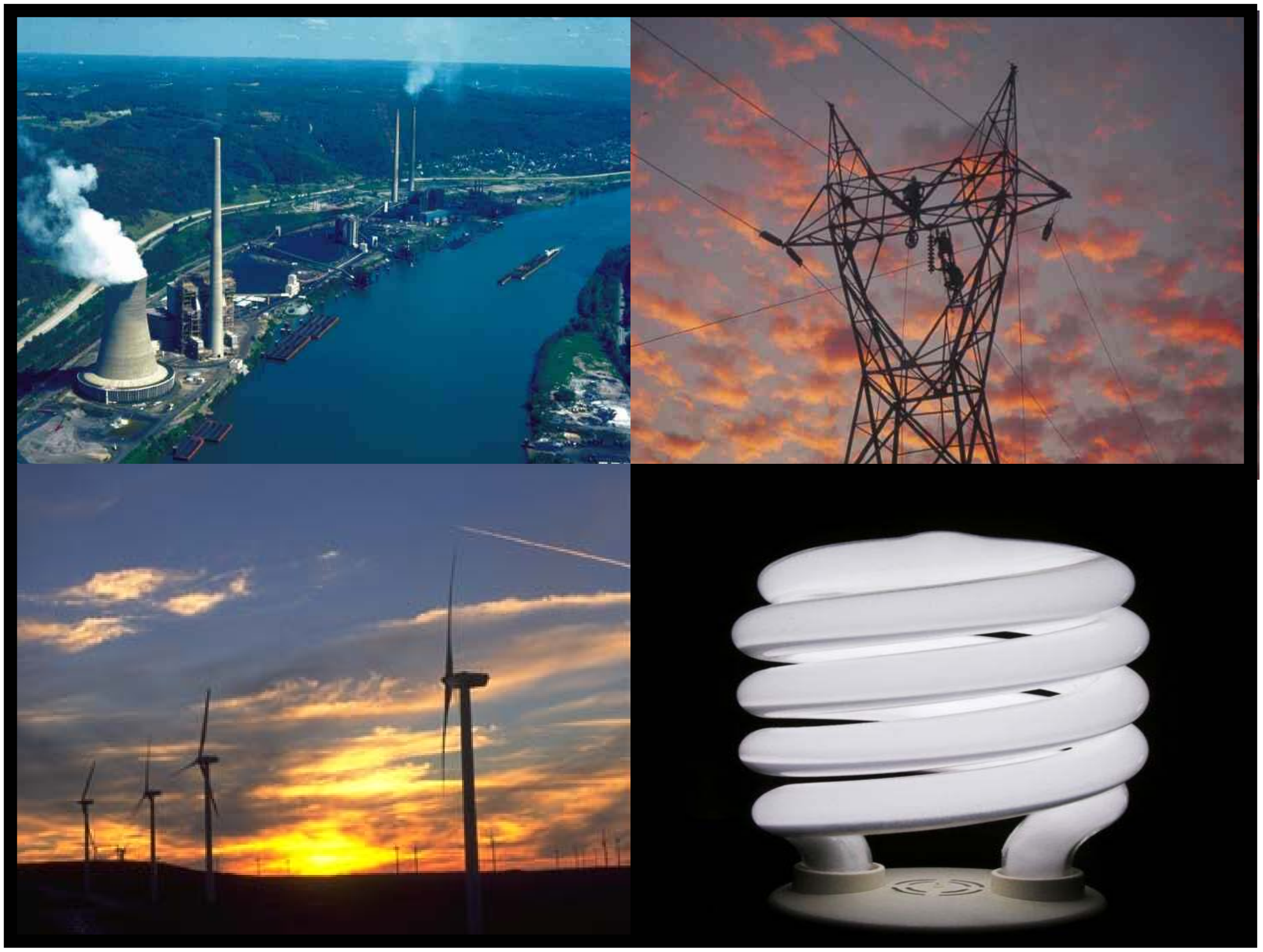
AEP AMERICAN® ELECTRIC POWER

2009 AEP-SPP

(Public Service Company of Oklahoma & Southwestern Electric Power Company)

INTEGRATED RESOURCE PLAN



2010-2019

Date Issued: July 2009

Business Confidential
Copy Control # ______

The Integrated Resource Plan (IRP) is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore **this plan is not a commitment to a specific course of action**, since the future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, access to capital, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative proposals to control "greenhouse gases."

The implementation action items as described herein are subject to change as new information becomes available or as circumstances warrant. It is AEP's intention to revisit and refresh the IRP annually.

The contents of this report contain the Company's forward-looking projections and recommendations concerning the capacity resource profile of its affiliated operating companies located in the Southwest Power Pool (SPP) Regional Transmission Organization. This report contains information that may be viewed by the public. Business sensitive information has been excluded from this document, but will be made available in a confidential supplement on an as needed basis to third parties subject to execution of a confidentiality agreement. The confidential supplement should be considered strictly **business sensitive and proprietary** and should not be duplicated or transmitted in any manner. Any questions or requests for additional copies of this document should be directed to:

Scott C. Weaver
Managing Director—Resource Planning and Operational Analysis
Corporate Planning & Budgeting
(614) 716-1373 (audinet: 200-1373)
scweaver@aep.com

Table of Contents

Exhibits

Appendices

Acknowledgements

The Resource Planning group appreciates the support and input of the various individuals throughout the Service Corporation who provided input into the development of this Integrated Resource Plan document. In addition, a number of people provided valuable comments as the report was being developed including the operating company regulatory support staffs.

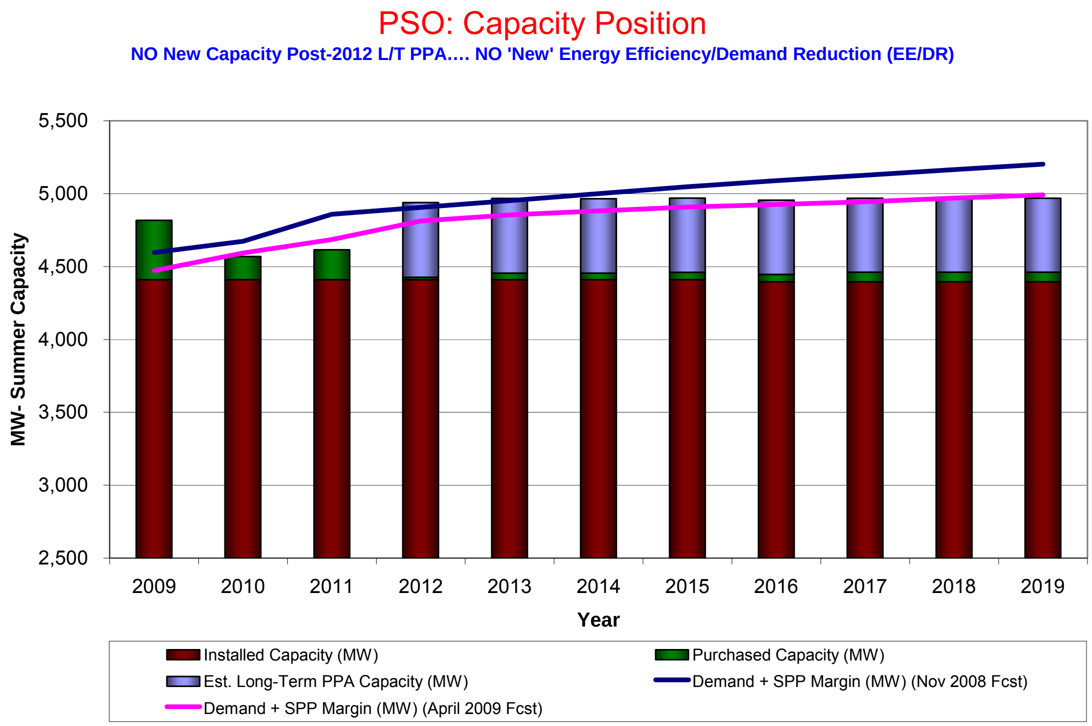
Executive Summary

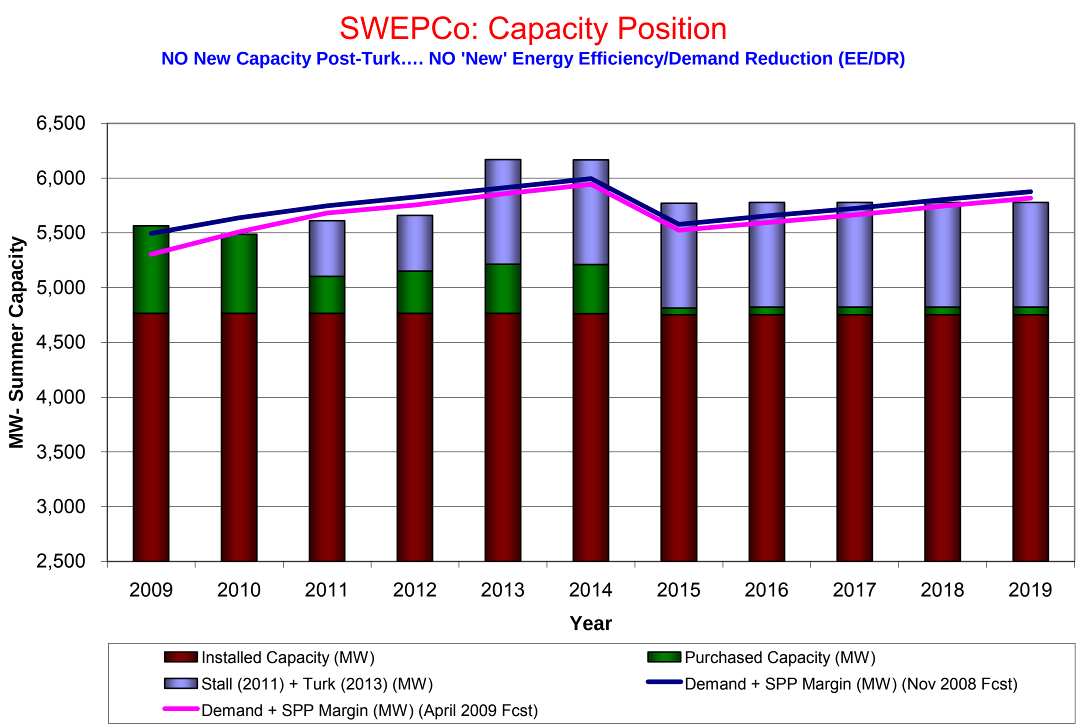
The goal of resource planning is to match a utility's future suite of resources with projected demand for those resources. As such the plan lays out the amount, timing and type of resources that achieve this goal at the lowest reasonable cost, considering all the various constraints – reserve margins, emission limitations, renewable and energy efficiency requirements – that it is mandated to meet. Planning for future resource requirements during volatile periods can be challenging. Unprecedented economic contraction and varying levels of proposed regulation regarding greenhouse gases and renewable energy are two major drivers of uncertainty that must be addressed during the planning process. Over the 10-year, 2010-2019 Integrated Resource Plan (IRP or "Plan") planning period, the AEP's integrated western zone (AEP-SPP) which includes Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO) is expected to experience load growth at a compound annual rate of 1.5% per year, or roughly 140 MW annually. This growth can be considered as occurring in two phases. 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, there is 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.

The following **Summary Exhibit 1** depicts the "going-in" capacity needs of PSO and SWEPCO with committed capacity additions (Stall and Turk for SWEPCO, Exelon-Green Country PPA for PSO) but excluding uncommitted planned capacity additions. It amplifies that the recent economic downturn has reduced the need for new resources, beyond current commitments, to the end of the planning horizon. However, PSO and SWEPCO must still make resource additions to satisfy reserve requirements.

With the supply side additions and demand side measures that provide demand reductions/energy efficiency (DR/EE or "DSM") included in this 2009 IRP, **Summary Exhibit 2** shows that PSO and SWEPCO will be able to meet their margin requirements without market capacity purchases beginning in 2013.

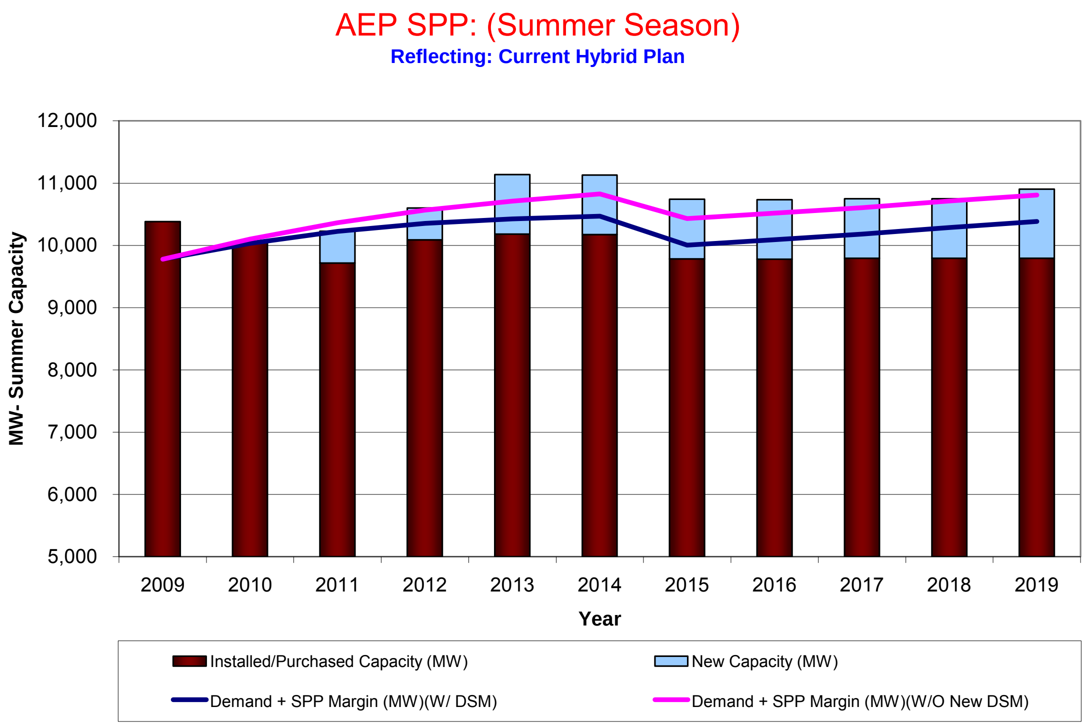
Summary Exhibit 1





Source: AEP Resource Planning

Summary Exhibit 2



Source: AEP Resource Planning

Both the proposed Turk (SWEPCO) baseload ultra-supercritical pulverized coal (USC-PC) plant and a 509 MW Stall Natural Gas Combined Cycle were considered embedded for 2009 AEP-SPP resource planning purposes, as they were secured during the SWEPCO 2006 Long-term Baseload Resource Request For Proposal (RFP) process. These units are currently under construction with Stall approximately 60% physically complete—with 95 % of the construction costs committed—and scheduled to begin commercial operation prior to the summer peak of 2011 and Turk approximately 15% physically complete—with 81 % of the construction costs committed—and scheduled to be in service prior to the summer peak of 2013. The 2008 PSO RFP process resulted in the selection of a purchase power agreement (PPA) with Exelon for 512 MW of the Green Country combined cycle facility which is also embedded in this IRP beginning 2012. Each project is fulfilling commission-approved findings of need/necessity in Arkansas, Louisiana, Texas (Stall and Turk), and Oklahoma (450 MW of baseload capacity), and are still required for meeting SPP minimum reserve margin requirements.

Major Drivers:

Global Climate Change

This 2009 IRP for AEP-SPP is consistent with the AEP 2009 Corporate Sustainability Report with regard to the assumption of potential legislation related to greenhouse gas (GHG)/carbon dioxide (CO_2) emissions, renewable portfolio standards (RPS), and energy efficiency. The driving planning assumptions include:

- CO_2 mitigation in the form of substantive CO_2 reduction legislation effective by 2015 with a cap-and-trade regime effective in the same year.
- Prospect of a future Federal RPS, or a growing critical mass or "patchwork" of AEP state-legislated RPS initiatives—which could be in the range of 10%, or more.

> *With that, AEP has positioned itself by assuming an aggressive posture in the adoption of renewable alternatives including a 2,000 MW system-wide renewable initiative (by 2011). That strategy would be an underpinning of an overall renewable energy target of 10% of sales by 2020 and is consistent with the existing state renewable energy targets.*

Demand Side Management and Energy Efficiency (DR/EE)

Recognizing the prospects of higher (avoided) costs, AEP initiatives to improve grid efficiency and install advanced metering, and a national groundswell focused on efficiency, the AEP-SPP IRP calls for:

- Approximately 78 MW of incremental DR/EE by 2010, growing to 389 by 2019.
- This is "incremental" since it is over-and-above current estimates of existing AEP-SPP interruptible-type measures totaling over 48 MW at peak. However, it is inclusive of current and pending energy efficiency programs at both PSO and SWEPCO.

Wind and Other Renewable Resources

Along with the prospects of CO_2 legislation, the possible introduction of a Federal (or "en masse" state) RPS, helped justify the planned system-wide purchase of 2,000 MW of renewable resources—for planning purposes assumed to be in the form of wind power—by 1/31/2011. The largest portion of these purchases is for AEP-East.[1] When added to current and planned PSO and SWEPCO long-term wind purchases as well as economically-screened wind and biomass co-firing opportunities beyond the 10-year IRP period, these operating companies as well as AEP are positioned to achieve 10% of energy sales from renewable sources.

Emerging Technology

AEP is committed to pursuing emerging technologies that fit into the capacity resource planning process, including Sodium Sulfur (NaS) Batteries, fuel cells, solar panels, and "smart" grid enabling meters. These "distributed" technologies, while currently expensive relative to traditional demand

[1] Note: Firm "capacity" attributable to wind would be limited to roughly 8%, of the nameplate amount for purposes of capacity planning in SPP.

and supply options, have the capacity to evolve into common resource options as costs come down and the capabilities continue to improve. For each of these options, both the technology and associated costs will continue to be monitored for increased inclusion in future planning cycles, if warranted.

AEP-SPP Recommended Plan:

- ✓ Complete the 509 MW Stall combined Cycle Facility in SWEPCO by the by the third quarter of 2011 so it is ready for the summer peak in 2011
- ✓ Begin receipt of 512 MW of baseload/intermediate capacity from Green Country (Exelon PPA) in PSO by summer of 2012
- ✓ Complete the joint owned (AEP share - 447 MW) Turk Ultra-Supercritical PC plant in SWEPCO by the fourth quarter of 2012 so it is ready for the summer peak in 2013
- ✓ Purchase (or construction) of an additional 750 MW (nameplate) of wind generation by 2019
- ✓ Acquire 158 MW of peaking capacity in SWEPCO by 2019
- ✓ Implement new DR/EE programs totaling 332 MW over the IRP planning period, or over 860 GWH annually after 2015.

The following **Summary Exhibit 3** offers a view of the 2009 AEP-SPP IRP:

Summary Exhibit 3

2009 AEP-SPP Integrated Resource Plan (Hybrid Plan)

	PSO					SWEPCO				
	Planned Resource Reductions	*Planned Resource Additions (MW)*				Planned Resource Reductions	*Planned Resource Additions (MW)*			
		DSM		RENEWABLE	THERMAL		DSM		RENEWABLE	THERMAL
	Environmental Retrofits[G]	Embedded Demand Reduction[B] (Cumul. Contribution)	New Demand Reduction[C] (Cumul. Contribution)	Wind (Nameplate)	Duty Cycle Type: BL=Baseload INT=Intermediate PKG=Peaking	Environmental Retrofits[G]	Embedded Demand Reduction[B] (Cumul. Contribution)	New Demand Reduction[C] (Cumul. Contribution)	Wind (Nameplate)	Duty Cycle Type: BL=Baseload INT=Intermediate PKG=Peaking
2009		9	0				10	0		
2010		13	31				16	24	79.5[F]	
2011		16	62	198 [E]			20	48	100	(Stall) 509-MW INT
2012		19	94		(Grn Cntry PPA) 512-MW BL		24	72	100	
2013		21	125				26	96	150	(Turk) 447-MW BL
2014		22	157			FC1 (4)	29	120		
2015		23	188	67		WSH2 (8)	30	144	33	
2016	NE3&4 (15)	24	188				31	144	100	
2017		25	188	200			32	144		
2018		25	188				32	144		
2019		25	188				32	144		157-MW PKG
Nameplate Capacity	*(15)*	*25*	*188*	*465*	*512*	*(12)*	*32*	*144*	*563*	*1,113*
(SPP) Capacity Value (Wind 8%;)				*60*					*45*	
Cumul. (Nameplate)		*2%*	*16%*	*39%*	*43%*		*2%*	*8%*	*30%*	*60%*
Cumul. (Capacity) Contribution		*3%*	*24%*	*8%*	*65%*		*2%*	*11%*	*42%*	*83%*

(A) Not shown are relatively small unit uprates and derates embedded in the current plan (e.g. FGD retrofit auxliary load losses)
(B) "Embedded" DSM represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(C) "New" DSM represents incremental activity projected based on estimated contribution & program cost (vs. avoided cost) parameters, from recent Market Potential Studies, and were generally limited to an EPRI Jan. '09 study identifying a "Realistically Achievable Potential". This 'New' (increm) DSM-DR activity modeled thru 2015 only
(D) PPA term for PSO 2012 baseload capacity & energy: 9 years, 7 months (thru 2021)
(E) Assumes Elk City and Blue Canyon V wind energy available by 2011, but firm transmission delayed until 2013
(F) Assumes Majestic wind energy available by 2010, but firm transmission delayed until 2012
(G) Derate associated with the addition of and FGD system

Source: AEP Resource Planning

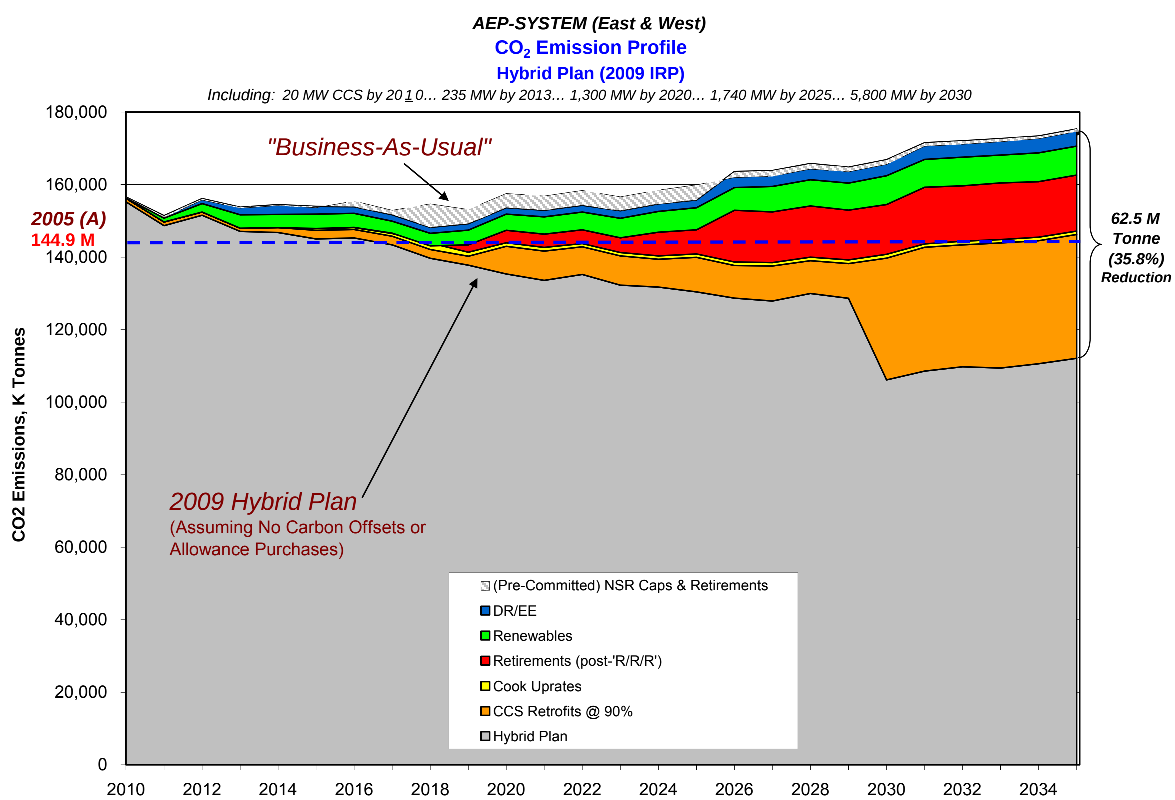
Plan Impact on Carbon Mitigation (*"Prism" Analysis*)

Global Climate Change and the prospect for comprehensive CO_2 legislation has had a direct bearing on the outcome of the 2009 AEP-SPP Plan. To gauge the respective CO_2 mitigation impacts incorporated into this resource planning, an assessment was performed that emulates an approach undertaken by the Electric Power Research Institute (EPRI). This profiling seeks to measure the contributions of various "portfolio" components that could, when taken together, effectively achieve such carbon mitigation:

