper XLPE cable to improve reliability and reduce spare material parts and costs for the project.

AEP worked with the city of Upper Arlington to develop a mutually-beneficial plan ensuring timely project completion with a minimum of interruption to vital city services and activities.

15 manholes for access into the underground line were installed along with 93,000 linear feet of cable. To prevent future accidental damage to the new underground line, AEP used red-dyed concrete for the duct bank as a warning measure for any digging near AEP facilities. After installation, new line locations were documented using advanced GPS surveying prior to backfilling to create the most accurate as-built records for future use.

Static VAR System (SVS) Installation – St. Clair Station, Columbus Ohio

Project Summary

Load growth in the Columbus, Ohio area and additional generation requirements led AEP System Studies to order a variable, 0-250 MVar static VAR system (SVS) with a switched 100-MVar air core reactor for the Columbus area. St. Clair substation was selected due to its proximity to the load center and its interconnection to adjacent substations via a 138 kV ring bus and five 138 kV lines. The St. Clair station was also equipped with two 138/13kV transformers to serve local distribution load and a 138 kV capacitor bank.

Completion Date:
June 1, 2012
Services Provided:

- Permitting
- Engineering
- Procurement
- Construction Management

Project Challenges

The SVS had to be integrated into the existing 138kV ring bus and had to be able to control capacitor banks at adjacent substations to act as one system. This integration also required updates to station communications and remote control systems. While some facilities were relocated, AEP developed a layout that avoided multiple existing distribution & transmission facilities.

Project Solutions

AEP worked with several local government entities on drainage & storm water permits, site development plans, fire code compliance and noise restrictions. AEP also exercised great care to avoid an existing sewer line.

AEP worked with the SVS vendor to conduct system impact studies and design integration of the SVS into the existing 138 kV ring bus.

AEP conducted system studies to determine which stations to integrate together and updated the remote station control and telecommunications systems needed for integrated operation.

The project was delivered on-time with minimal environmental impact and relocations, and has improved system performance.

APPENDIX B: *Example of System Restoration Capabilities*

Report on 500kV Broadford-Sullivan Line Restoration

INTRODUCTION

An F3 tornado touched down during the early morning hours of April 28, 2011 in Glade Spring, Virginia. The National Weather Service in Blacksburg estimated that winds for this tornado approached 140 mph. It carved a path of destruction that measured one-half mile wide and four miles in length. The path of the tornado is illustrated in Figure 1.

American Electric Power Company's EHV 500kV Broadford-Sullivan transmission line was badly damaged over a five mile section. This transmission line is located in predominantly rolling to hilly terrain.

DAMAGE ASSESSMENT

The restoration effort began immediately with a preliminary damage assessment performed by AEP maintenance personnel. Detailed inspections involving engineering, climbing crews and contractors then followed the preliminary assessment. The intent was to identify the damaged towers that could be repaired at a reasonable cost and the towers that had to be replaced. The detailed field evaluations revealed that 16 structures were destroyed and seven lattice towers were damaged by the tornado. In addition, 64 new concrete pier foundations with stub angles would need to be installed.

Access to the tower sites was hampered by debris and fallen timber blocking local, county, and state roads. Government crews and their contractors had to clear these roads before AEP and its restoration contractors could bring in the heavier equipment needed to begin the restoration and repair process.

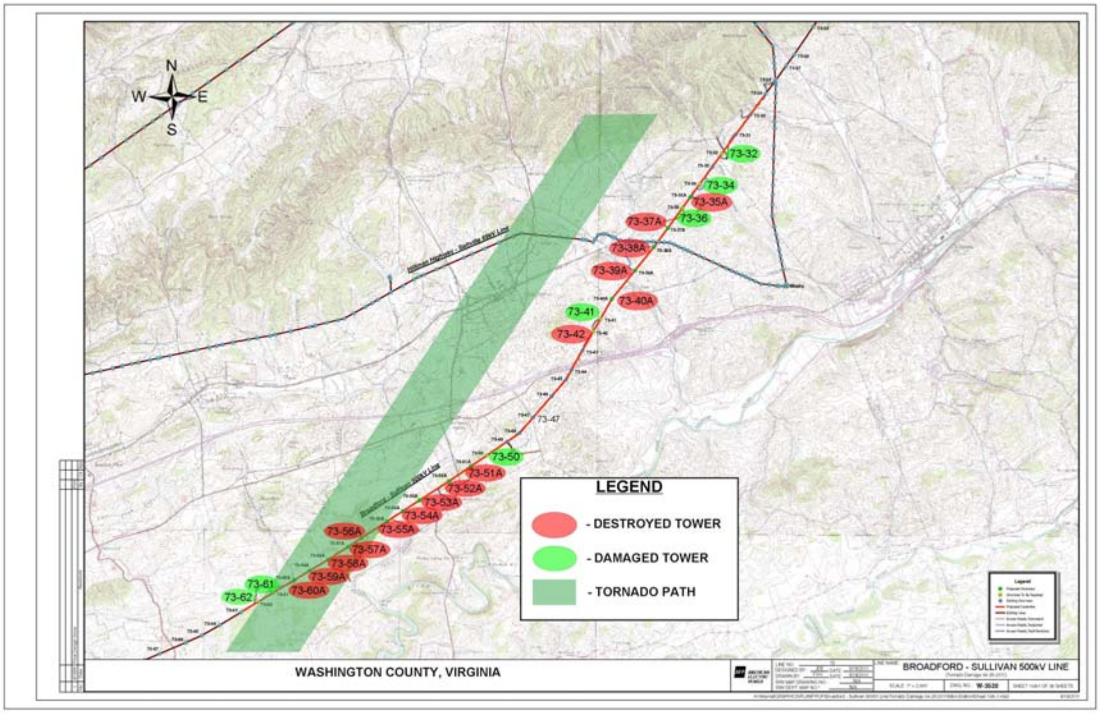


Figure 1 – Map Showing Tornado Damage to 500kV Broadford-Sullivan Line

STRUCTURE SELECTION & AVAILABILITY

Fundamental to any successful restoration plan is first selecting and then obtaining appropriate structure replacements. The 500kV Broadford-Sullivan line is comprised of single circuit 500kV lattice structures arranged in a three-phase horizontal configuration. This tower series was designed in the 1960's. Most towers were approximately 120 feet in height with average phase spacing of 30 feet.

AEP contacted fabricators for projected lead times for replacement structures. Responses from both lattice and tubular suppliers revealed a range of six to ten weeks for final delivery of steel structures upon receipt of a final design package. Creation of a final design package would add at least one additional week.

In parallel, AEP began contacting neighboring utilities to inquire about availability of their stock. Most had stocking protocols similar to AEP with limited structure availability. However, FirstEnergy was nearing completion of a major 500kV line and had several lattice towers available. The towers were also less than 300 miles away. Based on tower models provided by FirstEnergy, preliminary line design and tower analysis revealed that these lattice towers were an acceptable option.

All 16 replacement towers including 64 stub angles were purchased from FirstEnergy. Identifying this opportunity saved valuable time and incredibly, the delivery of the tower steel began arriving on-site during the week of May 9, which was less than two weeks after the tornado event. Thanks to the assistance from FirstEnergy, structure acquisition was removed from the critical path. However, items such as conductor delivery with corresponding hardware as well as foundation design and construction were now on the critical path.

The 16 replacement towers were similar but not identical to the destroyed towers in height or footprint and were offset by a small distance (less than about 25 feet) to mitigate the risk of interference between the old grillage foundations and the new drilled shaft foundations.

The restoration plan also involved seven miles of new access road construction to support material removal, repair work, and construction of the replacement towers. This was projected to take two to three weeks. Tower debris, conductor and overhead ground wire removal would take several additional weeks once the access roads were finished. The start of this work was also impacted by the efforts to clear local roads controlled by government agencies.

In summary, the final restoration plan included sixteen structures that would require total replacement and seven structures that would need repair. Sixty-four drilled reinforced concrete pier foundations would also be required. Nearly five miles of two-bundled ACAR conductor and associated groundwire would have to be restrung. Considering the critical path items denoted above, the restoration plan moved forward with a target date for re-energizing the line set at September 15, 2011.

TOWER SITE CLEAN-UP

The initial plan was to remove damaged towers and associated material using trucks, cranes, and other heavy equipment. This effort would take several weeks. Helicopter removal was then investigated and deemed a viable option. Two helicopters were used to remove the damaged towers and materials. Using helicopters shortened the site clean-up to less than one week for the removal of all damaged structures. This also enabled the foundation crews to begin concrete pier installation sooner than expected. In contrast, removal by truck would have required access road construction first, therefore delaying pier installation by several weeks.

FOUNDATION SELECTION

The foundation installation remained on the critical path. AEP traditionally uses earth grillage foundations with lattice towers in moderate to rugged terrain. Earth grillage foundations, spread footings constructed of structural steel, would have required multiple crews working simultaneously to install 64 grillage foundations within a two month window. Grillage installation is a lengthy and labor intensive process involving a large amount of excavation that can prove challenging in terrain with erratic depths to bedrock. Thorough compacting operations are essential to ensure proper installation. Although advantageous in many situations, this choice would not support a fast track in-service date. Concrete pier foundations provided a strong advantage since stub angles were already designed, detailed and fabricated; a concrete plant was located within 30 minutes of the project; and the rolling terrain allowed easy access to the site. Fortunately, the foundation crews that installed the 500kV tower piers for the FirstEnergy project were also available. Using crews experienced with installing these tower piers eliminated any type of learning curve associated with a new structure type and complex installation techniques required to accurately set a stub angle. There is not quick fix for incorrectly installed concrete piers.

GEOTECHNICAL INVESTIGATION

A notable problem remained. This was taking a soil and rock sample at each of the 64 foundation locations before construction began. This was not a viable option because it would have delayed foundation design and construction by several weeks. Another challenge was identified when a site reconnaissance of the area discovered vast sinkholes, meaning that the project site was in an active karst area. Karst refers to the dissolution of carbonate rock. In this particular case, voids were created within the limestone which can eventually collapse and leave behind vast depressions at the ground surface referred to as sinkholes. Another common trait of karst areas is a highly variable depth to rock which would further complicate the design process. This is easily addressed with a boring at each location but was not a practical option in this case due to schedule constraints. The picture in Figure 3 is a sinkhole which is over 50 feet in diameter and 10 feet deep. Geotechnical borings were drilled from Friday, May 13, 2011 to Sunday May 15, 2011, which was about two weeks after the tornado event.

