3.0 Implications of Industry Issues in this IRP Cycle

3.1 Demand Response/Energy Efficiency (DR/EE)

The AEP System (East and West/SPP zones) has adopted peak demand reduction and energy efficiency goals which are 1,000 MW and 2,250 GWh, respectively by year-end 2012. Concurrently, several states served by the AEP System have mandated levels of efficiency and demand reduction. There also exists the possibility of federally mandated efficiency levels. While this IRP establishes a method for obtaining an estimate of DR/EE that is reasonable to expect for the zone, as a whole; the ratemaking process in the individual states will ultimately shape the amount and timing of DR/EE investment. As those processes evolve and mature, the "order of magnitude" estimates can be refined and replaced with definitive programs.

3.2 Renewables

Renewable Portfolio Standards and goals have been enacted in over one half of the states in the U.S. Adoption of further RPS at the state level or the enactment of Federal carbon limitations or RPS, will impose the need for adding more renewables and the potential expenditure of billions of dollars.

Wind is currently one of the most viable large-scale renewable technologies (with incentives) and has been added to utility portfolios mainly via long-term power purchase agreements. Recently, many IOUs have begun to add renewable assets to their portfolios. The best sites in terms of wind resource and transmission are rapidly being secured by developers. Further, while an extension of the Federal Production Tax Credit (PTC) for wind projects - to the end of 2012 - was enacted in February 2009, it will probably not be extended further as the implementation of Federal carbon or RPS is expected to make unnecessary the incentive provided by the PTC. Acquiring this renewable energy and/or the associated Renewable Energy Credit (REC) or Carbon Offset *now* will likely limit the risk of increased cost that comes with waiting for further legislative clarity in the AEP states.

In early 2007, AEP committed to the acquisition of energy from 1,000 MW (nameplate) of additional wind generation projects by the end of 2010 via long-term purchase power agreements as part of AEP's comprehensive strategy to address greenhouse gas emissions. In light of progress in meeting this commitment, the goal was expanded in early 2009 to 2,000 MW by the end of 2011. SWEPCO is already receiving energy from one wind project with nameplate rating of 79.5 MW. Additional contracts have been executed for PSO for an additional 198 MW to be placed in service by December, 2009 which will result in a total of 591 MW or approximately 12 percent of PSO's energy needs being met with renewables. **Exhibit 3-1** lays out the AEP-SPP zone's renewable plan by operating company to meet its share of this target.

As can be seen in Exhibit 3-1, PSO and SWEPCO have a greater contribution to the renewable goal than the remaining AEP companies. This is due to wind being economically favored in states like Oklahoma and Texas, particularly due to the higher wind profile. Wind is the primary source of renewable energy in the AEP plan.

Exhibit 3-1: Renewable Energy Plan Through 2030

AEP Sytem - SPP Zone

Potential Renewables Profile to Achieve a 7% System Target by 2013, 10% by 2020, and 15% by 2030 [(a)]

***...as well as* Known or Emerging State-Specific Mandates**

2009 IRP

	PSO				SWEPCO				AEP-SPP				AEP SYSTEM			
	Solar Nmplt (MW)	Wind Nmplt (MW)	Biomass Equiv (MW)	Rnwbl Percent of Sales	Solar Nmplt (MW)	Wind Nmplt (MW)	Biomass Equiv (MW)	Rnwbl Percent of Sales	Solar Nmplt (MW)	Wind Nmplt (MW)	Biomass Equiv (MW)	Rnwbl Percent of Sales	Solar Nmplt (MW)	Wind Nmplt (MW)	Biomass Equiv (MW)	Rnwbl Percent of Sales
2009	0	393	0	9.4%	0	31	0	0.6%	0	424	0	5.0%	-	499	-	1.3%
2010	0	393	0	9.0%	0	111	0	2.3%	0	503	0	5.6%	10	1,029	-	2.5%
2011	0	591	0	13.3%	0	211	0	4.3%	0	801	0	8.6%	13	2,027	10	4.5%
2012	0	591	0	12.8%	0	311	0	6.3%	0	901	0	9.5%	15	2,827	109	6.4%
2013 (b)	0	591	0	12.7%	0	461	0	9.3%	0	1,051	0	10.9%	29	3,477	235	8.0%
2014	0	591	0	12.6%	0	461	0	9.2%	0	1,051	0	10.9%	42	3,477	235	8.0%
2015	0	658	0	14.0%	0	494	0	9.8%	0	1,151	0	11.8%	56	3,577	385	8.8%
2016	0	658	0	13.9%	0	594	0	11.6%	0	1,251	0	12.7%	70	3,777	385	9.1%
2017	0	858	0	18.0%	0	594	9	11.7%	0	1,451	9	14.7%	83	3,977	394	9.6%
2018	0	858	0	17.9%	0	594	9	11.6%	0	1,451	9	14.6%	100	3,977	521	10.1%
2019	0	858	0	17.8%	0	594	9	11.4%	0	1,451	9	14.5%	118	3,977	650	10.5%
2020	0	1,058	0	21.8%	0	594	9	11.3%	0	1,651	9	16.3%	133	4,377	650	11.3%
2021	0	1,058	0	21.6%	0	694	9	12.9%	0	1,751	9	17.0%	168	4,627	777	12.2%
2022	0	1,058	0	21.4%	0	794	9	14.6%	0	1,851	9	17.9%	220	4,827	777	12.6%
2023	0	1,158	0	23.3%	0	794	9	14.4%	0	1,951	9	18.6%	220	5,027	904	13.3%
2024	0	1,158	0	23.1%	0	894	9	16.0%	0	2,051	9	19.4%	271	5,327	904	13.9%
2025	0	1,158	0	22.9%	0	994	9	17.4%	0	2,151	9	20.0%	271	5,527	904	14.1%
2026	17	1,258	0	24.8%	17	994	9	17.3%	35	2,251	9	20.8%	340	5,727	904	14.5%
2027	17	1,258	0	24.6%	17	1,094	9	18.8%	35	2,351	9	21.5%	340	5,927	1,032	15.2%
2028	35	1,258	0	24.5%	35	1,094	9	18.7%	69	2,351	9	21.4%	409	6,127	1,032	15.5%
2029	35	1,358	0	26.2%	35	1,194	9	20.0%	69	2,551	9	22.8%	409	6,327	1,032	15.7%
2030	56	1,358	0	26.0%	56	1,394	9	23.1%	112	2,751	9	24.4%	496	6,527	1,032	16.1%

(a) Data EXCLUDES:
- o AEP-Texas Central Co. & AEP-Texas Northern Co... as current and potential future state/federal RPS would be applicable to LSEs only.
- o Conventional (run-of-river) hydro energy as a renewable source as it has been excluded from certain state and proposed federal RPS criteria… Should hydro be ultimately included, it would contribute roughly 1% to the AEP System target by 2020.

(b) 2012/2013 represent the initial years for Federal RPS/RES mandates as currently proposed by several draft bills before Congress. Further, 2013 would represent the initial year after the likely expiration of Production Tax Credits (PTC) for, particularly, wind resources. The notion being that establishment of a Federal renewables standard would likely eliminate further extension of such PTC opportunities.

Source: AEP Resource Planning

3.3 Carbon Capture & Storage/Sequestration (CCS)

Utility applications of CCS technologies continue to be developed and tested, and as such are not yet commercially available on a large scale. However, given the focus on the advancement and associated cost reduction of such technologies, it is likely to become both available and cost-effective at some point over the IRP's longer-term planning horizon (through 2030). However, this is very dependent on the type of federal climate legislation that is passed and the degree to which there is financial support for CCS technology in such legislation. Assuming carbon capture and storage becomes commercially viable weight must be given to the options that are most readily adaptable to this technology

3.4 Emission Compliance

Emission compliance requirements have a major influence on the consideration of supply-side resources for inclusion in the IRP because of their potential significant effects on both capital and operational costs. The AEP System's strategy for complying with Title IV of the Clean Air Act Amendments of 1990, as well as recent regulations tied to environmental air emissions, takes into consideration additional power plant emission reduction requirements for SO_2, NO_x, and mercury (Hg) emissions.

Specifically, in 2005, the U.S. Environmental Protection Agency (USEPA) established new emission regulations for these pollutants as part of the CAIR (which the D.C. Circuit Court

overturned on July 11, 2008), the now vacated Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR) rulemaking. Further, on-going debate over CO_2/GHG emissions, particulate matter (PM), and regional haze, as well as the previously mentioned potential enactment of additional state and/or Federal RPS will likewise influence future capacity resource planning surrounding decisions to retrofit, modify operations, or retire/mothball generating assets.

Certain PSO and SWEPCO coal and gas-fired generating units are subject to CAVR and application of Best Available Retrofit Technology (BART) for SO_2 and NO_X. PSO will be equipping its units with NO_X combustion technology to meet BART limits for NO_X and is expected to install flue gas desulfurization technology (FGD) at the Northeastern 3 & 4 coal units to meet BART limits for SO_2 and PM. The specific timing of these installations is uncertain as the Oklahoma Department of Environmental Quality is still developing its State Implementation Plan for the CAVR program. SWEPCO plans to install FGD at Flint Creek station to meet CAVR.

4.0 Current Resources

The initial step in the IRP process is the demonstration of the region-specific capacity resource requirements. This "needs" assessment must consider projections of:

- Existing capacity resources—current levels and anticipated changes
- Anticipated changes in capability due to efficiency and/or environmental retrofit projects
- Changes resulting from decisions surrounding unit disposition evaluations
- Regional and sub-regional capacity and transmission constraints/limitations
- Load and (peak) demand (see Section 5.2.)
- Current DR/EE (see Section 5.3.)
- SPP capacity reserve margin and reliability criteria (see Section 6.1.)

In addition to the establishment of the absolute annual capacity position, an additional "need" to be discussed in this section will be a determination of the specific operational expectation (duty type) of generating capacity–baseload vs. intermediate vs. peaking.

4.1 Existing PSO and SWEPCO Generating Resources

Appendix A offers a summary of all owned supply resources for the AEP-SPP zone plus long-term wind contracts. The current (June 1, 2009) AEP-SPP summer supply of 9,216 MW is composed of the following (with wind projects' capacity at ratings allowed by SPP, generally about 8% of nameplate):

Exhibit 4-1: Existing PSO and SWEPCO Generating Resources

	PSO	SWEPCO	Total
Coal/Lignite	**1,026 MW**	**2,680 MW**	**3,706 MW**
Gas/Diesel	**3,384 MW**	**2,086 MW**	**5,470 MW**
Wind	**17 MW**	**--**	**17 MW**
Total	**4,427 MW**	**4,766 MW**	**9,193 MW**

Source: AEP Resource Planning

4.2 Capacity Impacts of Environmental Compliance Plan

As detailed in **Exhibit 4-2** and ***Appendix D***, the capability forecast of the existing generating fleet reflects 27 MW in unit de-ratings associated with environmental retrofits - largely flue gas desulphurization (FGD), and activated carbon injection with a baghouse (ACIBH) or with an electrostatic precipitator (ACIESP) over the IRP period.

Exhibit 4-2: PSO and SWEPCO Capacity Change After June 2009
AEP West Capacity Changes (MW) after June 1, 2009

Unit and Cause	As Modeled		In Final Plan	
	Year (a)	Capacity Impact	Year (a)	Capacity Impact
Welsh 2 (FGD)	2013	-8	2015	-8
Flint Creek 1 (FGD)	2014	-4	2014	-4
Pirkey 1 (ACIESP)	2014	0	--	--
Dolet Hills 1 (ACIESP)	2014	0	--	--
Flint Creek 1 (ACIESP)	2014	0	--	--
Welsh 1 (ACIBH)	2014	-11	--	--
Welsh 2 (ACIESP)	2014	0	--	--
Welsh 3 (ACIBH)	2014	-11	--	--
Northeastern 3 (FGD + ACIESP)	2014	-7	2016	-7
Northeastern 4 (FGD + ACIESP)	2014	-8	2016	-8
Oklaunion 1 (ACIESP)	2014	0	--	--
Net Change		**-49**		**-27**

Note : (a) Summer season of effective SPP delivery year.

Source: AEP Resource Planning

4.3 Existing Unit Disposition

A long-term view of disposition alternatives facing older units in the AEP-SPP region was established. The work group affirmed the findings of previous studies, recommending no unit disposition planned for the IRP period. In general, the capacity value provided by the older units far outweigh the fixed costs associated with their continued operations, The work group report is include in the technical addendum.

4.4 AEP-SPP Transmission

4.4.1 Transmission System Overview

The western Transmission System, which consists of the transmission facilities of the four western AEP operating companies, is operated in both the SPP and ERCOT. The western Transmission System spans portions of four states and comprises nearly 10,000 miles of circuitry operating at or above 69 kV.

The portion of the western Transmission System operating in SPP (AEP-SPP zone) consists of approximately 1,270 miles of 345 kV, approximately 3,400 miles of 138 kV, and 2,197 miles of 69 kV. The AEP-SPP zone is also integrated with and directly connected to ten other companies at 87 interconnection points, of which 69 are at or above 69 kV and to ERCOT via two high voltage direct current (HVDC) ties. These interconnections provide an electric pathway to provide access to off-system resources, as well as a delivery mechanism to neighboring systems.

4.4.2 Current AEP-SPP Transmission System Issues

Historically, the AEP SPP Transmission System was planned to deliver operating company generation to their respective loads, as well as to provide interconnections with neighboring utilities

for replacement and emergency power exchanges when needed and available. With the creation of the SPP Regional Transmission Organization (RTO), the system is primarily planned under the current SPP Transmission Expansion Plan (STEP) annual process for reliability and transmission owner projects. The STEP process also identifies transmission reliability improvements to accommodate approved transmission service and approved economic upgrades on an annual basis looking out over a ten year period. SPP RTO's process addresses transmission service needs to deliver energy to loads and generation interconnection requests in separate studies. *Going forward, the SPP RTO will be using an Integrated Transmission Planning (ITP) process that is being developed.*

The limited capacity of interconnections between SPP and neighboring systems, as well as the electrical topology of the SPP footprint transmission system, influences the ability to deliver non-affiliate generation, both within and external to the SPP footprint, to AEP-SPP loads and from sources within AEP-SPP balancing authority to serve AEP-SPP loads. Moreover, a lack of seams agreements between SPP and its neighbors has significantly slowed down the process of developing new interconnections. Despite the robust nature of the AEP-SPP transmission system as originally designed, its current use is in a different manner than originally designed, in order to meet SPP RTO requirements, which can stress the system. In addition, factors such as outages, extreme weather, and power transfers also stresses the system. This has resulted in a transmission system in the AEP-SPP zone that is constrained when generation is dispatched in a manner inconsistent with the original design of utilizing local generation to serve local load. The resulting use of the AEP-SPP system is inconsistent with the assumptions used to develop the models AEP provides to SPP to develop and plan the system. SPP uses models provided by all load serving entities to study the reliability needs of the SPP footprint. As discussed above, SPP currently uses separate modeling and studies to address transmission service and interconnection requests.