- Energy Efficiency
- Renewable Generation
- Fossil Plant Efficiency, including coal-unit retirements
- Nuclear Generation
- Technology Solutions, including Carbon Capture and Sequestration

The following **Summary Exhibit 4** reflects those comparable components within this 2009 IRP–set forth as uniquely-colored "prisms"—that are anticipated to contribute to the overall AEP System's (*combined East and West regions*) initiatives to reduce its carbon footprint:

Summary Exhibit 4

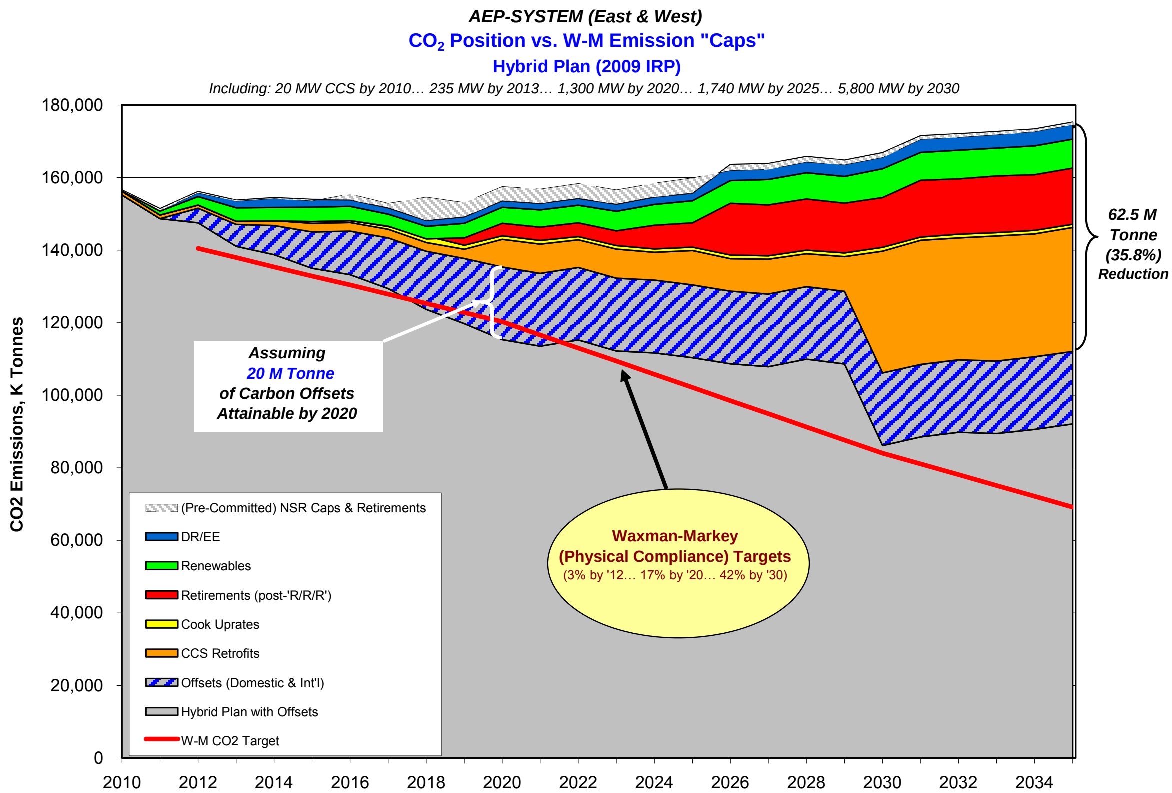


Source: AEP Resource Planning

While these results would suggest significant improvement in the AEP System CO_2 emission profile over time, it could still fall short of prospective legislation that would attempt to further limit

CO_2. Specifically, using H.R. 2454 (the Waxman-Markey Bill) that passed the U.S. House in June, 2009 as a proxy, this profile would require reduction in CO_2 emissions that would have to consider acquisition of carbon "offsets"—financial instruments that represent certified initiative to remove 1 ton of carbon—to begin to approximate the levels of reduction set forth by such mandates. The following **Summary Exhibit 5** offers such a comparison for the AEP System:

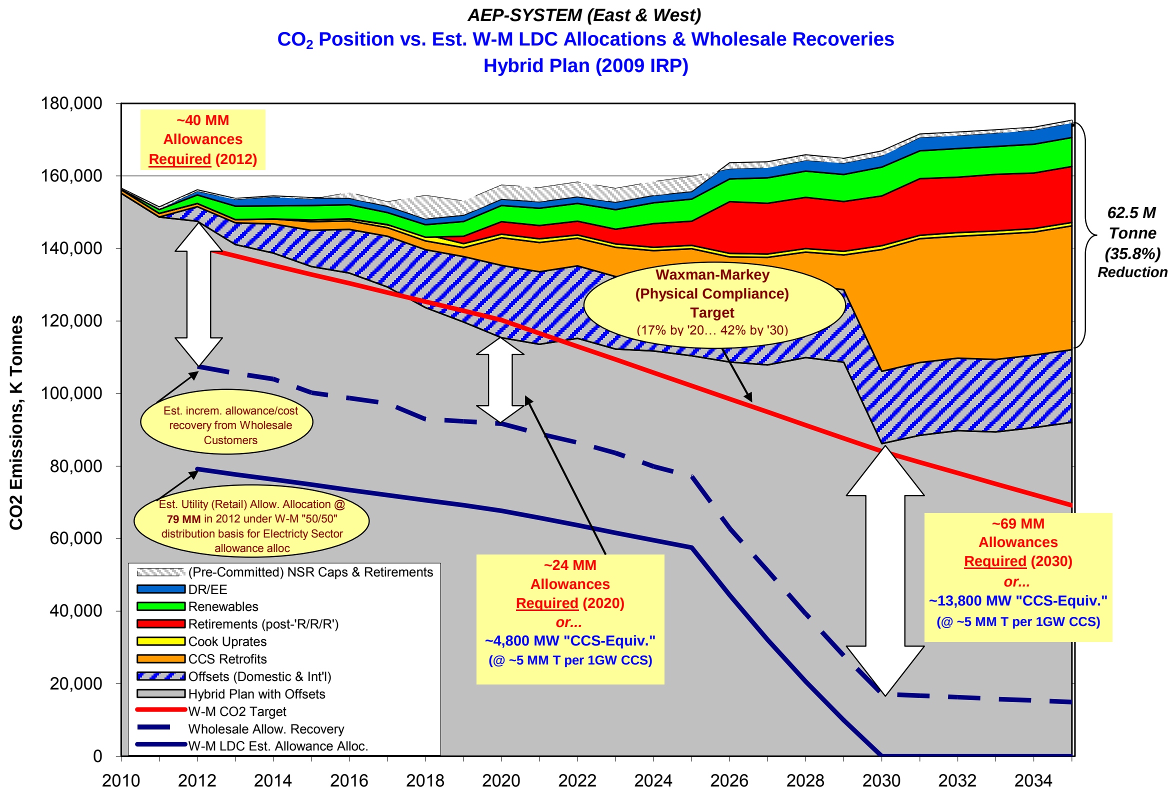
Summary Exhibit 5



Source: AEP Resource Planning

Further, under the assumption that a cap-and-trade mechanism could emerge from any set of carbon legislation, it is reasonable to assume that such CO_2 mitigation efforts, inclusive of offset acquisitions, may not provide for an adequate CO_2 position within that mechanism. Specifically, if the legislation provides for the *allocation* of an insufficient level of (free) CO_2 allowances to the utility, any such remaining CO_2 position "shortfall" must subsequently be borne by the utilities' customers through additional, potentially more costly, CO_2 mitigation efforts, including the purchase of additional allowances. The following **Summary Exhibit 6** identifies this potential position based on the current allowance allocation format set forth by the Waxman-Markey Bill:

Summary Exhibit 6



Source: AEP Resource Planning

In summary, this prism analysis would suggest that the carbon mitigation requirements in the AEP System (East and SPP) 2009 IRPs offer a meaningful pathway to the attainment of potential Climate Change/CO_2 legislation, however, **additional** contributions–over-and-above the acquisition of CO_2 allowances—may be required in future planning cycles to protect AEP's customers from significant cost exposures.

Plan Impact on Capital Requirements

This Plan includes new capacity additions, as well as unit uprates and environmental retrofits. Such generation additions require a *significant* investment of capital. Some of these projects are still conceptual in nature, others do not have site specific information to perform detailed estimates; however, it is important to provide an order of magnitude cost estimate for the projects included in this plan. As some of the initiatives represented in this plan span both East and West AEP zones, this **Summary Exhibit 7** includes estimates for projects over the entire AEP system Generation (G) functional discipline.

It is important to reiterate the capital spend level reflected on the Summary Exhibit 7 is "incremental" in that it does not include "base"/business-as-usual capital expenditure requirements of the "G" sector. Achieving this additional level of expenditure will therefore be a significant challenge going-forward and would suggest the Plan itself *will remain under constant evaluation and subject to change.*

Summary Exhibit 7

AEP System (East & West)

PRELIMINARY (Incremental) "G" Capex Spend

Reflecting...

2009 IRP (E&W)

Assuming 1,300 MW CCS (MT only) by 2020... (w/ 1,740 MW by 2025... 5,800 MW by 2030)

2010-2019

($Millions)

By Type...	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	TOTAL (2010-2019)	Group %
IRP (New Generation)	362	306	321	110	175	281	306	302	177	634	2,974	25%
IRP (Response to Carbon / RPS Legislation)	-	-	-	44	147	381	349	548	848	623	2,941	24%
Subtotal	**362**	**306**	**321**	**154**	**322**	**662**	**655**	**850**	**1,025**	**1,257**	**5,915**	
Plus:												
Environmental Compliance / Cook License Extension	58	242	519	794	1,039	1,297	866	839	439	33	6,126	51%
TOTAL INCREMENTAL "G" CAPEX	**420**	**548**	**840**	**948**	**1,361**	**1,959**	**1,521**	**1,689**	**1,464**	**1,290**	**12,041**	
Annual %	3%	5%	7%	8%	11%	16%	13%	14%	12%	11%		

By Operating Company...	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	TOTAL (2010-2019)
AEG	4	5	90	37	50	135	246	370	220	17	1,172
APCo	14	15	14	15	98	298	251	546	723	582	2,555
CSP	0	0	13	30	70	98	9	0	100	125	444
I&M	30	90	110	152	352	684	642	470	220	93	2,842
KPCo	2	18	100	150	190	154	102	90	5	0	811
OPCo	4	3	33	95	164	188	73	69	30	89	748
PSO	0	5	63	203	258	331	129	23	153	271	1,436
SWEPCO	366	412	417	267	179	72	70	122	15	114	2,033
TOTAL INCREMENTAL "G" CAPEX	**420**	**548**	**840**	**948**	**1,361**	**1,959**	**1,521**	**1,689**	**1,464**	**1,290**	**12,041**

Source: AEP Resource Planning

Conclusion:

The recommended plan provides the "lowest, reasonable cost" solution through a combination of traditional supply, renewable and demand side investments. The tempered load growth combined with additional renewable resources, increased DR/EE initiatives, completion of Stall and Turk plants, and the execution of the Exelon PPA, will allow AEP-SPP to meet its resource requirements through 2018 at which point new peaking capacity will be required. No new uncommitted baseload capacity is required over the term of the forecast period.

Keep in mind that the planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and are modified as appropriate. Indeed, the resource expansion plan reported herein reflects, to a large extent, assumptions that are subject to change. It is simply a snapshot of the future at this time. The Plan is not a commitment to a specific course of action. The future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative proposals to control "greenhouse gases" which could result in the retirement or retrofit of existing generating units, impacting the supply of capacity and energy to AEP-SPP companies. The resource planning process is becoming increasingly complex given pending legislative and regulatory restrictions, technology advancement, changing energy supply fundamentals, uncertainty of demand and energy efficiency advancements all of which necessitate flexibility in any ongoing plan. The ability to invest in capital-intensive infrastructure is increasingly challenged in light of current economic conditions, and the impact on the AEP-SPP customers will continue to be a primary planning consideration.

1.0 Introduction

This document contains the assumptions and steps required to develop the recommended resource plan. Section 1 discusses the company and the resource planning process in general. Section 2 describes emerging industry issues and commodity forecasts that impact utilities including AEP. Section 3 describes the implications of these issues as they relate to resource planning. Section 4 describes current supply resources, including transmission integration, and Section 5 discusses projected growth in demand and energy which serves as the underpinning of the plan. Then Section 6 combines these two projected states (resources versus demand) to identify the need to be filled. Sections 7 through 12 describe the analysis and assumptions that are used to develop the plan such as planning objectives (Section 7), resource options (Section 8), evaluation of demand side measures (Section 9), and fundamental modeling parameters (Section 10). The modeling process and portfolio development, including the selection of the "Hybrid Plan" is covered in Section 11, and finally a risk analysis of selected portfolios is performed in Section 12. Section 13 describes the findings and recommendations and lastly, Section 14 describes the plan implementation.

1.1 IRP Process Overview

This report presents the results of the Integrated Resource Plan (IRP) analysis for the AEP-SPP zone of the AEP System, covering the period 2009-2019, with additional planning modeling and analyses conducted through the year 2030. The information presented with this IRP ("Plan") includes descriptions of assumptions, study parameters, methodologies, and results including the integration of supply-side resources and demand-side management (DSM) programs. The IRP process is displayed graphically in **Exhibit 1-1**.

The goal of the IRP process is to identify the amount, timing and type of resources required to ensure a reliable supply of power and energy to customers at the least reasonable cost.

In addition to the need to set forth a long-term strategy for achieving regional reliability/reserve margin requirements, capacity resource planning is critical to AEP due to its impact on:

- **Determining Capital Expenditure Requirements**—which represents one of the basic elements of the Company's long-term business plan.
- **Rate Case Planning—**many of AEP's regulated operating companies will plan rate recovery filings that will reflect input based on a prudent planning process.
- **Integration with other Strategic Business Initiatives**—generation/capacity resource planning is naturally integrated with the Company's current and anticipated environmental compliance, transmission planning, and other corporate planning initiatives such as gridSMART^{sm}.

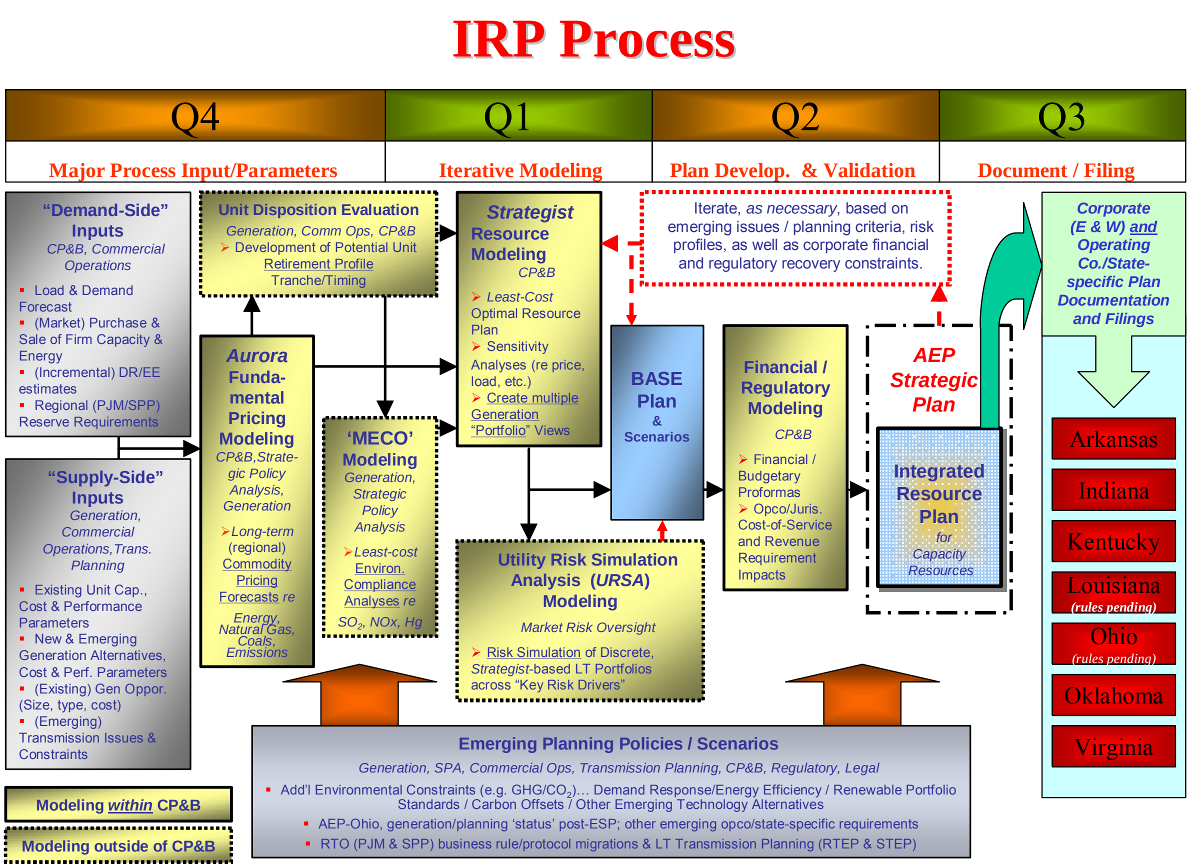
1.2 Introduction to AEP

AEP, with more than five million American customers and serving parts of 11 states, is one of the country's largest investor-owned utilities. The service territory covers 197,500 square miles in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

AEP owns and/or operates 58 generating stations in the United States, with a capacity of approximately 37,000 megawatts. AEP's customers are served by one of the world's largest transmission and distribution systems. System-wide there are more than 39,000 circuit miles of transmission lines and more than 213,000 miles of distribution lines.

AEP's operating companies are managed in two geographic zones for resource planning purposes. Its SPP zone, which comprises two companies in the Southwest Power Pool (SPP): Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO); and its eastern zone, comprising Indiana & Michigan Power Company (I&M), Kentucky Power Company (KPCo), Ohio Power Company (OPCo), Columbus Southern Power Company (CSP), Appalachian Power Company (APCo), Kingsport Power Company (KgP), and Wheeling Power Company (WPCo).[2]

Exhibit 1-1: IRP Process Overview



Source: AEP Resource Planning

---

[2] Both KgP and WPCo are non-generating companies purchasing all power and energy under FERC-approved wholesale contracts with affiliates APCo and OPCo, respectively. AEP also has two operating companies that reside in the Electric Reliability Council of Texas (ERCOT), AEP Texas North Company (TNC) and Texas Central Company (TCC). These companies are essentially "wires" companies only, as neither owns nor operates generating assets within ERCOT.

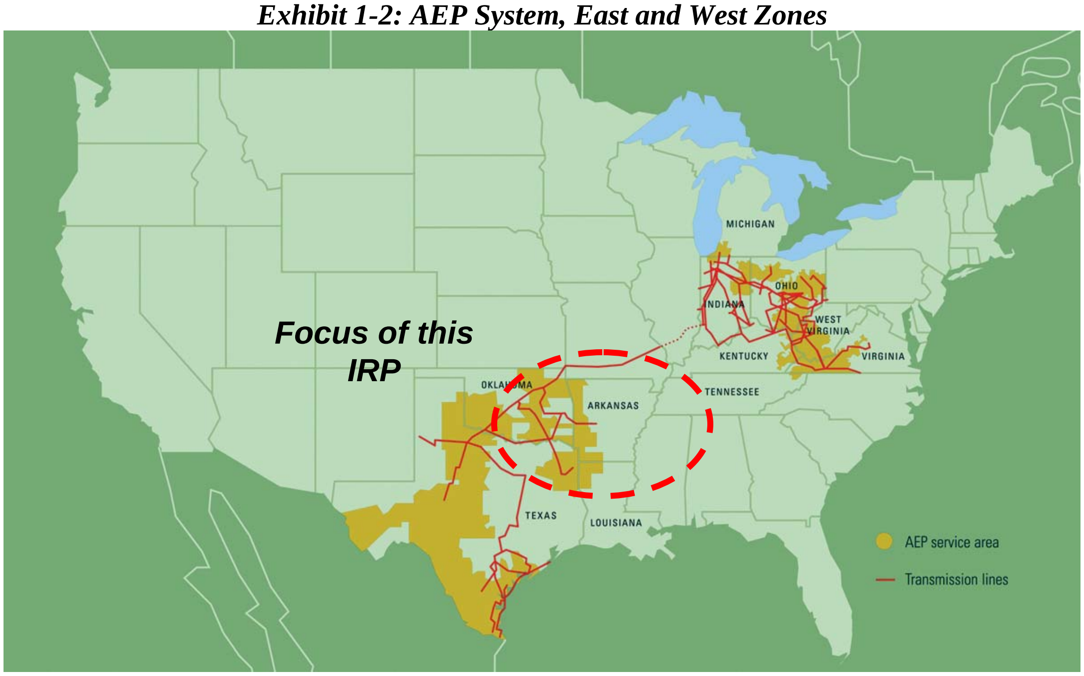
Other than a discussion of the requirements of the FERC-approved AEP System Integration Agreement (SIA), this document will only address 2009 resource planning for the AEP-SPP zone. Planning for AEP affiliates residing in AEP-East has been communicated in separate documents.

1.2.1 AEP-SPP Zone:

The operating companies in AEP's SPP zone collectively serve a population of about 3.83 million customers (995,050 retail) in a 36,000 square mile area in parts of Arkansas, Louisiana, Oklahoma, and Texas (see **Exhibit 1-2**). In 2008, the residential, commercial, and industrial customers accounted for 29%, 27%, and 27%, respectively, of AEP-SPP's total internal energy requirements of 42,868 GWh, including energy losses. The remaining 17% was supplied for use in the other retail and wholesale categories.

AEP-SPP experienced an all-time peak internal demand of 9,120 MW on August 4, 2008. An all-time winter peak internal demand, 6,902 was experienced on February 16, 2007.The capacity resource planning of the respective AEP-SPP and East zones is performed on a mutually-exclusive basis regardless of the covenants of the System Interchange Agreement (SIA).

Exhibit 1-2: AEP System, East and West Zones



Source: AEP Internal Communications

1.2.2 Embedded Baseload Assets

Both the proposed Turk (SWEPCO) baseload ultra-supercritical pulverized coal (USC-PC) plant and a Stall Combined Cycle (CC) plant were considered embedded for 2009 AEP-SPP resource planning purposes, as they were secured during the SWEPCO 2006 Long-term Baseload Resource Request For Proposal (RFP) process. The 2008 PSO RFP process resulted in the selection of a purchase power agreement (PPA) with Exelon for the 512 MW Green Country combined cycle facility which is also embedded in this IRP. These additions were approved by the appropriate state regulatory commissions based, in part, on the demonstrated need at the time the applications were filed. During the past year, the economic downturn has lead to reduced load growth forecasts in the near term. However, SWEPCO and PSO, respectively, still find these facilities necessary to the meet the peak demand and energy needs of their customers. To illustrate this point, the **Exhibit 1-2** for PSO and **Exhibit 1-3** for SWEPCO have been prepared to show the reserve margin exposure with and without these resources.