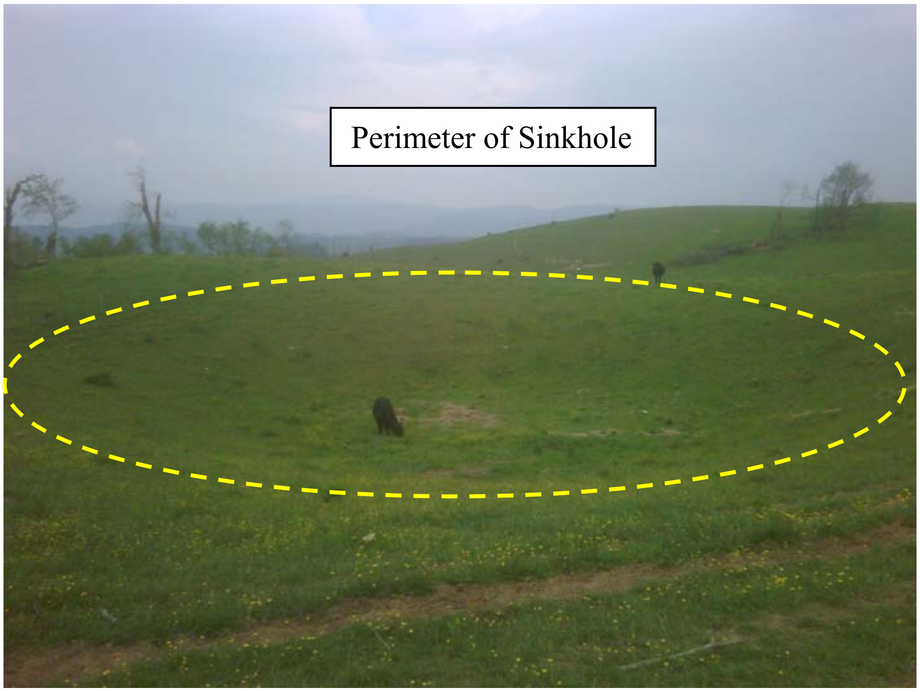


Figure 3 – Sinkhole Located Near the 500 kV Broadford-Sullivan Line

FOUNDATION DESIGN

Foundation design challenges included limited subsurface information, highly variable subsurface conditions, and an aggressive construction schedule. The design team was tasked to develop reliable and flexible foundation designs that would avoid the long installation schedules and high material costs that would result from a conservative one-size fits all design. This challenge was met by employing a unique design approach using nomographs based on five subsurface borings taken along the damaged corridor. This process involved developing a design matrix based upon the structure foundation reactions, geotechnical data, and geologic properties that were derived from only five investigative borings. The nomographs were developed early in the project. This approach resulted in dramatic cost and schedule savings while producing reliable foundation designs.

An experienced engineering firm was responsible for the drilled pier foundation design and had previous experience with these towers, enabling a quick design start. Both AEP and the engineering firm had used design nomographs for past projects with success. Some of the many advantages that this process offers include:

- The ability to produce reliable foundation designs from a limited amount of subsurface information while avoiding conservative, one-size-fits all designs.
- The flexibility to empower construction crews to make real-time, on-site design decisions based upon as-encountered subsurface drilling results. This avoided

construction delays from office re-designs and resulted in dramatic schedule savings.

- The reduction in both material and labor. On average, it is estimated that pier depths were reduced on average by 20% from their respective "worst-case" depths, saving rebar, concrete, and time. This was achieved by producing drilled pier designs that were tailor-fit to the subsurface conditions at each respective tower leg.

Nomographs were developed as an aid in determining the required rock socket length for a drilled pier with various overburden depths in a given subsurface stratigraphy, or design profile. A single design profile of clay over limestone was selected for this project as the most representative model because the subsurface investigation revealed fairly consistent soil and rock types within the project area. Since there were four unique tower types with significantly different foundation loads, four separate nomographs using the clay over limestone model were developed. A single design profile was selected as being representative because the subsurface investigation revealed fairly consistent soil and rock types within the project area.

The design nomographs would then be used during construction by on-site geotechnical engineers to evaluate the soil/rock conditions in each foundation excavation, select the appropriate subsurface profile and structure type, estimate the as-drilled overburden depth, and modify the design length of each drilled pier. A graphical representation of the nomograph used for a mid-span tangent tower is shown below in Figure 4.

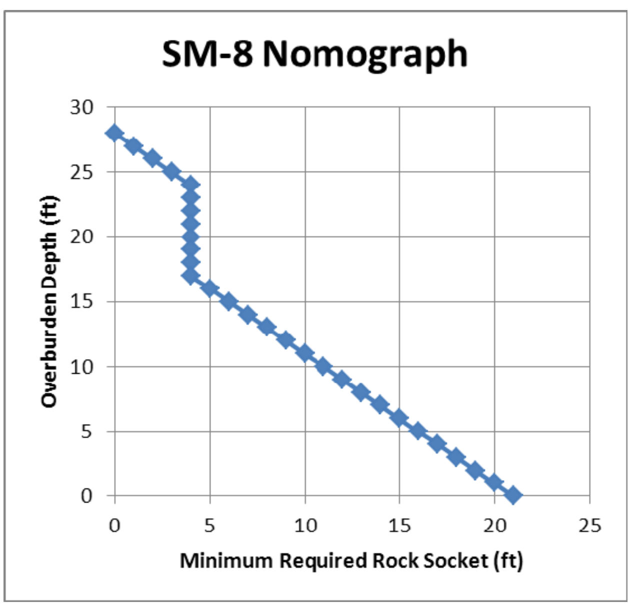


Figure 4 - Nomograph for Mid-Span Tangent Tower

Final foundation construction drawings were submitted on Friday, May 20, 2011 and construction began on Monday, May 23, 2011, only 25 days after the tornado event.

FOUNDATION INSTALLATION

During foundation installation, a geotechnical engineer accompanied each of the three separate drilled pier crews. The geotechnical engineer, armed with the nomographs, observed the in-situ drilling spoil and made real-time decisions based upon the material drilled from each tower leg. This information was used to finalize each individual drilled pier design. The main responsibilities of the on-site geotechnical engineer included the following:

- Evaluating as-drilled subsurface conditions at each foundation to ensure they match the assumptions as denoted in the matrix.
- Selecting the appropriate nomograph for the applicable structure type.
- Determining the design depth for each drilled pier.
- Selecting the appropriate rock socket depth from the nomograph.
- Communicating the final drilled pier design depth to the Contractor.
- Recording geotechnical data and final design parameters and depths for each foundation.

The active karstic limestone area presented a real risk that a void may exist beneath the bottom of the drilled pier. To mitigate this risk, 10-foot long pilot holes, six inches in diameter were drilled beyond the bottom of each drilled pier to see if problematic voids existed below the pier. If no void was encountered, then drilling was complete. However, if a significant void was found, the overburden depth was considered to be the depth from ground surface to the bottom of the void. The drilled pier design depth was then modified accordingly. Five of the sixty-four drilled pier depths were adjusted as a result of encountering voids within their pilot holes.

Three IMT AF 240 drilling rigs (Figure 5) capable of drilling up to 100 feet below ground surface were used on the project. The as-drilled depth of embedment for the drilled piers ranged from 20 feet to 42 feet with an average of 25 feet. Each stub angle was located and staked with a deviation tolerance of no more than 1/8 inch from its required horizontal stub dimension. This involved the use of a Trimble Robotics S3 Series total station unit which confirmed the alignment and orientation of each structure leg based on the tower type. A centerline stake and two offset stakes for each tower leg were placed as a reference to help assist with alignment of each shaft during drilling. Up to two IMT AF 240 drill rigs operating simultaneously at each tower site excavated to the pier depth established by the onsite geotechnical engineering representative.

When drilling was completed, the foundation reinforcing steel was lowered into the excavation and the drilled pier reveal was established at each structure leg using a piece of specialty equipment called a "stub jack" (Figure 6). A cylindrical concrete form was attached to the top of the stub jack. This form was then raised or lowered to achieve the desired reveal based on the survey control. Once the reveal was determined, the centerline and orientation of each stub leg was established using longitudinal and transverse string lines.

A second piece of specialty equipment called the "stub angle positioner" (Figure 6) was mounted to the top of the stub jack to hold the stub angle in-place. The final position and orientation of each stub leg was established by surveying the control point (top of each stub leg) with the Trimble unit, checking both the angle of rotation (twist) and vertical position. The stub angle batter was checked by a digital protractor. The Stub Angle Positioner was locked in place upon positioning the stub angle. The structure stub angle was now ready for concrete placement.

Concrete was placed into each drilled pier excavation using a hydraulic concrete pumping truck. The mix design was made and tested to achieve 3000 psi in 3 days and 4000 psi in 7 days. The mix contained wetting agents and other admixtures to allow free flow within deep holes and unencumbered pumping through the equipment. The engineered design strength was to be no less than 4000 psi after 28 days.

Figure 5 – IMT AF 240 Drill Rig

Daily summaries of concrete strength test results were tabulated and distributed to the project team with advisements on when adequate strength was achieved. Adequate strengths included 3,000 psi to commence tower erection and 4,000 psi to commence line stringing.

There were initial challenges with the concrete mix design and concrete conveyance operations. These problems included plugging of the hydraulic pump, some initial slow curing strength rates, and dealing with hot day mixtures with long trucking times. For example, one problem included a malfunctioning valve in one of the admixture dispensers that resulted in slow curing strength rates. Astute field observations and judgment along with close work between the AEP construction representatives, foundation contractor and the concrete batching company made for effective and timely resolution to these challenges. Again, team work and technical competence paid huge dividends. The project was now in a position to routinely achieve concrete strengths in excess of 4,000 psi after 3 days, allowing tower erection to follow closely behind foundation installation. This achieved significant savings in time.

The nomograph process, using both a skilled and experienced geotechnical engineer and contractor, facilitated the installation of 64 drilled concrete piers in one month. Foundation installation was completed on June 28, 2011; 61 days after the tornado event.

Figure 6 – Concrete Form with Stub Jack and Positioner

TOWER ERECTION

Tower erection was the next critical step in the restoration. Erection began on June 6, 2011, involving two 12-man crews. These crews were familiar with the furnished 500 kV structures, having assembled them on a lengthy earlier project. This again saved valuable time as it eliminated any type of learning curve associated with assembling and erecting a new tower.

These crews also worked diligently to assemble the towers into components suitable for independent crane lifts, working adjacent to each tower site as the foundation crews were drilling, setting stub angles, and placing concrete. Tower erection could not begin until each tower site had reached three-day compression strengths of 3000 psi. Once the foundations had achieved adequate strength, one assembly crew transitioned to tower erection, while the second crew continued with tower assembly. This second crew continued until tower assembly was complete and then started tower erection. Eventually, all structures were assembled and erected. The tower erection was completed on July 8, 2011; 71 days after the tornado event.

TOWER REPAIR

Every tower within or near the path of the tornado was visually inspected immediately following the storm. From this inspection, a list was created identifying those towers with deformed members. Heavily damaged towers that required extensive repair were scheduled for replacement. Structures with un-repairable earth grillages were also replaced. It was determined that seven towers could be repaired. Although some of these towers had a large number of damaged members, the damage was limited to smaller member sizes and did not include the main legs or other primary load carrying members. On all seven towers, the foundations were intact and suffered no translation or rotation.

A list of damaged members on each repairable structure was compiled from the engineers' visual inspection, and supplemented following a thorough climbing inspection. The repairs included member and connection plate replacements, shield wire trunion clamp replacements, and miscellaneous bolt replacements.

Once a list of required repairs was compiled, structure tower models were created to determine the load capacity of each structure during the repair process. The tower models were used to ensure safe member replacements in low wind conditions without having to support the structure. This proved to be a significant dollar savings as the need to build roads and crane pads to repair the damaged structures was eliminated.

The tower repair process began on May 24, 2011 and was completed on June 8, 2011; 41 days after the tornado event.