4.4.2.1 The SPP Transmission Planning Process

Currently, SPP produces an annual SPP transmission expansion plan (STEP) that includes a ten year system forecast. The STEP is developed through an open stakeholder process with AEP participation. SPP studies the transmission system, checking for base case and contingency overload and voltage violations in all of the SPP base case load flow models, plus models which include power transfers biased in the various transfer directions.

The 2008 STEP summarizes 2008 activities, including expansion planning and long-term SPP Open Access Transmission Tariff studies (Tariff Studies) that impact future development of the SPP transmission grid. Six key topics are included in the STEP:

1) Tariff Studies,

2) Regional reliability assessment 2009-2018,

3) Subregional and local area planning,

4) High priority economic studies,

5) Interregional coordination; and

6) Project tracking.

These topics are critical to meeting mandates of either the SPP strategic plan or the nine planning principles in FERC Order 890. As a RTO under the domain of the Federal Energy Regulatory Commission (FERC), SPP must meet requirements of FERC and the SPP Open Access Transmission Tariff (OATT or Tariff). The SPP RTO acts independently of any single market participant or class of participants. It has sufficient scope and configuration to maintain electric reliability, effectively perform its functions, and support efficient and non-discriminatory power markets. Regarding short-term reliability, the SPP RTO has the capability and exclusive authority to receive, confirm, and implement all interchange schedules. It also has operational authority for all transmission facilities under its control. The 10-year RTO regional reliability assessment continues to be a primary focus.

STEP projects are categorized by the following designations:

- Economic: Projects identified for economic benefit;
- Generation Interconnect – Projects associated with a FERC-filed Interconnection Agreement;
- Interregional- Projects developed with neighboring Transmission Providers;
- Regional reliability - Base Plan projects needed to meet the reliability of the region;
- Transmission service – Projects associated with a FERC-filed Service Agreement; and
- Zonal Reliability - Projects identified to meet more stringent local Transmission Owner criteria.

The 2008 STEP identified approximately $2.7 billion of transmission Network Upgrades. These include Network Upgrades required for NERC Reliability Standards or SPP Criteria; Zonal Reliability Upgrades (compliance to Transmission Owner company-specific planning criteria); requests for transmission service under the Tariff with a FERC-filed Service Agreement; and generation interconnections with a FERC-filed interconnection agreement.

In addition, the SPP Regional State Committee and SPP Board of Directors/Members Committee approved a long-awaited group of extra high voltage economic transmission expansion upgrade projects totaling over $700 million, to be funded by FERC-approved "postage stamp" rates, applicable to SPP's transmission-owning members across the region. The adjusted production cost benefits of this group of transmission upgrades have been demonstrated by model analysis to outweigh the costs (benefits greater than costs), thus achieving a "balanced portfolio" of projects. A portfolio approach alleviates potential disputes that may arise from the construction of a single project that may benefit one zone but not others. The balanced portfolio includes five new 345 kV transmission lines, a 345 kV transformer, and a new connection between two existing 345 kV lines. Details of the balanced portfolio results can be found at:

http://www.spp.org/publications/2009%20Balanced%20Portfolio%20-%20Final%20Approved%20Report.pdf

The SPP Board of Directors also recently approved a new report, prepared by the Synergistic Planning Project Team that recommends restructuring the organization's regional planning processes to focus on the construction of a robust transmission system, large enough in both scale and geography to provide flexibility to meet SPP's future needs. The new Integrated Transmission

Planning (ITP) process is intended to integrate or replace the STEP, balanced portfolio, and the Extra-High Voltage Overlay process.

4.4.2.2 PSO-SWEPCO Interchange Capability

Operational experience and internal assessments of company transmission capabilities indicate that, when considering a single contingency outage event, the present firm capability transfer limit from PSO to SWEPCO is about 200 MW, and from SWEPCO to PSO is about 900 MW. As much as 900 MW may be available bi-directionally for economical *energy* transfers when no transmission facilities are out of service. However, the intra-company available transmission capability between the two companies is available to all transmission users under the provisions established by FERC Order 888 and subsequent orders. Thus, there is some question as to whether, in the future, as SPP grants further transmission rights, any transfer capability will in fact be available without further upgrades to the transmission system.

Increasing the firm transfer capability from PSO to SWEPCO beyond about 200 MW may not be cost-effective. As previously indicated each, company's capacity additions are planned so that each meets its own reserve requirement over the long-term. Any capacity transfers (i.e. "reserve sharing") should be considered for short time frames only. Specifically, the practice has been that, as the last step of the planning process, the respective PSO and SWEPCO expansion plans are adjusted to take advantage of any surplus of one company that might match a potential deficit of the other, and thereby delay some of the identified new capacity. Because of the sizes, demand growth rates, and peak coincidence of the two companies, it rarely appears that either company would ever have more than 200 MW of surplus capacity in any year that could be transferred to the other company.

4.4.2.3 AEP-SPP Import Capability

Currently the transmission system cannot accommodate incremental firm imports to the AEP-SPP area, based on preliminary AEP studies. Generally, the transfers are limited by the facilities of neighboring systems rather than by transmission lines or equipment owned by AEP.

Increasing the import capabilities with AEP-SPP's neighboring companies could require a large capital investment for new transmission facilities by the neighboring systems or through sponsored upgrades by SPP transmission owners. An analysis of the cost of the upgrades cannot be performed until the capacity resources are determined. For identified resources, the cost of any transmission upgrades necessary on AEP's transmission system can be estimated by AEP once SPP has identified the upgrade. AEP's Southwest Transmission Planning group can identify constraints on third-party systems through ad hoc power flow modeling studies, but Southwest Transmission Planning does not have information to provide estimates of the costs to alleviate those third-party constraints.

4.4.2.4 SPP Studies that may Provide Import Capability

Besides the annual STEP process, SPP also performs other special studies or area studies on an as needed basis. Two recent SPP studies could in time lead to improved transfer capability between AEP-SPP and neighboring companies and regions.

4.4.2.4.1 EHV Overlay Study

SPP hired a consultant, Quanta, to determine if SPP should build a 345, 500 or 765 kV overlay to the existing SPP footprint. As of May 2008, the most recent version of this EHV Overlay Study included plans for construction of a 765 kV transmission system across much of SPP that would accommodate 13.5 GW of wind generation resources. One 765 kV loop would encompass much of the Texas Panhandle and portions of western Oklahoma. Another 765 kV loop would encompass much of the Oklahoma Panhandle and southwestern Kansas. These loops could be used to connect large amounts of potential wind generation and wind generation in the generation interconnection queue to the transmission grid. From these loops, two 765 kV paths would be extended, one to Lawton and Muskogee, Oklahoma, and then northward toward the Kansas City area; the other to Wichita, Kansas and eastward toward the Kansas City area. The 765 kV system would also extend eastward with two 765 kV lines, one to the southeast to Entergy and one to the northeast to Associated Electric Cooperative, Inc. (AECI). The plan also includes a new 500 kV line extending eastward from Oklahoma Gas and Electric's (OG&E) Fort Smith Station across central Arkansas to Entergy, a large amount of 345 kV in northwestern Arkansas and southwestern Missouri, and five 345 kV lines in Kansas and Oklahoma. The total cost to implement the plan is approximately $8 billion. The future of the overlay is uncertain. SPP performed an economic analysis of the original overlay study. However, routing changes to the original projects have been proposed since the inclusion of the Nebraska entities into SPP and the study is not yet completely vetted among stakeholders. From an AEP perspective, the proposed overlays in the various study versions would enhance bulk power transfers among the involved regions, but it is not known what additional, local facilities would be required to create increased import capability. The SPP Board of Directors has yet to approve an overlay plan but is now looking at a new synergistic integrated transmission planning process that may incorporate the results of the study.

4.4.2.4.2 Ozark Transmission Study

This study, completed by SPP in June 2007, provides a long-range plan for the northern Arkansas and southern Missouri region and provides guidance for future reinforcements to the transmission system in this area. The recommendations include 500 kV lines from Entergy's Arkansas Nuclear One Station to OG&E's VBI Station to AEP's South Fayetteville Station. The recommendations also included a 345 kV loop around the Fayetteville / Springdale area of northwestern Arkansas as well as 345 kV expansion eastward to SWPA's Table Rock Station located in southwestern Missouri. From Table Rock Station, 345 kV lines to AECI's Gobbler Knob Station in southeastern Missouri and City Utilities of Springfield's Brookline Station in southwestern Missouri were also recommended. AEP and Arkansas Electric Cooperative Corporation (AECC) have asked SPP to further study the 345 kV loop around the south side of the Fayetteville / Springdale area as a complex priority project.

4.4.3 Recent AEP-SPP Bulk Transmission Improvements

Over the past several years, there have been several major transmission enhancements initiated to reinforce the AEP-SPP transmission system. These enhancements include:

- **Northwest Arkansas**— Northwest Arkansas is one of the fastest growing areas on the AEP-SPP Transmission System. The approximate 1,200 MW of load in this area, about 47% of which is AECC retail load, is supplied primarily by the SWEPCO and AECC jointly-owned Flint Creek generating plant, the SWEPCO Mattison generating plant, the GRDA-Flint Creek 345 kV line, and the Clarksville-Chambers Spring 345 kV line. Wal-Mart's international headquarters and its supplying businesses' offices and Tyson's headquarters are all located in this area. A significant conversion of the 69 kV transmission system to 161 kV and extensive rebuilding and upgrading of portions of the existing 161 kV system have been completed in recent years. In May 2008, the conversion of the 69 kV line between Dyess and South Fayetteville stations to 161 kV and the construction of a new 345 kV line between Chambers Spring and Tontitown stations were completed. In May 2009, a rebuild and reconductoring of the Flint Creek-Motley Road 161 kV line section was also completed.
- **Port of Shreveport (Port), Louisiana**— A 138 kV loop is under construction, in phases, around the Port to increase system reliability and to serve the increasing area load. In May 2008, a six -mile 138 kV transmission line was completed from Wallace Lake Station to Port Robson Station to supply new loads under development at the Port. The 138 kV loop has been extended from Port Robson Station to Bean Station and was further extended to Caplis Station in June 2009. A 138 kV line approximately 23 miles long, connecting Caplis Station to Red Point Station is also planned to complete the 138 kV loop. Together, these improvements will supply power to the Port and the new distribution station site near Caplis; correct contingency low voltage and thermal overloads in Bossier City, Louisiana and the vicinity; and supply a second feed to Bean, Caplis, McDade, and Haughton stations. This loop is currently expected to be completed in 2012.
- **Shreveport line upgrades for Stall Plant generation addition –** Several 138 kV and 69 kV lines in Shreveport, Louisiana have been or are being upgraded to accommodate the Stall generation unit that is to be added at the Arsenal Hill Power Plant.

4.4.4 Impacts of New Generation:

There has been significant growth of approximately 5,700 MW of merchant generation in the AEP-SPP zone. The total generation connected to the AEP-SPP Transmission System, including electric cooperative generation, is approximately 15,600 MW. Integration of additional generation capacity within the AEP-SPP zone will likely require significant transmission upgrades. At most locations, any additional generation resources will aggravate existing transmission constraints. Specifically:

- **Western Oklahoma/Texas Panhandle**—there are very few EHV transmission lines in this area. In fact, transmission facilities above 69 kV are limited. However, the area is one of the highest wind density areas within the SPP RTO footprint. The potential wind farm capacity for this area has been estimated to exceed 4,000 MW. Several wind farms have already been built, and several more are in the development stages. Wind generation additions in the SPP footprint in this region will likely require significant transmission

enhancements, including EHV line and station construction, to address thermal, voltage, and stability constraints.

- **PSO/SWEPCO Interface -** There is one 345 kV EHV line linking PSO's service area with the majority of SWEPCO's generation resources in its service area. Until recently, constraints on the underlying transmission system limited the amount of firm generation that can flow from PSO to SWEPCO and from SWEPCO to PSO to approximately zero in a single contingency situation. However, an SPP approved project to rebuild the Danville to North Magazine 161 kV line will increase the transfer capability from SWEPCO to PSO to approximately 900 MW when completed in the Summer of 2009. Also, an SPP approved project to rebuild the Broken Bow to Craig Junction 138 kV line has been completed and has increased the transfer capability from PSO to SWEPCO to approximately 200 MW. Significant generation additions to the AEP-SPP transmission facilities (or connection to neighbor's facilities) may require significant transmission enhancements, possibly including EHV line and station construction, to address thermal, voltage, and stability constraints.
- **Tulsa Metro Area**—the Tulsa metro area load is supplied primarily by the PSO Northeastern, Riverside, and Tulsa Power Station generating plants. Additionally, Oklahoma Gas & Electric Company has large generation plants located to the southeast and southwest of Tulsa, and there are large merchant plants just east and south of Tulsa. The Grand River Dam Authority has a large plant located to the east of Tulsa. Generation additions in the Tulsa area would likely require significant enhancements in the EHV and sub-transmission system to address thermal, voltage and stability constraints.
- **SPP Eastern Interface**—there are only five east-west EHV lines into the SPP region, which stretches from the Gulf of Mexico (east of Houston) north to Des Moines, Iowa. This limitation constrains the amount of imports and exports along the eastern interface of SPP with neighboring regions. It also constrains the amount of transfers from the capacity rich western SPP region to the market hubs east and north of the SPP RTO region. Significant generation additions near or along the SPP eastern interface would likely require significant transmission enhancements, including EHV line and station construction, to address thermal and stability constraints should such generation additions adversely impact existing transactions along the interface. SPP has addressed some of these potential ties in the EHV Overlay Study discussed above.

Integration of generation resources at any location within the AEP-SPP zone will require significant analysis by SPP to identify potential thermal, short circuit, and stability constraints resulting from the addition of generation. Depending on the specific location, EHV line and station construction, in addition to connection facilities, could be necessary. Other station enhancements, including transformer additions and breaker replacements may be necessary. Some of the required transmission upgrades could be reduced or increased in scope if existing generating capacity is retired concurrent with the addition of new capacity.