Exhibit 1-3: PSO Reserve Margin With and Without Exelon PPA

PSO

Stand-Alone Reserve Margins*

Based on (April 2009) Demand Forecast "Banding"

10-Year 2009 IRP Period: **2010-2019**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reserve Margin										
Under **"Base"** Demand Forecast:										
Per 2009 Resource Plan	**13.8%**	**13.2%**	**19.2%**	**19.7%**	**19.9%**	**20.3%**	**19.5%**	**19.3%**	**18.7%**	**18.1%**
Exclusive of Exelon PPA (2012)	*13.8%*	*13.2%*	**6.9%**	**7.4%**	**7.6%**	**7.9%**	**7.2%**	**7.1%**	**6.5%**	**6.1%**
Under **"Accelerated (High)"** Demand Forecast:										
Per 2009 Resource Plan	**11.0%**	**8.2%**	**15.2%**	**14.8%**	**14.2%**	**14.2%**	**13.2%**	**12.6%**	**11.6%**	**10.9%**
Exclusive of Exelon PPA (2012)	*11.0%*	*8.2%*	***3.2%***	***3.0%***	***2.5%***	***2.5%***	***1.5%***	***1.1%***	***0.2%***	***-0.5%***
Reserve Margin -- MW Position										
Above / <Below> 13.6% SPP Requirement)										
Under **"Base"** Demand Forecast:										
Per 2009 Resource Plan	**6**	**(18)**	**232**	**253**	**259**	**275**	**242**	**237**	**211**	**190**
Exclusive of Exelon PPA (2012)	*6*	*(18)*	**(280)**	**(259)**	**(251)**	**(235)**	**(268)**	**(271)**	**(297)**	**(318)**
Under **"Accelerated (High)"** Demand Forecast:										
Per 2009 Resource Plan	**(108)**	**(228)**	**65**	**51**	**26**	**24**	**(19)**	**(46)**	**(92)**	**(124)**
Exclusive of Exelon PPA (2012)	*(108)*	*(228)*	**(447)**	**(461)**	**(484)**	**(486)**	**(529)**	**(554)**	**(600)**	**(632)**

* Excludes short-term capacity transfers to/from affiliate Southwestern Electric Power Company

Note: Minimum Reserve Margin Requirement per SPP Criteria is 13.6%

Source: AEP Resource Planning

Exhibit 1-4: SWEPCO Reserve Margin With and Without Turk and Stall Plants

SWEPCO

Stand-Alone Reserve Margins*

Based on (April 2009) Demand Forecast "Banding"

10-Year 2009 IRP Period: **2010-2019**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reserve Margin										
Under **"Base"** Demand Forecast:										
Per 2009 Resource Plan	**13.8%**	**14.0%**	**13.3%**	**22.0%**	**20.6%**	**22.3%**	**20.9%**	**19.4%**	**17.6%**	**19.2%**
Exclusive of Turk (2013)	*13.8%*	*14.0%*	*13.3%*	**13.1%**	**11.9%**	**12.8%**	**11.6%**	**10.1%**	**8.5%**	**7.1%**
Exclusive of Stall (2011) & Turk (2013)	*13.8%*	**3.7%**	**3.1%**	**3.1%**	**1.9%**	**2.0%**	**0.9%**	**-0.4%**	**-1.8%**	**-3.1%**
Under **"Accelerated (High)"** Demand Forecast:										
Per 2009 Resource Plan	**11.0%**	**10.6%**	**9.4%**	**16.9%**	**14.9%**	**15.6%**	**14.0%**	**12.0%**	**10.0%**	**11.2%**
Exclusive of Turk (2013)	*11.0%*	*10.6%*	*9.4%*	**8.5%**	**6.6%**	**6.6%**	**5.2%**	**3.4%**	**1.5%**	**-0.1%**
Exclusive of Stall (2011) & Turk (2013)	*11.0%*	**0.6%**	**-0.4%**	**-1.2%**	**-2.9%**	**-3.6%**	**-4.9%**	**-6.5%**	**-8.2%**	**-9.6%**

* Excludes short-term capacity transfers to/from affiliate Public Service Company of Oklahoma

Note: Minimum Reserve Margin Requirement per SPP Criteria is 13.6%

Source: AEP Resource Planning

As these exhibits illustrate, reserve margin requirements would fall below the minimum SPP criteria of 13.6% without these facilities under the most recent load forecast. AEP also prepared an "Accelerated (High)" Demand Forecast which assumes a more robust recovery from the current recession. Under this scenario, the need for the embedded assets is even more pronounced.

1.2.3 AEP System Interchange Agreement (East and West)

The 2000 System Interchange Agreement among AEPSC, as agent for the AEP-East, Central and Southwest Inc. (CSW), and AEP-SPP operating companies, was designed to operate as an umbrella agreement between the FERC-approved 1997 Restated and Amended CSW Operating Agreement for its western (former CSW) operating companies and the FERC-approved 1951 AEP Interconnection Agreement for its eastern operating companies. The System Interchange Agreement provides for the integration and coordination of AEP's eastern and western companies' zones. In that regard, the SIA provides for the option to transfer capacity and energy between the AEP-SPP zone and under certain conditions the AEP-East zone. Since the inception of the SIA, AEP has continued to reserve annually, the transmission rights associated with a prescribed (up to) 250 MW of capacity from the AEP-East zone to the AEP-West zone. This transmission capacity has now been reserved through 2013 and this reservation may be extended in five year increments.

1.2.4 AEP-SPP Operating Agreement –Company-Specific Obligations

The fundamental construct for this AEP-SPP IRP is that the initial planning evaluation be performed on an integrated basis among the applicable operating companies–PSO and SWEPCO–so as to leverage any opportunities such joint planning may offer as per the Operating Agreement. Specifically, Section 9.2 of that 1997 Restated and Amended SPP (CSW) Operating Agreement establishes that "…ownership share in each Joint Unit shall be allocated insofar as practical to achieve a Prorated Reserve Level for all Companies participating in the Unit."

However, the Operating Committee of the AEP-West Operating Agreement issued a formal recommendation in December 2005, stating that the PSO and SWEPCO capacity-build as established by the 2005 IRP cycle, and embedded within this 2009 IRP cycle, should not be considered for joint-ownership. This is due to the significant amount of capacity required by both companies for each duty cycle/type, and the parallel timing of those significant needs.

For the same reasons identified in 2005 by the Operating Committee, at a minimum, the (embedded) build tranche through the nearer-term 2012 timeframe will naturally continue to be set forth on a "stand-alone" (PSO and SWEPCO) basis. Therefore, largely for consistency and considering the current, known intercompany firm transmission constraints between PSO and SWEPCO that will be discussed in this 2009 report, as well as specific regulatory (needs determination/cost recovery and competitive bidding) issues, subsequent new capacity resource tranches (beyond 2012) will also be considered from a company-specific, stand-alone perspective. That said, the ultimate makeup/ownership of such subsequent AEP-SPP capacity resource tranches will likewise need to be reconsidered over future planning cycles from a shared-benefit perspective.

2.0 Current Resource Planning Issues in the Electric Utility Industry

2.1 Regulation/Deregulation

Both SWEPCO and PSO are regulated, and are expected to remain regulated throughout the IRP ten-year period. This *includes* the portion of SWEPCO's retail load residing in Texas, but outside of ERCOT. Texas Senate Bill 547, which was signed into law in May 2009, statutorily delays retail electric competition for SWEPCO in Texas until the proper infrastructure is in place. The new law becomes effective September 1, 2009 and virtually assures that SWEPCO will remain regulated during the period of the IRP.

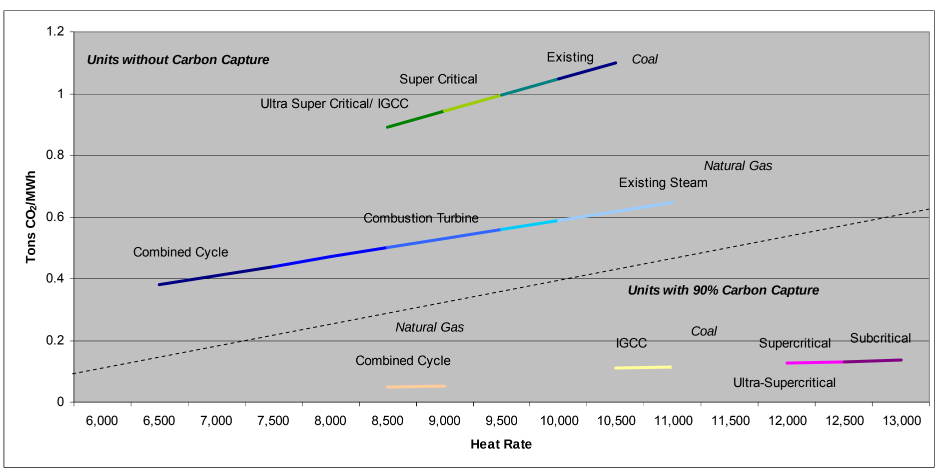
2.2 Climate Change and Greenhouse Gases

A growing consensus of scientists concludes that the Earth's climate is warming and that the warming is due, at least in part, to anthropomorphic production of greenhouse gases (GHG). Many gases exhibit greenhouse properties; some occur naturally, others are exclusively man-made. While Carbon Dioxide ($CO_{2)}$ is the most prevalent and significant greenhouse gas in terms of its global warming potential, there are other major greenhouse gases including methane (CH_4), nitrous oxide (N_2O) and chlorofluorocarbons (CFCs).

Gases are typically quoted in terms of either CO_2, carbon dioxide equivalents (CO_2e) or carbon equivalents (Ce). CO_2 has an atomic weight of 44 while carbon has an atomic weight of 12. Thus, CO_2 equivalents are 3.67 times the mass of carbon equivalents, but the two measures have the same relative purpose and can be used interchangeably if consistently applied. Anthropomorphic CO_2 is produced primarily from burning fossil fuels, a portion of which is used to produce electricity. In the U.S., roughly one-third of GHG (measured in CO_2e) result from the conversion of fossil fuels to electricity.

Finally, the fuel and heat rate of the plant used in the production of electricity makes a difference in the quantity of CO_2 produced. **Exhibit 2-1** demonstrates the advantage lower heat rates (Btu/kWh) and fuel types can have.

Exhibit 2-1: Fossil Fuel-to-Electricity Emissions, by Fuel Type



Source: AEP Resource Planning

2.2.1 Environmental Legislation

The electric utility industry, as a major producer of CO_2, will be significantly affected by any GHG legislation. During the 109th Congress (2005-2006), 106 bills, resolutions, and amendments specifically addressing global climate change and greenhouse gas emissions were introduced. In 110th Congress, more than 235 bills were introduced that would put controls on the emissions of greenhouse gases. One Senate bill, Lieberman-Warner, was voted out of the Senate Environmental Committee and received floor consideration in June 2008. However, after a few days of debate, the bill failed to pass a Senate cloture vote. The push towards federal climate change legislation is continuing within the 111th Congress as well. The Waxman-Markey "American Climate and Energy Security Act of 2009" was recently passed out of the House Energy and Commerce Committee, was subsequently approved by the House of Representatives in June, and is now being considered by the Senate. Virtually all of these bills employed "cap and trade" mechanisms (rather than carbon taxes) with declining CO_2 caps over time.

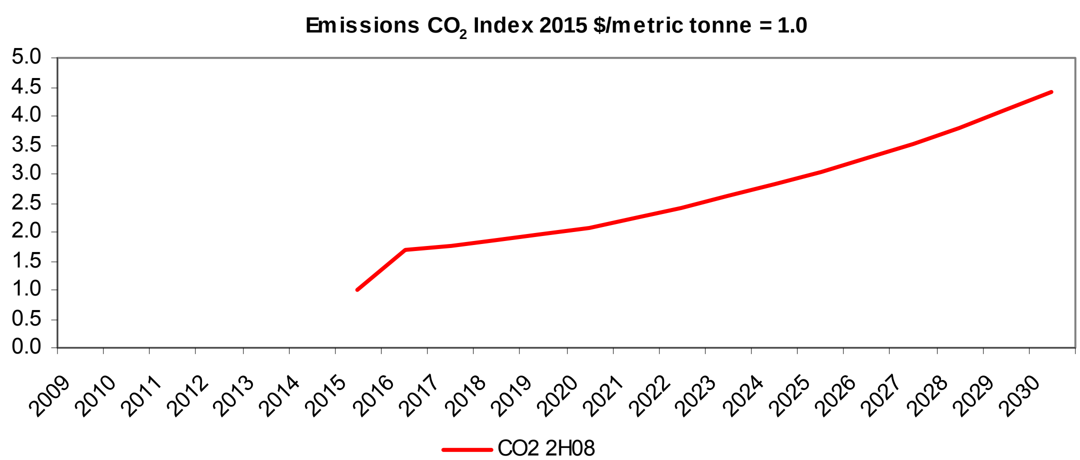
2.2.2 Impact of Environmental Legislation on Industry

Any binding legislation is likely to be "economy-wide"–generally meaning all fossil fuel use will be targeted–because the production of GHG is not limited to specific sectors. Most legislation that has been introduced to date is economy-wide. Furthermore, most legislation caps electric utility emissions "downstream." That is, electric generator emissions are limited, similar to the EPA's current programs that limit utility SO_2 and NO_x emissions.

2.2.2.1 AEP's Assumption on CO_2 Policy/Price

For the 2009 IRP cycle, the impact of CO_2/GHG legislation on AEP's long-term planning is essentially modeled as a simple CO_2 price beginning in 2015, as shown in **Exhibit 2-2,** that would impact fossil unit dispatch cost.

Exhibit 2-2: CO2 Price Forecast



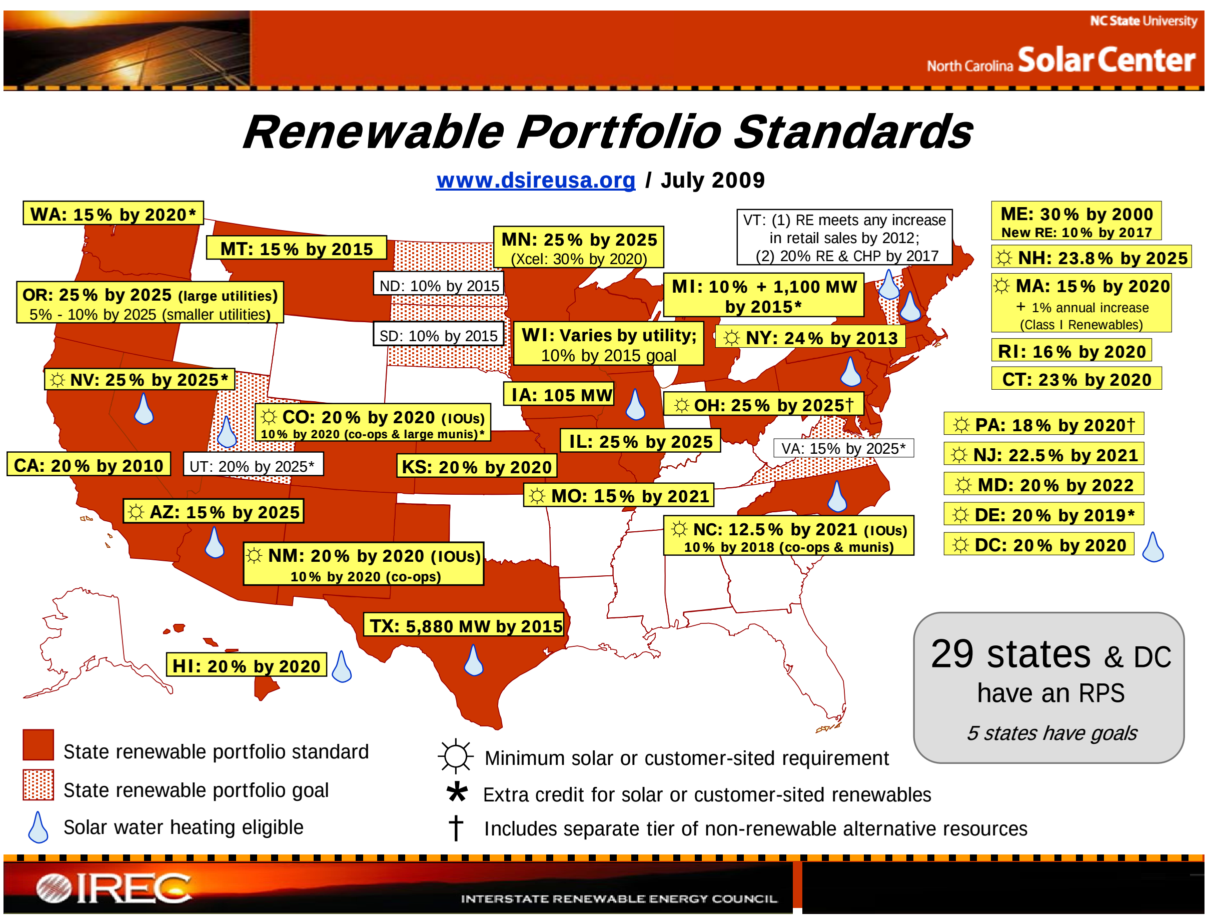
Source: AEP Fundamental Analysis

2.2.2.2 Renewable Portfolio Standards

As identified in **Exhibit 2-3**, 29 states and the District of Columbia have set standards specifying that electric utilities generate a certain amount of electricity from renewable sources. Most of these requirements take the form of "renewable portfolio standards," or RPS, which require a certain percentage of a utility sales to ultimate customers come from renewable generation sources by a given date. The standards range from modest to ambitious, and definitions of renewable energy vary. Though climate change may not always be the primary motivation behind some of these standards, the use of renewable energy does deliver significant GHG reductions. For instance, Texas is expected to avoid 3.3 million tons of CO_2 emissions annually with its RPS, which requires 2,000 MW of new renewable generation by 2009.

At the federal level, an RPS ranging from 10-20% was proposed for inclusion in the *Energy Independence and Security Act of 2007*; but the final bill as passed into law did not contain an RPS. However, a combined federal renewable energy standard (RES) and energy efficiency standard (EES) of 20% was adopted as part of the Waxman-Markey bill passed by the House. The Senate also passed out of Committee a combined 15% RES/EES and is also considering the House legislation. Therefore, a federal RPS remains a distinct possibility in 2009 or 2010.

Exhibit 2-3: Renewable Standards by State



2.2.3 AEP's Voluntary Greenhouse Gas Mitigation Strategy

2.2.3.1 Plan through 2010

As a founding member of the Chicago Climate Exchange (CCX), AEP committed to cumulatively reduce or offset 48 million metric tons of CO_2 emissions from 2003 to 2010. Through 2008, AEP reduced or offset 51 million metric tons of CO_2 — exceeding our target. We've done this in a number of ways, such as improving power plant efficiency, replacing or retiring less efficient and higher emitting units, increasing our use of renewable power, reducing SF_6 emissions and investing in forestry projects in the United States and abroad. For example, we have signed contracts to add 903 MW of wind capacity in the past two years — about 90 percent of our goal toward adding 1,000 MW of wind by 2011. Consequently, we will double this goal and add a total of 2,000 MW of renewable energy by the end of 2011, with regulatory support.

This will help AEP to further diversify its fuel portfolio. This plan contains a minimal 10 percent renewable energy target by 2020. AEP already plans to go beyond its initial commitment.

AEP has made significant progress in reducing a potent GHG — SF_6 — which is found in some electrical equipment. When AEP joined the Environmental Protection Agency's (EPA) SF_6 Emission Reduction Partnership in 1999, our SF_6 leakage rate was 10 percent. In 2008, this rate had been reduced to 0.38 percent based on total system capacity, falling well below a self-imposed goal to achieve a maximum 2.5 percent leak rate from 1996 levels. This was done by employing a combination of technologies such as replacing SF_6 insulated circuit breakers on lines to lower leakage rates.

2.2.3.2 Post-2010 Plan For Voluntary Reductions

AEP's post-2010 strategy is to voluntarily reduce or offset an additional 5 million tons of CO_2 per year by purchasing offsets from projects such as forestry, reducing methane from agriculture, adding more renewable energy in our portfolio and improving the efficiency of our power plants. The investments AEP has made in its coal-fired power plants make them more efficient than the national average for coal plants. Between 2001 and 2007, these improvements helped us to avoid burning 16.2 million tons of coal, preventing the release of 39 million tons of CO_2.

AEP has signed contracts to add 903 MW of wind capacity in the past two years — about 90 percent of our original goal toward adding 1,000 MW of wind by 2011. In light of the increasing number of state mandates and potential federal legislation, as well as the upcoming expiration of the PTC, AEP will double this goal and add a total of 2,000 MW of renewable energy by the end of 2011, with regulatory support. This will help us to further diversify our fuel portfolio. This integrated resource plan contains a 10 percent renewable energy target by 2020.

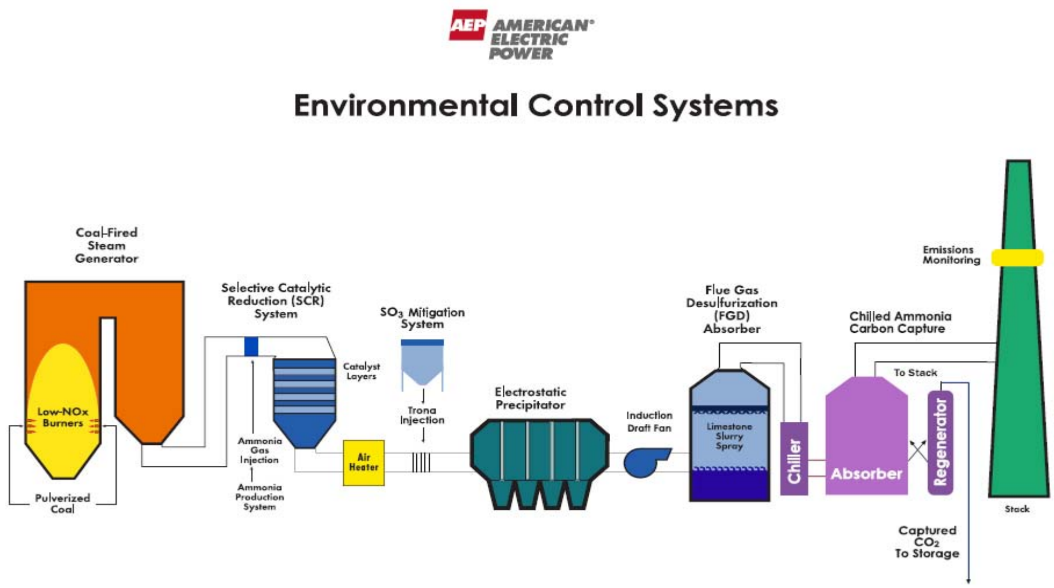
As discussed in the following section, additional actions, including a future carbon capture and storage program, will also help offset the anticipated growth in AEP's carbon footprint.

2.2.3.3 The Role of Technology

Throughout its 100-year history, AEP has led the industry in advancing technology. The time is right, with climate legislation on the horizon, to advance carbon capture technology to a commercial scale. In March 2007 AEP signed agreements with world-renowned technology providers for carbon capture and storage. A "product validation facility" is being constructed at the Mountaineer Plant in West Virginia.

The Mountaineer project will employ Alstom's chilled ammonia carbon capture technology (**Exhibit 2-4**). Laboratory testing has shown that this process could capture more than 90 percent of CO_2 at a lower cost than other technologies that could be retrofitted at pulverized coal power plants. A vendor-sponsored project demonstrating the technology was successfully completed on a 1.7 MW (electric) slipstream at Pleasant Prairie a Wisconsin plant in 2008. This projected operated around the clock for over 4,600 hours capturing 88 – 90 percent of CO_2 emissions, and achieved purity levels exceeding 99 percent.

Exhibit 2-4: CO_2 Capture and Sequestration Process



Source: 2007AEP Corporate Responsibility Report

The chilled ammonia technology equipment is now being installed on AEP's 1,300-MW Mountaineer Plant as a 20MW (electric) product validation in the second half of 2009. It is designed to capture approximately 100,000 metric tons of CO_2 per year over a four to five year period, which will be stored in deep geologic reservoirs. Battelle Memorial Institute is serving as AEP's consultant on geological storage. Following the completion of commercial verification AEP plans to scale up the Mountaineer Chilled Ammonia Process (CAP) to capture CO_2 from a 235 MWe slip stream. AEP is seeking funding from the U.S. Department of Energy to then further scale up the Mountaineer CAP to capture carbon dioxide from the entire flue gas stream. The expectation is for the commercial scale technology to have a 90% capture rate of approximately 1.5 million tons of CO_2 per year.

A second carbon capture technology AEP considered involves oxy-coal combustion. This technology uses pure oxygen for the combustion of coal. Current generation technologies use air, which contains nitrogen that is not used in the combustion process and is emitted with the flue gas. By eliminating the nitrogen, this process leaves a flue gas that is a relatively pure stream of CO_2 that is ready for storage. At commercial scale, the CO_2 likely would be stored in deep geologic formations.

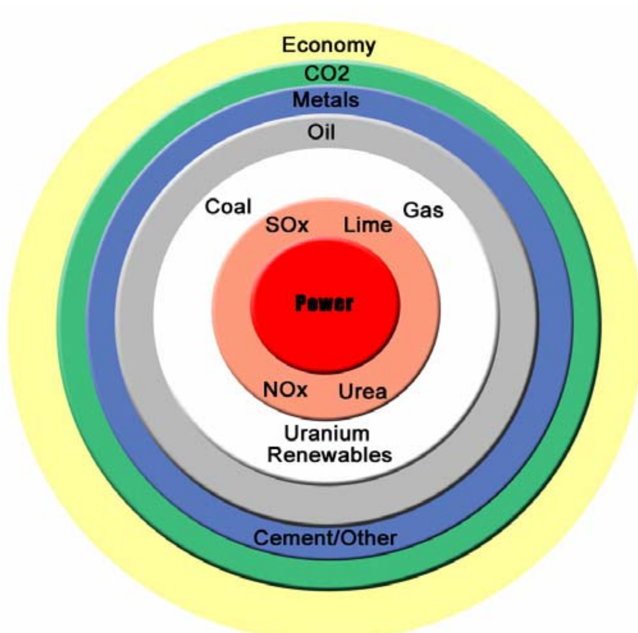
AEP's vendor B&W completed a pilot demonstration and retrofit feasibility study in 2nd Quarter 2008. Unfortunately, this technology proved to be cost prohibitive for use on our sub-critical coal fleet.