LINE STRINGING

Line stringing was the final step in restoring the 500kV Broadford-Sullivan line. Approximately five circuit miles of conductor had to be restrung. The conductor configuration was a two conductor bundle, horizontal three-phase 500kV arrangement. Conductor stringing began on June 27, 2011 and was completed on July 19, 2011; 82 days after the tornado event.

SUMMARY OF WORK COMPLETED

- 7 miles of newly built access road
- 1,590 cubic yards of concrete placed
- 400 tons of latticed steel assembled and erected
- 5,000 new insulators installed
- 140,000 ft. of new conductor installed

CONCLUSIONS

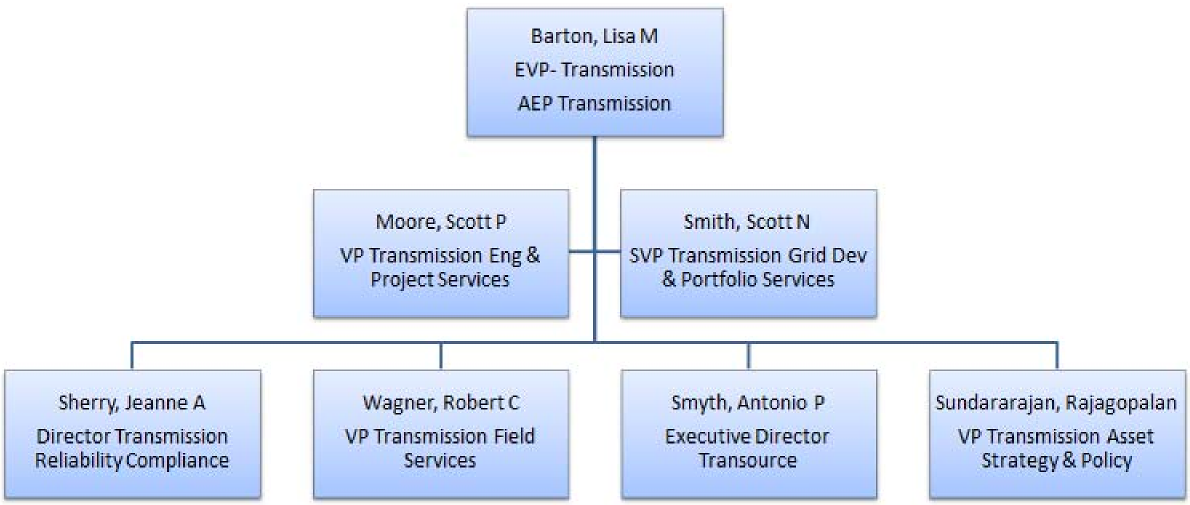
The restoration of the 500kV Broadford-Sullivan line was successful because of the collective effort and diverse skill sets of the contractors and AEP personnel which comprised the project team. Key decisions made by the project team on several critical path tasks facilitated the timely restoration of this EHV transmission line. These decisions included:

- Tower removal - using helicopters instead of cranes, trucks, and other ground support equipment.
- Foundation type - proceeding with concrete drilled piers instead of steel grillages.
- Foundation design and installation - using nomographs with on-site geotechnical engineering observation instead of developing a one-size fits all design.
- Material source – checking on large scale projects, inventory, or supplier fabrication.
- Contractor experience – utilizing a high level of skill and experience with chosen method of restoration.
- Tower repair - as opposed to tower replacement.

The 500kV Broadford-Sullivan line was placed back in service on July 21, 2011. The outage lasted 85 days and the line was placed into service 57 days ahead of the original schedule.

APPENDIX C: AEP TRANSMISSION ORGANIZATION

AEP Transmission's functional organizations report to Lisa Barton, AEP's Executive Vice President – Transmission. More than 1700 employees report through the following structure.



Appendix D: American Electric Power Company, Inc. 2009-2012 Financial Statements

Appendix E: Great Plains Energy, Inc. 2009-2012 Financial Statements

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in millions, except per-share and share amounts)

	Years Ended December 31, 2012	2011	2010
REVENUES			
Utility Operations	$ 13,677	$ 14,091	$ 13,687
Other Revenues	1,268	1,025	740
TOTAL REVENUES	14,945	15,116	14,427
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,111	4,421	4,029
Purchased Electricity for Resale	1,169	1,191	1,000
Other Operation	2,962	2,868	3,132
Maintenance	1,115	1,236	1,142
Asset Impairments and Other Related Charges	300	139	-
Depreciation and Amortization	1,782	1,655	1,641
Taxes Other Than Income Taxes	850	824	820
TOTAL EXPENSES	12,289	12,334	11,764
OPERATING INCOME	2,656	2,782	2,663
Other Income (Expense):			
Interest and Investment Income	8	27	38
Carrying Costs Income	53	393	70
Allowance for Equity Funds Used During Construction	93	98	77
Interest Expense	(988)	(933)	(999)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,822	2,367	1,849
Income Tax Expense	604	818	643
Equity Earnings of Unconsolidated Subsidiaries	44	27	12
INCOME BEFORE EXTRAORDINARY ITEM	1,262	1,576	1,218
EXTRAORDINARY ITEM, NET OF TAX	-	373	-
NET INCOME	1,262	1,949	1,218
Net Income Attributable to Noncontrolling Interests	3	3	4
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,259	1,946	1,214
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,259	$ 1,941	$ 1,211
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	484,682,469	482,169,282	479,373,306
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 2.60	$ 3.25	$ 2.53
Extraordinary Item, Net of Tax	-	0.77	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	485,084,694	482,460,328	479,601,442
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 2.60	$ 3.25	$ 2.53
Extraordinary Item, Net of Tax	-	0.77	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
CASH DIVIDENDS DECLARED PER SHARE	$ 1.88	$ 1.85	$ 1.71

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31, 2012	2011	2010
Net Income	$ 1,262	$ 1,949	$ 1,218
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $8, $18 and $14 in 2012, 2011 and 2010, Respectively	(15)	(34)	26
Securities Available for Sale, Net of Tax of $1, $1 and $4 in 2012, 2011 and 2010, Respectively	2	(2)	(8)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $16, $13 and $12 in 2012, 2011 and 2010, Respectively	31	24	22
Pension and OPEB Funded Status, Net of Tax of $62, $41 and $25 in 2012, 2011 and 2010, Respectively	115	(77)	(47)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	133	(89)	(7)
TOTAL COMPREHENSIVE INCOME	1,395	1,860	1,211
Total Comprehensive Income Attributable to Noncontrolling Interests	3	3	4
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,392	1,857	1,207
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,392	$ 1,852	$ 1,204

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	AEP Common Shareholders						
	Common Stock				Accumulated Other Comprehensive Income (Loss)		
	Shares	Amount	Paid-in Capital	Retained Earnings		Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140
Issuance of Common Stock	3	18	75				93
Common Stock Dividends				(820)		(4)	(824)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			5				5
Subtotal – Equity							12,411
Net Income				1,214		4	1,218
Other Comprehensive Loss					(7)		(7)
TOTAL EQUITY – DECEMBER 31, 2010	501	3,257	5,904	4,842	(381)	-	13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends				(894)		(4)	(898)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Loss on Reacquired Preferred Stock			(4)				(4)
Capital Stock Expense			(16)				(16)
Other Changes in Equity			11	(2)		2	11
Subtotal – Equity							12,805
Net Income				1,946		3	1,949
Other Comprehensive Loss					(89)		(89)
TOTAL EQUITY – DECEMBER 31, 2011	504	3,274	5,970	5,890	(470)	1	14,665
Issuance of Common Stock	2	15	68				83
Common Stock Dividends				(913)		(3)	(916)
Other Changes in Equity			11			(1)	10
Subtotal – Equity							13,842
Net Income				1,259		3	1,262
Other Comprehensive Income					133		133
TOTAL EQUITY – DECEMBER 31, 2012	506	$ 3,289	$ 6,049	$ 6,236	$ (337)	$ -	$ 15,237

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in millions)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 279	$ 221
Other Temporary Investments (December 31, 2012 and 2011 Amounts Include $311 and $281, Respectively, Related to Transition Funding and EIS)	324	294
Accounts Receivable:		
Customers	685	690
Accrued Unbilled Revenues	195	106
Pledged Accounts Receivable - AEP Credit	856	920
Miscellaneous	171	150
Allowance for Uncollectible Accounts	(36)	(32)
Total Accounts Receivable	1,871	1,834
Fuel	844	657
Materials and Supplies	675	635
Risk Management Assets	191	193
Regulatory Asset for Under-Recovered Fuel Costs	88	65
Margin Deposits	76	67
Prepayments and Other Current Assets	241	216
TOTAL CURRENT ASSETS	4,589	4,182
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,279	24,938
Transmission	9,846	9,048
Distribution	15,565	14,783
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	3,945	3,780
Construction Work in Progress	1,819	3,121
Total Property, Plant and Equipment	57,454	55,670
Accumulated Depreciation and Amortization	18,691	18,699
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	38,763	36,971
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,106	6,026
Securitized Transition Assets	2,117	1,627
Spent Nuclear Fuel and Decommissioning Trusts	1,706	1,592
Goodwill	91	76
Long-term Risk Management Assets	368	403
Deferred Charges and Other Noncurrent Assets	1,627	1,346
TOTAL OTHER NONCURRENT ASSETS	11,015	11,070
TOTAL ASSETS	$ 54,367	$ 52,223

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2012 and 2011
(dollars in millions)

	December 31, 2012	December 31, 2011
CURRENT LIABILITIES		
Accounts Payable	$ 1,169	$ 1,095
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	657	666
Other Short-term Debt	324	984
Total Short-term Debt	981	1,650
Long-term Debt Due Within One Year (December 31, 2012 and 2011 Amounts Include $367 and $293, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	2,171	1,433
Risk Management Liabilities	155	150
Customer Deposits	316	289
Accrued Taxes	747	717
Accrued Interest	269	279
Regulatory Liability for Over-Recovered Fuel Costs	47	8
Other Current Liabilities	968	990
TOTAL CURRENT LIABILITIES	6,823	6,611
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2012 and 2011 Amounts Include $2,227 and $1,674, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	15,586	15,083
Long-term Risk Management Liabilities	214	195
Deferred Income Taxes	9,252	8,227
Regulatory Liabilities and Deferred Investment Tax Credits	3,544	3,195
Asset Retirement Obligations	1,696	1,472
Employee Benefits and Pension Obligations	1,075	1,801
Deferred Credits and Other Noncurrent Liabilities	940	974
TOTAL NONCURRENT LIABILITIES	32,307	30,947
TOTAL LIABILITIES	39,130	37,558
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2012	2011
Shares Authorized	600,000,000	600,000,000
Shares Issued	506,004,962	503,759,460

	December 31, 2012	December 31, 2011
(20,336,592 Shares were Held in Treasury as of December 31, 2012 and 2011)	3,289	3,274
Paid-in Capital	6,049	5,970
Retained Earnings	6,236	5,890
Accumulated Other Comprehensive Income (Loss)	(337)	(470)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	15,237	14,664
Noncontrolling Interests	-	1
TOTAL EQUITY	15,237	14,665
TOTAL LIABILITIES AND EQUITY	$ 54,367	$ 52,223