4.4.5 Horizon Transmission LLC, Joint Venture in the SPP

On July 15, 2008, Electric Transmission America (ETA), a joint venture of American Electric Power and MidAmerican Energy Holdings, formed a joint venture company with OGE Energy Corp.

to build and own new electric transmission assets in Oklahoma. The joint venture, Horizon Transmission LLC, will build the Tallgrass Project, which will include approximately 170 miles of extra-high voltage 765 kilovolt transmission from the Kansas-Oklahoma border north of Woodward, Oklahoma, that will link into OGE´s station at Woodward and then extend west into the Oklahoma panhandle to a new station that will be built near Guymon, Oklahoma.

SPP's estimated cost for the project is approximately $500 million based on SPP´s Extra-High Voltage Overlay Study, but final costs will depend on the routing of the line, equipment and commodity costs. Anticipated completion would be in 2013. AEP´s ownership share of the joint venture will be 25 percent.

The ETA-OGE joint venture anticipates filing for the necessary state and federal regulatory approvals for the project in the coming months.

ETA also has formed a joint venture with Westar to build 765 kV transmission in Kansas (Prairie Wind Project) that will connect with the OGE project at the Kansas-Oklahoma border. The combined projects encompass the first two phases of the SPP EHV Overlay Study plan.

"This collaboration with Oklahoma Gas and Electric will build a segment of a larger extra-high voltage transmission highway that has been proposed by the Southwest Power Pool to enhance reliability and support development of the sizable renewable generation resources available in the region…"

Mike Morris, AEP Chairman, President and CEO

4.4.6 Summary of Transmission Overview

In the SPP region, the process of truly integrating Generation and Transmission planning is still developing. AEP continues to stand ready to engage in that process. At this time, though, PSO and SWEPCO can do very little to import capacity from outside of its control area. Both companies have been open to such imports as evidenced by the issuing of recent RFP's for non-site specific generation types. These RFP's allow bidding entities to offer generation coupled with transmission solutions, which would be subject to SPP approvals.

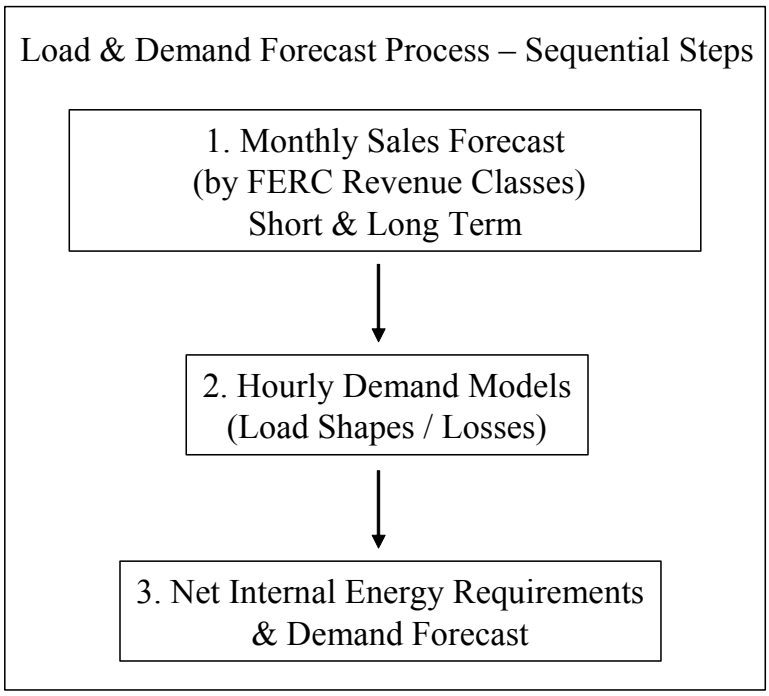
5.0 Demand Projections

5.1 Load and Demand Forecast - Process Overview

One of the most critical underpinnings of the IRP process is the projection of anticipated resource "needs," which, in turn, centers on the long-term forecast of load and (peak) demand. The AEP-SPP internal long-term load and peak demand forecasts were based on the AEP Economic Forecasting group's load forecast performed in May 2009.

The electric energy and demand forecast process involves three specific forecast model processes, as identified in **Exhibit 5-1**.

Exhibit 5-1: Load and Demand Forecast Process—Sequential Steps



Source: AEP Economic Forecasting

The first process models the consumption of electricity at the aggregated customer level: Residential, Commercial, Industrial, Other Ultimate customers, and Municipals and Cooperatives. It involves modeling both the short- and long-term sales. The second process contains models that derive hourly load estimates from blended short- and long-term sales, estimates of energy losses for distribution and transmission, and class and end-use load shapes. The aggregate revenue class sales and energy losses is generally called "net internal energy requirements." The third process reconciles historical net internal energy requirements and seasonal peak demands through a load factor analysis which results in the load forecast.

The long-term forecasts are developed using a combination of econometric models to project load for the Industrial, Other Ultimate and Municipal and Cooperative customer classes, as well as Statistically-Adjusted End-use (SAE) models for the modeling of Residential and Commercial classes.

The long-term process starts with an economic forecast provided, under proprietary license, by Moody's Economy.com for the United States as a whole, each state, and regions within each state. These forecasts include projections of employment, population, and other demographic and financial variables for both the U.S. as a whole and for specific AEP service territories. The long-term forecasting process incorporates these economic projections and other inputs to produce a forecast of kilowatt-hour (kWh) sales. Other inputs include regional and national economic and demographic conditions, energy prices, weather data, and customer-specific information.

The AEP Economic Forecasting department uses Statistically Adjusted End-use (SAE) models for forecasting long-term Residential and Commercial kWh energy sales.

- SAE models are econometric models with end-use features included to specifically account for energy efficiency impacts, such as those included in the Energy Policy Act of 2005 (EPAct 2005) and the Energy Independence and Security Act of 2007 (EISA).
- SAE models start with the construction of structured end-use variables that embody end-use trends, including equipment saturation levels and efficiency. Factors are also included to account for changes in energy prices, household size, home size, income, and weather conditions.
- Regression models are used to estimate the relationship between observed customer usage and the structured end-use variables. The result is a model that has implicit end-use structure, but is econometric in its model-fitting technique.
- The SAE approach explicitly accounts for energy efficiency which has served to slightly lower the forecast of Residential and Commercial class demand and energy in the forecast horizon particularly when EPAct 2005 and EISA impacts begin to manifest.

AEP uses processes that take advantage of the relative strengths of each method. The regression models typically used in the shorter-term modeling employ the latest available sales and weather information to represent the variation in sales on a monthly basis for short-term applications. While these models generally produce accurate forecasts in the short run, without specific ties to economic factors they are less capable of capturing the structural trends in electricity consumption that are important for longer-term planning. The long-term modeling process, with its explicit ties to economic and demographic factors, is appropriate for longer-term decisions and the establishment of the most likely, or base case, load and demand over the forecast period. By overlaying these respective output profiles, AEP Economic Forecasting can then effectively apply the strengths of both load-modeling approaches, thereby achieving a reasonable validation of such forecasted results.

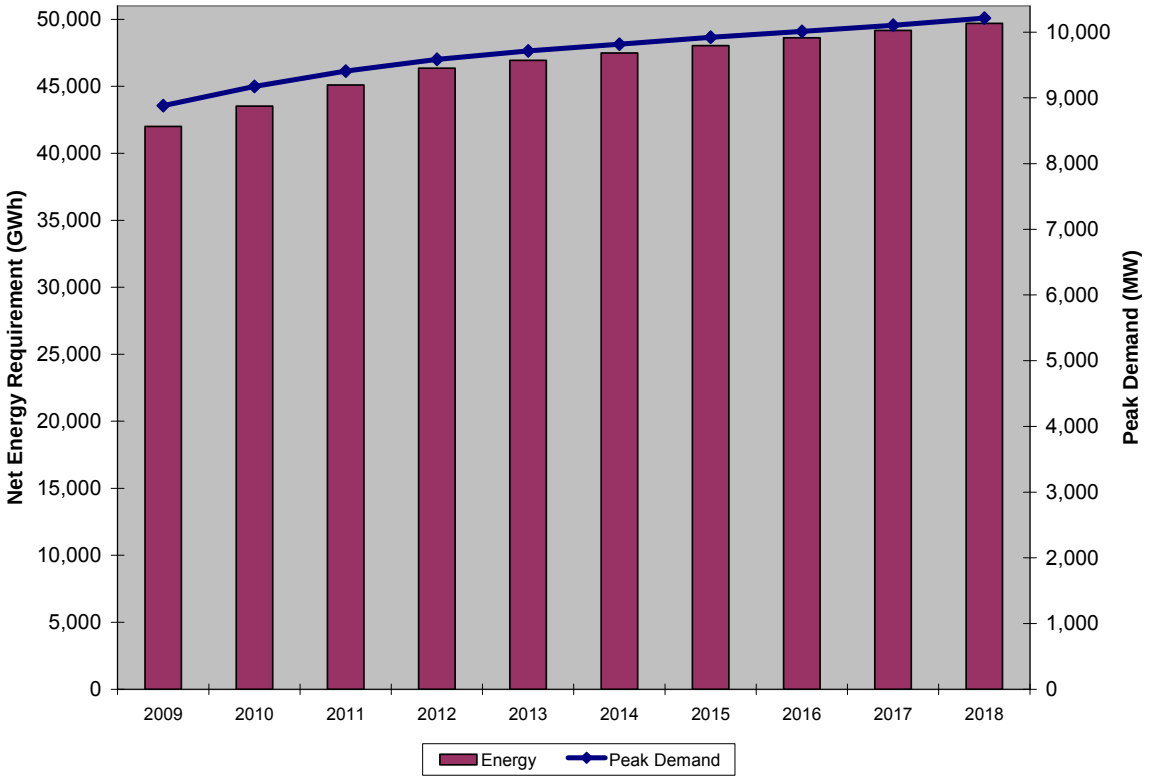
5.2 Peak Demand Forecast

Exhibit 5-2 reflects the AEP Economic Forecasting Group's forecast of annual peak demand for the AEP-SPP zone, utilized in this IRP process.

Specifically, Exhibit 5-2 identifies the AEP-SPP region's internal demand profile as having 1.5% Compound Annual Growth Rate (CAGR). This equates to roughly a **140 MW per year increase** (one-third PSO, two-thirds SWEPCO) over the IRP planning period if the load growth was steady. As the graph shows, the impact of the existing recession depresses peak demand in 2009 and

2010 with a rapid increase in 2011 from the assumed economic recovery. In addition, the chart indicates a comparable rate of growth for internal energy sales over the 10-year period, with load factors increasing in 2011 due to the recovery of recession impacted industrial load.

Exhibit 5-2: AEP-SPP Peak Demand and Energy Projection



Source: AEP Economic Forecasting

It is critical to note some of the major assumptions driving these demand profiles for the AEP-SPP zone:

1. Any major *wholesale load* obligations (largely, municipalities and cooperatives who currently have or have had a relationship with AEP as a "FERC tariff" customer) would largely be renewed or extended over the planning period under *long-term contracts*. However, an observation from the underlying data to support Exhibit 5-2 is that such firm or "committed" wholesale demand projections are relatively constant over the long-term forecast period and, in total, represent approximately 15% of the zone's (predominantly SWEPCO) overall load obligation.
2. Additionally, as described below, this forecast incorporates the effects of all current Demand Response and Energy Efficiency (DR/EE) program offerings. It also includes energy efficiency and peak demand reduction that "occurs naturally" as a function of shifting consumer behavior. Consumer-driven, naturally occurring DR/EE has a significant impact on energy consumption, and can be masked by increased energy use for other activities. The impacts from energy policy such as the Energy Independence and Security

Act of 2007 (EISA) are expected to be on the demand side. These will predominantly come through increased lighting, appliance, and building efficiency standards and codes. The efficiency of lighting is set to increase by 20-30% by 2012-24. Standards for appliance equipment including residential boilers, clothes washers and dishwashers are also set to increase during the period of 2008 to 2014. Strides to promote energy efficiency in commercial buildings as well as in industrial energy use are expected as well. The current forecast does not include impacts of the Energy Improvement and Extension Act of 2008 (EIEA) or the American Recovery and Reinvestment Act of 2009 (ARRA). The impacts of these acts were being determined at the time of this forecast. The acts are not expected to have the as significant of an impact to forecasted load growth as did the 2005 and 2007 acts.

3. The economic impacts of any carbon dioxide cap regime will be wide reaching and impact electricity demand through market adjustments in various sectors. As an early attempt to quantify some type of initial impact, an "own-price effect" on demand is estimated. The timing and impact of this scenario is truly speculative, and represents only one of many possible policy actions.

5.3 Current DR/EE Programs

PSO and SWEPCO have numerous peak demand shifting programs. These consist of "Interruptible" contracts with larger industrial customers and, in PSO, the tariff-based "Value Choice" program which provides large users of electricity with advance notice of pricing changes, enabling them to avoid using power during expensive, peak periods.

SWEPCO's Texas region currently has several traditional utility-sponsored Energy Efficiency programs in place:

- Home$avers Low Income Program. The Home$avers is an energy efficiency and weatherization program that targets households that are 125% below the poverty level.
- SWEPCO CARE$ Energy Efficiency Improvement Program (EEIP) for Not-for-Profit agencies.
- Standard Offer Programs (SOPs). These programs are available for commercial and industrial (C&I) consumers (>100 kW) and residential and small commercial (<100 kW), where incentives are paid for new and retrofit projects that provided verifiable demand or energy savings.
- Appliance Recycling Pilot Market Transformation Program. This program seeks to decrease the number of inefficient refrigerators and freezers in general use, and by doing so, deliver long-term electric energy savings and peak demand reduction.
- Home$avers low-income weatherization
- Load Management. The Load Management standard offer program targets commercial customers with a minimum peak electric demand of 500 kW or more. Incentives are paid to project sponsors that provide curtailment of peak interruptible electric load on short (1-hour ahead) notice.
- Texas Statewide ENERGY STAR® Residential (Compact Fluorescent Lighting). SWEPCO will be participating for the second year with other Transmission and Distribution

Utilities in a statewide effort to promote the awareness, understanding, and use of compact fluorescent light bulbs (CFLs) by residential customers.

- Commercial Solutions Pilot Market Transformation Program (CS MTP). This program targets commercial customers that do not have the in-house capacity or expertise to: 1) identify, evaluate, and undertake efficiency improvements; 2) properly evaluate energy efficiency proposals from vendors; and/or 3) understand how to leverage their energy savings to finance projects.
- SCORE Market Transformation Program (SCORE MTP). This provides energy efficiency and demand reduction solutions for public schools and local government entities.