2.3 Role and Impact of Commodity Pricing on Planning

*Note: This section includes excerpts from the "**Long Term Price Forecast 2009-2030: Return to Fundamentals, 2H-2008**" prepared by AEPSC's Strategic & Economic Analysis Group (SEA) and issued February 2009). Price forecasts are included in the Confidential Supplement.*

The internal process utilized by AEP-SEA for projecting fundamental commodity pricing utilized in long-term resource planning is a time-intensive and iterative process. Many factors ultimately affect power prices as shown in **Exhibit 2-5.**

Exhibit 2-5: Power Price Layers



Source: AEP Fundamental Analysis

These numerous layers are also interdependent. For instance, oil prices affect rail transportation costs, which impact coal prices, which impact SO_2, NO_X, and power prices. It is easy to see how minor deviations in one commodity can have a trickle-down effect to power prices.

The fundamental price drivers in the modeling performed for the entire eastern interconnect, as well as PJM, are the assumptions around fuel prices, new capacity builds and retirement, and load growth. In the near term, fuel prices and load growth play the most important role.

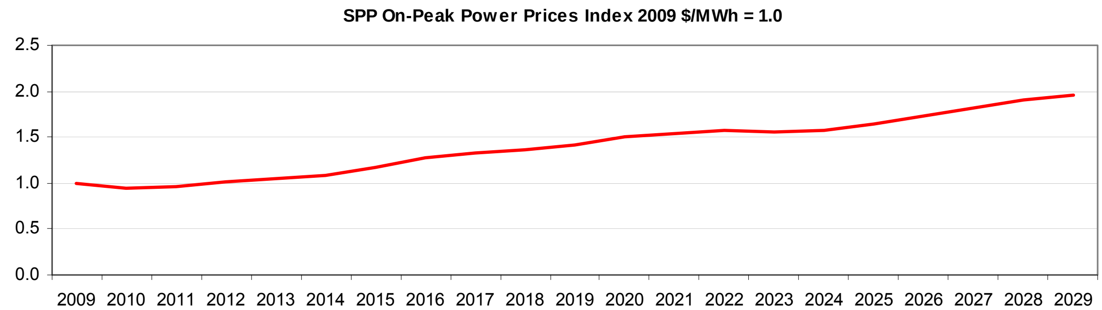
2.3.1 Power Prices

In the short-term, wholesale electricity prices remain extremely volatile due to the uncertainty in the economy, environmental policy, and commodity markets. As such, the short term Reference price does not fully capture the most recent market signals – see Confidential Supplement for a revised short term forecast. In general, the Reference forecast overestimates current market prices.

In the mid-term, the value of the forecast resides less in the ability to precisely predict the power price and more in the ability to accurately capture the trends in the power market. Starting in the mid-term, the Reference Case begins to deviate from the external forecasts due to a range of views on environmental policy and commodity markets. In particular, resolution on greenhouse gas (GHG) legislation is expected to result in a range of power market trends.

In the Reference Case, carbon policy (2015) is incorporated in the power price – see **Exhibit 2-6**. To an average coal market, the Reference carbon policy could represent an immediate increase in the power price. In addition, the Reference carbon policy disproportionately impacts coal markets on and off peak power prices. For example, in SPP on-peak prices increase 28% compared to 32% in the off-peak market over the same period.

Exhibit 2-6: SPP On-Peak Price Index



Source: AEP Fundamental Analysis

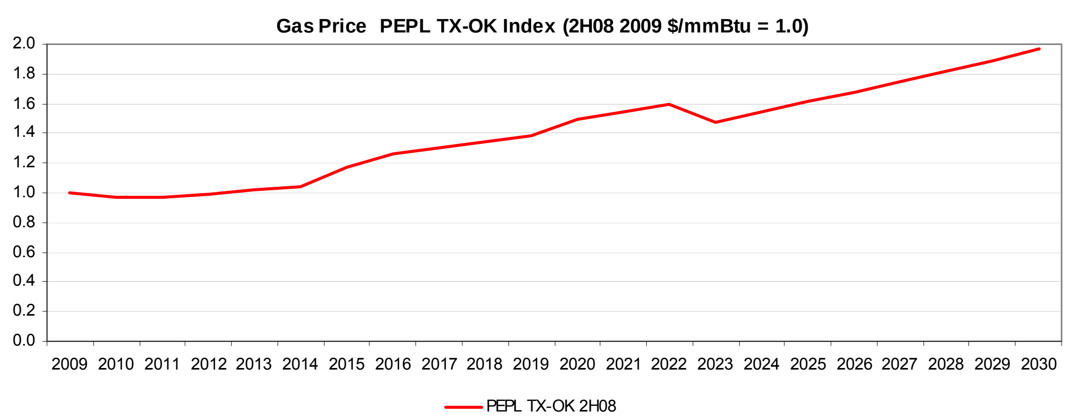
2.3.2 Fuel

2.3.2.1 Natural Gas

United States natural gas supply and consumption is currently rather loosely balanced because of the global recession, but the market is still vulnerable to price spikes resulting from weather or supply disruptions. Prices in 2009, while still reflective of Hurricane Ike-related supply loss, will decline through 2012 as domestic natural gas production reverses its traditional decline due to heretofore unconventional exploitation plays (see **Exhibit 2-7**).

Beyond 2014, unconventional natural gas production, buoyed by technology advancements, provide adequate supply to meet demand when given long-term price signals above finding and production costs of approximately $5.00 - $6.00/MMBtu (in 2008 dollars). The factor that will most likely shape the fundamentals of overall gas demand will be the growth of gas consumption for electricity generation. Additionally, the Alaskan Pipeline, projected to be on line in 2023, will deliver gas from the North Slope to the Chicago Citygate.

Exhibit 2-7: Natural Gas Price Index



Source: AEP Fundamental Analysis

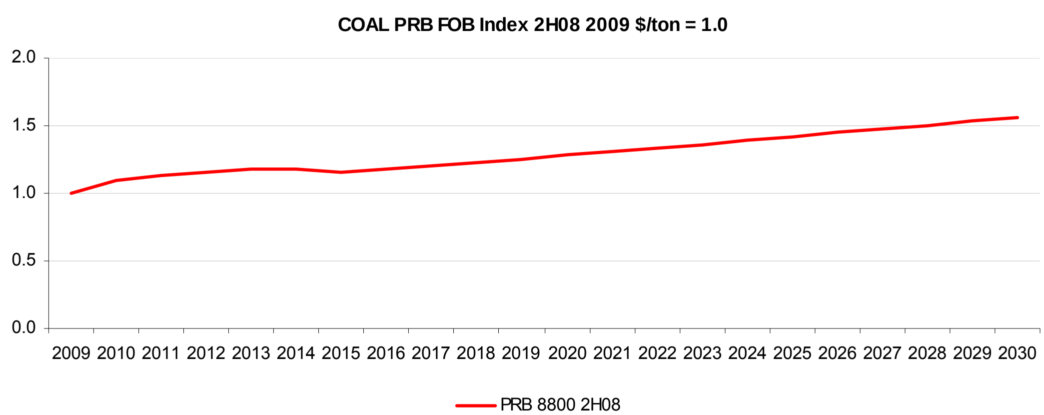
2.3.2.2 Coal

Coal is a unique commodity that comes with many different specifications. Coal is traded over-the-counter at relatively thin volumes. The majority of coal transactions are done through contracts between sellers and buyers, which sometimes results in significant differences between coal spot prices and contract prices. Because of the high percentage of transportation cost relative to total delivered coal cost and the significant capital investment required for a boiler to switch from one type of coal to another, Btu and/or SO_2 spreads may not hold when comparing different types of coal. In addition to coal quality, reliability of coal delivery is another factor to consider in coal pricing. The forecast (**Exhibit 2-8**) represents coal prices under a contract of 2-5 years, rather than spot prices.

During 2008, both international and U.S. domestic coal markets were on a rollercoaster. In January of 2008, the international coal supply chain was disrupted by coal mine region flooding in Australia, severe winter storm in China, and power outages in South Africa. As a result of these events, coal producers in Australia declared force majeure for their mines in the flooding region, the Chinese government issued an order to suspend its coal exports, and South Africa reduced its coal output and exports.

International coal markets reacted to the coal supply disruptions and pushed coal prices even higher for both thermal and metallurgical coals. High coal prices in international markets created a great opportunity for U.S. coal producers to gain higher profits by exporting coal to international markets rather than selling it in domestic markets. The increase in U.S. coal exports drained U.S. domestic coal supply, especially in the Appalachian region, because of its location advantage for coal export and its high energy content.

Exhibit 2-8: PRB Coal Price Index



Source: AEP Fundamental Analysis

Now, the situation of supply shortage of metallurgical coal has reversed due to the global economic downturn. Demand for steel has been reduced dramatically, and the international metallurgical coal benchmark at Newcastle of Australia is expected to be around $130/metric ton. This is much lower than the $300/metric ton peak in 2008. The U.S. metallurgical coal exports fell and the metallurgical coal producers in Appalachia are cutting their production, in contrast to production expansion in early and middle 2008. For example, Consol closed its Mine 84, citing low metallurgical coal prices.

2.3.3 New Build Cost

The capital cost forecast trends for pulverized coal, integrated gasification combined cycle (IGCC), and nuclear power plants show similar trends. Capital costs have increased significantly from rising materials, equipment, and labor. However, costs have declined recently due to the credit crisis and economic concerns. Demand has dropped as companies look to delay their project schedules or cancel projects outright. Demand has also dropped from industries that share similar materials and labor with the energy industry. These factors lead to a downward trend in forecasts in the near term. Longer term shows a slight upward trend, as demand returns in future years.

Given the trend for natural gas units to be built due to the combination of low capital cost, short time frame to build, environmental uncertainty, and relatively lower gas price projections, the cost of a gas plant will be driven more on the physical supply chain constraints of constructing the plant versus the variable cost of the plants as seen in the base load unit profile. Gas plants are unlikely to follow the downward projection of steel prices.

Renewable capacity offers almost no variable cost and for some renewables, reasonable capital cost. However, the reliability and the amount of land required for renewable is a concern. The primary driver for renewable build will be the environmental policies and technical improvements to lower the cost of renewable generation and the build out of transmission capacity to move the wind energy to the load centers.

Wind power has also experienced recent high material and equipment costs, as well as a sharp increase in demand. U.S. wind power projects have increased significantly in recent years. Reduced material costs and slower future growth rates may lead to wind power cost forecasts trending downward in the near term.

Solar power is still in its early stage for wide commercial applications for power generation. It is not as prevalent commercially as other types. Near term solar forecasts will benefit from reduced material costs. Longer term forecasts show additional benefits as the technology develops and solar power enjoys a better economy of scale.

2.3.4 Load Growth

The most overriding short-term concern for the economy is the recession. The National Bureau of Economic Research (NBER), the official arbiter of the timing of recessions, has stated that the recession began in December 2007. NBER utilizes data beyond the classic real Gross Domestic Product (GDP) to gauge the beginning and ending of recessions. As an aside, the common definition of recession is two consecutive quarters of negative GDP growth. The current recession has been lengthy when compared with previous post World War II recessions. The longest recessions in this period were 16 months and it appears likely that this economic downturn will exceed this length.

2.3.5 Emissions

2.3.5.1 SO_2, NO_X, and Mercury (Hg)

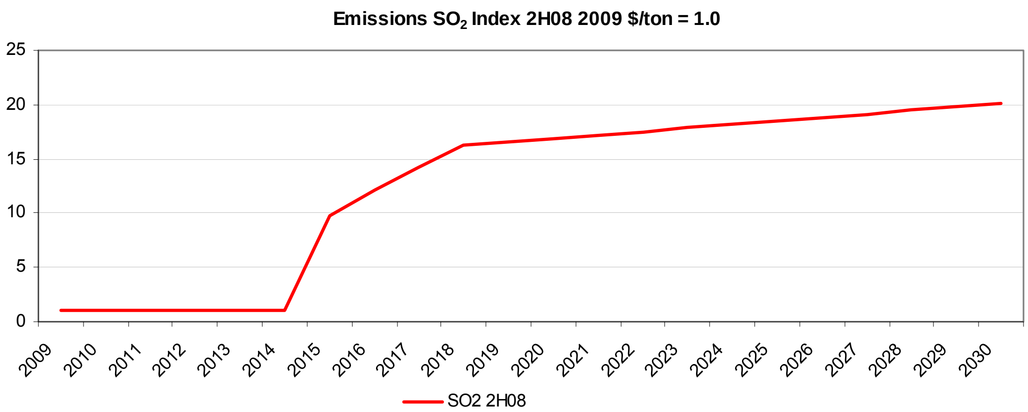
Environmental policy is one of the most fluid and unstable factors impacting the accuracy of the long-term forecast. Policy options range from the Business-As-Usual Case (government policy is very unlikely to become less regulated) to an extremely restrictive option with the potential to significantly alter how the country fuels its electricity consumption.

On February 8, 2008, the D.C. Court vacated the Clean Air Mercury Rule (CAMR) governing the release of mercury emissions. Today, there are no uniform technology standards or market-based programs for mercury in the states in which AEP operates, although some other states have established mercury control programs. According to the Environmental Group, Federal action is anticipated and could become effective in 2014 when a command-and-control policy could require all coal units to install either a mercury-specific control technology such as Activated Carbon Injection (ACI) or Flue Gas Desulphurization/Selective Catalytic Reduction (FGD/SCR) emissions control equipment. For development of market scenarios, the 2H08 forecast limits the FGD/SCR installations to projects currently under construction as a result of equipment economics and the evolution in emission regulations.

There is also a strong possibility that a plant-by-plant standard will replace a mercury trading system. If this is the case, a dispatch price would not be required, but additional controls such as baghouses or ACI would be needed. This could have an impact on proposed retirement dates of older, non-controlled units and ultimately the timing for new capacity. When new standards and implementation timelines are known, our plan will be re-evaluated and adjusted accordingly.

On July 11, 2008, the D.C. Circuit Court invalidated the Clean Air Interstate Rule (CAIR), and the rule has been remanded to EPA. Today, policy alternatives remain fluid. The AEP Environmental Group expects the CAIR program to be replaced with a more restrictive policy. In particular, the absence of any guidance from EPA, the Environmental Group has postulated a scenario in which SO_2 and NO_x emissions will be 10 percent below the CAIR Phase II limits (fully implemented by 2025) and exclude an allowance bank to meet emission targets. In the 2H08 forecast, annual NO_x emissions require a $1,000/ton price signal to remain in compliance, while SO_2 emissions require a significant price signal and an allowance bank to meet emission targets (**Exhibit 2-9**). The consultant forecast represents the uncertainty associated with a replacement to CAIR, where policy options range from a command-and-control policy (CERA-Breakpoint) to an additional constraint applied to the current policy. However, the cap-and-trade policies typically include an allowance bank to meet emission targets.

Exhibit 2-9: SO_2 Emission Price Index

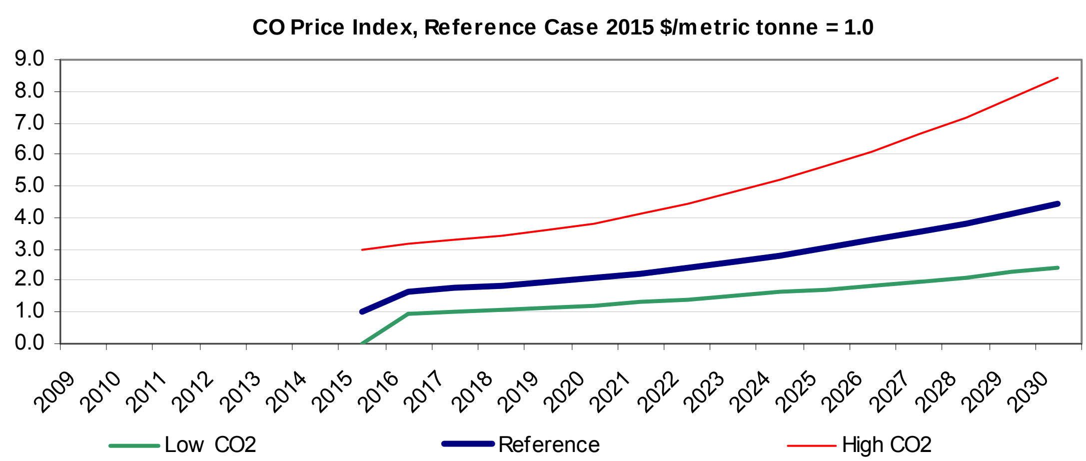


Source: AEP Fundamental Analysis

2.3.5.2 CO_2

The forecasting of future CO_2 allowance prices is subject to considerable uncertainty as the underlying assumptions are entirely predicated upon a yet to be defined federal climate policy. Strategic Policy Analysis has developed three potential CO_2 price forecasts for each of the cases (**Exhibit 2-10**). These forecasts attempt to represent a range of potential policy outcomes and resulting pricing to account for the uncertainty. The Abundance and Constrained Cases are based on the realistic limits of U.S. climate policy given current political and economic realities, while the Reference Case is a weighting of the high and low forecasts and represents the most likely price trajectory. Note: As the political and economic situation changes so will the politically acceptable pricing range and likely pricing trajectory.

Exhibit 2-10: CO_2 Emission Price Index



Source: AEP Fundamental Analysis

The price forecasts were developed at the beginning of 2009 based on public analyses of two of the most prominent pieces of comprehensive U.S. climate legislation; the “Low Carbon Economy Act of 2007” introduced by Senators Bingaman and Specter and the “Climate Security Act of 2008” introduced by Senators Lieberman and Warner. The Bingaman-Specter bill was widely supported by industry for its moderate emission reduction timeline, while the Lieberman-Warner was praised by environmentalists for its more aggressive emission reduction timeline. Thus, these bills represent relative "bookends" for likely climate policy outcomes.

********************End of 2H08 Fundamental Analysis excerpt***********************

2.4 Issues Summary

The increasing number of variables and their uncertainty has added to the complexity of producing an integrated resource plan. No longer are the variables merely the cost to build the generation, a forecast of what had traditionally been stable fuel prices and growth in demand over time. Highly volatile fuel prices, and uncertainty surrounding the economy and environmental legislation require that the process used to determine a resource plan is sufficiently flexible to incorporate more subjective criteria. The introduction of a cap-and-trade system and high capital construction costs weigh unfavorably on solid-fuel options, but conclusions must be metered with the knowledge that there is a great deal of uncertainty.

One way of dealing with uncertainty is to hedge one's bets. That is, if there exists the potential for very expensive carbon legislation, one might favor a solution that minimizes carbon emissions, even if that solution is not the least expensive. While there may not yet be a national RPS, procuring or adding wind generation resources now will put a company ahead of the game if one does come to pass. In this way, the company is trading future uncertainty for a known cost. Lastly, adding diversity to the generating portfolio reduces the risk of the overall portfolio. That may not be the least expensive option in a "base" (or most probable) case, but it minimizes exposure to adverse future events and could reduce the ultimate cost of compliance if the resultant demand for renewable resources continues to grow, outpacing the supplier resource base akin to past experience associated with the "dash to gas"..

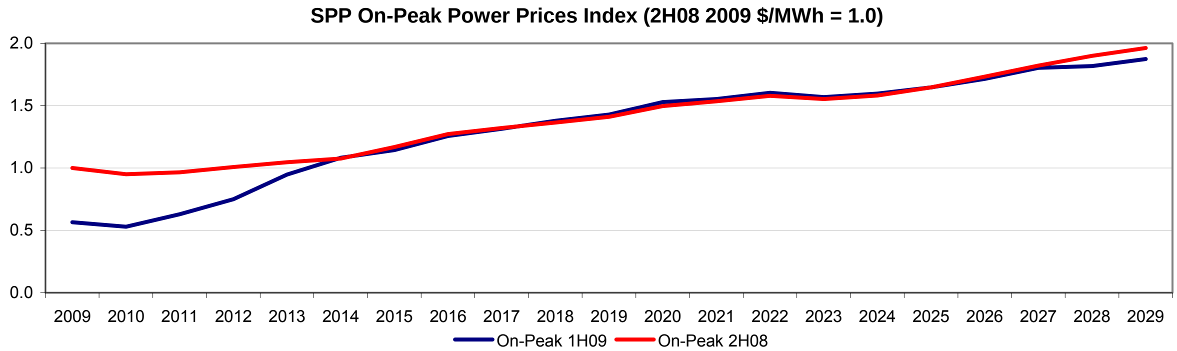
The long-term planning horizon is characterized by several primary variables. First and foremost, the prospect of legislation that in some way regulates GHGs. *Any* system enacted will likely result in:

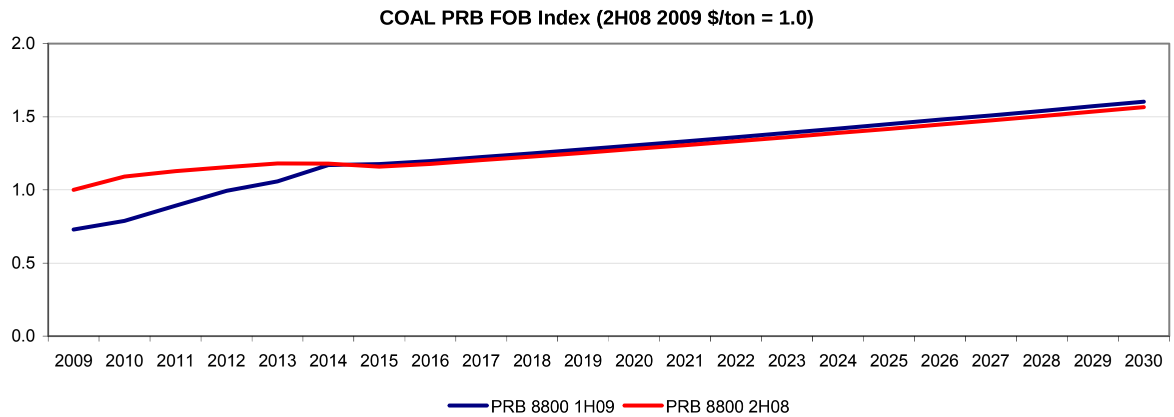
- Ultimate development and implementation of CO_2 capture and sequestration technologies which, in the east where higher-quality bituminous coals are prevalent, could ultimately favor current Integrated Gasification Combined Cycle (IGCC) design technology over traditional Pulverized Coal (PC) plants.
- Implementation of Renewable Portfolio Standards, either at a state or, ultimately, a national level.
- Efficiency improvements, both supply and demand side.
- A system for offsetting CO_2 emissions.
- Potential for volatile natural gas pricing marked by the offsetting effects of both increased supply and increased demand.

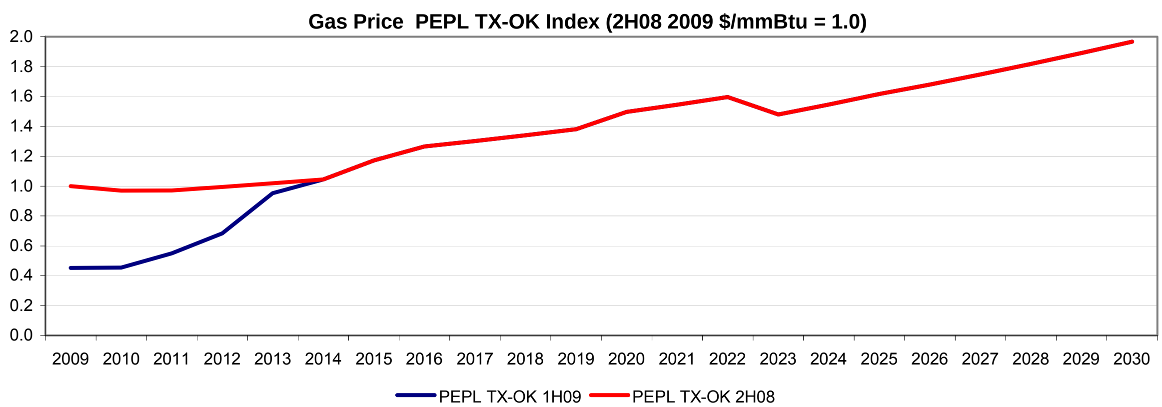
- Emissions allowance prices in light of the as yet unresolved CAIR and CAMR/mercury requirements, assumptions directly affecting the economic viability of uncontrolled coal generation.

Finally, the IRP process was complicated further by the economic slowdown that escalated in late 2008, which resulted in very different ***near-term*** *commodities forecasts. The 2H08 forecast was completed prior to this economic slow down. However, after comparing the long-term commodities forecasts used in this IRP (the 2H08 Forecast) to the subsequent long term forecast prepared in the Spring of 2009 (1H09 Forecast) as shown in* ***Exhibit 2-11*** *it was apparent that the effects of the revised pricing estimates were negligible after 2013 and did not warrant a new resource evaluation.*

Exhibit 2-11: 2H08 vs. 1H09 Commodities Comparison







Source: AEP Fundamental Analysis

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

Load & Demand Forecast Process – Sequential Steps

1. Monthly Sales Forecast
(by FERC Revenue Classes)
Short & Long Term

↓

2. Hourly Demand Models
(Load Shapes / Losses)

↓

3. Net Internal Energy Requirements
& Demand Forecast

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.