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31, 2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 1,262	$ 1,949	$ 1,218
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,782	1,655	1,641
Deferred Income Taxes	636	794	809
Gain on Settlement with BOA and Enron	-	(51)	-
Settlement of Litigation with BOA and Enron	-	(211)	-
Extraordinary Item, Net of Tax	-	(373)	-
Asset Impairments and Other Related Charges	300	139	-
Carrying Costs Income	(53)	(393)	(70)
Allowance for Equity Funds Used During Construction	(93)	(98)	(77)
Mark-to-Market of Risk Management Contracts	57	37	30
Amortization of Nuclear Fuel	136	137	139
Pension Contributions to Qualified Plan Trust	(200)	(450)	(500)
Property Taxes	(19)	(15)	(21)
Fuel Over/Under-Recovery, Net	157	(25)	(253)
Change in Other Noncurrent Assets	(236)	(112)	(89)
Change in Other Noncurrent Liabilities	127	307	202
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(16)	107	(866)
Fuel, Materials and Supplies	(224)	176	221
Accounts Payable	(60)	(44)	(36)
Accrued Taxes, Net	174	193	179
Other Current Assets	(3)	37	73
Other Current Liabilities	77	29	62
Net Cash Flows from Operating Activities	3,804	3,788	2,662
INVESTING ACTIVITIES			
Construction Expenditures	(3,025)	(2,669)	(2,345)
Change in Other Temporary Investments, Net	(27)	8	(4)
Purchases of Investment Securities	(1,047)	(1,321)	(1,918)
Sales of Investment Securities	988	1,379	1,817
Acquisitions of Nuclear Fuel	(107)	(106)	(91)
Acquisitions of Assets/Businesses	(94)	(19)	(155)
Acquisition of Cushion Gas from BOA	-	(214)	-
Proceeds from Sales of Assets	18	123	187
Other Investing Activities	(97)	(71)	(14)
Net Cash Flows Used for Investing Activities	(3,391)	(2,890)	(2,523)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	83	92	93
Issuance of Long-term Debt	2,856	1,328	1,270
Commercial Paper and Credit Facility Borrowings	25	488	565
Change in Short-term Debt, Net	(654)	744	770
Retirement of Long-term Debt	(1,643)	(1,665)	(1,993)
Retirement of Cumulative Preferred Stock	-	(64)	-
Commercial Paper and Credit Facility Repayments	(40)	(928)	(115)
Principal Payments for Capital Lease Obligations	(71)	(71)	(95)
Dividends Paid on Common Stock	(916)	(898)	(824)
Dividends Paid on Cumulative Preferred Stock	-	(2)	(3)
Other Financing Activities	5	5	(3)
Net Cash Flows Used for Financing Activities	(355)	(971)	(335)
Net Increase (Decrease) in Cash and Cash Equivalents	58	(73)	(196)
Cash and Cash Equivalents at Beginning of Period	221	294	490
Cash and Cash Equivalents at End of Period	$ 279	$ 221	$ 294

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in millions, except per-share and share amounts)

	2011	2010	2009
REVENUES			
Utility Operations	$ 14,091	$ 13,687	$ 12,733
Other Revenues	1,025	740	756
TOTAL REVENUES	15,116	14,427	13,489
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,421	4,029	3,478
Purchased Electricity for Resale	1,191	1,000	1,053
Other Operation	2,868	3,132	2,620
Maintenance	1,236	1,142	1,205
Asset Impairments and Other Related Charges	139	-	-
Depreciation and Amortization	1,655	1,641	1,597
Taxes Other Than Income Taxes	824	820	765
TOTAL EXPENSES	12,334	11,764	10,718
OPERATING INCOME	2,782	2,663	2,771
Other Income (Expense):			
Interest and Investment Income	27	38	11
Carrying Costs Income	393	70	47
Allowance for Equity Funds Used During Construction	98	77	82
Interest Expense	(933)	(999)	(973)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	2,367	1,849	1,938
Income Tax Expense	818	643	575
Equity Earnings of Unconsolidated Subsidiaries	27	12	7
INCOME BEFORE EXTRAORDINARY ITEMS	1,576	1,218	1,370
EXTRAORDINARY ITEMS, NET OF TAX	373	-	(5)
NET INCOME	1,949	1,218	1,365
Net Income Attributable to Noncontrolling Interests	3	4	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,946	1,214	1,360
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	5	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,941	$ 1,211	$ 1,357
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	482,169,282	479,373,306	458,677,534
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Items	$ 3.25	$ 2.53	$ 2.97
Extraordinary Items, Net of Tax	0.77	-	(0.01)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.02	$ 2.53	$ 2.96
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	482,460,328	479,601,442	458,982,292
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Items	$ 3.25	$ 2.53	$ 2.97
Extraordinary Items, Net of Tax	0.77	-	(0.01)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.02	$ 2.53	$ 2.96
CASH DIVIDENDS DECLARED PER SHARE	$ 1.85	$ 1.71	$ 1.64

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	2011	2010	2009
NET INCOME	$ 1,949	$ 1,218	$ 1,365
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $18 in 2011, $14 in 2010 and $4 in 2009	(34)	26	7
Securities Available for Sale, Net of Tax of $1 in 2011, $4 in 2010 and $6 in 2009	(2)	(8)	11
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8 in 2009	-	-	15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $13 in 2011, $12 in 2010 and $13 in 2009	24	22	23
Pension and OPEB Funded Status, Net of Tax of $41 in 2011, $25 in 2010 and $12 in 2009	(77)	(47)	22
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(89)	(7)	78
TOTAL COMPREHENSIVE INCOME	1,860	1,211	1,443
Total Comprehensive Income Attributable to Noncontrolling Interests	3	4	5
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,857	1,207	1,438
Preferred Stock Dividend Requirements Including Capital Stock Expense	5	3	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,852	$ 1,204	$ 1,435

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2008	426	$ 2,771	$ 4,527	$ 3,847	$ (452)	$ 17	$ 10,710
Issuance of Common Stock	72	468	1,311				1,779
Common Stock Dividends				(753)		(5)	(758)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Purchase of JMG			37			(18)	19
Other Changes in Equity			(51)			1	(50)
SUBTOTAL – EQUITY							11,697
NET INCOME				1,360		5	1,365
OTHER COMPREHENSIVE INCOME					78		78
TOTAL EQUITY – DECEMBER 31, 2009	498	3,239	5,824	4,451	(374)	-	13,140
Issuance of Common Stock	3	18	75				93
Common Stock Dividends				(820)		(4)	(824)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			5				5
SUBTOTAL – EQUITY							12,411
NET INCOME				1,214		4	1,218
OTHER COMPREHENSIVE LOSS					(7)		(7)
TOTAL EQUITY – DECEMBER 31, 2010	501	3,257	5,904	4,842	(381)	-	13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends				(894)		(4)	(898)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Loss on Reacquired Preferred Stock			(4)				(4)
Capital Stock Expense			(16)				(16)
Other Changes in Equity			11	(2)		2	11
SUBTOTAL – EQUITY							12,805
NET INCOME				1,946		3	1,949
OTHER COMPREHENSIVE LOSS					(89)		(89)
TOTAL EQUITY – DECEMBER 31, 2011	504	$ 3,274	$ 5,970	$ 5,890	$ (470)	$ 1	$ 14,665

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in millions)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 221	$ 294
Other Temporary Investments (December 31, 2011 and 2010 amounts include $281 and $287, respectively, related to Transition Funding and EIS)	294	416
Accounts Receivable:		
Customers	690	683
Accrued Unbilled Revenues	106	195
Pledged Accounts Receivable - AEP Credit	920	949
Miscellaneous	150	137
Allowance for Uncollectible Accounts	(32)	(41)
Total Accounts Receivable	1,834	1,923
Fuel	657	837
Materials and Supplies	635	611
Risk Management Assets	193	232
Accrued Tax Benefits	51	389
Regulatory Asset for Under-Recovered Fuel Costs	65	81
Margin Deposits	67	88
Prepayments and Other Current Assets	165	145
TOTAL CURRENT ASSETS	4,182	5,016
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,938	24,352
Transmission	9,048	8,576
Distribution	14,783	14,208
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	3,780	3,846
Construction Work in Progress	3,121	2,758
Total Property, Plant and Equipment	55,670	53,740
Accumulated Depreciation and Amortization	18,699	18,066
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	36,971	35,674
OTHER NONCURRENT ASSETS		
Regulatory Assets	6,026	4,943
Securitized Transition Assets	1,627	1,742
Spent Nuclear Fuel and Decommissioning Trusts	1,592	1,515
Goodwill	76	76
Long-term Risk Management Assets	403	410
Deferred Charges and Other Noncurrent Assets	1,346	1,079
TOTAL OTHER NONCURRENT ASSETS	11,070	9,765
TOTAL ASSETS	$ 52,223	$ 50,455

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2011 and 2010
(dollars in millions)

	2011	2010
CURRENT LIABILITIES		
Accounts Payable	$ 1,095	$ 1,061
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	666	690
Other Short-term Debt	984	656
Total Short-term Debt	1,650	1,346
Long-term Debt Due Within One Year (December 31, 2011 and 2010 amounts include $293 and $237, respectively, related to Transition Funding, DCC Fuel and Sabine)	1,433	1,309
Risk Management Liabilities	150	129
Customer Deposits	289	273
Accrued Taxes	717	702
Accrued Interest	279	281
Regulatory Liability for Over-Recovered Fuel Costs	8	17
Deferred Gain and Accrued Litigation Costs	-	448
Other Current Liabilities	990	952
TOTAL CURRENT LIABILITIES	6,611	6,518
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2011 and 2010 amounts include $1,674 and $1,857, respectively, related to Transition Funding, DCC Fuel and Sabine)	15,083	15,502
Long-term Risk Management Liabilities	195	141
Deferred Income Taxes	8,227	7,359
Regulatory Liabilities and Deferred Investment Tax Credits	3,195	3,171
Asset Retirement Obligations	1,472	1,394
Employee Benefits and Pension Obligations	1,801	1,893
Deferred Credits and Other Noncurrent Liabilities	974	795
TOTAL NONCURRENT LIABILITIES	30,947	30,255
TOTAL LIABILITIES	37,558	36,773
Cumulative Preferred Stock Not Subject to Mandatory Redemption	-	60
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2011	2010
Shares Authorized	600,000,000	600,000,000
Shares Issued	503,759,460	501,114,881

	2011	2010
(20,336,592 shares and 20,307,725 shares were held in treasury at December 31, 2011 and 2010, respectively)	3,274	3,257
Paid-in Capital	5,970	5,904
Retained Earnings	5,890	4,842
Accumulated Other Comprehensive Income (Loss)	(470)	(381)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	14,664	13,622
Noncontrolling Interests	1	-
TOTAL EQUITY	14,665	13,622
TOTAL LIABILITIES AND EQUITY	$ 52,223	$ 50,455