Consistent with recent rule-making in **SWEPCO-Arkansas**, the following programs were proposed and became effective in October 2007 as part of the Arkansas Public Service Commission's (APSC) "Quick Start" initiative:

- Energy Education Arkansas (EEA). This is a state-wide program that provides energy efficiency information to customers through a website and various media outlets.
- C&I Standard Offer Program - A "traditional" DR/EE program offered to customers with >100 kW of load.
- Load Management Standard Offer Program. The LM SOP targets commercial and industrial customers with a minimum peak demand of 250 kW. Incentives are paid to customers that provide curtailment of peak load on short notice.
- Residential and Small Commercial CFL Program (RSC CFL). This program targets residential and commercial customers.
- ENERGY STAR® Appliance Program. This program targets residential and small commercial customers. Incentives are paid to customers who purchase a new qualifying central air conditioner or heat pump with an ENERGY STAR rating
- Arkansas Weatherization Program (AWP). This is a residential weatherization program that targets severely inefficient homes (SIEH). It is designed as a "piggyback" program that uses the existing infrastructure/resources of the DOE Weatherization Assistance Program (WAP).
- Commercial Solutions Market Transformation Program. This targets commercial and industrial customers.
- Residential Solutions Market Transformation Program. This targets residential customers and provides incentives to homeowners for eligible energy efficient improvements. A network of qualified energy efficiency service providers will become partnering contractors and can both offer and accept incentives for program eligible upgrade measures.

As part of **PSO**'s last base rate case (cause number PUD 200600285), the Company proposed two additional Real-Time Pricing pilot programs for both residential and general services (commercial) classes. A slate of "quick start" programs have been implemented. The quick start programs consist of

- low income weatherization,
- ENERGY STAR® new homes,
- C&I standard offer,
- residential ENERGY STAR® Appliance and CFL, and
- Emergency Load Management.

In September 2009 PSO will file its recommended changes to the Quick Start programs based on the results of the first year of implementation.

The peak demand and annual energy conservation that results from the currently approved, but not fully implemented, SPP programs are summarized in **Exhibit 5-3**:

Exhibit 5-3: AEP-SPP Current DR/EE Programs full-year impacts

Load Forecast - Embedded DR/EE Demand Impacts (MW) - Summer							
Operating Company	2009	2010	2011	2012	2013	2014	2015
PSO	9	13	16	19	21	22	23
SWEPCO	10	16	20	24	26	29	30
AEP-SPP (MW)	19	29	36	43	47	51	53

Load Forecast - Embedded DR/EE Energy Impacts (GWh)							
Operating Company	2009	2010	2011	2012	2013	2014	2015
PSO	40	56	70	81	90	97	102
SWEPCO	38	57	73	87	96	103	109
AEP-SPP (GWh)	78	113	143	168	186	200	211

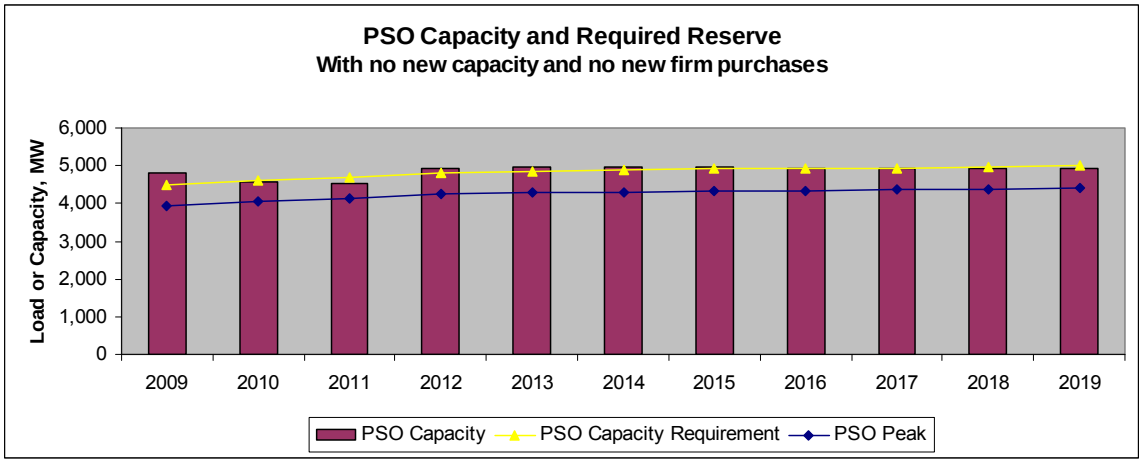
Source: AEP Resource Planning

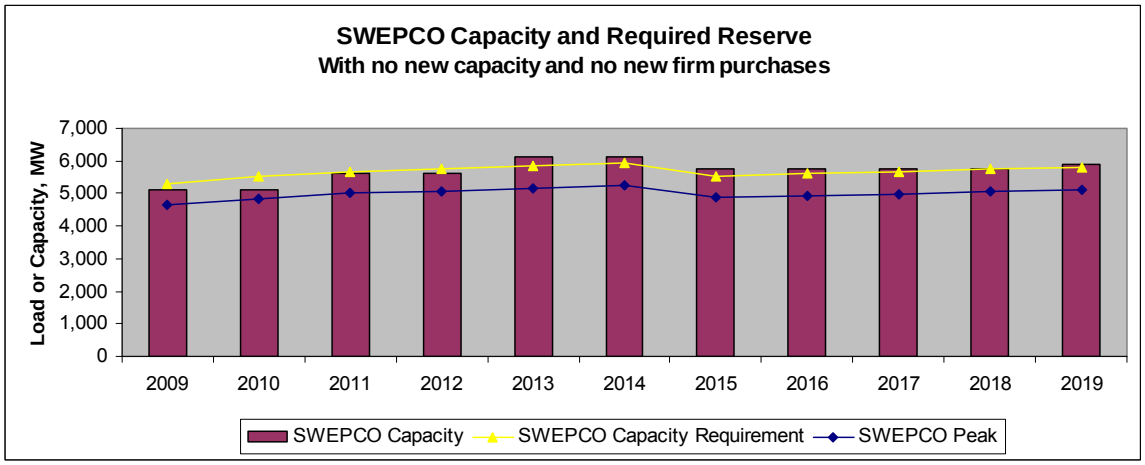
6.0 Capacity Needs Assessment

Based on the assessment of the AEP-SPP Current Resources (Section 4) and its (Peak) Demand Projections (Section 5); a "Capacity Needs" assessment can be established that will determine the Amount and Timing of capacity resources for this 2009 IRP cycle.

Exhibits 6-1 and 6-2 are companion charts that summarize the "going-in" need to add over 900 MW of capacity through the 10-year 2009 IRP window, beyond the current commitments of SWEPCO to construct the Stall natural gas combined cycle unit (509 MW) and its share of the Turk USC-PC Unit (447 MW). No other new capacity additions are included. Exhibit 6-1 compares the demand (line) and capacity (bar) trends over the period. Exhibit 6-2 reflects the culmination of these separate impacts. Based on the assumptions discussed, the capacity of the AEP-SPP zone will be in a deficit position in 2010.

Exhibit 6-1: Capacity vs. SPP Minimum Required Reserves

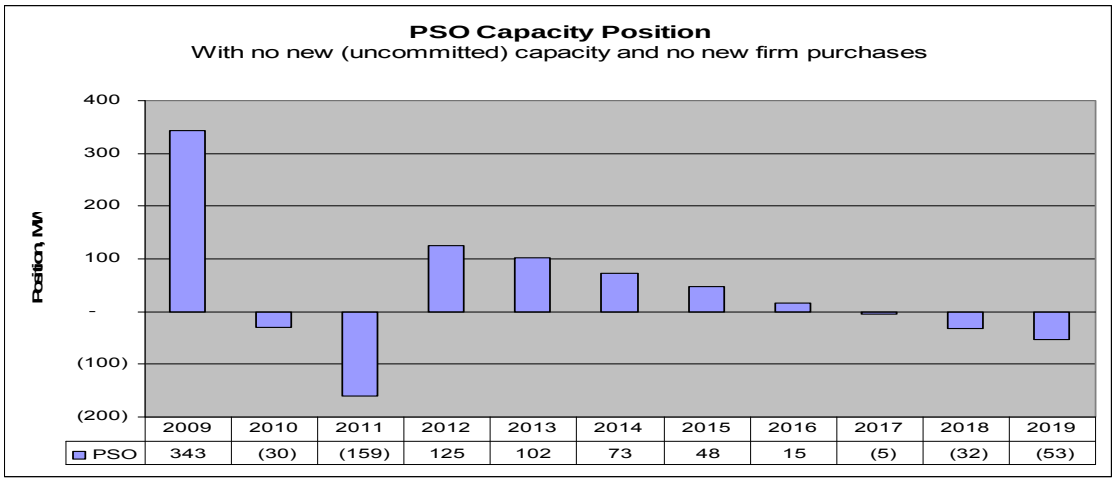


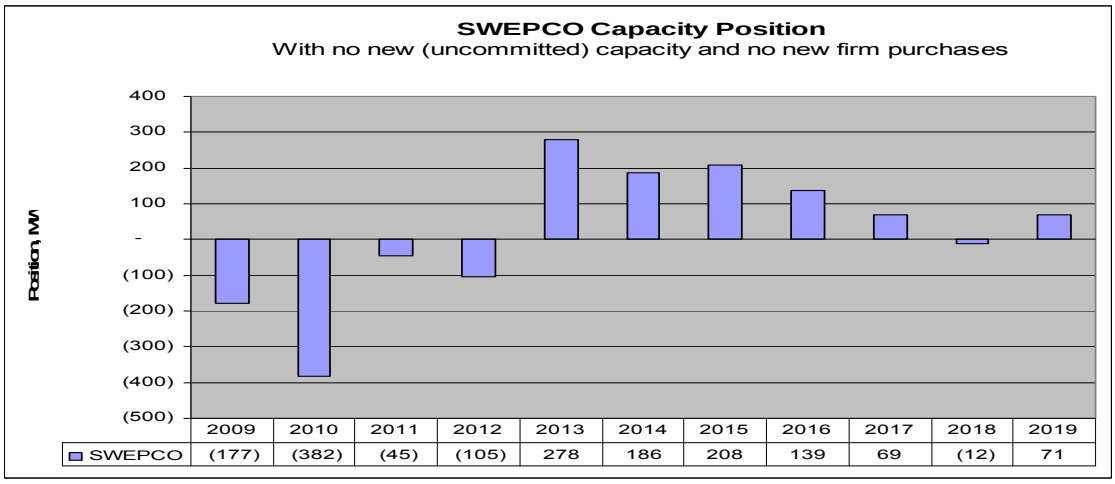


Source: AEP Resource Planning

Note: SWEPCO 2015 peak demand and supply are adjusted to reflect the shift of the NTEC wholesale contract from a full requirements basis (inclusive of NTEC self supply) to a fixed (200 MW) demand only basis.

Exhibit 6-2: Summary of Capacity Deficiency Positions





Source: AEP Resource Planning

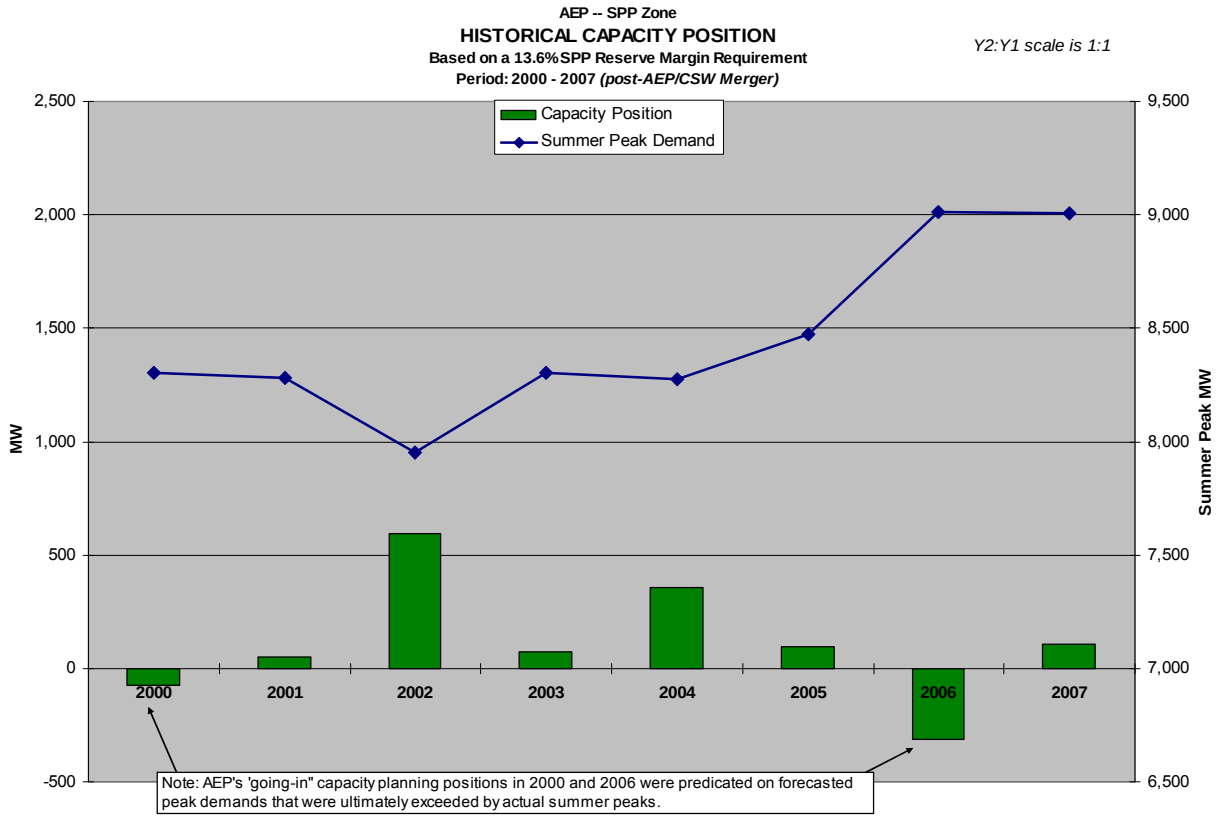
6.1 RTO Requirements

A minimum planning reserve margin of 13.6% of demand (12% of capacity) is currently required by the Southwest Power Pool Criteria and has been assumed to apply throughout the planning period. As previously discussed, for purposes of its detailed planning, PSO and SWEPCO are assumed to meet this criterion separately, under the assumption that the transmission system would limit intra-system capacity transfers. (However, this constraint was relaxed in forming the final plan, which allowed up to 200 MW of intercompany capacity transfer.) Moreover, such separate planning is in keeping with the spirit of the SPP operating agreement, which intended for reserve sharing to be limited among these affiliate companies. Finally, note that this does not preclude PSO and SWEPCO assuming joint ownership of future generation asset(s) if the circumstances – inclusive of such inter-company firm transfer issues – would warrant.