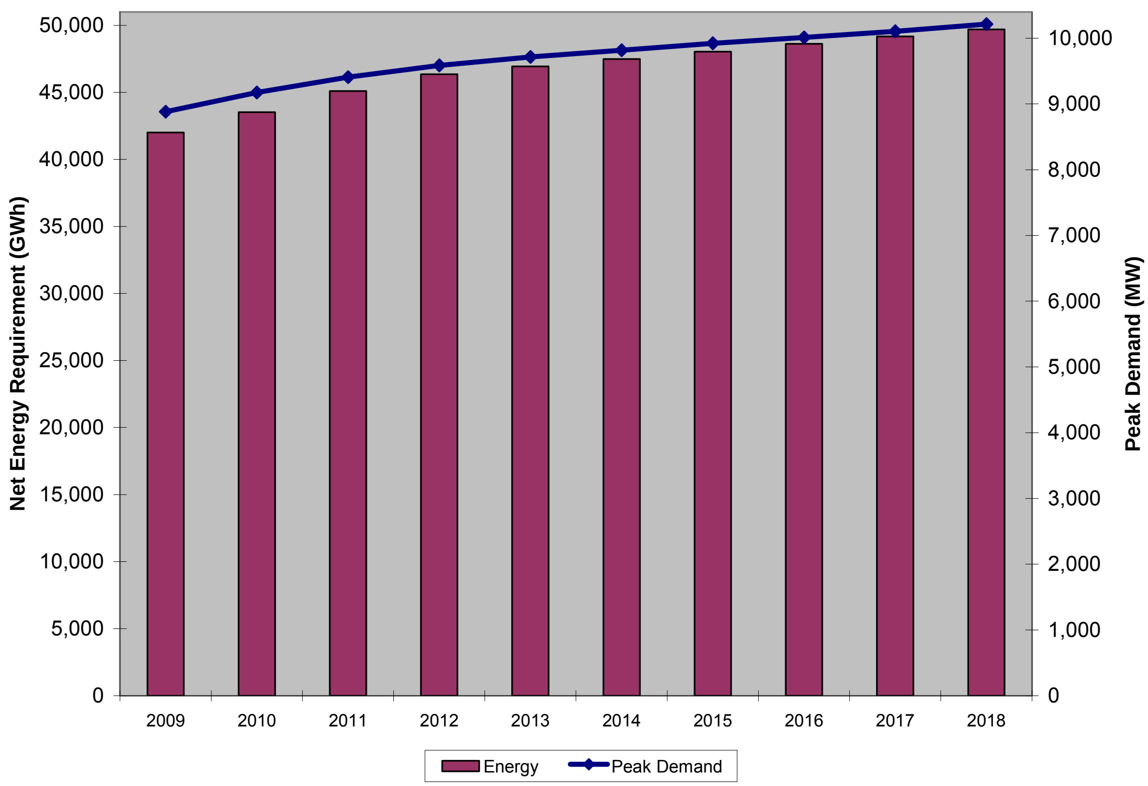
5.2 Peak Demand Forecast

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

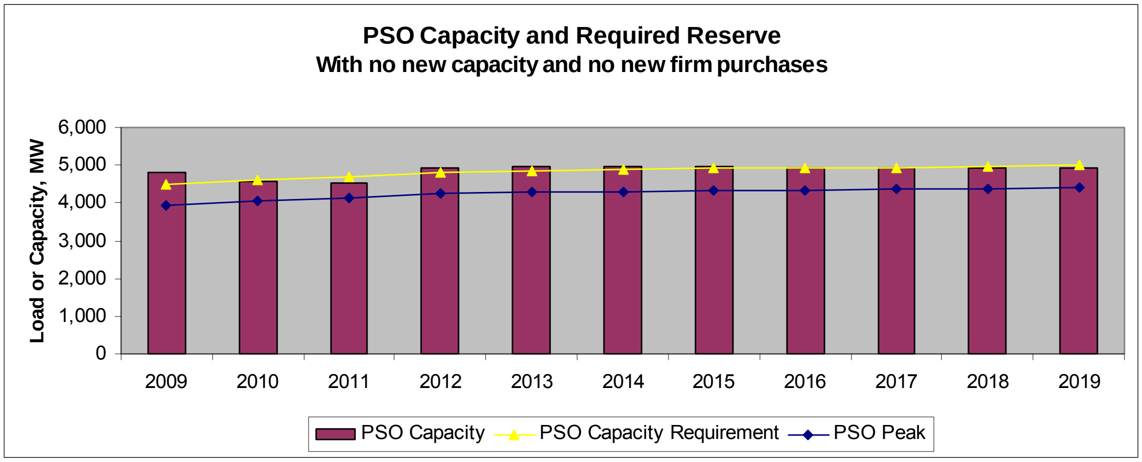
Source: AEP Resource Planning

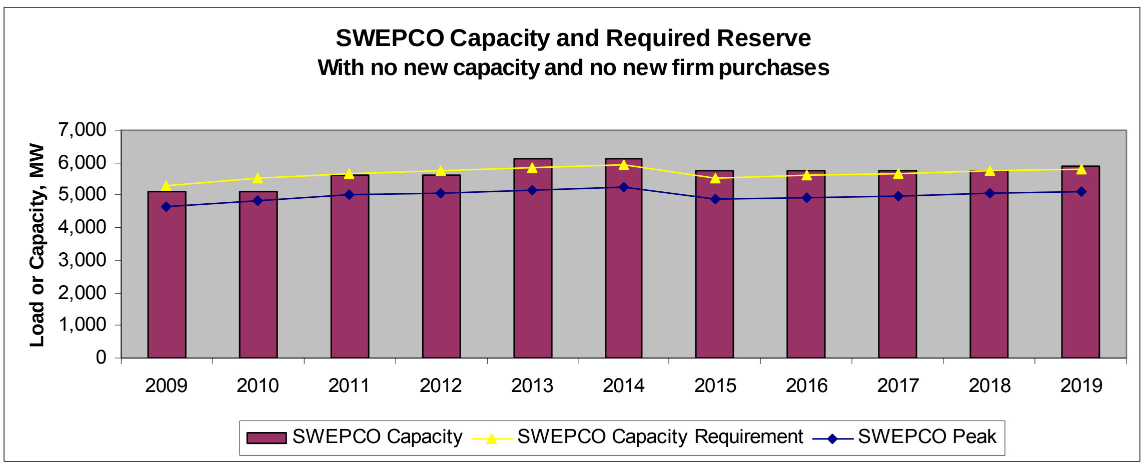
6.0 Capacity Needs Assessment

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

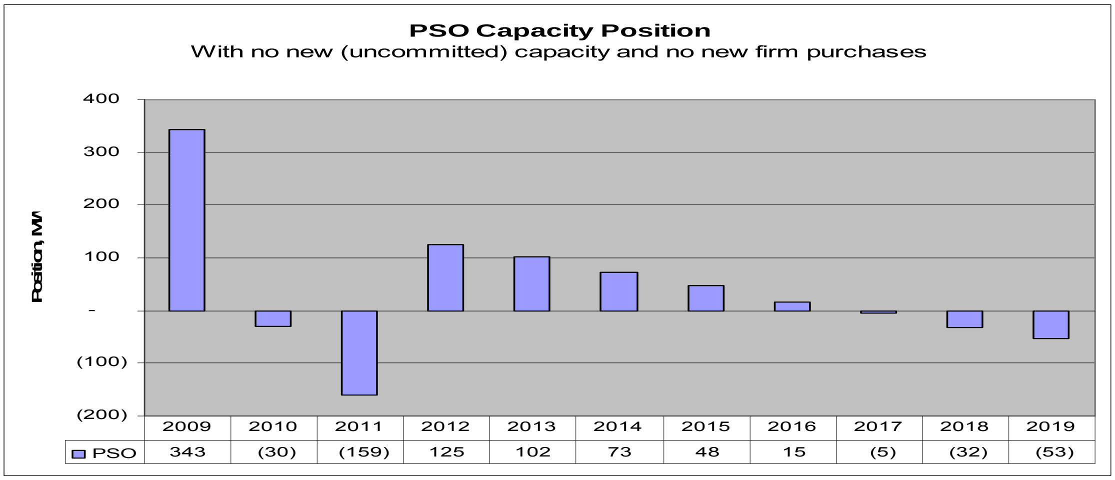


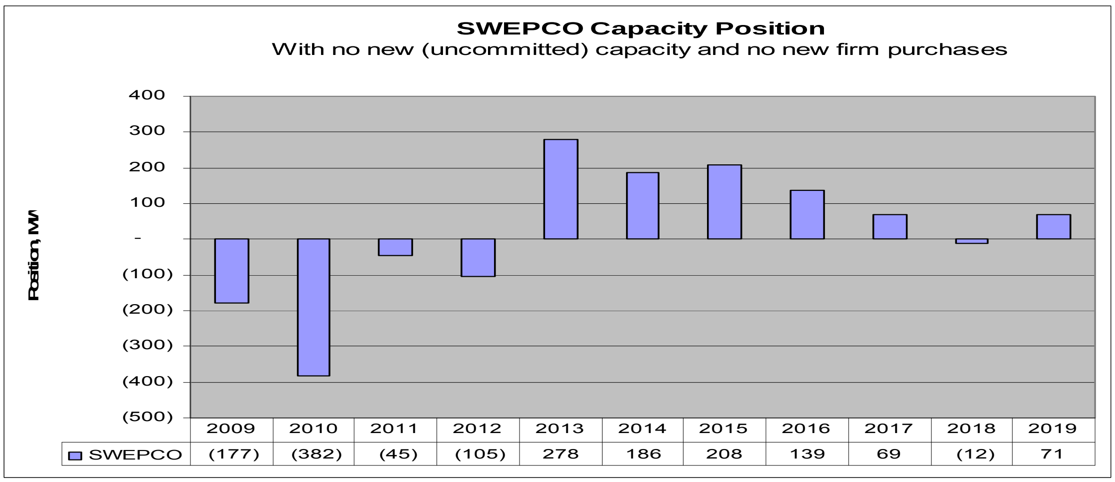


Source: AEP Resource Planning

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

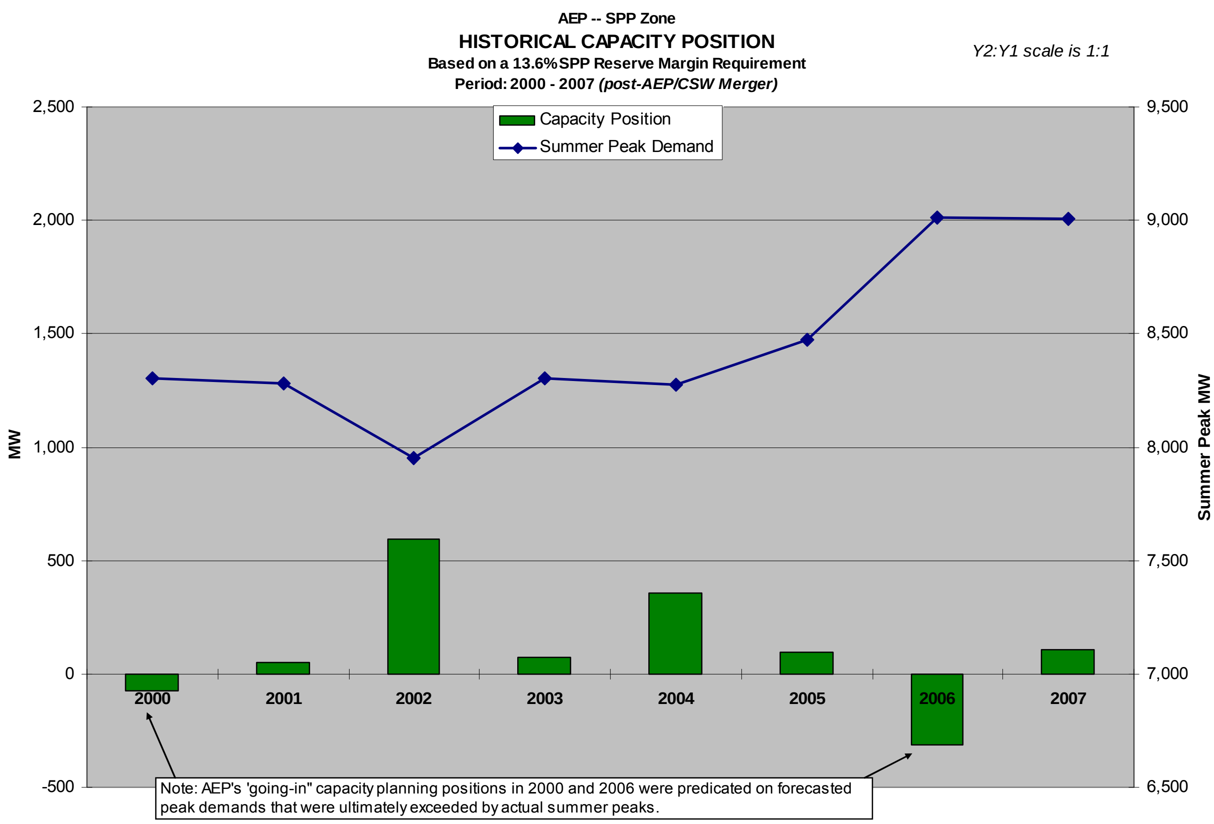
6.1 RTO Requirements

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.

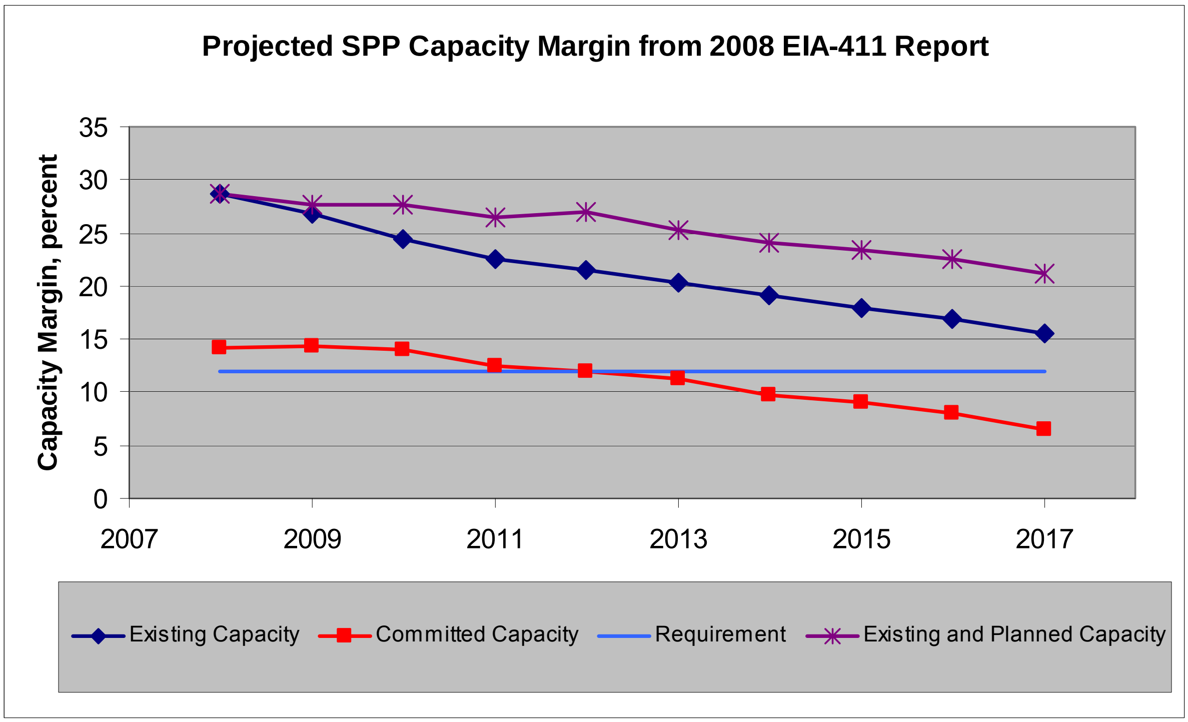
As a result, AEP Corporate Planning & Budgeting and Corporate Finance, among others, continually assess plans generated through the IRP cycle process, making recommendations to alter the timing, amount, and nature of resource additions specified in the Plan, as warranted.

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.

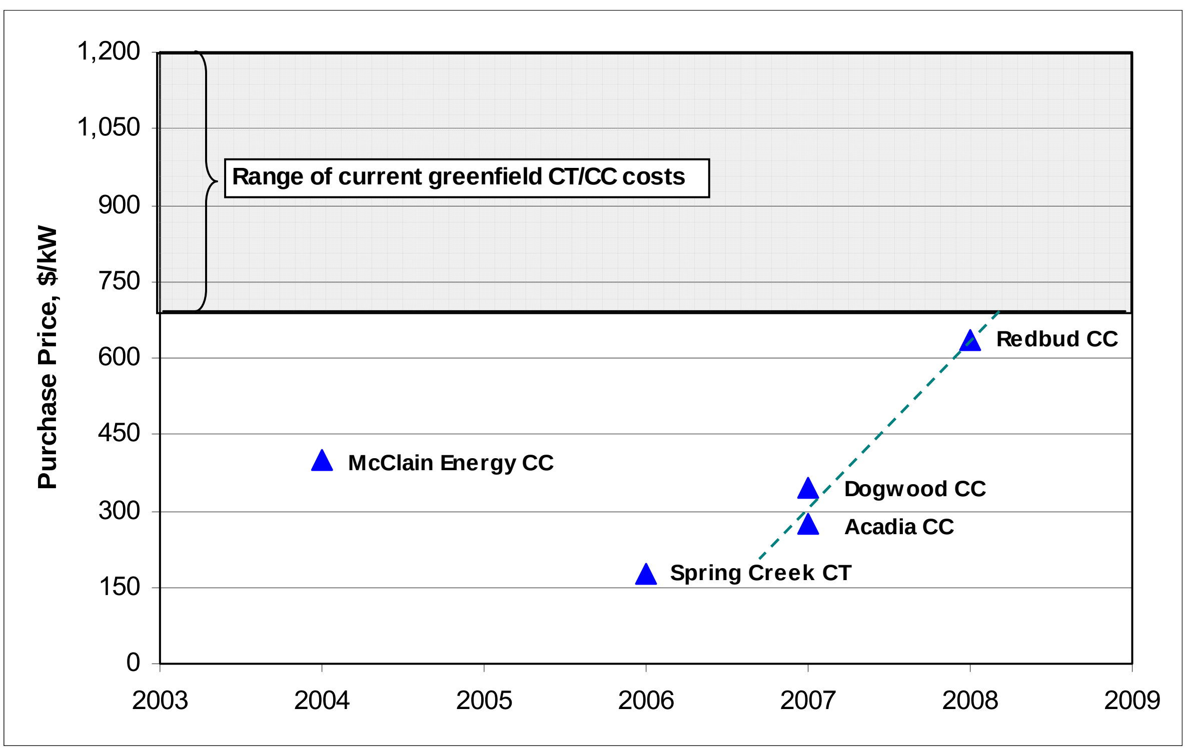
As with the need to maintain resource planning and implementation flexibility for various supply or demand exposures as identified above, the Plan should likewise seek to continually consider such market "buy" prospects, since:

- 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*.