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 1,949	$ 1,218	$ 1,365
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,655	1,641	1,597
Deferred Income Taxes	794	809	1,244
Gain on Settlement with BOA and Enron	(51)	-	-
Settlement of Litigation with BOA and Enron	(211)	-	-
Extraordinary Items, Net of Tax	(373)	-	5
Asset Impairments and Other Related Charges	139	-	-
Carrying Costs Income	(393)	(70)	(47)
Allowance for Equity Funds Used During Construction	(98)	(77)	(82)
Mark-to-Market of Risk Management Contracts	37	30	(59)
Amortization of Nuclear Fuel	137	139	63
Pension Contributions to Qualified Plan Trust	(450)	(500)	-
Property Taxes	(15)	(21)	(17)
Fuel Over/Under-Recovery, Net	(25)	(253)	(474)
Change in Other Noncurrent Assets	(112)	(89)	(152)
Change in Other Noncurrent Liabilities	307	202	244
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	107	(866)	41
Fuel, Materials and Supplies	176	221	(475)
Accounts Payable	(44)	(36)	8
Accrued Taxes, Net	193	179	(470)
Other Current Assets	37	73	(73)
Other Current Liabilities	29	62	(243)
Net Cash Flows from Operating Activities	3,788	2,662	2,475
INVESTING ACTIVITIES			
Construction Expenditures	(2,669)	(2,345)	(2,792)
Change in Other Temporary Investments, Net	8	(4)	16
Purchases of Investment Securities	(1,321)	(1,918)	(853)
Sales of Investment Securities	1,379	1,817	748
Acquisitions of Nuclear Fuel	(106)	(91)	(169)
Acquisitions of Assets	(19)	(155)	(104)
Acquisition of Cushion Gas from BOA	(214)	-	-
Proceeds from Sales of Assets	123	187	278
Other Investing Activities	(71)	(14)	(40)
Net Cash Flows Used for Investing Activities	(2,890)	(2,523)	(2,916)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	92	93	1,728
Issuance of Long-term Debt	1,328	1,270	2,306
Commercial Paper and Credit Facility Borrowings	488	565	127
Change in Short-term Debt, Net	744	770	119
Retirement of Long-term Debt	(1,665)	(1,993)	(816)
Retirement of Cumulative Preferred Stock	(64)	-	-
Commercial Paper and Credit Facility Repayments	(928)	(115)	(2,096)
Principal Payments for Capital Lease Obligations	(71)	(95)	(82)
Dividends Paid on Common Stock	(898)	(824)	(758)
Dividends Paid on Cumulative Preferred Stock	(2)	(3)	(3)
Other Financing Activities	5	(3)	(5)
Net Cash Flows from (Used for) Financing Activities	(971)	(335)	520
Net Increase (Decrease) in Cash and Cash Equivalents	(73)	(196)	79
Cash and Cash Equivalents at Beginning of Period	294	490	411
Cash and Cash Equivalents at End of Period	$ 221	$ 294	$ 490

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2009, 2008 and 2007
(in millions, except per-share and share amounts)

REVENUES	2009	2008	2007
Utility Operations	$ 12,733	$ 13,326	$ 12,101
Other Revenues	756	1,114	1,279
TOTAL REVENUES	13,489	14,440	13,380
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	3,478	4,474	3,829
Purchased Electricity for Resale	1,053	1,281	1,138
Other Operation	2,620	2,856	2,664
Maintenance	1,205	1,053	1,162
Gain on Settlement of TEM Litigation	-	(255)	-
Depreciation and Amortization	1,597	1,483	1,513
Taxes Other Than Income Taxes	765	761	755
TOTAL EXPENSES	10,718	11,653	11,061
OPERATING INCOME	2,771	2,787	2,319
Other Income (Expense):			
Interest and Investment Income	11	57	51
Carrying Costs Income	47	83	51
Allowance for Equity Funds Used During Construction	82	45	33
Gain on Disposition of Equity Investments	-	-	47
Interest Expense	(973)	(957)	(838)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,938	2,015	1,663
Income Tax Expense	575	642	516
Equity Earnings of Unconsolidated Subsidiaries	7	3	6
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	1,370	1,376	1,153
DISCONTINUED OPERATIONS, NET OF TAX	-	12	24
INCOME BEFORE EXTRAORDINARY LOSS	1,370	1,388	1,177
EXTRAORDINARY LOSS, NET OF TAX	(5)	-	(79)
NET INCOME	1,365	1,388	1,098
Less: Net Income Attributable to Noncontrolling Interests	5	5	6
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,360	1,383	1,092
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,357	$ 1,380	$ 1,089
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	458,677,534	402,083,847	398,784,745
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.97	$ 3.40	$ 2.87
Discontinued Operations, Net of Tax	-	0.03	0.06
Income Before Extraordinary Loss	2.97	3.43	2.93
Extraordinary Loss, Net of Tax	(0.01)	-	(0.20)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.96	$ 3.43	$ 2.73
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	458,982,292	403,640,708	400,198,799
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.97	$ 3.39	$ 2.86
Discontinued Operations, Net of Tax	-	0.03	0.06
Income Before Extraordinary Loss	2.97	3.42	2.92
Extraordinary Loss, Net of Tax	(0.01)	-	(0.20)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.96	$ 3.42	$ 2.72
CASH DIVIDENDS PAID PER SHARE	$ 1.64	$ 1.64	$ 1.58

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2009, 2008 and 2007
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2006	418	$ 2,718	$ 4,221	$ 2,696	$ (223)	$ 18	$ 9,430
Adoption of Guidance for Uncertainty in Income Taxes, Net of Tax				(17)			(17)
Issuance of Common Stock	4	25	119				144
Common Stock Dividends				(630)		(6)	(636)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			12				12
SUBTOTAL – EQUITY							8,930
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $10					(20)		(20)
Securities Available for Sale, Net of Tax of $1					(1)		(1)
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $6					11		11
Pension and OPEB Funded Status, Net of Tax of $42					79		79
NET INCOME				1,092		6	1,098
TOTAL COMPREHENSIVE INCOME							1,167
TOTAL EQUITY – DECEMBER 31, 2007	422	2,743	4,352	3,138	(154)	18	10,097
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $6				(10)			(10)
Adoption of Guidance for Fair Value Accounting, Net of Tax of $0				(1)			(1)
Issuance of Common Stock	4	28	131				159
Reissuance of Treasury Shares			40				40
Common Stock Dividends				(660)		(6)	(666)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			4				4
SUBTOTAL – EQUITY							9,620
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $2					4		4
Securities Available for Sale, Net of Tax of $9					(16)		(16)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $7					12		12
Pension and OPEB Funded Status, Net of Tax of $161					(298)		(298)
NET INCOME				1,383		5	1,388
TOTAL COMPREHENSIVE INCOME							1,090
TOTAL EQUITY – DECEMBER 31, 2008	426	2,771	4,527	3,847	(452)	17	10,710
Issuance of Common Stock	72	468	1,311				1,779
Common Stock Dividends				(753)		(5)	(758)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Purchase of JMG			37			(18)	19
Other Changes in Equity			(51)			1	(50)
SUBTOTAL – EQUITY							11,697
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $4					7		7
Securities Available for Sale, Net of Tax of $6					11		11
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8					15		15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $13					23		23
Pension and OPEB Funded Status, Net of Tax of $12					22		22
NET INCOME				1,360		5	1,365
TOTAL COMPREHENSIVE INCOME							1,443
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2009 and 2008
(in millions)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 490	$ 411
Other Temporary Investments	363	327
Accounts Receivable:		
Customers	492	569
Accrued Unbilled Revenues	503	449
Miscellaneous	92	90
Allowance for Uncollectible Accounts	(37)	(42)
Total Accounts Receivable	1,050	1,066
Fuel	1,075	634
Materials and Supplies	586	539
Risk Management Assets	260	256
Accrued Tax Benefits	547	46
Regulatory Asset for Under-Recovered Fuel Costs	85	284
Margin Deposits	89	86
Prepayments and Other Current Assets	211	126
TOTAL CURRENT ASSETS	4,756	3,775
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	23,045	21,242
Transmission	8,315	7,938
Distribution	13,549	12,816
Other Property, Plant and Equipment (including coal mining and nuclear fuel)	3,744	3,741
Construction Work in Progress	3,031	3,973
Total Property, Plant and Equipment	51,684	49,710
Accumulated Depreciation and Amortization	17,340	16,723
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	34,344	32,987
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,595	3,783
Securitized Transition Assets	1,896	2,040
Spent Nuclear Fuel and Decommissioning Trusts	1,392	1,260
Goodwill	76	76
Long-term Risk Management Assets	343	355
Deferred Charges and Other Noncurrent Assets	946	879
TOTAL OTHER NONCURRENT ASSETS	9,248	8,393
TOTAL ASSETS	$ 48,348	$ 45,155

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2009 and 2008

	2009	2008
CURRENT LIABILITIES	(in millions)	
Accounts Payable	$ 1,158	$ 1,297
Short-term Debt	126	1,976
Long-term Debt Due Within One Year	1,741	447
Risk Management Liabilities	120	134
Customer Deposits	256	254
Accrued Taxes	632	634
Accrued Interest	287	270
Regulatory Liability for Over-Recovered Fuel Costs	76	66
Other Current Liabilities	931	1,219
TOTAL CURRENT LIABILITIES	5,327	6,297
NONCURRENT LIABILITIES		
Long-term Debt	15,757	15,536
Long-term Risk Management Liabilities	128	170
Deferred Income Taxes	6,420	5,128
Regulatory Liabilities and Deferred Investment Tax Credits	2,909	2,789
Asset Retirement Obligations	1,254	1,154
Employee Benefits and Pension Obligations	2,189	2,184
Deferred Credits and Other Noncurrent Liabilities	1,163	1,126
TOTAL NONCURRENT LIABILITIES	29,820	28,087
TOTAL LIABILITIES	35,147	34,384
Cumulative Preferred Stock Not Subject to Mandatory Redemption	61	61
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2009	2008
Shares Authorized	600,000,000	600,000,000
Shares Issued	498,333,265	426,321,248

	2009	2008
(20,278,858 shares and 20,249,992 shares were held in treasury at December 31, 2009 and 2008, respectively)	3,239	2,771
Paid-in Capital	5,824	4,527
Retained Earnings	4,451	3,847
Accumulated Other Comprehensive Income (Loss)	(374)	(452)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,140	10,693
Noncontrolling Interests	-	17
TOTAL EQUITY	13,140	10,710
TOTAL LIABILITIES AND EQUITY	$ 48,348	$ 45,155

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2009, 2008 and 2007
(in millions)