6.2 Capacity Positions—Historical Perspective

To provide a perspective, a historical relative capacity position for the AEP-SPP zone is presented in **Exhibit 6-3**. The AEP-SPP zone has experienced minimal capacity reserves above minimum SPP requirements throughout the current decade, such positions shifting as a direct function of relative peak demand shifts since no long term capacity has been added over that timeframe, until the recent addition of 600 MW of peaking capacity. During this period AEP-SPP has relied on limited-term (market) capacity purchases to achieve the necessary SPP 13.6% reserve criterion.

Exhibit 6-3: AEP-SPP Zone, Historical Capacity Position



Source: AEP Resource Planning

7.0 Planning Objectives

In addition to the determination of a fundamental capacity "needs assessment," the other objective of the resource planning effort was to recommend an optimum system expansion plan, not only from a least-cost perspective, but also from the perspectives of planning flexibility, creation of an optimum asset mix, adaptability to risk and, ultimately, from the perspective of affordability. In addition, given its unique impact on generation, the Integrated Resource Planning modeling effort must ultimately be in concert with anticipated long-term environmental compliance requirements as established by the Environmental Compliance planning process.

7.1 Planning Flexibility—Covering Capacity Deficient Positions with Market Opportunities

It has been established in the previous section that, in spite of the recent additions of the Mattison (SWEPCO), Riverside (PSO) and Southwestern (PSO) gas generation assets, the AEP-SPP zone is faced with a capacity deficiency through 2011 that will need to be met through short-term capacity purchases.

Power market opportunities in the form of limited-term bilateral capacity purchases from non-affiliated sources and asset purchases at significant discounts relative to new generation will continue to be pursued, subject to the firm transportation limitations previously discussed. Therefore, the resource modeling and its ultimate results that will drive recommended regional long-term resource plans must maintain sufficient implementation flexibility to consider such market or "purchase or buy" opportunities in the future.

7.2 Planning Horizon

Recognizing the significant time period typically encompassed by the capacity planning process–both from the perspective of the ultimate cost exposure of these long-lived assets as well as considering the typical in-service lead-time requirement–the evaluations were performed over a 22 year (2009-2030) detailed capacity resource planning period. In order to recognize the ultimate cost-based end-effects of any capacity option established in the latter years of that study period, the economics were extended an additional 5 years, resulting in an overall 2009-2035 evaluation period.

7.3 Establishing the Optimal Asset "Mix"

Another important "needs" consideration in the planning process is the establishment of long-term regional generating capacity profiles that consider the optimal distribution or "mix" of generation technology and, with that, fuel types. As will be discussed later in this section, these capacity profiles will need to be **practical and useful** in terms of operational requirements (dictated by operation within the RTO) and affordable in terms of their ability to be funded corporately.

7.4 Other Operational Factors

In addition to focusing on the creation of a capacity resource plan that would be considered the lowest reasonable life-cycle costs for those customers for whom it is being established, such planning must likewise consider the practicality of the Plan from the perspective of it addressing the on-going operational needs of the system. Given that, the *Strategist* modeling (to be discussed) currently

considers in its costing-profile traditional commodities including energy, fuels, environmental (allowance) values, as well as an emerging capacity market. Pricing or value points not currently considered represent those factors often thought of as "ancillary" services/values.

7.5 Affordability

Any Resource Plan is subjected to a test of affordability. In traditional ratemaking, utilities fund the construction of a power plant from start to finish, at which point they seek recovery of the investment over time. The initial outlay of capital for such a major investment can be onerous to the utility. While earnings are typically not affected by investment program through the accounting of "Allowance for Funds Used During Construction" (AFUDC) (which allows utilities to defer to the balance sheet book recognition of project financing expenses that are associated with spending capital until the project is complete), cash flow will be negatively affected. To fund this cash need, capital must be raised; there is a practical limit, however, to how much can be raised before corporate credit ratings and, with that, earnings are negatively affected.

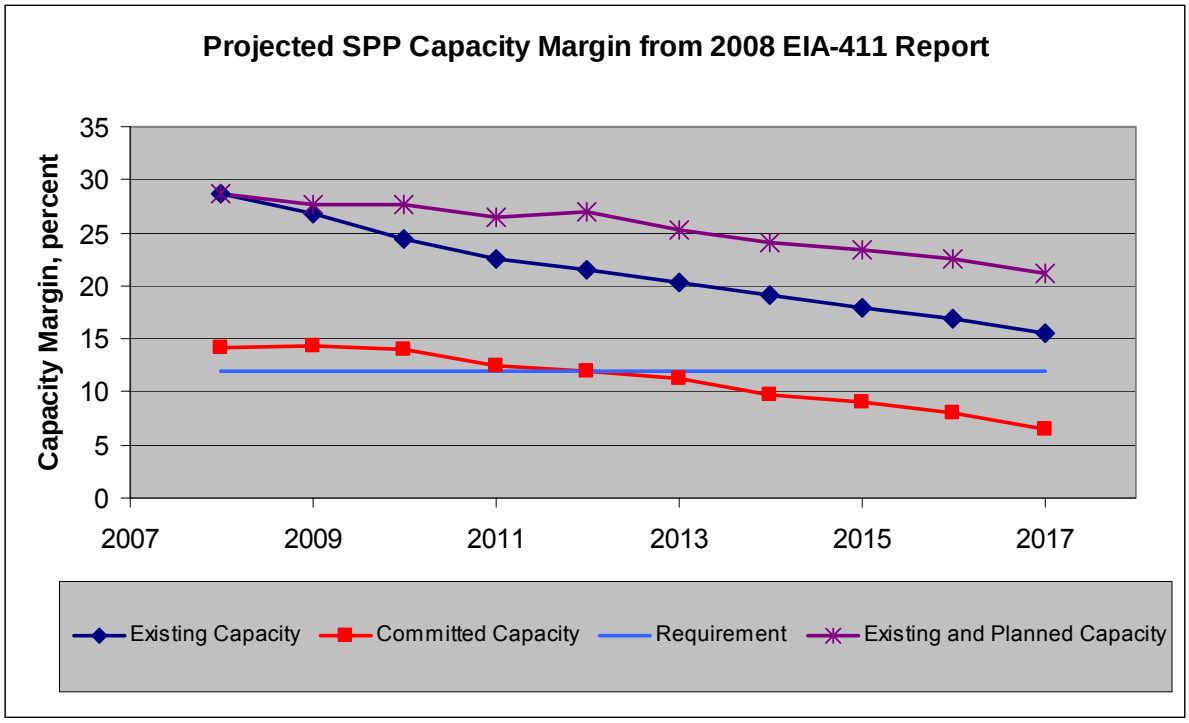
As a result, AEP Corporate Planning & Budgeting and Corporate Finance, among others, continually assess plans generated through the IRP cycle process, making recommendations to alter the timing, amount, and nature of resource additions specified in the Plan, as warranted.

8.0 Resource Options

8.1 Market Options and "Build vs. Buy" Considerations

In addition to the fundamental capacity pricing information utilized in the modeling, available information suggests that capacity reserve margins–inclusive of current and anticipated merchant capacity–is declining in the Southwest Power Pool. These pressures may become more pronounced as the impact of potential CO_2 legislation could depress regional capacity resources. In addition, as suggested in Section 4.4, future limitations surrounding inter- and intra-regional transmission adequacy could limit planned capability.

Exhibit 8-1: Projected SPP Capacity Margin



Source: AEP Resource Planning

Due to various factors discussed here and elsewhere in this document, firm capacity supply as well as the firm power mobility of existing merchantable generating assets cannot be assured significantly beyond the middle portion of the next decade. *Therefore, the intent of this resource planning process is to suggest that capacity requirements beyond approximately the year 2013 will be met with a combination of new build (or buy) and DR/EE alternatives.*

8.1.1 Non-Affiliated (Market) Purchases

AEP's planning position for its SPP zone is to take advantage of market opportunities when they *are* available and economic, either in the form of limited-term bilateral capacity purchases from non-affiliated sources or by way of available, discounted, merchant generation asset purchases. Such market opportunities could be utilized to hedge capacity planning exposures should they emerge and create (energy) option value to the company. However, such opportunities must be tempered with the

realization that two of the AEP west jurisdictions (Louisiana and Oklahoma) have competitive bidder rules under which such exceptions must be granted to realize the benefit of an arm's length bilateral transaction.

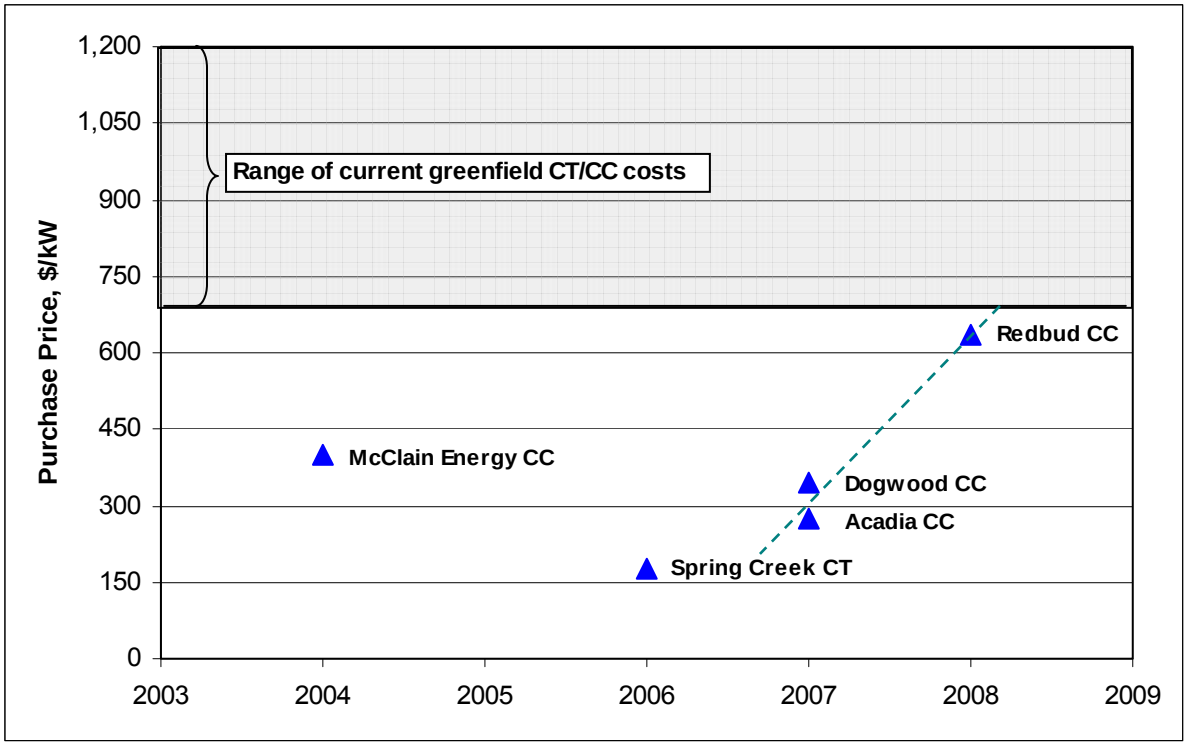
As with the need to maintain resource planning and implementation flexibility for various supply or demand exposures as identified above, the Plan should likewise seek to continually consider such market "buy" prospects, since:

- this IRP assumes the need to ultimately build generating capability to meet the requirements of its customers for which it has assumed an obligation to serve;
- the regional market price of capacity will likely approach the fixed cost of new-build generation;
- the purchase of merchant generation assets relative to new build generation represents a different risk profile with respect to siting, costs and schedule, and
- the planning flexibility that market purchases could enable is critical to the process.

8.1.2 Generation Acquisition Opportunities

AEP investigates the viability of placing indicative offers on additional utility or IPP-owned natural gas peaking and combined cycle facilities as such opportunities arise. Analyses are performed in the *Strategist* model based on the most recent IRP studies, to estimate a break-even purchase price that could be paid for the early acquisition of such an asset, in lieu of an ultimate greenfield installation. As shown in **Exhibit 8-2**, the cost of these assets now approaches that of a greenfield project.

Exhibit 8-2: Recent Merchant Generation Purchases



Source: AEP Resource Planning

8.2 Traditional Capacity-Build Options

8.2.1 Generation Technology Assessment and Overview

AEP's New Technology Development organization is responsible for the tracking and monitoring of estimated cost and performance parameters for a wide array of generation technology alternatives. Utilizing access to industry collaboratives such as EPRI and Edison Electric Institute (EEI), AEP's association with architects and engineering firms (A&Es) and original equipment manufacturers (OEMs), as well its own experience and market intelligence, this group continually monitors such supply-side trends. **Appendix C** offers a summary of the most recent technology cost and performance parameter data developed.

8.2.2 Baseload Alternatives

Coal-based baseload technologies include *pulverized coal* combustion designs, *integrated gasification combined cycle* facilities, and *circulating fluidized bed* combustors. Nuclear is becoming a more viable option, and the application process for the construction of nuclear power plants has been initiated by several utilities. It is AEP's current view that, while great difficulty and risk still exist in the siting and construction of nuclear power plants, nuclear power should be among our baseload options for the future. Nuclear power was modeled in the AEP-SPP planning scenarios and sensitivities, primarily due to the sheer (MW Nameplate) size of economical nuclear unit options vis-à-vis the relative capacity requirements of PSO and SWEPCO. Nuclear power, however, should not be excluded from future plans, especially if partners could be found.

8.2.2.1 Pulverized Coal (PC)

PC plants have been considered to be the workhorse of the U.S. electric power generation infrastructure. In a PC plant, the coal is ground into fine particles that are blown into a furnace where combustion takes place. The heat from the combustion of coal is used to generate steam to supply a steam turbine that drives a generator to make electricity. Major by-products of combustion include SO_2, NO_X, CO_2, and ash, as well as various forms of elements in the coal ash including Mercury (Hg).