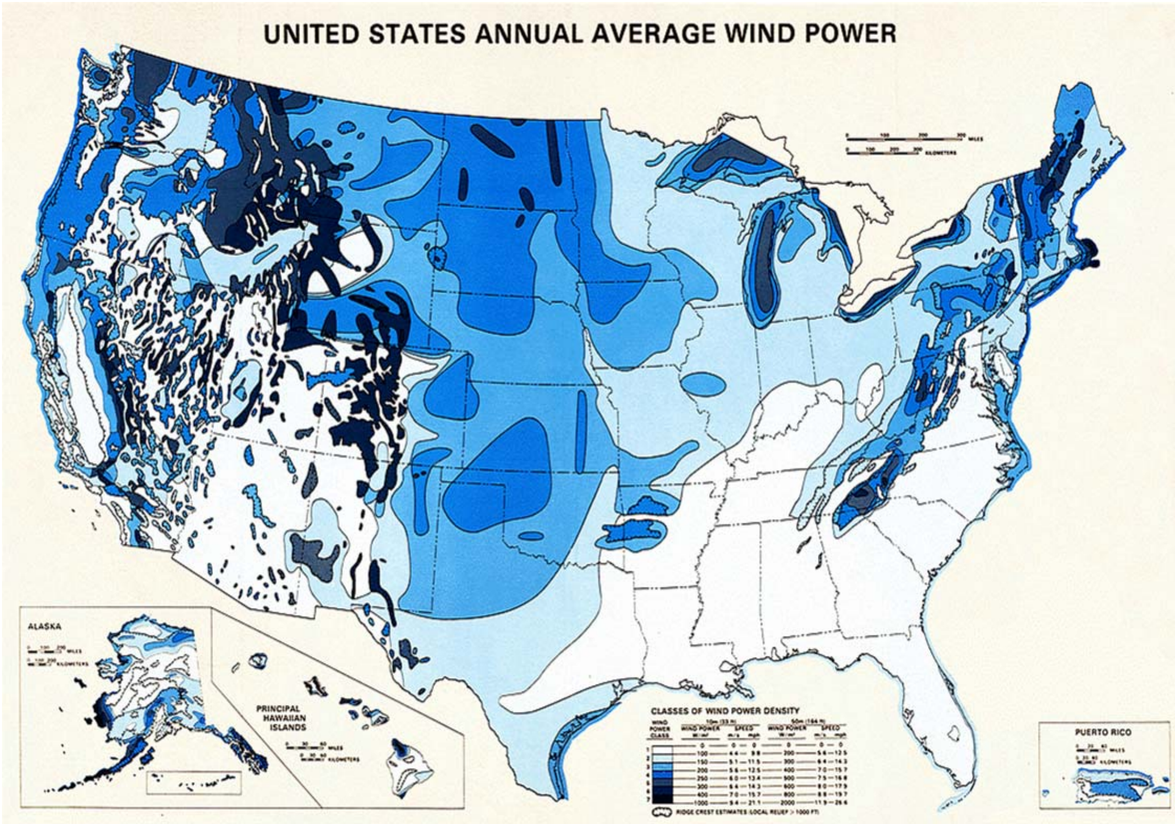
8.3.1 Wind

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

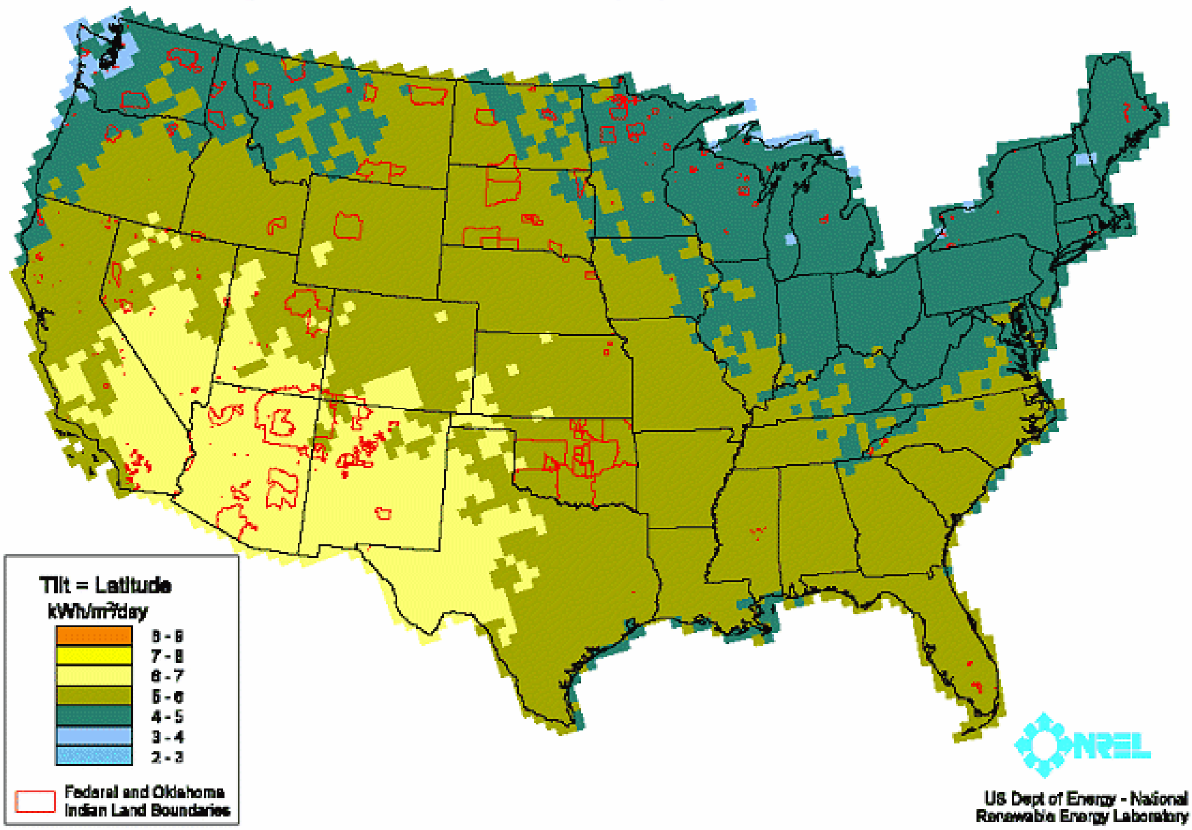


Source: NREL

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

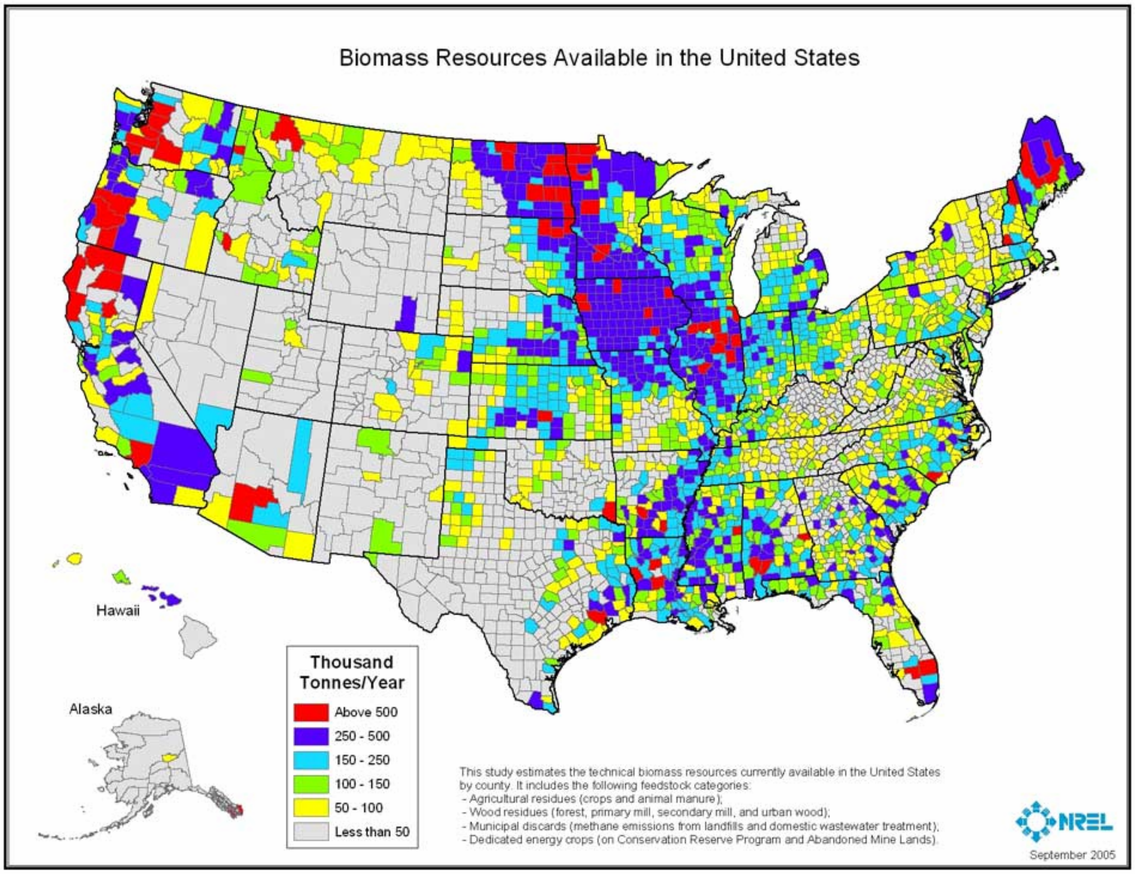
Switchgrass	**Wood Chips / Sawdust**
(per Purdue University Study) o 6 -to- 8 tons /yr. per acre yield o @ 6700 Btu/lb (non-dried, as harvested) *A 200-MW Dedicated Biomass Facility* *(70% C.F.) would require…* **110k -to- 150k harvested acres** *(172 - 234 sq. mi,)*	*(per AEP-Forestry)* o 70 -to-100 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) before 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.

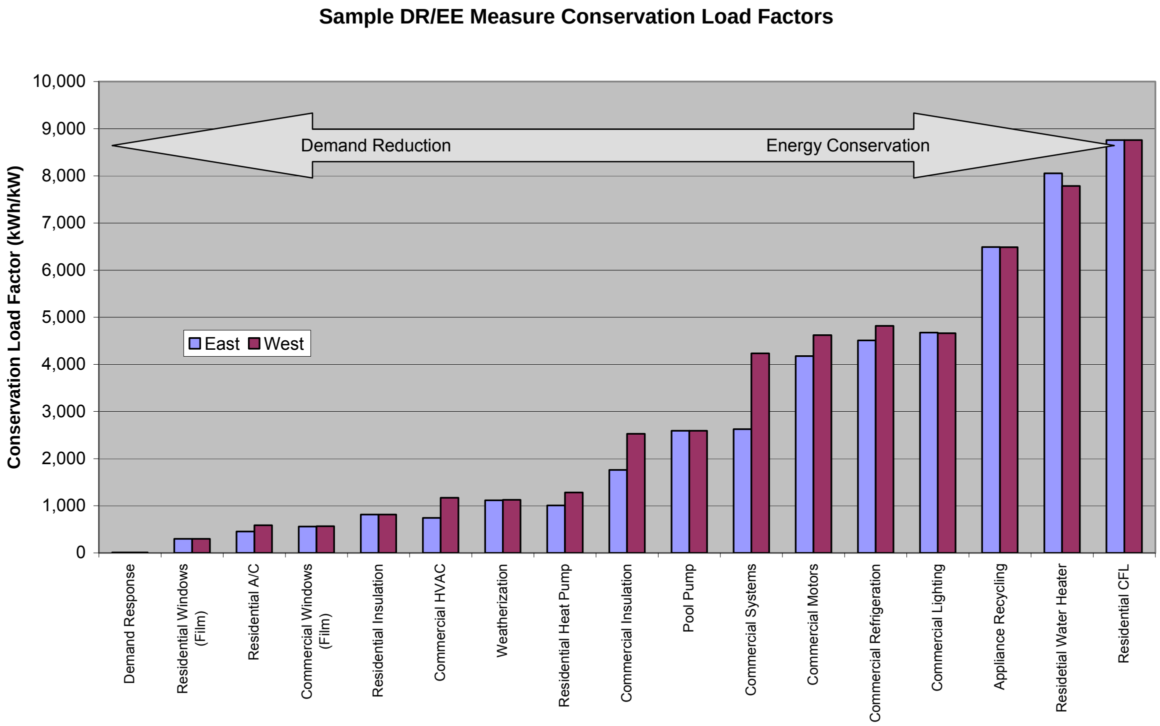
Some examples will illustrate this point. First, a more efficient air conditioner will likely reduce consumption at the peak; the same amount of cool air is being generated with less energy. A more efficient refrigerator will have a lesser impact on the peak as the chance of it running consistently at 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.

9.0 Evaluating DR/EE Impacts for the 2009 IRP

9.1 gridSMART^{SM}

AEP continues to evaluate distribution technologies that operate off the gridSMART^{SM} platform. These include "smart meters" that allow the consumer of electricity to receive pricing signals, or variable rates, encouraging the migration of consumption from times of peak demand, to times when power is more readily available.

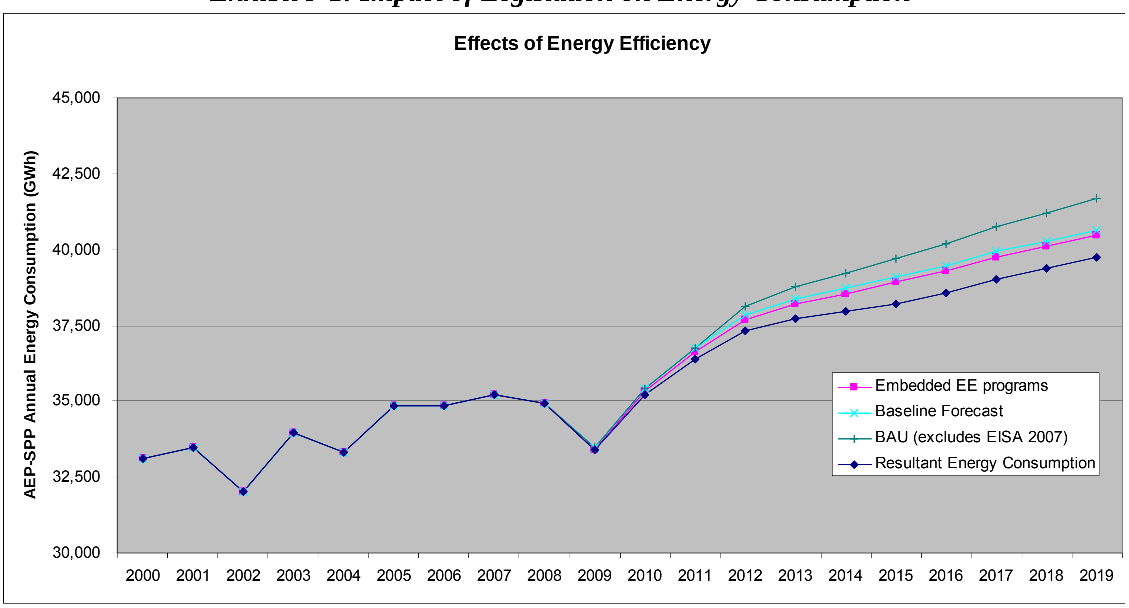
Pilot programs employing smart meters are currently underway in Texas, Ohio and Indiana. The results of these pilots will greatly inform the impacts assigned to larger roll-outs of these meters, should they ultimately be approved.

The bulk of the impacts of DR/EE modeled in this IRP are the forecasted results of "traditional" residential and commercial DR/EE programs, including tariff offerings.

9.2 Demand Response/Energy Efficiency Mandates and Goals

In November of 2007, the Energy Independence and Security Act of 2007 ("EISA") became law. The Act requires, among other things, a phase-in of lighting efficiency standards, appliance standards, and building codes. The increased standards will have a discernable effect on energy consumption as is shown in **Exhibit 9-1**. As Exhibit 9-1 indicates, by 2019 AEP-SPP energy consumption will be about 4.5 percent lower than a business-as-usual case. Additionally, mandated levels of demand reduction and/or energy efficiency attainment, subject to cost effectiveness criteria, are in place in Texas.

Exhibit 9-1: Impact of Legislation on Energy Consumption



Source: AEP Resource Planning

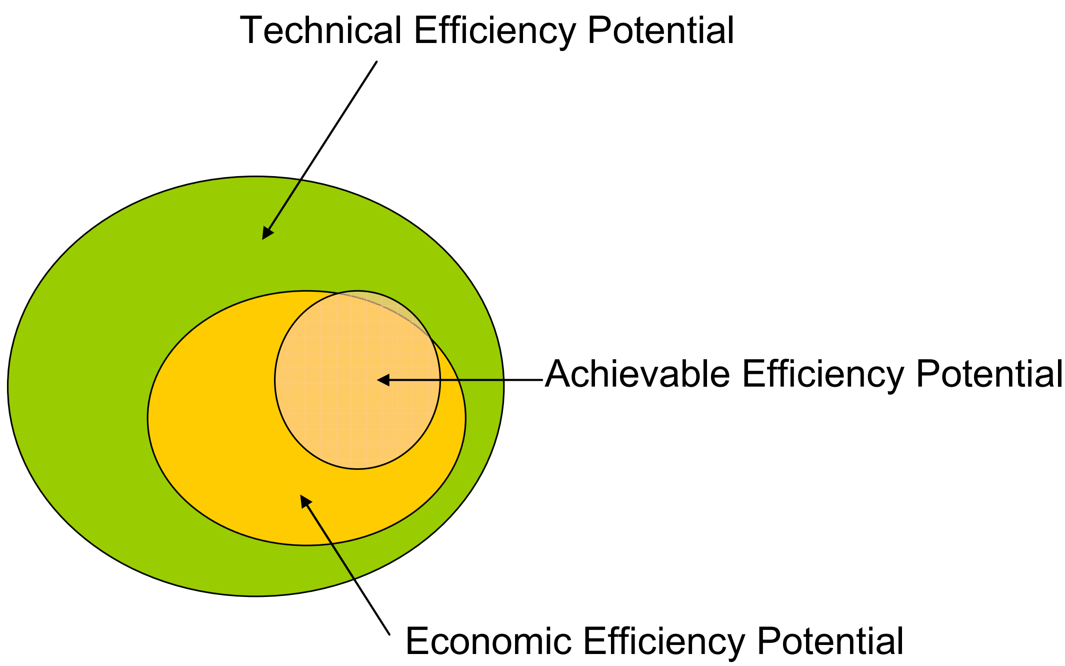
As identified in this document, AEP has internally committed to (system-wide) peak demand reductions of 1,000 MW by year-end 2012 and energy reductions of 2,250 GWh for the entire AEP-System, approximately 20-25% of which is in the AEP-SPP zone.

The IRP does not necessarily assume that these state DR/EE targets, currently set fourth, will be explicitly met over the long-term, preferring a more conservative approach that certainly recognizes the mandates, but prepares for the possibility that costs or other factors may intercede, triggering a revision or, perhaps, reaffirmation of the targets. The time horizon associated with building fossil fuel supply options is such that there will be other opportunities to further rationalize the appropriate levels of peak demand reduction and energy efficiency for the zone, prior to financially committing to non-renewable supply options.

9.3 Assessment of Achievable Potential

The amount of DR/EE that are available are typically described in three buckets: technical potential, economic potential, and achievable potential (**Exhibit 9-2**).

Exhibit 9-2: Achievable versus Technical Potential (Illustrative)



Source: AEP Resource Planning

Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, cost-effectiveness. The logical subset of this pool is the economic potential. Most commonly, the total resource cost test is used to define economic. This compares the avoided cost savings achieved over the life of a measure/program with its cost to implement it, regardless of who paid for it. The third set of efficiency assets is that which is achievable.

Of the total potential, only a fraction is achievable, and only then over time. Why all economic measures are not adopted by rational consumers speaks to the existence of "market barriers". Barriers such as lack of access to capital and lack of information are addressed with utility-based energy efficiency and demand response programs. How much effort and money is deployed towards removing or lowering the barriers is a decision made state by state.

9.4 Determining Programs for the IRP

Market Potential Studies (MPS) have been commissioned for 10 of AEP's 11 jurisdictions. In the SPP zone, at the time the analysis for this IRP was performed, only the Oklahoma MPS study was complete. Additionally, one national study of energy efficiency was published by the Electric Power Research Institute (EPRI). These two studies formed the basis for the analysis in the IRP.

The EPRI study, *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the United States*, "documents the results of an exhaustive study to assess the achievable potential for energy savings and peak demand reduction from energy efficiency and demand response programs." EPRI further defines the "achievable potential" as an estimated range of savings attainable through programs that encourage adoption of energy efficient technologies, taking into consideration technical, economic, and market conditions. The study differentiates what these programs can achieve prospectively from what may occur through the natural adoption of efficiency by consumers, either through preferences or codes and standards. The EPRI study provides a useful basis for assigning realistic levels of energy efficiency and demand response in lieu of jurisdiction-specific studies as well as a basis for assessing jurisdiction-specific study results which are typically stated as a range of possible outcomes.

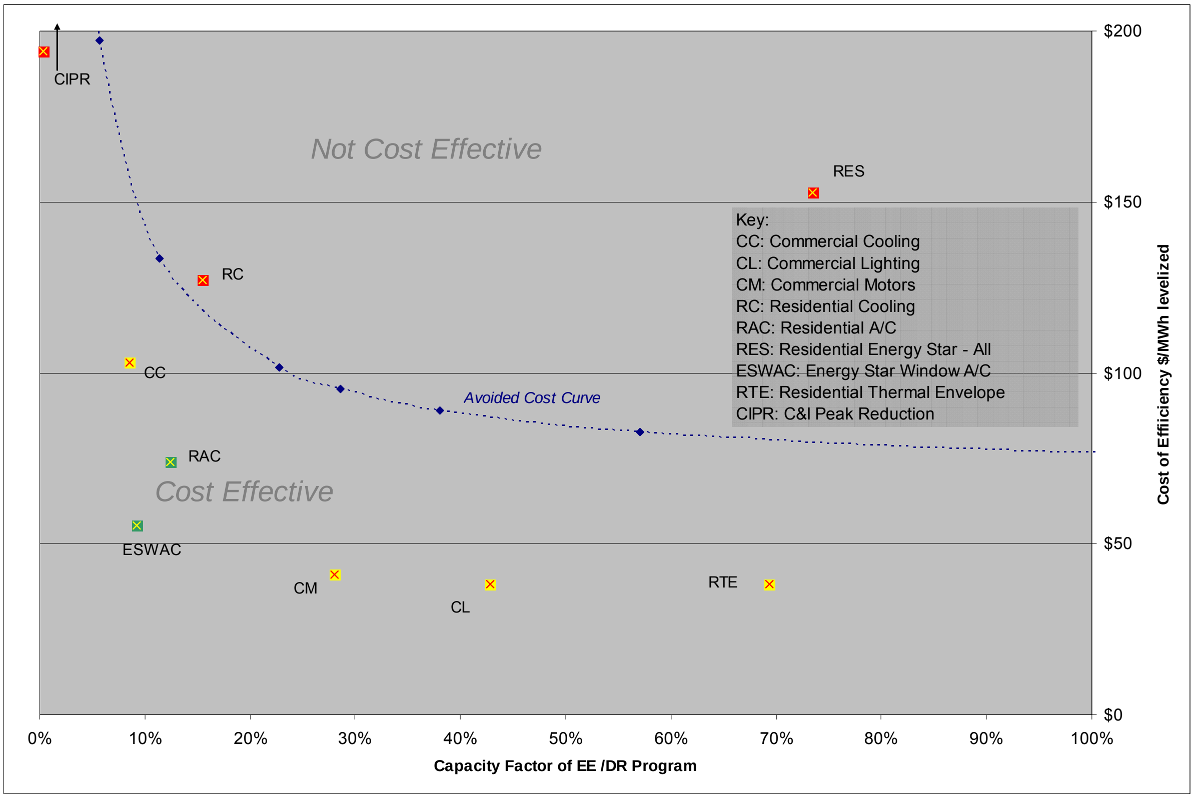
The economic potential for Energy Efficiency lies in the 10-23 percent range (relative to the Baseline forecast) for the 20-year period presented in each of the two studies. More importantly, estimates for what is achievable are a 1.8 percent reduction after five years (Oklahoma MPS – Base Case) and 3.3 percent after 12 years (EPRI). Both studies include periods of ramping up from a standing start.

Embedded in the load forecast are the effects of DR/EE programs that are either currently in place or have been filed with the appropriate regulatory commission. The Oklahoma study was used as the basis for the construction of DR/EE "blocks" to be used in the modeling process. The blocks are proxies for actual programs that are likely to be implemented, incremental to the programs that have already been filed. The blocks have the cost, energy, and peak demand reduction characteristics of the programs evaluated in the Oklahoma study.

9.4.1 Validating the DR/EE Program "Blocks"

Because the blocks represent possible programs as recommended by the Oklahoma MPS, the blocks should be economically cost effective. Prior to allowing the resource modeling to optimize with the blocks as possible capacity and energy alternatives, their impacts were validated using current avoided costs. **Exhibit 9-3** shows the recommended programs and their relative cost effectiveness. To reduce the problem set for the more holistic modeling that considered all resource alternatives, not all of the recommended programs were available for selection. From the exhibit, the green programs were not modeled. The red programs were modeled but not selected. The yellow programs are representative of the proxy resources.

Exhibit 9-3: AEP-SPP Zone Cost Effectiveness of Relative Programs



Source: AEP Resource Planning

Not shown on the chart are the Commercial & Industrial Demand Response (CIDR) resource which would be off the chart on the upper left side, but still cost effective, and the Residential Peak Reduction (RDR) which was not cost effective. Note that all of the other resources are cost effective with the exception of the Residential Cooling and Residential Energy Star™ (All). As modeled, these program blocks consist of many measures and even programs, some cost effective, others not. As the green blocks show, there are both Energy Star and residential cooling measures that are cost effective. Modeling constraints limit the ability to optimize all measures or programs, thus similar programs were aggregated for the purpose of quantifying typical impacts that could be expected from implementation of a portfolio of cost effective programs.

The use of these proxy resources is necessary to model supply-side and demand-side resources within the same optimization process. In no way does this process imply that these programs, in their current form and composition must be done in equal measure and in all jurisdictions. All states are different and may have specific rules regarding the ability of C&I customers to "opt out" of utility programs, influencing the ultimate portfolio mix. Some states have a collaborative process that can greatly influence the tenor and composition of a program portfolio. That said, these blocks provide a reasonable proxy for demand-side resources within the context of an optimization model.

A list of the programs and impacts used to develop the proxy resources is included in the Technical Addendum.

9.5 Optimizing the Incremental DR/EE Resources

Using the red and yellow program characteristics, **DR/EE** "blocks" were constructed of equal energy impacts, corresponding demand impacts and costs. The proxy "blocks" available for optimization and their monthly characteristics are summarized in **Exhibit 9-4.** The modeling limitations placed on the respective DR/EE "blocks" and cost data are provided in Exhibit 9-5.

Exhibit 9-4: AEP-SPP Zone DR/EE Proxy Blocks

Monthly Peak Reduction (MW)								
	CC	CL	CM	RC	ES	TE	RPR	CIPR
Jan	0.01	3.34	4.43	1.60	2.40	2.35		
Feb	0.52	3.08	3.92	1.60	2.37	2.39		
Mar	0.05	2.59	2.95	1.90	2.41	2.37		
Apr	3.09	3.03	3.84	3.89	2.43	2.38		
May	7.97	3.60	4.94	7.51	2.50	2.60		
Jun	17.83	4.65	6.91	10.69	2.67	2.79	8.00	8.00
Jul	26.49	5.21	7.93	14.78	3.06	3.24	8.00	8.00
Aug	26.84	5.33	8.15	13.05	3.11	3.29	8.00	8.00
Sep	11.36	4.80	7.19	9.96	2.53	2.63		
Oct	6.10	3.40	4.55	2.98	2.42	2.38		
Nov	0.92	2.89	3.56	2.58	2.40	2.36		
Dec	0.01	3.02	3.81	1.60	2.33	2.33		
Peak	26.84	5.33	8.15	14.78	3.11	3.29	8.00	8.00

Monthly Energy Reduction (GWh)								
	CC	CL	CM	RC	ES	TE	RPR	CIPR
Jan	0.01	1.55	1.40	1.28	1.66	1.65	-	-
Feb	0.01	1.37	1.20	1.15	1.51	1.50	-	-
Mar	0.01	1.44	1.16	1.27	1.70	1.69	-	-
Apr	0.12	1.39	1.13	1.24	1.66	1.65	-	-
May	0.73	1.58	1.46	1.39	1.70	1.69	-	-
Jun	2.68	1.84	2.04	1.84	1.63	1.64	-	-
Jul	7.93	2.33	2.97	3.40	1.76	1.80	-	-
Aug	6.34	2.23	2.77	2.95	1.74	1.77	-	-
Sep	1.96	1.83	2.03	1.69	1.64	1.64	-	-
Oct	0.18	1.54	1.37	1.29	1.71	1.70	-	-
Nov	0.02	1.39	1.11	1.23	1.64	1.63	-	-
Dec	0.01	1.52	1.35	1.28	1.65	1.65	-	-
Annual	20.00	20.00	20.00	20.00	20.00	20.00	-	-

Source: AEP Resource Planning

Note: See Exhibit 9-3 Legend for all program acronyms

Exhibit 9-5: AEP-SPP Zone DR/EE Modeling Constraints

Strategist Model Block	Block Type	Life	Incremental cost $(000)	Annual Cost ($000)	MW	MWh	Max Incremental Blocks Per Year
Commercial Cooling (CC)	EE	15	11,808	-	18.0	13,400	1
Commercial Lighting (CL)	EE	12	3,846	-	3.6	13,400	2
Commercial Motors (CM)	EE	15	4,689	-	5.5	13,400	1
Residential Cooling (RC)	EE	15	14,576	-	9.9	13,400	1
Residential Energy Star (ES)	EE	8	11,749	-	2.1	13,400	1
Residential Thermal Envelope (TE)	EE	20	5,009	-	2.2	13,400	2
C&I Peak Reduction (CIPR)	DR	20	585	287	10.1	-	2
Residential Peak Reduction (RPR)	DR	20	6,021	280	10.1	-	1

Source: AEP Resource Planning

These individual program constraints, coupled with an over-arching ceiling on the annual level of resources allowed, keep Strategist from selecting DR/EE resources faster than is practical. The result of the constraints is a roll out of programs that is consistent with both the Oklahoma MPS recommendations and the EPRI Reasonably Achievable level of demand side resources.

Exhibit 9-6 shows the blocks selected by the resource modeling, by year. Again, this does not imply that blocks that were not selected are not cost effective and should not be part of any future portfolios in any jurisdiction. It does show, however, that certain characteristics of programs are more desirable than others in the context of a dynamic, constrained optimization. As a practical matter, actual DR/EE programs are likely to contain elements of many of these programs but not match the blocks exactly. However, for the purposes of validating the cost-effectiveness of demand options, and quantifying the benefits relative to supply options, the proxy demand resources are suitable.