	2009	2008	2007
OPERATING ACTIVITIES			
Net Income	$ 1,365	$ 1,388	$ 1,098
Less: Discontinued Operations, Net of Tax	-	(12)	(24)
Income Before Discontinued Operations	1,365	1,376	1,074
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,597	1,483	1,513
Deferred Income Taxes	1,244	498	76
Provision for SIA Refund	-	149	-
Extraordinary Loss, Net of Tax	5	-	79
Carrying Costs Income	(47)	(83)	(51)
Allowance for Equity Funds Used During Construction	(82)	(45)	(33)
Mark-to-Market of Risk Management Contracts	(59)	(140)	3
Amortization of Nuclear Fuel	63	88	65
Pension and Postemployment Benefits	83	42	41
Property Taxes	(17)	(13)	(26)
Fuel Over/Under-Recovery, Net	(474)	(272)	(117)
Gains on Sales of Assets, Net	(15)	(17)	(88)
Change in Noncurrent Liability for NSR Settlement	-	-	58
Change in Other Noncurrent Assets	(137)	(244)	(142)
Change in Other Noncurrent Liabilities	161	(34)	66
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	41	71	(113)
Fuel, Materials and Supplies	(475)	(183)	16
Margin Deposits	(3)	(40)	50
Accounts Payable	8	(94)	(21)
Customer Deposits	2	(48)	49
Accrued Taxes, Net	(470)	4	(90)
Accrued Interest	17	30	11
Other Current Assets	(70)	(29)	(11)
Other Current Liabilities	(262)	82	(15)
Net Cash Flows from Operating Activities	2,475	2,581	2,394
INVESTING ACTIVITIES			
Construction Expenditures	(2,792)	(3,800)	(3,556)
Change in Other Temporary Investments, Net	16	45	(114)
Purchases of Investment Securities	(853)	(1,922)	(11,086)
Sales of Investment Securities	748	1,917	11,213
Acquisitions of Nuclear Fuel	(169)	(192)	(74)
Acquisitions of Assets	(104)	(160)	(512)
Proceeds from Sales of Assets	278	90	222
Other Investing Activities	(40)	(5)	(14)
Net Cash Flows Used for Investing Activities	(2,916)	(4,027)	(3,921)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	1,728	159	144
Issuance of Long-term Debt	2,306	2,774	2,546
Borrowings from Revolving Credit Facilities	127	2,055	85
Change in Short-term Debt, Net	119	(660)	659
Retirement of Long-term Debt	(816)	(1,824)	(1,286)
Repayments to Revolving Credit Facilities	(2,096)	(79)	(102)
Proceeds from Nuclear Fuel Sale/Leaseback	-	-	85
Principal Payments for Capital Lease Obligations	(82)	(97)	(67)
Dividends Paid on Common Stock	(758)	(666)	(636)
Dividends Paid on Cumulative Preferred Stock	(3)	(3)	(3)
Other Financing Activities	(5)	20	(21)
Net Cash Flows from Financing Activities	520	1,679	1,404
Net Increase (Decrease) in Cash and Cash Equivalents	79	233	(123)
Cash and Cash Equivalents at Beginning of Period	411	178	301
Cash and Cash Equivalents at End of Period	$ 490	$ 411	$ 178

Schedule I - Parent Company Financial Statements

GREAT PLAINS ENERGY INCORPORATED

Statements of Income and Comprehensive Income of Parent Company

Year Ended December 31	2012	2011	2010
Operating Expenses	(millions, except per share amounts)		
General and administrative	**$ 3.3**	$ 0.8	$ 1.2
General taxes	**0.7**	0.9	0.9
Total	**4.0**	1.7	2.1
Operating loss	**(4.0)**	(1.7)	(2.1)
Equity in earnings from subsidiaries	**219.2**	200.8	239.3
Non-operating income	**42.7**	24.7	3.4
Interest charges	**(69.6)**	(66.5)	(44.7)
Income before income taxes	**188.3**	157.3	195.9
Income tax benefit	**11.6**	17.1	15.8
Net income	**199.9**	174.4	211.7
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	**$ 198.3**	$ 172.8	$ 210.1
Average number of basic common shares outstanding	**145.5**	135.6	135.1
Average number of diluted common shares outstanding	**147.2**	138.7	136.9
Basic earnings per common share	**$ 1.36**	$ 1.27	$ 1.55
Diluted earnings per common share	**$ 1.35**	$ 1.25	$ 1.53
Cash dividends per common share	**$ 0.855**	$ 0.835	$ 0.83
Comprehensive Income			
Net income	**$ 199.9**	$ 174.4	$ 211.7
Other comprehensive income			
Derivative hedging activity			
Loss on derivative hedging instruments	**—**	(5.3)	(27.1)
Income tax benefit	**—**	2.1	10.5
Net loss on derivative hedging instruments	**—**	(3.2)	(16.6)
Reclassification to expenses	**11.5**	8.2	1.3
Income tax benefit	**(4.6)**	(3.2)	(0.4)
Net reclassification to expenses	**6.9**	5.0	0.9
Derivative hedging activity, net of tax	**6.9**	1.8	(15.7)
Other comprehensive income from subsidiaries, net of tax	**4.5**	4.5	4.5
Total other comprehensive income (loss)	**11.4**	6.3	(11.2)
Comprehensive income attributable to Great Plains Energy	**$ 211.3**	$ 180.7	$ 200.5

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GREAT PLAINS ENERGY INCORPORATED

Balance Sheets of Parent Company

	December 31	
	2012	2011
ASSETS	(millions, except share amounts)	
Current Assets		
Accounts receivable from subsidiaries	**$ 0.1**	$ —
Notes receivable from subsidiaries	**0.6**	0.6
Money pool receivable	**4.0**	0.9
Taxes receivable	**—**	0.9
Other	**2.4**	0.6
Total	**7.1**	3.0
Investments and Other Assets		
Investment in KCP&L	**2,096.7**	2,045.5
Investment in other subsidiaries	**1,405.4**	1,377.0
Note receivable from subsidiaries	**883.6**	596.2
Deferred income taxes	**32.3**	33.7
Other	**7.6**	6.4
Total	**4,425.6**	4,058.8
Total	**$ 4,432.7**	$ 4,061.8
LIABILITIES AND CAPITALIZATION		
Current Liabilities		
Notes payable	**$ 12.0**	$ 22.0
Current maturities of long-term debt	**250.0**	287.5
Accounts payable to subsidiaries	**34.1**	31.8
Accrued taxes	**0.5**	5.1
Accrued interest	**6.8**	7.6
Other	**2.1**	2.9
Total	**305.5**	356.9
Deferred Credits and Other Liabilities	**5.2**	6.7
Capitalization		
Great Plains Energy common shareholders' equity		
Common stock - 250,000,000 shares authorized without par value		
153,779,806 and 136,406,306 shares issued, stated value	**2,624.7**	2,330.6
Retained earnings	**758.8**	684.7
Treasury stock - 250,236 and 264,567 shares, at cost	**(5.1)**	(5.6)
Accumulated other comprehensive loss	**(38.4)**	(49.8)
Total	**3,340.0**	2,959.9
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	**10.0**	10.0
4.50% - 100,000 shares issued	**10.0**	10.0
4.20% - 70,000 shares issued	**7.0**	7.0
4.35% - 120,000 shares issued	**12.0**	12.0
Total	**39.0**	39.0
Long-term debt	**743.0**	699.3
Total	**4,122.0**	3,698.2
Commitments and Contingencies		
Total	**$ 4,432.7**	$ 4,061.8

GREAT PLAINS ENERGY INCORPORATED
Statements of Cash Flows of Parent Company

Year Ended December 31	2012	2011	2010
Cash Flows from Operating Activities		(millions)	
Net income	**$ 199.9**	$ 174.4	$ 211.7
Adjustments to reconcile income to net cash from operating activities:			
Amortization	**12.6**	11.2	3.9
Deferred income taxes, net	**(4.8)**	(18.6)	13.9
Equity in earnings from subsidiaries	**(219.2)**	(200.8)	(239.3)
Cash flows affected by changes in:			
Accounts receivable from subsidiaries	**(0.1)**	—	(2.6)
Taxes receivable	**0.9**	6.3	—
Accounts payable to subsidiaries	**2.3**	(0.3)	2.2
Other accounts payable	**—**	—	(0.1)
Accrued taxes	**(4.4)**	5.2	—
Accrued interest	**6.1**	1.2	2.7
Cash dividends from subsidiaries	**144.0**	148.0	138.6
Interest rate hedge settlement	**—**	(26.1)	(6.9)
Other	**2.7**	2.1	(0.9)
Net cash from operating activities	**140.0**	102.6	123.2
Cash Flows from Investing Activities			
Intercompany lending	**(287.4)**	(347.4)	(248.8)
Net money pool lending	**(3.1)**	1.1	(1.1)
Net cash from investing activities	**(290.5)**	(346.3)	(249.9)
Cash Flows from Financing Activities			
Issuance of common stock	**293.0**	5.9	6.2
Issuance of long-term debt	**—**	349.7	249.9
Issuance fees	**(2.7)**	(3.2)	(3.2)
Net change in short-term borrowings	**(10.0)**	12.5	(10.5)
Dividends paid	**(125.5)**	(115.1)	(114.2)
Other financing activities	**(4.3)**	(6.4)	(7.3)
Net cash from financing activities	**150.5**	243.4	120.9
Net Change in Cash and Cash Equivalents	**—**	(0.3)	(5.8)
Cash and Cash Equivalents at Beginning of Year	**—**	0.3	6.1
Cash and Cash Equivalents at End of Year	**$ —**	$ —	$ 0.3

GREAT PLAINS ENERGY INCORPORATED
Consolidated Statements of Income

Year Ended December 31	2009	2008	2007
	(millions, except per share amounts)		
Operating Revenues			
Electric revenues	**$ 1,965.0**	$ 1,670.1	$ 1,292.7
Operating Expenses			
Fuel	**405.5**	311.4	245.5
Purchased power	**183.7**	208.9	101.0
Utility operating and maintenance expenses	**599.3**	499.7	387.5
Skill set realignment deferral (Note 10)	**-**	-	(8.9)
Depreciation and amortization	**302.2**	235.0	175.6
General taxes	**139.8**	128.1	114.4
Other	**14.4**	12.0	21.1
Total	**1,644.9**	1,395.1	1,036.2
Operating income	**320.1**	275.0	256.5
Non-operating income	**49.5**	31.9	8.8
Non-operating expenses	**(6.9)**	(10.8)	(5.6)
Interest charges	**(180.9)**	(111.3)	(91.9)
Income from continuing operations before income tax expense and loss from equity investments	**181.8**	184.8	167.8
Income tax expense	**(29.5)**	(63.8)	(44.9)
Loss from equity investments, net of income taxes	**(0.4)**	(1.3)	(2.0)
Income from continuing operations	**151.9**	119.7	120.9
Income (loss) from discontinued operations, net of income taxes (Note 24)	**(1.5)**	35.0	38.3
Net income	**150.4**	154.7	159.2
Less: Net income attributable to noncontrolling interest	**(0.3)**	(0.2)	-
Net income attributable to Great Plains Energy	**150.1**	154.5	159.2
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	**$ 148.5**	$ 152.9	$ 157.6
Average number of basic common shares outstanding	**129.3**	101.1	84.9
Average number of diluted common shares outstanding	**129.8**	101.2	85.2
Basic earnings (loss) per common share			
Continuing operations	**$ 1.16**	$ 1.16	$ 1.41
Discontinued operations	**(0.01)**	0.35	0.45
Basic earnings per common share	**$ 1.15**	$ 1.51	$ 1.86
Diluted earnings (loss) per common share			
Continuing operations	**$ 1.15**	$ 1.16	$ 1.40
Discontinued operations	**(0.01)**	0.35	0.45
Diluted earnings per common share	**$ 1.14**	$ 1.51	$ 1.85
Cash dividends per common share	**$ 0.83**	$ 1.66	$ 1.66