The steam cycle for the pulverized coal-fired units – which determines the efficiency of generating electricity – falls into one of two categories, *subcritical* or *supercritical*. Subcritical operating conditions are generally accepted to be at up to 2,400 psig/1,000°F superheated steam, with a single reheat to 1,000°F, while supercritical steam cycles typically operate at up to 3,600 psig, with 1,000-1,100°F main steam and reheat steam temperatures. AEP has recognized the benefits of the supercritical design for many years. All eighteen of the units in the AEP-East system built since 1964 have utilized the supercritical design. There have been advances in the supercritical design over the years, and there are now commercial units operating at or above 3,600 psig and >1,100°F steam temperatures. This is known as an *ultra supercritical* (USC) design, as defined by temperature.

The initial capital costs of subcritical units are lower than those of a comparable supercritical unit by about 4 to 6 percent, but the overall efficiency of the supercritical design is higher than the subcritical design by approximately 3 percent. Due to cycle design improvements, the new variable pressure ultra supercritical units are projected to have–at commercial quantities–an initial capital cost of only 1-2 percent greater than a comparable supercritical unit. While the overall efficiency remains

approximately 3 percent better than the comparable supercritical unit, the efficiency improvement is present throughout the entire load range, not just at full load conditions.

8.2.2.2 Integrated Gasification Combined Cycle (IGCC)

Given the long time-horizons of most resource planning exercises, IRP processes must be able to consider new technologies with uncertain costs, such as IGCC. The assessment of such technologies is based on cost and performance estimates from commonly cited public sources, consortiums where AEP is actively engaged, vendor relationship, as well as AEP's own experience and expertise.

IGCC technology has the potential to achieve the environmental benefits closer to those of a natural gas-fired plant, and thermal performance closer to that of a combined cycle facility, yet with the low fuel cost associated with coal. As discussed in this year's IRP report for the AEP East Zone, IGCC appears well-positioned for integration of ultimate carbon capture and sequestration technologies, which will be a critical measure in any future mitigation of greenhouse gas emissions. As an additional observation, the small number of IGCC equipment suppliers means a large share of technology and performance risk falls on owners, although the on-going collaboration with technology developers, including GE/Bechtel, mitigates some of this risk. However, as it applies to a design that would utilize sub-bituminous (PRB) coal, IGCC technology is less mature and therefore is not a viable resource option in this near (2010-2019) term.

8.2.2.3 Circulating Fluidized Bed Combustion (CFB)

A CFB plant is similar to a PC plant except that the coal is crushed rather than pulverized, and the coal is combusted in a reaction chamber rather than the furnace of a PC boiler. CFB boilers are capable of burning a wide range of fuels that cannot be accommodated by PC designs, including bituminous and sub-bituminous coal, coal waste, lignite, petroleum coke, a variety of waste fuels, and biomass. Units are sometimes designed to fire using several fuels, which emphasizes this technology's major advantages: its inherent fuel flexibility. Coal is combusted in a hot bed of sorbent particles that are suspended in motion (fluidized) by combustion air blown in from below through a series of nozzles. CFB boilers operate at lower temperatures than pulverized coal-fired boilers. The energy conversion efficiency of CFB plants tends to be slightly lower than that of pulverized coal-fired counterparts of the same size and steam conditions because of higher excess air and auxiliary power requirements.

CFB boilers capitalize on the unique characteristics of fluidization to control the combustion process, minimize NO_X formation, and capture SO_2 in-situ. Specifically, SO_2 is captured during the combustion process by limestone being fed into the bed of hot particles that are fluidized by the combustion air blown in from below. The limestone is converted into free lime, which reacts with the SO_2. The chemical process does disadvantage CFB by contributing to relative Hg emission exposure.

8.2.2.4 Nuclear

Although new reactor designs and ongoing improvements in safety systems make nuclear power a potentially viable option as a new-build alternative due to it being an emission-free power source,

concerns about public acceptance/permitting, spent nuclear fuel storage, lead-time, and capital costs continue to temper its consideration. Because of the long lead time to bring a nuclear unit on-line, and the large generating capacity of nuclear units, AEP does not view nuclear as a viable candidate to meet the capacity resource needs of AEP-SPP within this near-term period (2010-2019).

8.2.3 Intermediate Alternatives

Intermediate generating sources are typically expected to serve a load-following and cycling duty and shield baseload units from that obligation.

8.2.3.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Hot gases (~1,100°F) from a combustion turbine exhaust pass through a heat recovery steam generator (HRSG) where they are cooled to about 250°F, and in doing so, produce steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power with, depending upon the gas-to-steam turbine design "platform," while one or more combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-55% LHV), low emission levels, and shorter construction period than coal-based plants. In the past 8 to 10 years NGCC plants were most widely selected to meet new intermediate and certain baseload needs. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Installation of gas dampers to bypass gas from turbine exhaust, maintaining exhaust/steam temperatures while steam flow to the steam turbine generator is decreased with load.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of a multiple gas turbine coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

8.2.4 Peaking Alternatives

Peaking generating sources are required to provide needed capacity during extreme high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for "quick-response" capability. As a result, fuel efficiency and other variable cost are of lesser concern. In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency (black-start) capability to the grid.

8.2.4.1 Simple Cycle Combustion Turbines (NGCT)

In "industrial" or "frame-type" combustion turbine systems, air compressed by an axial compressor (front section) is mixed with fuel and burned in a combustion chamber (middle section). The resulting hot gasses then expand and cool while passing through a turbine (rear section). The rotating rear turbine not only runs the axial compressor in the front section but also powers an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A simple cycle combustion turbine system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost. While not as efficient (at 30-35% LHV), they are, however, inexpensive to purchase, compact, and simple to operate. Further, simple cycle CTs can be started up and placed in service far more rapidly than any system involving a steam turbine.

8.2.4.2 Aeroderivatives (AD)

Aeroderivatives are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7EA requires 20 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes to full load. However, the cost per kW of an aeroderivative is on the order of 50% higher than a frame machine.

Their performance requirements, calling for rapid startup and shutdown, make the aeroderivatives well suited to peaking generation needs. The aeroderivatives can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to industrial units which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide aeroderivatives the ability to backup intermittent renewables such as solar and wind.

Aeroderivatives weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an aeroderivative over an industrial turbine. Aeroderivatives in the below 50 MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of the same size. Exhaust gas temperatures are also lower in the aeroderivative units.

Some of the better known aeroderivative vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.

8.2.5 Energy Storage

Energy storage refers to technologies that allow for storage of energy during periods of reduced demand and discharge of energy during periods of peak demand. This has the effect of flattening the load curve by reducing the peaks and "filling the valleys." In this sense, it is considered a peaking asset. Energy storage consists of batteries (Sodium Sulfur "NaS," Lithium Ion, and others), super capacitors, flywheels, or pumped hydro storage. Pumped storage hydro uses two water reservoirs, separated vertically. During off peak hours water is pumped from the lower reservoir to the upper reservoir. When required, the water flow is reversed to generate electricity.

The investment requirements for pumped hydro storage are significant. Further, site-selection and attainment of FERC licensing represent huge challenges. NaS Batteries are the leading technology under consideration for storage-related utility planning.

Appendix C, page 2 describes an energy storage technology screening curve which could be used to indicate whether a particular technology warrants further investigation.

8.2.5.1 Sodium Sulfur Batteries (NaS):

Storage technologies have begun to receive greater consideration due partly to the improved battery-storage technologies; efficiencies now are approaching 90%. That, coupled with the ability to offer market time-of-day pricing arbitrage by charging during low-cost off-peak periods and discharging at higher-cost daytime periods, works to its advantage. Batteries can be sited near load points, thus avoiding peak line losses. The downside currently is the significant cost per kW and, due to their weight and transportation, total costs approaching $1,800-2,000 per kW.

In light of battery-storage's potential for 1) the market arbitrage, 2) line loss reduction, 3) deferral of selected distribution infrastructure through selective siting of storage capacity, coupled with the prospect for reduced capital costs due to improvements in battery technology, its consideration as a potential capacity resource is warranted.

8.2.5.2 Community Energy Storage (CES)

Community energy storage (CES) is being tested for distributed storage. The use of distributed storage technology, which will involve the placement of small energy storage batteries throughout residential areas, will look similar to the small transformer boxes currently seen throughout neighborhoods. Each box should be able to power four to six houses. AEP is testing this potential game-changing technology, which should also provide voltage sag mitigation as well as emergency transformer load relief.

8.2.5.3 Flywheel Energy Storage and Frequency Regulation

AEP has contracted with Beacon Power Corp., to build a 1 MW, 250 kWh energy storage and frequency regulation facility at AEP's Groveport, Ohio, site using Beacon's flywheel-based technology.

The new agreement supports grid efficiency and reliability and follows closely on contracts Beacon has entered with independent system operators (ISO) in New England and New York to deploy its system, which stores kinetic energy on spinning flywheels. Beacon can then release that energy on command from ISOs to balance the grid in a more cost-effective manner than using peaker plants, the method now used by grid operators. Under the contract with AEP, which includes the utility's Columbus Southern Power Co. operating unit, Beacon will deliver, install, test and operate the 1 MW facility at its own expense beginning mid-year 2009. AEP will provide materials and services needed to interconnect the flywheel system to PJM, including the foundation, electrical transformer, associated wiring and connection to power lines. However, given the existing limitations associated with the energy storage capabilities, flywheel technology is not a practical alternative for AEP-SPP capacity planning.

8.3 Renewable Alternatives

Renewable generation alternatives represent those in which nontraditional (e.g., non-fossil) fuel sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas), are utilized. Numerous renewable energy sources are under development or exist, but many sources like solar, geothermal, and tidal, are simply not economic options for AEP within our service territory, based on the current state of development for those technologies or for meteorological or geographical reasons. Within the AEP service territory and without significant leaps in technology, biomass co-firing in coal power plants and wind plants are the primary options for economically (or realistically) generating electricity on a significant scale from renewable sources.

As highlighted in the Section 2 Overview, although effective in 29 states and the District of Columbia, a mandatory RPS exists today in Ohio, Michigan, West Virginia and Texas, and a voluntary RPS exists in Virginia. This being said, the notion of a potential Federal RPS is sufficiently tenable to warrant an evaluation of the merits of renewable generation in conjunction with this IRP process. Further, renewable energy sources have the ability to deliver attractive CO_2 benefits in a potentially carbon-constrained policy environment.

AEP's New Technology Development group evaluated a wide range of renewable technologies beginning in 2005, with the latest updates in early 2009. The evaluations involved a multifaceted effort using input from many AEP groups. Technologies were evaluated on cost, location, feasibility, applicability to AEP's service territory, and commercial availability. After a high-level evaluation, economic screening was carried out considering each technology's estimated costs and effectiveness, to develop a levelized dollar-per-renewable-MWh cost. Costs and benefits considered in the screening included project capital and O&M costs; avoided capacity and energy costs; alternative fuel costs; alternative emission rates and associated allowance costs; and available federal or state production tax credits, if any. The levelized cost was used to rank the various technologies.

The renewable technologies ultimately screened include:

- biomass co-firing on existing coal-fired units
- separate injection of biomass on existing coal-fired units
- wind farms
  - ✓ evaluated separately for the East and West regions
  - ✓ with and without the federal production tax credit
- solar generation
- incremental hydroelectric production
- landfill gas with microturbine
- geothermal generation
- distributed generation

Although some of the renewable technologies listed above could be economic, AEP is constrained from doing some of these projects because the energy sources are geographically constrained in AEP service territory (e.g., geothermal). Similarly, biomass co-firing is constrained by a supply of suitable fuel and/or transportation options anticipated to be in proximity to the host coal units evaluated. *Thus, the renewable resources available to be included in the Plan are not*

necessarily the least expensive options screened, but rather those that provide suitable economics and practicality. A complete list of screened renewable technologies and their incremental levelized life cycle costs is included in *Appendix B*.

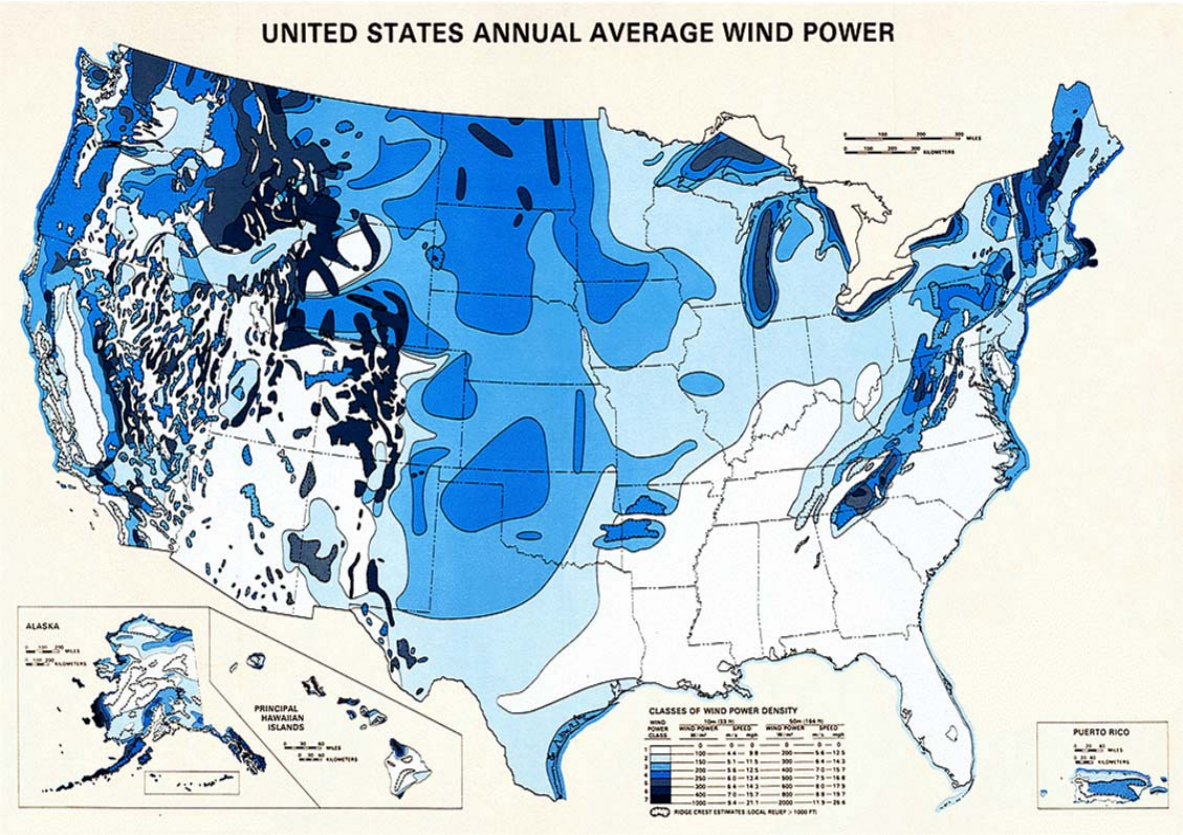
8.3.1 Wind

Wind is currently the fastest growing form of electricity generation in the world. Utility wind energy is generated by wind turbines with a range 1.0 to 2.5 MW, with a 1.5 MW turbine being the most common size used in commercial applications today. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical from the perspective of both the existing wind resource and its proximity to a transmission system with available capacity.