Exhibit 9-6: AEP-SPP Zone DR/EE Blocks Selected in Resource Modeling (AEP-SPP)

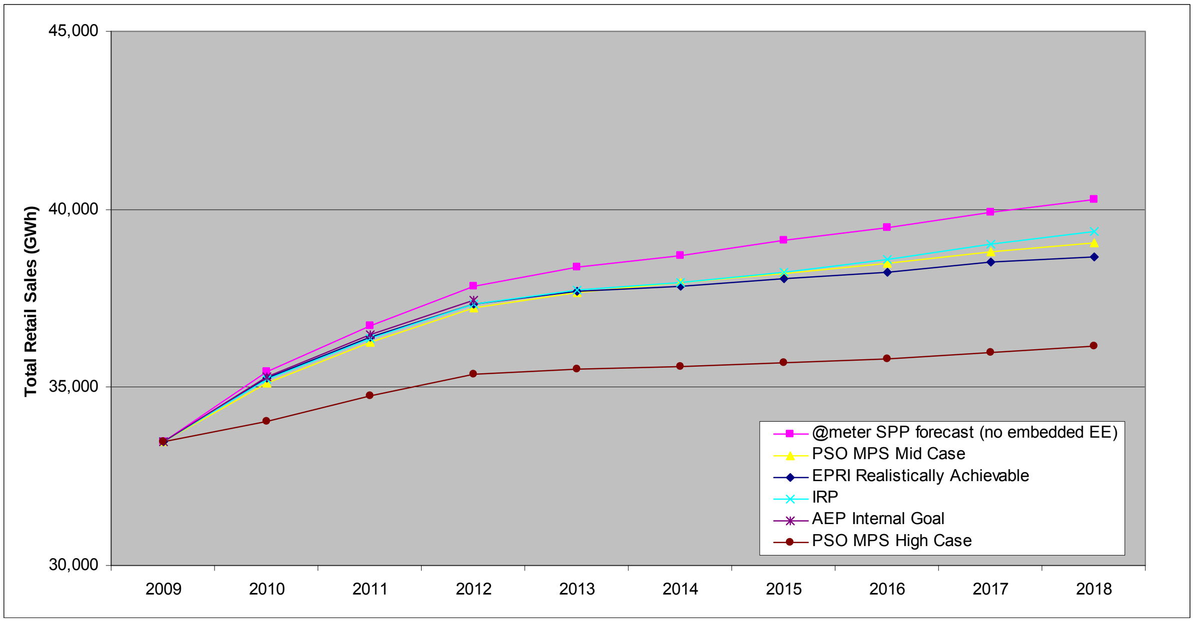
Strategist Optimized Demand Side Proxy Resources (GWh)						
	CC	CL	CM	TE	Total	Cumulative Total
PSO						
2010	12	24	12	24	72	72
2011	12	24	12	24	72	144
2012	12	24	12	24	72	216
2013	12	24	12	24	72	288
2014	12	24	12	24	72	360
2015	12	24	12	24	72	432
SWEPCO						
2010	9	18	9	18	55	55
2011	9	18	9	18	55	110
2012	9	18	9	18	55	166
2013	9	18	9	18	55	221
2014	9	18	9	18	55	276
2015	9	18	9	18	55	331

Strategist Optimized Demand Side Proxy Resources (MW)						
	CC	CL	CM	TE	Total	Cumulative Total
PSO						
2010	16	6	5	4	31	31
2011	16	6	5	4	31	63
2012	16	6	5	4	31	94
2013	16	6	5	4	31	125
2014	16	6	5	4	31	157
2015	16	6	5	4	31	188
SWEPCO						
2010	12	5	4	3	24	24
2011	12	5	4	3	24	48
2012	12	5	4	3	24	72
2013	12	5	4	3	24	96
2014	12	5	4	3	24	120
2015	12	5	4	3	24	144

Source: AEP Resource Planning

Exhibit 9-7 shows the relative cohesiveness of the two studies, the internal AEP target applicable to AEP-SPP and the amount of EE in this AEP-SPP IRP cycle.

Exhibit 9-7: AEP-SPP Internal EE Target versus IRP



Source: AEP Resource Planning

Results:
By 2015, peak demand at the meter is reduced by 385 MW in the AEP-SPP zone; consumption is reduced by 974 GWh at the generator. These reductions are consistent with studies performed in the AEP-SPP zone and internal goals.

9.6 Discussion and Conclusion

The assumption of aggressive peak demand reduction and energy efficiency achievements reflect AEP's commitment to demand-side resources.

The amount of DR/EE included in this Plan is significantly higher than past IRP plans have included. There are a few reasons why this is valid:

- Mandates at the state and potentially at the federal level will encourage adoption of demand side resources at a pace higher than would have been reasonably forecast in the past.
- Increased awareness and acceptance of the purported link between global warming and the consumption of fossil fuels will drive increased adoption of conservation measures, independent of economic benefit.
- Increased interest in demand response resulting from FERC initiatives.

As the mechanism for regulatory cost recovery and the appetite for utility-sponsored DR/EE is formalized through the legislative and ratemaking processes in the various jurisdictions in which AEP operates, the amount and type of DR/EE programs will likely change.

The following **Exhibit 9-8** summarizes the AEP-SPP Zone DR/EE assumptions for the 2009 IRP. AEP leadership has committed to initiatives that include the latest, most environmentally friendly technologies and protocols. Adoption of these measures is predicated on securing adequate cost recovery. For this planning cycle, it is assumed that such recovery would be forthcoming. For planning purposes, the *2015 DR/EE levels are held constant for 2016 and beyond*. For the 10 year planning horizon, this level of DR/EE still closely matches the EPRI Realistically Achievable level. By keeping this DR/EE level constant after 2015, future demand and energy requirements are not, potentially, made artificially lower. An artificially lower future demand and energy requirement could result in a plan that ultimately does not provide for adequate reserves. As more experience is gained implementing DR/EE programs, and results are observed, the level of DR/EE in future plans will be adjusted accordingly.

Exhibit 9-8: AEP-SPP Zone DR/EE Assumption Summary

	PSO					
	Energy Efficiency Impacts (GWh)			Peak Demand Impacts (MW)		
Year	Forecast (Embedded)	IRP Blocks	Total	Forecast (Embedded)	IRP Blocks	Total
2009	40		40	9		9
2010	56	72	128	13	31	44
2011	70	144	214	16	63	79
2012	81	216	297	19	94	113
2013	90	288	378	21	125	146
2014	97	360	457	22	157	179
2015	102	432	534	23	188	211

	SWEPCO					
	Energy Efficiency Impacts (GWh)			Peak Demand Impacts (MW)		
Year	Forecast (Embedded)	IRP Blocks	Total	Forecast (Embedded)	IRP Blocks	Total
2009	38		38	10		10
2010	57	55	112	16	24	40
2011	73	110	184	20	48	68
2012	87	166	252	24	72	96
2013	96	221	317	26	96	122
2014	103	276	379	29	120	149
2015	109	331	440	30	144	174

Source: AEP Resource Planning

10.0 Fundamental Modeling Parameters

10.1 Modeling and Planning Process—An Overview

A chart summarizing the IRP planning process, identifying the fundamental input requirements, major modeling activities, and process reviews and outputs, is presented in **Exhibit 1-1.** Given the diverse and far-reaching nature of the many elements as well as participants in this process, it is important to emphasize that this planning process is naturally a **continuous, evolving activity**.

In general, assumptions and plans are continually reviewed and modified as new information becomes available. Such continuous analysis is required by multiple disciplines across AEP to ensure that: market structures and governances; technical parameters; regulatory constructs; capacity supply; energy adequacy and operational reliability; and environmental mandate requirements are constantly reassessed to ensure optimal capacity resource planning.

Further impacting this process are growing numbers of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability planning. Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of this 2009 AEP-SPP IRP process. Therefore, as a result, the "objective function" of the modeling applications utilized in this process is the establishment of the least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. As discussed in this (and previous) section, other factors–some more difficult to monetize than others–were considered in the determination of the AEP-SPP integrated resource plan to be utilized by PSO and SWEPCO. To challenge the robustness of the Plan, sensitivity analyses were performed to address these factors.

10.2 Methodology

The IRP process aimed to address the long-term "gap" between resource needs and current resources (Section 6). Given the various assets and resources that can satisfy this expected long-term gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution–or portfolio–subject to constraints. *Strategist* [3] is the primary modeling application, used by AEP for identifying and ranking portfolios that address the gap between needs and current available resources. Given the set of proxy resources–both supply and demand side–and a scenario of economic conditions that include fuel prices, capacity costs, energy costs, effluent prices including CO_2, and demand, *Strategist* will return all combinations of the proxy resources (portfolios) that meet the resource need. The portfolios are ranked on the basis of cost, or cumulative present worth (CPW), of the resulting stream of revenue requirements. The least cost option was considered the initial "optimum" portfolio for that unique input parameter scenario.

[3] A Ventyx Co., long-term resource optimization tool utilized extensively in the utility industry for over two decades.

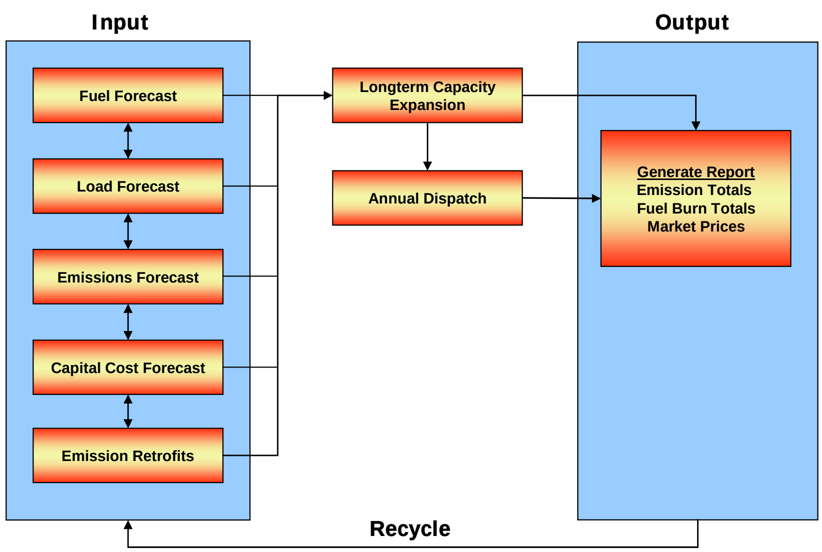
10.3 Key Fundamental Modeling Input Parameters

(This section includes excerpts from the "Long Term Price Forecast 2009-2030: Return to Fundamentals, 2H-2008" prepared by AEPSC's Strategic & Economic Analysis (AEP-SEA) Organization and issued February 2009..)

The AEP-SEA long-term power sector suite of commodity forecasts are derived from the Aurora model. Aurora is a fundamental production-costing tool that is driven by inputs into the model, not necessarily past performance. AEP-SEA models the eastern synchronous interconnect and ERCOT using Aurora. Fuel and emission forecasts established by AEP Fuel, Emissions and Logistics, are fed into Aurora. Capital costs for new-build generating assets by duty type are vetted through AEP Engineering Services. The CO_2 forecast is based on assumptions developed by AEP Strategic Policy Analysis.

Exhibit 10-1 shows the AEP-SEA process flow for solution of the long-term (power) commodity forecast. The input assumptions are initially used to generate the output report. The output is used as "feedback" to change the base input assumptions. This iterative process is repeated until the output is congruent with the input assumptions (e.g., level of natural gas consumption is suitable for the established price and all emission constraints are met).

Exhibit 10-1: Long-term Forecast Process Flow



Source: AEP-SEA

In this report, four distinct scenarios were developed: the Reference Case, Business As Usual (BAU) Case, Abundance Case, and Constrained Case. **Exhibit 10-2** presents the key inputs for the scenarios and how they have changed relative to the Reference Case.

Exhibit 10-2: Input Scenarios and Sensitivities

	Scenarios			
Case Name	Reference	Constrained	Abundance	BAU
Demand	Reference Case	Same	Same	Higher
Natural Gas Price				
Fuel Price	Reference Case	Higher	Lower	Same
Carbon Price	Reference Case	Higher	Lower	Zero
Coal Price				
Fuel Price	Reference Case	Higher	Lower	Blend
Carbon Price	Reference Case	Higher	Lower	Zero
Emission Price				
SO_2	Reference Case	Same	Same	Same
NO_X	Reference Case	Same	Same	Same
CO_2	Reference Case	Higher	Lower	Zero
Capital Costs	Reference Case	Higher	Lower	Same

Source: AEP Fundamental Analysis

The Abundance Case is a world where the economics, policies and/or the technology allow the overbuilding of capacity to produce commodities. In this world, the long-term price equilibrium will be set near the cost of production. The Constrained Case is a world where the economics, policies, and/or the lack of technology allow the market to be near balance. In this world, a scarcity premium can occur as result of supply chain disruptions via weather or political issues. The “Reference Case” sits inside the Abundance and Constrained Case. The “BAU” case is essentially a case where there is no carbon policy, and no attendant cost of CO_2.

Though the commodities are changing in each case, the key driver is the CO_2 price used. The CO_2 price in this report is elevated versus last year’s outlook. The mid-range CO_2 price from our April 2008 forecast is now the lower forecast while the mid-range forecast and high-range forecast went higher. This dampens any change applied to the other key inputs.

In the Reference Case, AEP-Hub power prices cross the SPP power prices in 2024. The significant rise in price and the relative change in market area prices put in doubt whether the full impact of this carbon outlook was completely dialed-in. Regional economical dislocations and the political reality constraints of carbon policy were not applied in the model.

Overall commodities are expected to retract back to supply/demand economic principles of marginal production cost. In the natural gas markets, this does not mean back to the 1990’s $2-$3 market – only because demand is much more elevated and the marginal supply source is more costly. However, this new marginal source, unconventional production, will likely be in play for quite sometime limiting any future massive runs as long as producers believe they will realize an average price above $5 - $6/MMBtu throughout the life of the reserves. In the long-term, natural gas prices will remain below the low teens ($/MMBtu).

For coal, the 2008 price spike will likely be just a price spike. This was the perfect storm for coal with many issues occurring at the same time. There is ample amount of coal in the world, particularly when the demand is being constrained by Carbon policy. Nonetheless, as in gas the 1990’s world of around $24-$28/ton of bituminous coal will not likely come back. Central Appalachian (CAPP) prices will remain high due to local supply issues. However, very similar to gas there is another coal supply source – Powder River Basin (PRB). Unlike unconventional gas, the ultimate end product of this supply will take modification to be able to use it due to the much lower energy content.

The metals market proved out the concern addressed in previous reports – the most cyclical market of all time is likely to be in a cycle near its peak. The steel markets have crashed to below some producers' variable cost ($450-$850/ton). U.S. steel mill production is at a level not seen in 25 years. The long-term outlook for steel is expected to be within this variable cost range. The purchases of new plants and environmental control equipment should go down. However much of our industrial load will likely be damaged if prices continue to stay low.

10.3.1 CO_2 Forecast

The forecasting of future CO_2 allowance prices is subject to considerable uncertainty as the underlying assumptions are entirely predicated upon a yet to be defined federal climate policy. AEP Strategic Policy Analysis organization has developed three potential CO_2 price forecasts to match potential prospective legislated outcomes. The Abundance ("High CO_2") and Constrained ("Low CO_2") Cases are based on the realistic limits of U.S. climate policy given current political and economic realities, while the Reference Case is a weighting of such high and low forecasts and represents the most likely price trajectory. *As the political and economic situations change, so will the politically acceptable pricing range and likely pricing trajectory.*

Specifically, the price forecasts were developed based on public analyses of two of the most prominent pieces of comprehensive U.S. climate legislation; the "Low Carbon Economy Act of 2007" introduced by Senators Bingaman and Specter and the "Climate Security Act of 2008" introduced by Senators Lieberman and Warner. The Bingaman-Specter bill was widely supported by industry for its moderate emission reduction timeline, while the Lieberman-Warner was praised by environmentalists for its more aggressive emission reduction timeline. Thus, these bills represent relative "bookends" for likely climate policy outcomes.

The Abundance Case CO_2 price forecast is predicated upon legislation similar to the Bingaman-Specter bill passing in 2011, with the resulting policy coming into effect in 2016, given the need for a five year policy "lead-in" period. This forecast also assumed that the "backstop" allowance price specified in the bill ($12 escalated) would be reached in every effective year, thus setting the price forecast. The Constrained CO_2 price forecast is based on an average of four modeling scenarios of the Lieberman-Warner bill: two conducted by EIA and two conducted by EPA. For this forecast we assume that climate legislation would pass in 2010 and become effective in 2015. Given concerns over the environmental leniency of the Bingaman-Specter bill and the potential negative economic ramifications of the Lieberman-Warner Bill, the Reference Forecast was developed using a 70%/30% relative weighting of these two bills. This forecast represents a pricing scenario which likely could occur under some level of political compromise within the United States government.

11.0 Resource Portfolio Modeling

11.1 The *Strategist* Model—An Overview

The *Strategist* optimization model served as the calculation tool from which the PSO and SWEPCO capacity requirements were examined and resource addition recommendations were made as part of the IRP process. In this process *Strategist* offers unique "portfolios" of capacity resource options for PSO and SWEPCO that can be assessed from a discrete, revenue requirement perspective.

As its objective function, *Strategist* determines the lowest revenue requirement resource mix for the AEP-SPP generation (G) system. The solution is bounded by user-defined set of resource technologies, commodity pricing, and prescribed sets of constraints.

Strategist develops a least-cost resource mix by considering a variety of expansion planning assumptions including:

- Resource alternative characteristics (e.g., capital cost, construction period, project life).
- Operating parameters (e.g., capacity ratings, heat rates, outage rates, emission effluent rates, must-run status, etc.) of existing and new units.
- Unit dispositions (retirement/mothballing).
- Delivered fuel prices.
- Prices of external market energy as well as SO_2, NO_X, and CO_2 emission allowances.
- Reliability constraints (in this study, minimum reserve margin targets).
- Transmission limitations
- Emission limits and environmental compliance options.
- Alternative DR/EE program costs and impacts on peak load and energy requirements.

These and other assumptions are considered in the development of an integrated plan that best fits the utility system being analyzed. *Strategist* is a holistic model in that existing units may operate differently under different scenarios. The model determines and reflects such impacts on overall system variable operating costs. *Strategist* does not develop a full regulatory cost-of-service (COS) profile. Rather, it typically considers only those generation-COS components that change from plan to plan. It does not consider embedded costs associated with existing generating capacity that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non site-specific) capacity resource modeling would not typically incorporate significant capital for transmission interconnection.

Specifically, *Strategist* includes and recognizes in its revenue requirement calculation:

- Fixed costs of capacity additions, i.e., carrying charges on capacity and associated transmission (based on a PSO and SWEPCO's weighted average cost of capital), and fixed O&M;
- Fixed costs of any capacity purchases;
- Installation and administrative costs of DR/EE alternatives.
- Affiliate energy purchases and sales based on split-savings per West Operating Agreement.

- Variable costs associated with the entire fleet of new and existing generating units (using its probabilistic unit dispatch optimization engine). This includes fuel, purchased energy, market replacement cost of emission allowances, and variable O&M costs;
- Market revenues from external energy transactions (i.e., off-system sales). These are netted against costs.

In the PROVIEW module of *Strategist*, the least-cost expansion plan is empirically formulated from potentially tens of thousands of resource alternative combinations created by the module's dynamic programming algorithm. On an annual basis, each capacity resource combination that satisfies various user-defined constraints (to be discussed below) is considered to be a "feasible state" and is saved by the program for consideration in following years. As the years progress, the previous years' feasible states are used as starting points for the addition of more resources that can be used to meet the current year's minimum reserve requirement. As the need for additional capacity on the system increases, the number of possible combinations and the number of feasible states increases exponentially with the number of resource alternatives being considered.

11.1.1 Modeling Constraints and Economic Scenarios

Given that the model's algorithm has the potential for creating a vast number of alternative combinations and feasible states, it can create an extremely large computational and data storage problem, if not constrained in some manner. The *Strategist* model includes a number of input variables specifically designed to allow the user to limit the size of the problem. There were numerous other known physical and economic issues that needed to be considered during the modeling in order to reduce the problem size:

- Maintain an installed minimum capacity reserve margin of 13.6% per SPP criteria.
- Intercompany (PSO-SWEPCO) firm capacity transfer capability was limited to zero MW in the *Strategist* model. This constraint was subsequently modified in the creation of final, "Hybrid" plan by way of assuming such temporary "reserve sharing" between the two companies could approach 200 MW.
- PSO's and SWEPCO's combined interface with the SPP energy market was constrained to 300 MW for non-firm hourly energy sales; likewise it was constrained to 900 MW for non-firm hourly energy purchases.
- All generation installation costs represent AEP-SEA view of capacity build prices that were predicated upon information from AEP Generation Technology Development.
- Blocks of DR/EE programs were limited to one or two a year per program, depending on the program. The blocks were equal in size from an energy reduction perspective but varied in their cost and their impact on peak demand. This constraint specifically addresses the practical limit of the ability to market and subsequently install that level of DR/EE, independent of cost effectiveness.

Strategist was used to develop optimal and suboptimal plans given the fundamental power and CO_2 pricing scenarios and sensitivity cases developed by AEP's Fundamental Analysis group.

11.2 *Strategist* Optimization

11.2.1 Purpose

Strategist should be thought of as a tool used in the development of potentially economically viable resource portfolios. It does not produce "the answer;" rather, it produces or suggests many portfolios that have different cost profiles under different scenarios and sensitivities. Portfolios that fare well under all scenarios and sensitivities are considered for further evaluation. The optimum, or least-cost, portfolio under one scenario may not be the least-cost portfolio in other scenarios. Portfolio selection may reflect strategic decisions embraced by AEP leadership, including a commitment to DR/EE, renewable resources, and/or clean coal technology. *Strategist* results, both "optimum" and "sub-optimum" serve as a starting point for constructing a company's final capacity expansion plan.

For example, if under a given a scenario the *Strategist* model consistently adds peaking capacity in large quantities, a portfolio that substitutes a combined cycle plant for an equivalent amount of CTs might be constructed and tested to determine whether the revenue requirements are significantly different. Constraining the model to insert some additional practical constraints or conform to a company's strategy often can yield a more diversified solution that is not significantly more expensive. The optimum or least expensive portfolio under a scenario may have practical limitations that *Strategist* does not take into full account or may result in a plan that is very expensive under a different scenario.

11.2.2 Strategic Portfolios

Management commitments as outlined in the *AEP 2009 Corporate Sustainability Report* that were considered when constructing the underlying AEP-SPP resource portfolios include:

- **Renewable Resources:**
  - ✓ On a AEP system-wide basis, to achieve 7% of energy sales from renewable energy sources by 2013, 10% by 2020 and 15% by 2030.
  - ✓ Recognition of potential for a Federal RPS and existing or potential state RPS
- **Assumptions on "early mover" commitment to these GHG and renewable strategies**
  - ✓ Limit exposure to scarce resource pricing.
  - ✓ Take advantage of current tax credit for renewable generation.
  - ✓ Reduce exposure to potential GHG legislation, as initial mitigation requirements unfold.
  - ✓ Plan to be in concert with other CO_2/GHG reduction options (offsets, allowances, etc.).
- **Energy efficiency:** Consideration of increased levels of cost-effective DR/EE over previous resource planning cycles reflect stakeholder desires for such measures, as well as regulator willingness in the form of revenue recovery certainty.

11.3 AEP–SPP Supply-side Resource "Type" Options/Characteristics

There are many variants of available supply- and demand-side resources. It is a practical limitation that not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed and the optimum assets then were made available as options in *Strategist*. Such screening for typical supply-side alternatives was performed for each of the major generating duty-cycle "families" (baseload, intermediate, and peaking) as discussed in Section 8.

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty cycle family. Rather, they reflect proxies for modeling purposes.

Other factors will be considered which will determine the ultimate technology (for example, for "peaking" duty cycle the options include GE frame E or F machines, GE LM5100 aeroderivative machine, or others).

Appendix C lists the screened supply-side technologies. In fact the results of this screening are very similar to those previously determined in prior AEP-SPP IRP processes. Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Strategist* for each duty cycle:

- Peaking capacity was added in blocks of two, 164 MW GE-7FA Combustion Turbine units (summer rating of 157 MW x 2 = 314 MW), available beginning in 2013.
- Intermediate capacity was modeled as single natural gas Combined Cycle (GE7FB platform) unit, rated 538 MW (505 MW summer) available beginning in 2013.
- Baseload capacity burning PRB coals was modeled as a 618 MW Supercritical PC unit considering availability beginning in 2017. Due to previous agreements with various third parties, it was assumed that if PSO or SWEPCO added a coal unit, the company making the addition would receive a 450 MW share of this unit. It was also assumed that the units installed between 2017 and 2019 would be retrofitted with carbon capture and storage (CCS) technology in 2020 and units installed in 2020 and thereafter would be constructed with CCS technology.
- Nuclear capacity was represented by a 1,606 MW Mitsubishi US-APWR unit. It was assumed that PSO or SWEPCO would be a joint owner in this unit and would receive a 417 MW (400 MW summer) share of the unit so that this option would have capacity comparable to the other supply alternatives.