GREAT PLAINS ENERGY INCORPORATED
Consolidated Balance Sheets

	December 31	
	2009	2008
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 65.9**	$ 61.1
Funds on deposit	**4.4**	10.8
Receivables, net	**230.5**	242.3
Fuel inventories, at average cost	**85.0**	87.0
Materials and supplies, at average cost	**121.3**	99.3
Deferred refueling outage costs	**19.5**	12.4
Refundable income taxes	**13.5**	26.0
Deferred income taxes	**36.8**	28.6
Assets held for sale (Note 5)	**19.4**	16.3
Derivative instruments	**1.5**	4.8
Prepaid expenses and other assets	**14.7**	15.2
Total	**612.5**	603.8
Utility Plant, at Original Cost		
Electric	**8,849.0**	7,940.8
Less-accumulated depreciation	**3,774.5**	3,582.5
Net utility plant in service	**5,074.5**	4,358.3
Construction work in progress	**1,508.4**	1,659.1
Nuclear fuel, net of amortization of $106.0 and $110.8	**68.2**	63.9
Total	**6,651.1**	6,081.3
Investments and Other Assets		
Affordable housing limited partnerships	**13.2**	13.9
Nuclear decommissioning trust fund	**112.5**	96.9
Regulatory assets	**822.2**	824.8
Goodwill	**169.0**	156.0
Derivative instruments	**7.9**	13.0
Other	**94.4**	79.6
Total	**1,219.2**	1,184.2
Total	**$ 8,482.8**	$ 7,869.3

GREAT PLAINS ENERGY INCORPORATED
Consolidated Balance Sheets

	December 31	
	2009	2008
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	**$ 252.0**	$ 204.0
Commercial paper	**186.6**	380.2
Current maturities of long-term debt	**1.3**	70.7
Accounts payable	**315.0**	418.0
Accrued taxes	**27.9**	27.7
Accrued interest	**72.5**	72.4
Accrued compensation and benefits	**45.1**	29.7
Pension and post-retirement liability	**4.6**	4.7
Derivative instruments	**0.3**	86.2
Other	**53.0**	43.8
Total	**958.3**	1,337.4
Deferred Credits and Other Liabilities		
Deferred income taxes	**381.9**	387.1
Deferred tax credits	**140.5**	105.5
Asset retirement obligations	**132.6**	124.3
Pension and post-retirement liability	**440.4**	445.6
Regulatory liabilities	**237.8**	209.4
Derivative instruments	**0.5**	-
Other	**145.1**	112.8
Total	**1,478.8**	1,384.7
Capitalization		
Great Plains Energy common shareholders' equity		
Common stock-250,000,000 shares authorized without par value		
135,636,538 and 119,375,923 shares issued, stated value	**2,313.7**	2,118.4
Retained earnings	**529.2**	489.3
Treasury stock-213,423 and 120,677 shares, at cost	**(5.5)**	(3.6)
Accumulated other comprehensive loss	**(44.9)**	(53.5)
Total	**2,792.5**	2,550.6
Noncontrolling interest	**1.2**	1.0
Total	**2,793.7**	2,551.6
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	**10.0**	10.0
4.50% - 100,000 shares issued	**10.0**	10.0
4.20% - 70,000 shares issued	**7.0**	7.0
4.35% - 120,000 shares issued	**12.0**	12.0
Total	**39.0**	39.0
Long-term debt (Note 13)	**3,213.0**	2,556.6
Total	**6,045.7**	5,147.2
Commitments and Contingencies (Note 16)		
Total	**$ 8,482.8**	$ 7,869.3

GREAT PLAINS ENERGY INCORPORATED
Consolidated Statements of Cash Flows

Year Ended December 31	**2009**	2008	2007
Cash Flows from Operating Activities		(millions)	
Net income	**$ 150.4**	$ 154.7	$ 159.2
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**302.2**	238.3	183.8
Amortization of:			
Nuclear fuel	**16.1**	14.5	16.8
Other	**(10.1)**	(1.9)	7.4
Deferred income taxes, net	**(3.6)**	44.1	23.8
Investment tax credit amortization	**(2.2)**	(1.8)	(1.5)
Loss from equity investments, net of income taxes	**0.4**	1.3	2.0
Fair value impacts from interest rate hedging	**-**	9.2	17.9
Fair value impacts from energy contracts - Strategic Energy	**-**	(189.1)	(52.8)
Loss on sale of Strategic Energy	**-**	116.2	-
Other operating activities (Note 3)	**(117.8)**	52.4	(24.4)
Net cash from operating activities	**335.4**	437.9	332.2
Cash Flows from Investing Activities			
Utility capital expenditures	**(841.1)**	(1,023.7)	(511.5)
Allowance for borrowed funds used during construction	**(37.7)**	(31.7)	(14.4)
Payment to Black Hills for asset sale working capital adjustment	**(7.7)**	-	-
Proceeds from sale of Strategic Energy, net of cash sold	**-**	218.8	-
GMO acquisition, net cash received	**-**	271.9	-
Purchases of nuclear decommissioning trust investments	**(99.0)**	(49.1)	(58.0)
Proceeds from nuclear decommissioning trust investments	**95.3**	45.4	54.3
Other investing activities	**(7.4)**	(10.7)	(17.4)
Net cash from investing activities	**(897.6)**	(579.1)	(547.0)
Cash Flows from Financing Activities			
Issuance of common stock	**219.9**	15.3	10.5
Issuance of long-term debt	**700.7**	363.4	495.6
Issuance fees	**(22.8)**	(5.3)	(5.7)
Repayment of long-term debt	**(70.7)**	(169.9)	(372.5)
Net change in short-term borrowings	**(145.6)**	118.4	251.4
Dividends paid	**(110.5)**	(172.0)	(144.5)
Credit facility termination fees	**-**	(12.5)	-
Equity forward settlement	**-**	-	(12.3)
Other financing activities	**(4.0)**	(2.2)	(2.4)
Net cash from financing activities	**567.0**	135.2	220.1
Net Change in Cash and Cash Equivalents	**4.8**	(6.0)	5.3
Cash and Cash Equivalents at Beginning of Year (includes $43.1 million and $45.8 million of cash included in assets of discontinued operations in 2008 and 2007, respectively)	**61.1**	67.1	61.8
Cash and Cash Equivalents at End of Year (includes $43.1 million of cash included in assets of discontinued operations in 2007)	**$ 65.9**	$ 61.1	$ 67.1

GREAT PLAINS ENERGY INCORPORATED
Consolidated Statements of Income

Year Ended December 31	2010	2009	2008
	(millions, except per share amounts)		
Operating Revenues			
Electric revenues	**$ 2,255.5**	$ 1,965.0	$ 1,670.1
Operating Expenses			
Fuel	**430.7**	405.5	311.4
Purchased power	**213.8**	183.7	208.9
Transmission of electricity by others	**27.4**	26.9	22.5
Utility operating and maintenance expenses	**602.5**	572.4	477.2
Depreciation and amortization	**331.6**	302.2	235.0
General taxes	**155.1**	139.8	128.1
Other	**22.1**	14.4	12.0
Total	**1,783.2**	1,644.9	1,395.1
Operating income	**472.3**	320.1	275.0
Non-operating income	**43.9**	49.5	31.9
Non-operating expenses	**(19.5)**	(6.9)	(10.8)
Interest charges	**(184.8)**	(180.9)	(111.3)
Income from continuing operations before income tax expense and loss from equity investments	**311.9**	181.8	184.8
Income tax expense	**(99.0)**	(29.5)	(63.8)
Loss from equity investments, net of income taxes	**(1.0)**	(0.4)	(1.3)
Income from continuing operations	**211.9**	151.9	119.7
Income (loss) from discontinued operations, net of income taxes (Note 23)	**-**	(1.5)	35.0
Net income	**211.9**	150.4	154.7
Less: Net income attributable to noncontrolling interest	**(0.2)**	(0.3)	(0.2)
Net income attributable to Great Plains Energy	**211.7**	150.1	154.5
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	**$ 210.1**	$ 148.5	$ 152.9
Average number of basic common shares outstanding	**135.1**	129.3	101.1
Average number of diluted common shares outstanding	**136.9**	129.8	101.2
Basic earnings (loss) per common share			
Continuing operations	**$ 1.55**	$ 1.16	$ 1.16
Discontinued operations	**-**	(0.01)	0.35
Basic earnings per common share	**$ 1.55**	$ 1.15	$ 1.51
Diluted earnings (loss) per common share			
Continuing operations	**$ 1.53**	$ 1.15	$ 1.16
Discontinued operations	**-**	(0.01)	0.35
Diluted earnings per common share	**$ 1.53**	$ 1.14	$ 1.51
Cash dividends per common share	**$ 0.83**	$ 0.83	$ 1.66

GREAT PLAINS ENERGY INCORPORATED
Consolidated Balance Sheets

	December 31	
	2010	2009
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 10.8**	$ 65.9
Funds on deposit	**5.2**	4.4
Receivables, net	**241.7**	230.5
Accounts receivable pledged as collateral	**95.0**	-
Fuel inventories, at average cost	**85.1**	85.0
Materials and supplies, at average cost	**132.8**	121.3
Deferred refueling outage costs	**9.6**	19.5
Refundable income taxes	**2.1**	13.5
Deferred income taxes	**14.3**	36.8
Assets held for sale (Note 4)	**-**	19.4
Derivative instruments	**1.1**	1.5
Prepaid expenses and other assets	**13.9**	14.7
Total	**611.6**	612.5
Utility Plant, at Original Cost		
Electric	**10,536.9**	8,849.0
Less-accumulated depreciation	**4,031.3**	3,774.5
Net utility plant in service	**6,505.6**	5,074.5
Construction work in progress	**307.5**	1,508.4
Nuclear fuel, net of amortization of $131.1 and $106.0	**79.2**	68.2
Total	**6,892.3**	6,651.1
Investments and Other Assets		
Affordable housing limited partnerships	**0.3**	13.2
Nuclear decommissioning trust fund	**129.2**	112.5
Regulatory assets	**924.0**	822.2
Goodwill	**169.0**	169.0
Derivative instruments	**7.8**	7.9
Other	**84.0**	94.4
Total	**1,314.3**	1,219.2
Total	**$ 8,818.2**	$ 8,482.8

GREAT PLAINS ENERGY INCORPORATED
Consolidated Balance Sheets

	December 31 2010	2009
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	**$ 9.5**	$ 252.0
Collateralized note payable	**95.0**	-
Commercial paper	**263.5**	186.6
Current maturities of long-term debt	**485.7**	1.3
Accounts payable	**276.3**	315.0
Accrued taxes	**26.6**	27.9
Accrued interest	**75.4**	72.5
Accrued compensation and benefits	**46.8**	45.1
Pension and post-retirement liability	**4.1**	4.6
Derivative instruments	**20.8**	0.3
Other	**35.6**	53.0
Total	**1,339.3**	958.3
Deferred Credits and Other Liabilities		
Deferred income taxes	**518.3**	381.9
Deferred tax credits	**133.4**	140.5
Asset retirement obligations	**143.3**	132.6
Pension and post-retirement liability	**427.5**	440.4
Regulatory liabilities	**258.2**	237.8
Derivative instruments	**-**	0.5
Other	**129.4**	145.1
Total	**1,610.1**	1,478.8
Capitalization		
Great Plains Energy common shareholders' equity		
Common stock-250,000,000 shares authorized without par value 136,113,954 and 135,636,538 shares issued, stated value	**2,324.4**	2,313.7
Retained earnings	**626.5**	529.2
Treasury stock-400,889 and 213,423 shares, at cost	**(8.9)**	(5.5)
Accumulated other comprehensive loss	**(56.1)**	(44.9)
Total	**2,885.9**	2,792.5
Noncontrolling interest	**1.2**	1.2
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	**10.0**	10.0
4.50% - 100,000 shares issued	**10.0**	10.0
4.20% - 70,000 shares issued	**7.0**	7.0
4.35% - 120,000 shares issued	**12.0**	12.0
Total	**39.0**	39.0
Long-term debt (Note 12)	**2,942.7**	3,213.0
Total	**5,868.8**	6,045.7
Commitments and Contingencies (Note 15)		
Total	**$ 8,818.2**	$ 8,482.8