Ultimately, as production increases to match the significant increase in demand, the high capital costs of wind generation should begin to decline. Currently, the cost of electricity from wind generation is competitive within the PSO and SWEPCO service territories *only because of the accompanying subsidies,* such as the federal production tax credit as well as consideration given to *REC values, rising fuel costs or future carbon costs.*

A drawback of wind is that it represents a sporadic or fluctuating source of power in most non-coastal locales, with capacity factors ranging from approximately 35 to 40+ percent in the west; thus its life-cycle cost ($/MWh) is more often higher than traditional generating sources, in spite of wind's zero fuel cost. Another obstacle with wind power is that its most critical factors (i.e., wind speed and sustainability) are typically highest in very remote locations, and this forces the electricity to be transmitted long distances to load centers necessitating the buildout of EHV transmission to optimally integrate large additions of wind into the grid. **Exhibit 8-3** shows the potential wind resource locations in the United States

Exhibit 8-3: United States Wind Power Locations

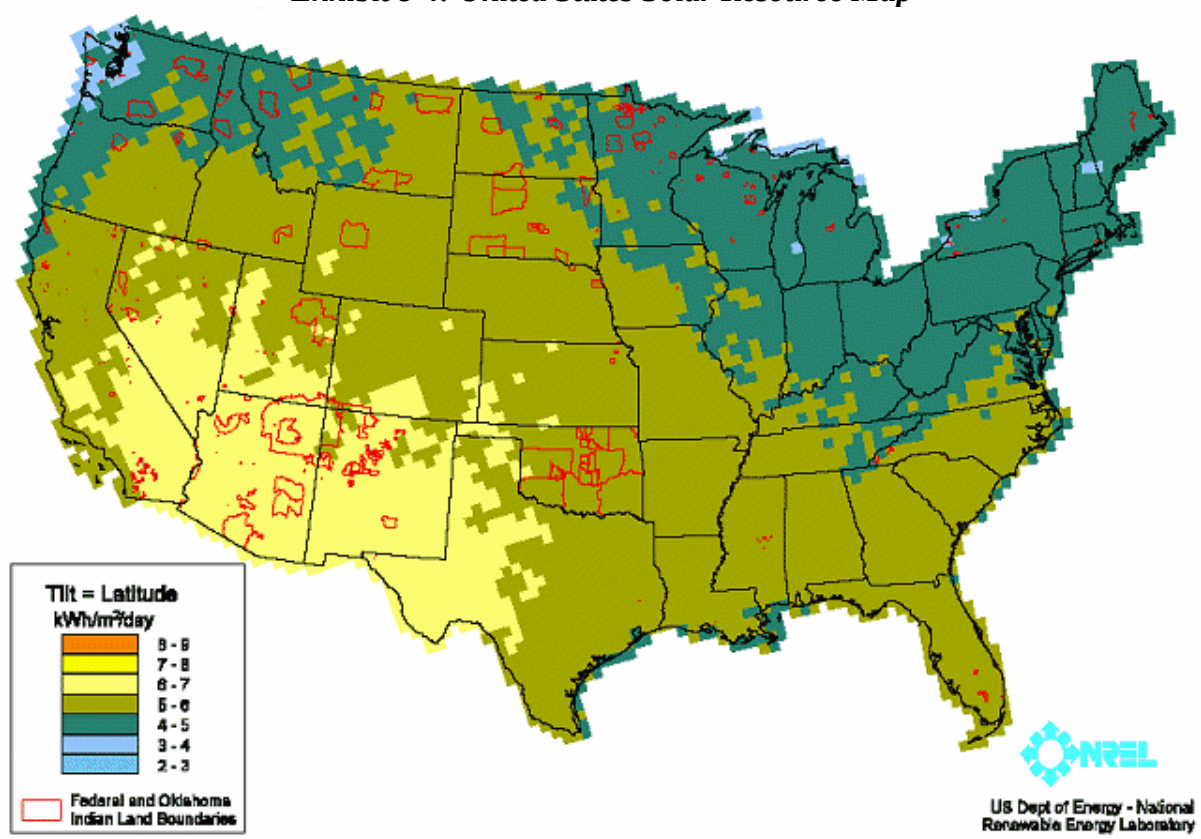


Source: NREL

8.3.2 Solar

Solar power takes a couple of viable forms to produce electricity: concentrating and photovoltaics. Concentrating solar – which heats a working fluid to temperatures sufficient to power a turbine - produces electricity on a large scale (100 MW) and is similar to traditional centralized supply assets in that way. Photovoltaics produce electricity on a smaller scale (2-500 kW per installation) and are distributed throughout the grid. **Exhibit 8-4** shows direct normal solar radiation in the United States.

Exhibit 8-4: United States Solar Resource Map



8.3.3 Biomass

Biomass is a term that includes organic waste products (sawdust or other wood waste), organic crops (switchgrass, poplar trees, willow trees, etc.), or biogas produced from organic materials.

It is generally accepted that biomass represents a carbon neutral fuel. Biomass is part of the carbon cycle. Carbon from the atmosphere is converted into biological matter by photosynthesis. On combustion the carbon goes into the atmosphere as carbon dioxide (CO_2). This happens over a relatively short timescale and plant matter used as a fuel can be replaced by planting for new growth. Therefore a reasonably stable level of atmospheric carbon results from its use as a fuel.

In the United States today, a large percentage of biomass power generation is based on wood-derived fuels, such as waste products from the pulp and paper industry and lumber mills. Biomass from agricultural wastes also plays a dominant role in providing fuels. These agricultural wastes include rice and nut hulls, fruit pits, and animal manure.

A relatively low-cost option to produce electricity by burning biomass is by co-firing it with coal in an existing boiler using existing coal feeding mechanisms. In a typical biomass co-firing application, 1.5% to 6% of the generating unit's heat input is provided by biomass, depending on the boiler's method of firing coal. A more capital-intensive option is separate injection, which involves separate handling facilities and separate injection ports for the biomass. Separate injection can achieve a 10% heat input from biomass.

Co-firing generally provides a lower-cost method of energy generation from biomass than building a dedicated biomass-to-energy power plant. In addition, a coal-fired power plant typically uses a more efficient steam cycle and consumes relatively less auxiliary power than a dedicated biomass plant, and thus generates more power from the same quantity of biomass.

Some possible drawbacks associated with biomass co-firing or separate injection include reduced plant efficiencies due to lower energy content fuels, loss of fly ash sales, and fouling of SCR catalysts. Although these relatively minor obstacles can be mitigated through various means, the major obstacle to the utilization of biomass as a feedstock is the transportability and resulting cost of the biomass fuel. Biomass has many competing demands, such as the pulp and paper, agriculture industries, as well as the ethanol market, which can dramatically escalate the market price for the material along with the transportation of such a low energy-density fuel. Another issue associated with biomass is the significant quantities of land dedicated and required to generate sufficient quantities of biomass as identified in **Exhibit 8-5**.

Exhibit 8-5: Land Area Required to Support Biomass Facility

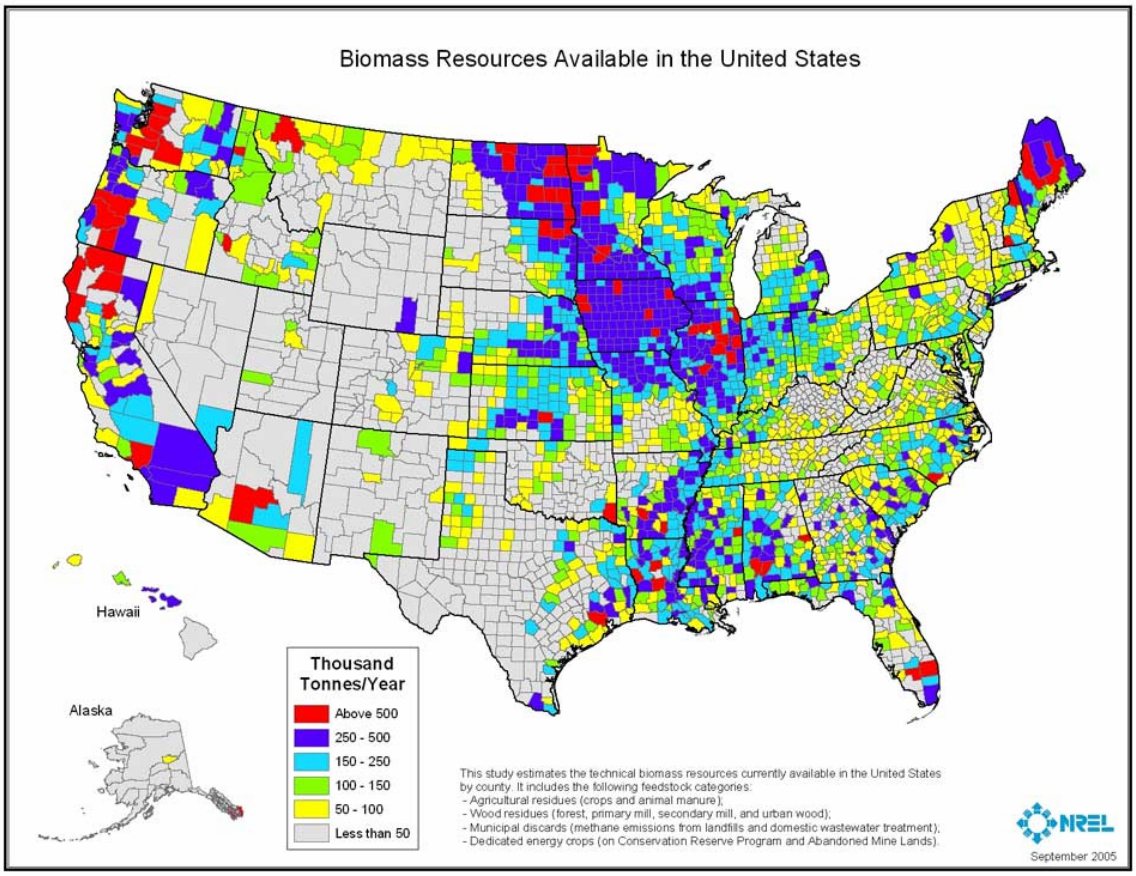
Switchgrass	**Wood Chips / Sawdust**
(per Purdue University Study) o 6 -to- 8 tons /yr. per acre yield o @ 6700 Btu/lb (non-dried, as harvested) *A 200-MW Dedicated Biomass Facility (70% C.F.) would require…* **110k -to- 150k harvested acres** *(172 - 234 sq. mi,)*	*(per AEP-Forestry)* o 70 -to-100 tons /yr. per acre yield* * "clear cutting" on a *40-year cycle* o @ 4800 Btu/lb (green, non-dried) *A 200-MW Dedicated Biomass Facility (70% C.F.) would require…* **510k -to- 730k timbered acres** *(795 - 1,140 sq. mi,)*
10-GW *(~60 Twh/yr.) of switchgrass-fired biomass capacity would require approx.* ***45 MM t/yr. of switchgrass*** *which would require dedicated agri-land mass =* ***6.5 MM acres*** *… or 100% of the cropland and pasture/grassland identified by the USDA in the state of* ***Georgia***	***10-GW*** *of (clear-cut) wood chip-fired capacity would require approx.* ***64 MM t/yr. of wood product*** *which would require dedicated forested-land mass =* ***31 MM acres*** *… or 100% of the forested acreage identified by the USDA in* ***North Carolina*** *and* ***South Carolina combined***

Source: AEP Resource Planning

Biomass co-firing provides many valuable benefits and holds some promise for the AEP generating fleet, but the high fuel/transportation costs and the limited deployment potential on a heat-input basis could inhibit the near-term viability of the technology on a large scale. **Exhibit 8-6** shows potential biomass resources.

Biomass co-firing is not a substitute for generation. Because it simply substitutes "carbon-neutral" fuel for fossil fuels, it does not eliminate the need for building generation as (peak) demand grows and assets are retired. However, if and when GHG become regulated, biomass co-firing could become an economically viable way to reduce the CO_2 output of certain coal-fired plants.

Exhibit 8-6: Biomass Resources in the United States



Source: NREL

8.3.4 Renewable Alternatives—Economic Screening Results

AEP has established an internal renewable target of 10% of System energy (total SPP and East zones) from renewable resources by 2020 (see Appendix E). Based on current AEP system renewable resources, and considering an additional 1,000 MW of renewable resources recently committed to by the year-end 2011 this internal commitment is projected to be satisfied as reflected in **Exhibit 8-7**.

Exhibit 8-7: Renewable Sources Included in AEP-SPP and East 2009 IRP

AEP System

Existing and Projected Renewables for 2009 IRP

Unit, Plant, or Contract	Size (MW)	Operating Company (Existing or Awarded Contracts)	No. of Units	First Full Year	Annual Energy (GWh)	Cumulative Annual Energy (GWh)	Percent of Projected Retail Sales	
Existing Wind								
SW Mesa	31	SWEPCO		Existing	99	99	0.1%	Note 1
Weatherford	147	PSO		Existing	569	668	0.5%	
Blue Canyon	151.2	PSO		Existing	581	1,249	0.9%	
Sleeping Bear	94.5	PSO		Existing	346	1,595	1.2%	
Camp Grove Wind	75	APCo		Existing	250	1,845	1.3%	
Executed PPA Contracts								
Fowler Ridge I Wind	200	APCo/I&M		2010	605	2,450	1.8%	
Grand Ridge II & III Wind	100.5	APCo		2010	288	2,738	2.0%	
Fowler Ridge II Wind	150	I&M/CSP/OPCo		2010	454	3,192	2.3%	
Majestic Wind	79.5	SWEPCO		2010	300	3,492	2.3%	
Solar (Wyandotte)	10.0	CSP/OPCo	144	2010	10	3,502	2.5%	
Blue Canyon V Wind	99	PSO		2011	373	3,875	2.6%	
Beech Ridge Wind	100.5	APCo		2011	288	4,164	2.8%	
Elk City Wind	98.9	PSO		2011	373	4,536	3.0%	
New Projects								
East Wind	600			2011	1722	5,224	3.5%	
West Wind	100			2011	377	5,601	3.8%	
Muskingum River 5	0			2011	63	6,698	4.5%	Note 2
Solar (Distributed)	3.1		45	2011	3	6,702	4.5%	
Biomass Plant	60			2012	463	7,164	4.8%	Note 3
Amos 3	0			2012	144	7,308	4.9%	Note 2
East Wind	600			2012	1722	9,030	6.0%	
(Indiana-specific) Wind	100			2012	287	9,317	6.2%	
West Wind	100			2012	377	9,694	6.4%	
Solar (Distributed)	1.5		22	2012	2	9,696	6.4%	
West Wind	150			2013	566	10,261	6.8%	
East Wind	400			2013	1148	11,409	7.5%	
(Indiana-specific) Wind	100			2013	287	11,696	7.7%	
Rockport 1-2	0			2013	385	12,081	8.0%	Note 2
Solar (Distributed)	14		200	2013	15	12,096	8.0%	
Solar (Distributed)	14		200	2014	15	12,110	8.0%	
West Wind	100			2015	377	12,487	8.2%	
Solar (Distributed)	14		200	2015	15	12,502	8.2%	
Muskingum R 5	0			2015	350	12,852	8.4%	Note 4
Big Sandy 2	0			2015	571	13,423	8.8%	Note 4
West Wind	100			2016	377	13,800	9.0%	
East Wind	100			2016	287	14,087	9.1%	
Solar (Distributed)	14		200	2016	15	14,101	9.1%	
West Wind	200			2017	754	14,855	9.6%	
East Wind	0			2017	0	14,855	9.6%	
Solar (Distributed)	13		190	2017	14	14,869	9.6%	
Welsh one unit	0			2017	54	14,923	9.6%	Note 2
East Wind	0			2018	0	14,923	9.5%	
Muskingum River unit	127			2018	779	15,702	10.0%	Note 5
Solar (Distributed)	17		250	2018	18	15,720	10.1%	
Amos 3	0			2019	792	16,512	10.5%	Note 4
Solar (Distributed)	17		250	2019	18	16,530	10.5%	
West Wind	200			2020	754	17,284	10.9%	
East Wind	200			2020	574	17,858	11.3%	
Solar (Distributed)	16		230	2020	17	17,875	11.3%	

These new projects after 2010 represent the results of a high level economic screen only

Note 1: RECs only
Note 2: Potential Biomass Cofire
Note 3: Potential Dedicated Facility PPA
Note 4: Biomass Separate Injection
Note 5: Convert to Biomass Stoker

Source: AEP Resource Planning

8.4 Carbon Capture

CO_2 capture is the separation of CO_2 from emissions sources or the atmosphere and the recovery of a concentrated stream of CO_2 that is suitable for sequestration or conversion. Efforts are focused on systems for capturing CO_2 from coal-fired power plants, although the technologies developed will also be applicable to natural-gas-fired power plants, industrial CO_2 sources, and other applications. In PC plants, which are 99% of all coal-fired power plants in the United States, CO_2 is exhausted in the flue gas at atmospheric pressure at a concentration of 10-15% of volume. This is a challenging application for CO_2 capture because:

- The low pressure and dilute CO_2 concentration dictate a high volume of gas to be treated.
- Trace impurities in the flue gas tend to reduce the effectiveness of the CO_2 absorption processes.
- Compressing captured CO_2 from atmospheric pressure to pipeline pressure (1,200 to 2,000 pounds per square inch) requires a large parasitic load.

Aqueous amines are the current state-of-the-art technology for CO_2 capture for PC power plants. The 2020 Department of Energy aspirational goal for advanced CO_2 capture systems is that CO_2 capture and compression added to a newly constructed power plant increases the cost of electricity no more than 35%, versus the current 65%, relative to a no-capture case.

However, with IGCC technology CO_2 can be captured from a synthesis gas (coming out of the coal gasification reactor) <u>before</u> it is mixed with air in a combustion turbine. The pre-combusted CO_2 is relatively concentrated (50% of volume) and at higher pressure. These conditions offer the opportunity for lower-cost CO_2 capture. The state-of-the-art technology for CO_2 capture from an IGCC power plant is the glycol-based *Selexol* sorbent. The 2012 Department of Energy aspirational goal as of April 2009 for advanced CO_2 capture and sequestration systems applied to an IGCC is no more than a 10% increase in the cost of electricity from the current 30%. It is a more stringent goal given that the conditions for CO_2 capture are more favorable in an IGCC plant.

8.4.1 Carbon Storage/Sequestration

Storage is the placement of CO_2 into a repository in such a way that it will remain sequestered for hundreds of thousands of years.

Geologic formations considered for CO_2 storage are layers of porous rock deep underground that are "capped" by a layer of nonporous rock above them. The storage process consists of drilling a well into the porous rock and then injecting pressurized ("spongy" liquid) CO_2 into it. The CO_2 is buoyant and flows upward until it encounters the layer of nonporous rock and becomes trapped. There are other mechanisms for CO_2 trapping as well. CO_2 molecules dissolve in brine and react with minerals to form solid carbonates, or be absorbed by porous rock. The degree to which a specific underground formation is suitable for CO_2 storage can be difficult to discern. Research is aimed at developing the ability to characterize a formation before CO_2 injection to be able to predict its CO_2 storage capacity. Another area of research is the development of CO_2 injection techniques that achieve broad dispersion of CO_2 throughout the formation, overcome low diffusion rates, and avoid fracturing the cap rock. These two areas, site characterization and injection techniques, are

interrelated because improved formation characterization will help determine the best injection procedure.

8.4.2 Carbon Capture Technology and Alternatives

While not yet considered as an economically viable supply-side option, the costs to remove CO_2 from the effluent stream and sequester it in geological formations will have increasing efficacy as the cost of CO_2 increases over time.

Reducing CO_2 emissions from a fossil-fuel technology can be accomplished in three ways: increased generating efficiency, removing the CO_2 from the flue gas, or reducing the carbon content of the fuel. While effective, increasing the generating efficiency of a coal-based plant has its practical limitations from a design and performance perspective. Removing the CO_2 from the flue gas of a PC plant is a very expensive process. Currently, the only demonstrated technology used to "scrub" the CO_2 from the flue gas is by using a monoethanolamine (MEA) or methyldiethanlamine (MEDA) absorption process.

As previously mentioned in this report, AEP is pursuing an alterative approach. The Company is currently conducting commercial validation of Alstom's chilled ammonia PC carbon capture technology at its 1,300 MW Mountaineer plant in West Virginia. It is anticipated that this technology can achieve 50% CO_2 capture at a lower cost than other retrofit technologies. Based on that Mountaineer (20 MW) slip-stream test, a subsequent 235 MW commercial installation of this chilled ammonia technology has been proposed for Mountaineer.

Reducing the carbon content of the fuel can be accomplished by either switching from coal to natural gas (natural gas has approximately 44% less carbon than coal and a correspondingly greater hydrogen content) *or* by removing the carbon from synthetic gas derived from coal before it is combusted, as would be the case for CO_2 removal in an IGCC system.

8.5 Demand Side Alternatives

8.5.1 Background

"Demand Side Management" (DSM) refers to, for the purposes of this IRP, utility programs, including tariffs, which encourage reduced energy consumption, either at times of peak consumption or throughout the day/year. Programs or tariffs that reduce consumption at the peak are "demand reduction" (DR) programs, while round-the-clock measures are "energy efficiency" (EE) programs. The distinction between peak demand reduction and energy efficiency is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive.

8.5.2 Demand Response

Peak demand, measured in megawatts (MW), can be thought of as the amount of power used at the time of maximum power usage. In the AEP-West zone, this maximum (peak demand) is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use

of other appliances and (industrial) machinery. At all other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak must be reduced. This can be addressed several ways via both "active" and "passive" measures:

- *Interruptible loads*. This refers to a contractual agreement with the utility and a heavy consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or turn off his power during peak periods, freeing up that capacity for other consumers.
- *Direct load control*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the utility to (remotely) deactivate discrete appliances, typically air conditioners, hot water heaters, or pool pumps during periods of peak demand. These power interruptions can be accomplished through radio signals that activate switches or through a digital "smart" meter that allows activation of thermostats and other control devices.
- *Variable rates*. Offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few a two rates (peak and off-peak) and to as often as hourly in what is known as "real-time pricing". Accomplishing real-time pricing requires digital metering.
- *Energy Efficiency measures*. If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less. This represents a "passive" demand response.
- *Line loss mitigation.* A line loss results during the transmission and distribution of power from the generating plant to the end user. To the extent that these losses can be reduced, less energy is required from the generator.

What may be apparent is that, with the exception of Energy Efficiency measures, the amount of power consumed is not typically reduced. Less power is consumed at the peak, but to accomplish the same amount of work, that power will be consumed at some point during the day. Instead of the air conditioner operating at four o'clock, it will come on at six to get the house cooled down. If rates encourage someone to avoid running their dishwasher at four, they will run it at some other point in the day. This is also referred to as load shifting.

8.5.3 Energy Efficiency

EE measures save money for customers billed on a "per kilowatt-hour" usage basis. The trade-off is the reduced utility bill for any up-front investment in an appliance/equipment modification, upgrade, or new technology. If the consumer feels that the new technology is a viable substitute and will pay him back in the form of reduced bills over an acceptable period, he will adopt it.

EE measures will, in all cases, reduce the amount of energy consumed. They will accomplish the same task for less energy. However, EE may have limited effectiveness at the time of peak demand and, in fact, that is often the case.

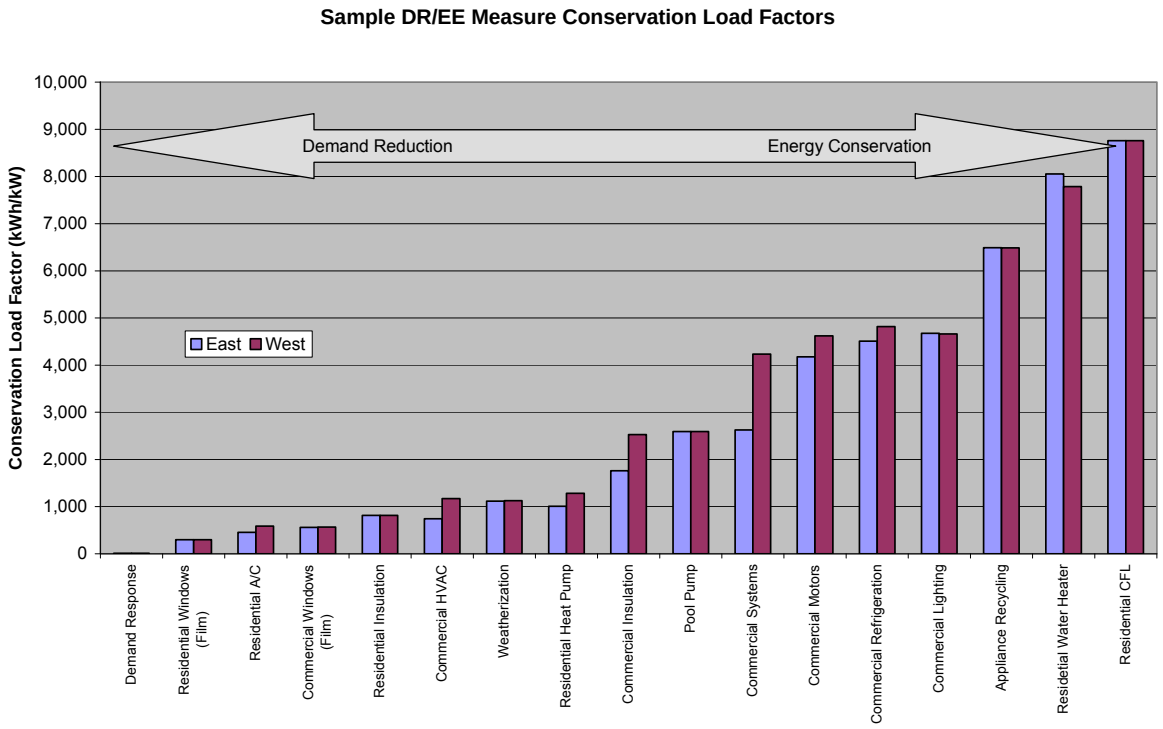
Some examples will illustrate this point. First, a more efficient air conditioner will likely reduce consumption at the peak; the same amount of cool air is being generated with less energy. A more efficient refrigerator will have a lesser impact on the peak as the chance of it running consistently at the peak time ("peak coincidence") is less than that of the air conditioner. A compact fluorescent light bulb (CFL), while using considerably less energy to accomplish the same task, has low coincidence (the peak occurs during the daylight hours), and outdoor lighting has coincidence of zero (for the same reason).

Conversely, the efficiency measures that have the greatest effectiveness at the peak save the least energy (in very broad terms) because they are seasonal. This is less true in warmer climates where the summer season is longer; an efficient air conditioner will conserve more energy in Oklahoma than in Michigan (note the ratio of peak savings to energy conservation differences for air conditioning measures between AEP's East and West service territories in the following chart).

Exhibit 8-8 shows the relationship of typical measures on the continuum of "Demand Response" to "Energy Efficiency." Demand response measures, which interrupt load at the peak and have no energy savings, are at the far left. Measures with larger energy efficiency components–with little corresponding peak demand reduction–are to the right. The y-axis is merely a ratio of energy conservation (kWh) to demand reduction (kW).

Notably, the air conditioning measures ("Residential AC" and "Commercial HVAC") show distinct differences by region. Because air conditioners are likely to be on during the peak (high coincidence), there is a significant peak demand reduction component. In the West, where the cooling season is longer, there is a larger energy conservation component. Thus, the ratio of demand reduction to energy conservation is *lower* for these measures in the West, relative to the East. While there are differences, it is perhaps equally notable that the differences aren't that great and non-existent or nearly so for the majority of the measures.

Exhibit 8-8: Typical DR/EE Measure Conservation Load Factor



Source: AEP Resource Planning

8.5.3.1 Energy Conservation

Often used interchangeably with efficiency, conservation results from foregoing the benefit of electricity either to save money or simply to reduce the impact of generating electricity. Higher rates for electricity typically result in lower consumption. Inclining block rates, or rates that increase with usage, are rates that encourage conservation.