GREAT PLAINS ENERGY
Consolidated Statements of Cash Flows

Year Ended December 31	2010	2009	2008
Cash Flows from Operating Activities		(millions)	
Net income	$ **211.9**	$ 150.4	$ 154.7
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**331.6**	302.2	238.3
Amortization of:			
Nuclear fuel	**25.1**	16.1	14.5
Other	**(4.7)**	(10.1)	(1.9)
Deferred income taxes, net	**123.8**	(3.6)	44.1
Investment tax credit amortization	**(2.9)**	(2.2)	(1.8)
Loss from equity investments, net of income taxes	**1.0**	0.4	1.3
Fair value impacts from interest rate hedging	**-**	-	9.2
Fair value impacts from energy contracts - Strategic Energy	**-**	-	(189.1)
Loss on sale of Strategic Energy	**-**	-	116.2
Other operating activities (Note 2)	**(133.7)**	(117.8)	52.4
Net cash from operating activities	**552.1**	335.4	437.9
Cash Flows from Investing Activities			
Utility capital expenditures	**(618.0)**	(841.1)	(1,023.7)
Allowance for borrowed funds used during construction	**(28.5)**	(37.7)	(31.7)
Payment to Black Hills for asset sale working capital adjustment	**-**	(7.7)	-
Proceeds from sale of Strategic Energy, net of cash sold	**-**	-	218.8
GMO acquisition, net cash received	**-**	-	271.9
Purchases of nuclear decommissioning trust investments	**(83.3)**	(99.0)	(49.1)
Proceeds from nuclear decommissioning trust investments	**79.6**	95.3	45.4
Other investing activities	**(7.5)**	(7.4)	(10.7)
Net cash from investing activities	**(657.7)**	(897.6)	(579.1)
Cash Flows from Financing Activities			
Issuance of common stock	**6.2**	219.9	15.3
Issuance of long-term debt	**249.9**	700.7	363.4
Issuance fees	**(12.1)**	(22.8)	(5.3)
Repayment of long-term debt	**(1.3)**	(70.7)	(169.9)
Net change in short-term borrowings	**(165.6)**	(145.6)	118.4
Net change in collateralized short-term borrowings	**95.0**	-	-
Dividends paid	**(114.2)**	(110.5)	(172.0)
Credit facility termination fees	**-**	-	(12.5)
Other financing activities	**(7.4)**	(4.0)	(2.2)
Net cash from financing activities	**50.5**	567.0	135.2
Net Change in Cash and Cash Equivalents	**(55.1)**	4.8	(6.0)
Cash and Cash Equivalents at Beginning of Year (includes $43.1 million in assets of discontinued operations in 2008)	**65.9**	61.1	67.1
Cash and Cash Equivalents at End of Year	$ **10.8**	$ 65.9	$ 61.1

GREAT PLAINS ENERGY INCORPORATED
Consolidated Statements of Income

Year Ended December 31	2011	2010	2009
	(millions, except per share amounts)		
Operating Revenues			
Electric revenues	**$ 2,318.0**	$ 2,255.5	$ 1,965.0
Operating Expenses			
Fuel	**483.8**	430.7	405.5
Purchased power	**203.4**	213.8	183.7
Transmission of electricity by others	**30.2**	27.4	26.9
Utility operating and maintenance expenses	**658.2**	602.5	572.4
Voluntary separation program	**12.7**	-	-
Depreciation and amortization	**273.1**	331.6	302.2
General taxes	**170.9**	155.1	139.8
Other	**5.9**	22.1	14.4
Total	**1,838.2**	1,783.2	1,644.9
Operating income	**479.8**	472.3	320.1
Non-operating income	**5.9**	43.9	49.5
Non-operating expenses	**(8.2)**	(19.5)	(6.9)
Interest charges	**(218.4)**	(184.8)	(180.9)
Income from continuing operations before income tax expense and loss from equity investments	**259.1**	311.9	181.8
Income tax expense	**(84.8)**	(99.0)	(29.5)
Loss from equity investments, net of income taxes	**(0.1)**	(1.0)	(0.4)
Income from continuing operations	**174.2**	211.9	151.9
Loss from discontinued operations, net of income taxes (Note 22)	**-**	-	(1.5)
Net income	**174.2**	211.9	150.4
Less: Net (income) loss attributable to noncontrolling interest	**0.2**	(0.2)	(0.3)
Net income attributable to Great Plains Energy	**174.4**	211.7	150.1
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	**$ 172.8**	$ 210.1	$ 148.5
Average number of basic common shares outstanding	**135.6**	135.1	129.3
Average number of diluted common shares outstanding	**138.7**	136.9	129.8
Basic earnings (loss) per common share			
Continuing operations	**$ 1.27**	$ 1.55	$ 1.16
Discontinued operations	**-**	-	(0.01)
Basic earnings per common share	**$ 1.27**	$ 1.55	$ 1.15
Diluted earnings (loss) per common share			
Continuing operations	**$ 1.25**	$ 1.53	$ 1.15
Discontinued operations	**-**	-	(0.01)
Diluted earnings per common share	**$ 1.25**	$ 1.53	$ 1.14
Cash dividends per common share	**$ 0.835**	$ 0.83	$ 0.83

GREAT PLAINS ENERGY INCORPORATED
Consolidated Balance Sheets

	December 31	
	2011	2010
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 6.2**	$ 10.8
Funds on deposit	**1.4**	5.2
Receivables, net	**231.2**	241.7
Accounts receivable pledged as collateral	**95.0**	95.0
Fuel inventories, at average cost	**89.0**	85.1
Materials and supplies, at average cost	**140.3**	132.8
Deferred refueling outage costs	**27.5**	9.6
Refundable income taxes	**0.3**	2.1
Deferred income taxes	**7.5**	14.3
Derivative instruments	**1.0**	1.1
Prepaid expenses and other assets	**19.7**	13.9
Total	**619.1**	611.6
Utility Plant, at Original Cost		
Electric	**10,924.8**	10,536.9
Less-accumulated depreciation	**4,235.8**	4,031.3
Net utility plant in service	**6,689.0**	6,505.6
Construction work in progress	**287.9**	307.5
Nuclear fuel, net of amortization of $132.7 and $131.1	**76.6**	79.2
Total	**7,053.5**	6,892.3
Investments and Other Assets		
Nuclear decommissioning trust fund	**135.3**	129.2
Regulatory assets	**1,058.2**	924.0
Goodwill	**169.0**	169.0
Derivative instruments	**6.8**	7.8
Other	**76.1**	84.3
Total	**1,445.4**	1,314.3
Total	**$ 9,118.0**	$ 8,818.2

GREAT PLAINS ENERGY INCORPORATED
Consolidated Balance Sheets

	December 31 2011	2010
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	**$ 22.0**	$ 9.5
Collateralized note payable	**95.0**	95.0
Commercial paper	**267.0**	263.5
Current maturities of long-term debt	**801.4**	485.7
Accounts payable	**275.6**	276.3
Accrued taxes	**25.8**	26.6
Accrued interest	**76.9**	75.4
Accrued compensation and benefits	**40.8**	46.8
Pension and post-retirement liability	**4.4**	4.1
Derivative instruments	**-**	20.8
Other	**26.0**	35.6
Total	**1,634.9**	1,339.3
Deferred Credits and Other Liabilities		
Deferred income taxes	**628.6**	518.3
Deferred tax credits	**131.2**	133.4
Asset retirement obligations	**149.6**	143.3
Pension and post-retirement liability	**461.9**	427.5
Regulatory liabilities	**268.5**	258.2
Other	**101.1**	129.4
Total	**1,740.9**	1,610.1
Capitalization		
Great Plains Energy common shareholders' equity		
Common stock - 250,000,000 shares authorized without par value 136,406,306 and 136,113,954 shares issued, stated value	**2,330.6**	2,324.4
Retained earnings	**684.7**	626.5
Treasury stock - 264,567 and 400,889 shares, at cost	**(5.6)**	(8.9)
Accumulated other comprehensive loss	**(49.8)**	(56.1)
Total	**2,959.9**	2,885.9
Noncontrolling interest	**1.0**	1.2
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	**10.0**	10.0
4.50% - 100,000 shares issued	**10.0**	10.0
4.20% - 70,000 shares issued	**7.0**	7.0
4.35% - 120,000 shares issued	**12.0**	12.0
Total	**39.0**	39.0
Long-term debt (Note 11)	**2,742.3**	2,942.7
Total	**5,742.2**	5,868.8
Commitments and Contingencies (Note 14)		
Total	**$ 9,118.0**	$ 8,818.2

GREAT PLAINS ENERGY
Consolidated Statements of Cash Flows

Year Ended December 31	2011	2010	2009
Cash Flows from Operating Activities		(millions)	
Net income	**$ 174.2**	$ 211.9	$ 150.4
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**273.1**	331.6	302.2
Amortization of:			
Nuclear fuel	**21.4**	25.1	16.1
Other	**12.7**	(4.7)	(10.1)
Deferred income taxes, net	**111.2**	123.8	(3.6)
Investment tax credit amortization	**(2.2)**	(2.9)	(2.2)
Loss from equity investments, net of income taxes	**0.1**	1.0	0.4
Other operating activities (Note 2)	**(147.5)**	(133.7)	(117.8)
Net cash from operating activities	**443.0**	552.1	335.4
Cash Flows from Investing Activities			
Utility capital expenditures	**(456.6)**	(618.0)	(841.1)
Allowance for borrowed funds used during construction	**(5.8)**	(28.5)	(37.7)
Payment to Black Hills for asset sale working capital adjustment	**-**	-	(7.7)
Purchases of nuclear decommissioning trust investments	**(18.5)**	(83.3)	(99.0)
Proceeds from nuclear decommissioning trust investments	**15.1**	79.6	95.3
Other investing activities	**(19.9)**	(7.5)	(7.4)
Net cash from investing activities	**(485.7)**	(657.7)	(897.6)
Cash Flows from Financing Activities			
Issuance of common stock	**5.9**	6.2	219.9
Issuance of long-term debt	**747.1**	249.9	700.7
Issuance fees	**(10.7)**	(12.1)	(22.8)
Repayment of long-term debt	**(598.5)**	(1.3)	(70.7)
Net change in short-term borrowings	**16.0**	(165.6)	(145.6)
Net change in collateralized short-term borrowings	**-**	95.0	-
Dividends paid	**(115.1)**	(114.2)	(110.5)
Other financing activities	**(6.6)**	(7.4)	(4.0)
Net cash from financing activities	**38.1**	50.5	567.0
Net Change in Cash and Cash Equivalents	**(4.6)**	(55.1)	4.8
Cash and Cash Equivalents at Beginning of Year	**10.8**	65.9	61.1
Cash and Cash Equivalents at End of Year	**$ 6.2**	$ 10.8	$ 65.9