It should be realized that the costs shown in Appendix C and used for screening are baseline costs, given the state of markets for commodities, labor, etc., at the time the estimates were made. The costs used in the *Strategist* model for various scenarios may be different, depending on the inflation or deflation assumed for these factors in each scenario. These inflation or deflation factors should have little influence on screening because within each family the costs should generally move up and down in concert.

11.4 AEP-SPP DR/EE and Renewable Resource Options/Characteristics

Exhibit 11-1 shows the DR/EE program blocks and their estimated cost, energy, and demand reduction parameters utilized in *Strategist*. Hourly demand reduction profiles were developed for each program for both PSO and SWEPCO. Depending on the program, blocks of one or two could be added each year starting in 2010 through 2015. A full description of the DR/EE measures and the underlying evaluation/screening process are included in Section 8.5 and Section 9 of this report. Costs are fully installed device costs with an 8 percent addition for administrative expenses.

Exhibit 11-1: AEP Sponsored DSM Programs

AEP-SPP Sponsored DSM (Energy Efficiency and Demand Reduction) Programs						
Program	Type	Life (Years)	Incremental Cost $(000)	Annual Cost ($000)	MW	MWh
Commercial Cooling	EE	15	17,623		26.84	20,000
Commercial Lighting	EE	12	5,740		5.33	20,000
Commercial Motors	EE	15	6,999		8.15	20,000
Residential Cooling	EE	15	21,756		14.78	20,000
Residential Energy Star	EE	8	17,536		3.11	20,000
Residential Thermal Envelope	EE	20	7,476		3.29	20,000
C&I Peak Reduction	DR	20	873	428	15	0
Residential Peak Reduction	DR	20	8,986	418	15	0

Source: AEP Resource Planning

Capacity, energy and cost assumptions were made for a new 100 MW (nameplate) wind resource block in the AEP-SPP IRP analysis. The energy varies by month. Costs were assumed to escalate 2.25 percent each contract year beginning in 2012. Descriptions of the renewable resource alternatives evaluated and the evaluation process are found in Section 8.3 of this report.

11.5 PSO Plan Development

One of the benefits of using *Strategist*'s dynamic programming optimization algorithm is the ability to not only determine the optimal plan, but also evaluate suboptimal plans created in the same optimization run. The impact of adding different types of resources can be evaluated by comparing the economics of suboptimal plans to the optimal plan. PSO has purchased a sufficient amount of firm capacity from third parties to meet their reserve requirements through 2010. It was assumed that PSO would purchase approximately 400 MW of firm market capacity for 2011.

In the Oklahoma Corporation Commission's (OCC) final order in Cause number 200600030, the OCC found that PSO had a need for 450 MW of additional baseload generation in or around 2012. In response to this order, PSO re-issued a Request for Proposals (RFP) in 2008 for supply-side capacity and energy resources. As a result of the RFP, PSO has successfully negotiated a Power Purchase Agreement (PPA) with Exelon Generation Company for approximately 512 MW[4] of firm capacity from the Green Country unit during the period June 1, 2012 through February 28, 2022. Although this agreement must still be approved by the OCC, *it was assumed to be "embedded" in this 2009 PSO IRP analysis due to having undergone its own unique merit evaluates as part of the formal application with the Commission to approve the transaction.*

The IRP analysis assumed that no other capacity additions would be available until 2013.

[4] 512 MW rating is based on SPP criteria. 520 MW rating is based on contractual capacity testing criteria.

11.5.1 Comparison of PSO Plans for Base Power Price Scenario

Exhibit 11-2 compares some of the suboptimal plans by screened supply technology to the optimal PSO plan for the Base Power price scenario. A review of this exhibit shows the diversity of plans created by the model, as well as the economic impact created by the addition of each supply alternative. For example, a comparison of the Optimal Plan to the best plan that includes a coal unit, shows that PSO's costs would increase by approximately $104 million, versus the lowest-cost scenario reflective of only gas-fired capacity and energy.

Exhibit 11-2: Comparison of PSO Optimal and Suboptimal Plans

Comparison of PSO Optimal and Suboptimal Plans
Reference Price Scenario

Plan Description	Optimal Plan		Best Coal Plan		Best Nuclear Plan		Best Combined Cycle Plan	
	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)
2010	1 - Com. Cooling	27	1 - Com. Cooling	27	1 - Com. Cooling	27	1 - Com. Cooling	27
	2 - Com. Lighting	38	2 - Com. Lighting	38	2 - Com. Lighting	38	2 - Com. Lighting	38
	1 - Com. Motors	46	1 - Com. Motors	46	1 - Com. Motors	46	1 - Com. Motors	46
	2 - Res. Thermal Env.	52	2 - Res. Thermal Env.	52	2 - Res. Thermal Env.	52	2 - Res. Thermal Env.	52
2011	1 - Com. Cooling	79	1 - Com. Cooling	79	1 - Com. Cooling	79	1 - Com. Cooling	79
	2 - Com. Lighting	90	2 - Com. Lighting	90	2 - Com. Lighting	90	2 - Com. Lighting	90
	1 - Com. Motors	98	1 - Com. Motors	98	1 - Com. Motors	98	1 - Com. Motors	98
	2 - Res. Thermal Env.	104	2 - Res. Thermal Env.	104	2 - Res. Thermal Env.	104	2 - Res. Thermal Env.	104
2012	1 - Com. Cooling	131	1 - Com. Cooling	131	1 - Com. Cooling	131	1 - Com. Cooling	131
	2 - Com. Lighting	142	2 - Com. Lighting	142	2 - Com. Lighting	142	2 - Com. Lighting	142
	1 - Com. Motors	150	1 - Com. Motors	150	1 - Com. Motors	150	1 - Com. Motors	150
	2 - Res. Thermal Env.	157	2 - Res. Thermal Env.	157	2 - Res. Thermal Env.	157	2 - Res. Thermal Env.	157
2013	1 - Com. Cooling	184	1 - Com. Cooling	184	1 - Com. Cooling	184	1 - Com. Cooling	184
	2 - Com. Lighting	194	2 - Com. Lighting	194	2 - Com. Lighting	194	2 - Com. Lighting	194
	1 - Com. Motors	202	1 - Com. Motors	202	1 - Com. Motors	202	1 - Com. Motors	202
	2 - Res. Thermal Env.	209	2 - Res. Thermal Env.	209	2 - Res. Thermal Env.	209	2 - Res. Thermal Env.	209
2014	1 - Com. Cooling	236	1 - Com. Cooling	236	1 - Com. Cooling	236	1 - Com. Cooling	236
	2 - Com. Lighting	246	2 - Com. Lighting	246	2 - Com. Lighting	246	2 - Com. Lighting	246
	1 - Com. Motors	255	1 - Com. Motors	255	1 - Com. Motors	255	1 - Com. Motors	255
	2 - Res. Thermal Env.	261	2 - Res. Thermal Env.	261	2 - Res. Thermal Env.	261	2 - Res. Thermal Env.	261
2015	1 - Com. Cooling	288	1 - Com. Cooling	288	1 - Com. Cooling	288	1 - Com. Cooling	288
	2 - Com. Lighting	299	2 - Com. Lighting	299	2 - Com. Lighting	299	2 - Com. Lighting	299
	1 - Com. Motors	307	1 - Com. Motors	307	1 - Com. Motors	307	1 - Com. Motors	307
	2 - Res. Thermal Env.	313	2 - Res. Thermal Env.	313	2 - Res. Thermal Env.	313	2 - Res. Thermal Env.	313
2016								
2017	2 - 164 MW CTs		2 - 164 MW CTs		2 - 164 MW CTs		2 - 164 MW CTs	
2018								
2019								
2020								
2021								
2022	4 - 164 MW CTs		4 - 164 MW CTs		4 - 164 MW CTs		1 - 538 MW CC	
2023								
2024							2 - 164 MW CTs	
2025								
2026	2 - 164 MW CTs		1 - 450 MW PC w/ CCS		1 - 400 MW Nuclear			
2027								
2028								
2029								
2030								
2009 - 2035 CPW ($000)								
PSO Cost	17,107,470		17,211,227		17,576,440		17,140,635	
Cost Over Optimal Plan			103,757		468,971		33,165	

Source: AEP Resource Planning

11.5.2 Optimal PSO Results by Scenario

Strategist was used to develop the above optimal and suboptimal plans under the Reference case power and CO_2 pricing scenario along with the constraints summarized in (Sections 2 and 10.3). (The scenarios above are defined in Chapter 10.) In addition, optimal plans for each of the other power and CO_2 price scenarios were developed. A summary of these optimal plans can be found in **Exhibit 11-3.**

Exhibit 11-3: PSO Optimal Plan Comparison for Power and CO_2 Price Scenarios

PSO Optimal Plan Comparison for Power and CO2 Price Scenarios								
Power or CO2 Price Scenario	BAU		*Abundance Case*		Reference Case		Constrained Case	
	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)
2010	1 - Com. Cooling	27	2 - Com. Lighting	11	1 - Com. Cooling	27	1 - Com. Cooling	27
	2 - Com. Lighting	38	1 - Com. Motors	19	2 - Com. Lighting	38	2 - Com. Lighting	38
	1 - Com. Motors	46	2 - Res. Thermal Env.	25	1 - Com. Motors	46	1 - Com. Motors	46
	2 - Res. Thermal Env.	52			2 - Res. Thermal Env.	52	2 - Res. Thermal Env.	52
2011	1 - Com. Cooling	79	2 - Com. Lighting	36	1 - Com. Cooling	79	1 - Com. Cooling	79
	2 - Com. Lighting	90	1 - Com. Motors	44	2 - Com. Lighting	90	2 - Com. Lighting	90
	1 - Com. Motors	98	2 - Res. Thermal Env.	51	1 - Com. Motors	98	1 - Com. Motors	98
	2 - Res. Thermal Env.	104			2 - Res. Thermal Env.	104	2 - Res. Thermal Env.	104
2012	1 - Com. Cooling	131	2 - Com. Lighting	61	1 - Com. Cooling	131	1 - Com. Cooling	131
	2 - Com. Lighting	142	1 - Com. Motors	70	2 - Com. Lighting	142	2 - Com. Lighting	142
	1 - Com. Motors	150	2 - Res. Thermal Env.	76	1 - Com. Motors	150	1 - Com. Motors	150
	2 - Res. Thermal Env.	157			2 - Res. Thermal Env.	157	2 - Res. Thermal Env.	157
2013	1 - Com. Cooling	184	2 - Com. Lighting	87	1 - Com. Cooling	184	1 - Com. Cooling	184
	2 - Com. Lighting	194	1 - Com. Motors	95	2 - Com. Lighting	194	2 - Com. Lighting	194
	1 - Com. Motors	202	2 - Res. Thermal Env.	102	1 - Com. Motors	202	1 - Com. Motors	202
	2 - Res. Thermal Env.	209			2 - Res. Thermal Env.	209	2 - Res. Thermal Env.	209
2014	1 - Com. Cooling	236	2 - Com. Lighting	112	1 - Com. Cooling	236	1 - Com. Cooling	236
	2 - Com. Lighting	246	1 - Com. Motors	120	2 - Com. Lighting	246	2 - Com. Lighting	246
	1 - Com. Motors	255	2 - Res. Thermal Env.	127	1 - Com. Motors	255	1 - Com. Motors	255
	2 - Res. Thermal Env.	261			2 - Res. Thermal Env.	261	2 - Res. Thermal Env.	261
2015	1 - Com. Cooling	288	2 - Com. Lighting	138	1 - Com. Cooling	288	1 - Com. Cooling	288
	2 - Com. Lighting	299	1 - Com. Motors	146	2 - Com. Lighting	299	2 - Com. Lighting	299
	1 - Com. Motors	307	2 - Res. Thermal Env.	152	1 - Com. Motors	307	1 - Com. Motors	307
	2 - Res. Thermal Env.	313	2 - 164 MW CTs		2 - Res. Thermal Env.	313	2 - Res. Thermal Env.	313
2016								
2017	2 - 164 MW CTs				2 - 164 MW CTs		2 - 164 MW CTs	
2018								
2019								
2020								
2021								
2022	4 -164 MW CTs		4 -164 MW CTs		4 -164 MW CTs		1 - 450 MW PC w/ CCS	
2023							1 - 450 MW PC w/ CCS	
2024								
2025								
2026	2 - 164 MW CTs		2 - 164 MW CTs		2 - 164 MW CTs			
2027								
2028								
2029								
2030								
PSO CPW System Cost ($millions)	14,399		13,500		17,107		22,743	

Source : AEP Resource Planning

11.5.3 Observations: PSO Optimal Plan Composition

The economically optimum plans (i.e., lowest study period CPW revenue requirement) under the four power and CO_2 price scenarios and sensitivities produced essentially two choices. The optimization runs under the "Reference" and "BAU" price scenarios and sensitivities produced the same optimum plan adding eight 164 MW of generic gas-fired combustion turbine unit/blocks (i.e. "peaking" duty cycle), between 2017 and 2026, in addition to 313 MW of cumulative DSM peak demand reduction from four program measures. The optimum plan under the Abundance scenario is very similar, with the exception of one fewer DR/EE program selected resulting in only 152 MW of cumulative peak reduction, thus advancing the need for the first two peaking blocks to 2015. Under the Constrained scenario and sensitivity respectively, the optimum plan includes two combustion turbine units and 313 MW of DSM, as in the BAU and Reference cases, but adds a baseload block (as proxied by a 450 MW supercritical coal unit with CCS technology) unit/block in each of the years 2022 and 2023 rather than additional combustion turbine units.

The same four DR/EE programs, Commercial Cooling, Commercial Lighting, Commercial Motors, and Residential Thermal Envelope, were found to provide cumulative CPW savings under three of the four price scenarios. Each optimum plan requires the addition of capacity in 2022 to replace the Exelon PPA which expires at that time. In addition, the optimization runs under all four discrete price scenarios and sensitivities selected the addition of only peaking supply-side resources until 2022.

11.5.4 Development of the PSO Hybrid Plan

The Hybrid plan is developed by determining which of the various developed plans appears to be most "robust" (i.e., least-cost while also representing a practical solution) under the various price scenarios being driven by, particularly, implicit CO_2 price loads. In order to make this comparison, the optimal plans for each price scenario are effectively "forced" into the other scenarios. **Exhibit 11-4** summarizes the CPW of each PSO plan under each scenario for the full Study Period and **Exhibit 11-56** shows the differences.

Exhibit 11-4: PSO Full Study Period Revenue Requirements

PSO Full Study Period Revenue Requirement Comparison (2009-2035 CPW $ millions)				
Commodity and CO2 Price Scenario	BAU	Abundance	Reference	Constrained
No CO2 Price Optimal Plan	**14,399**	13,507	17,107	23,054
Low Power Price Optimal Plan	14,400	**13,500**	17,114	23,085
Base Power Price Optimal Plan	14,399	13,507	**17,107**	23,054
High Power Price Optimal Plan	15,159	14,003	17,357	**22,743**

Source: AEP Resource Planning

Exhibit 11-5: PSO Full Study Period Cost over Optimal Plan

PSO Full Study Period Revenue Requirement Comparison (2009-2035 CPW) Cost Over Optimal Plan ($ millions)				
Commodity and CO2 Price Scenario	BAU	Abundance	Reference	Constrained
No CO2 Price Optimal Plan		7	0	311
Low Power Price Optimal Plan	1		7	342
Base Power Price Optimal Plan	0	7		311
High Power Price Optimal Plan	760	503	250	

Source: AEP Resource Planning

In order to provide additional information for use in developing the Hybrid plan, *Strategist* was also used to identify optimal and suboptimal plans under the fundamental pricing scenarios using additional modeling constraints and scenarios:

- Best Contrary Baseload Coal Plan – the best suboptimal plan identified under the Reference and Constrained scenario optimizations containing a baseload coal supply-side resource. Separate plans were identified for PSO and SWEPCO.
- Best Contrary Baseload Nuclear Plan – Separate suboptimal plans for PSO and SWEPCO were also identified that included a baseload nuclear resource.

- Optimization with Carbon Capture and Storage (CCS) Requirements on New Coal – the optimal plan without a requirement that new baseload coal additions be either retrofitted or constructed with CCS technology.
- Enhanced Renewables – the optimal plan when additional renewable resources are added to achieve a target of 15% of (AEP System-wide) energy sales from renewable sources by 2020, in lieu of the previously noted going-in objective of achieving a 10% target by 2010.
- "Green" Plan – the best suboptimal plan from the Enhanced Renewables scenario that contains a baseload nuclear resource. Separate plans were identified for PSO and SWEPCO.
- Demand Destruction – the optimal plans under the Reference and Constrained scenarios when the load forecast was reduced from year 2009 to 2010 and held constant during 2010 through 2013. After 2013, the annual load was increased at a reduced rate of 1.2%.
- Demand Destruction and Unit Retirements – this scenario assumes both the "Demand Destruction" load forecast described above as well as the currently-not-contemplated retirement of five PSO units (549 MW) between 2018 and 2024 and nine units (668 MW) at SWEPCO between 2020 and 2025.
- High Demand Reduction/Energy Efficiency (DR/EE) Bandwidth – the optimal plan under the Constrained scenario if the DSM blocks are increased by a relative 50%.
- CO_2 Limited – In this scenario, CO_2 emission limits were assumed to be placed on the AEP's East and SPP systems based on the continued prospect for comprehensive Climate Change/CO_2 legislation that would seek to reduce such emission levels. As a proxy for such reductions, H.R. 2454 (the Waxman-Markey Bill) that was introduced in draft form in April, 2009 (as was ultimately passed by the U.S. House in June) was used. In 2020, the CO_2 emission limit was based on a 15% reduction (W-M called for 17%) from 2005 actual CO_2 emissions. In 2030, the CO_2 emissions limit was based on a 40% reduction (W-M called for 42%) in 2005 CO_2 emissions of 145 million (metric) tonnes, or a limit of approximately 82 million tonnes for the AEP System. These emission limits were also developed under the assumption that the AEP System would receive a maximum of 20 million tonnes of carbon offsets. These offsets were assigned to the East and West systems based on their prorate share of 2005 CO_2 emissions, with the East being allocated approximately 15.5 million tonnes and the West receiving 4.5 million tonnes. In recognition of a CO_2 constrained environment, this scenario includes options to meet system CO_2 emission limits in 2020 and 2030, including the "Enhanced Renewables" and "High DR/EE" bandwidth scenarios described above plus the retrofitting of existing coal units with CCS technology.

Exhibit 11-6 provides a comparison of the optimal plans under each of the four price scenarios along with the results of the additional modeling constraints and scenarios listed above run under some or all of the price scenarios.

Exhibit 11-6: PSO Plan Comparisons

PSO Plan Comparison

New Capacity (Summer Rating)	Units	Capacity		BAU (No CO_2)	Abundance (Low Power)	Reference (Base Power)	Constrained (High Power)
No CO2 Price Optimal Plan							
CT	8	1,256	Total NPV-$B	14.40	13.51	17.11	23.05
CC	0	0	$/MWh	70.21	66.19	81.79	107.23
PC w/CCS	0	0	Fuel NPV-$B	12.22	10.54	13.38	17.99
Wind[a]	5	500	$/MWh	52.29	44.95	57.23	76.94
Total		1,296					
DR[b]		313					
Low Power Price Optimal Plan							
CT	8	1,256	Total NPV-$B	14.40	13.50	17.11	23.09
CC	0	0	$/MWh	70.21	66.16	81.82	107.36
PC w/CCS	0	0	Fuel NPV-$B	12.27	10.58	13.43	18.06
Wind[a]	5	500	$/MWh	52.49	45.13	57.45	77.24
Total		1,296					
DR[b]		152					
Base Power Price Optimal Plan							
CT	8	1,256	Total NPV-$B	14.40	13.51	17.11	23.05
CC	0	0	$/MWh	70.21	66.19	81.79	107.23
PC w/CCS	0	0	Fuel NPV-$B	12.22	10.54	13.38	17.99
Wind[a]	5	500	$/MWh	52.29	44.95	57.23	76.94
Total		1,296					
DR[b]		313					
High Power Price Optimal Plan							
CT	2	314	Total NPV-$B	15.16	14.00	17.36	22.74
CC	0	0	$/MWh	73.45	68.30	82.86	105.90
PC w/CCS	2	910	Fuel NPV-$B	11.12	9.36	11.73	15.55
Wind[a]	5	500	$/MWh	47.57	39.93	50.16	66.50
Total		1,264					
DR[b]		313					
Best Contrary Coal Plan							
CT	6	942	Total NPV-$B	14.68	13.70	17.21	22.96
CC	0	0	$/MWh	71.41	66.99	82.24	106.81
PC w/CCS	1	455	Fuel NPV-$B	11.82	10.12	12.78	17.10
Wind[a]	5	500	$/MWh	50.58	43.15	54.69	73.14
Total		1,437					
DR[b]		313					
Best Contrary Nuclear Plan							
CT	6	942	Total NPV-$B	15.05	14.03	17.58	23.35
CC	0	0	$/MWh	73.01	68.42	83.80	108.50
Nuclear	1	400	Fuel NPV-$B	11.79	10.11	12.76	17.08
Wind[a]	5	500	$/MWh	50.43	43.13	54.60	73.05
Total		1,382					
DR[b]		313					

Notes:
a) Wind assumed to contribute 8 MW of summer capacity for every 100 MW of nameplate capacity.
b) Demand Reduction, cumulative DSM peak reduction through 2015.

Exhibit 11-6: PSO Plan Comparisons (Cont'd)

PSO Plan Comparison

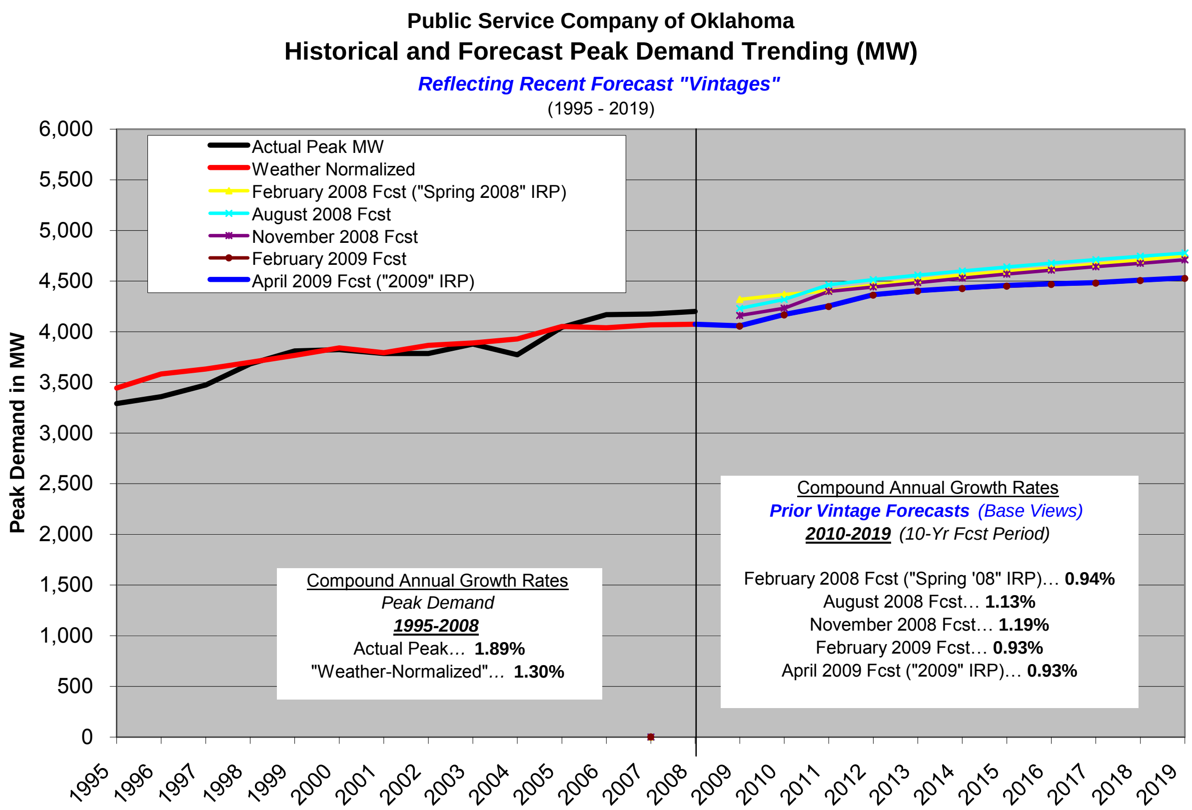
New Capacity (Summer Rating)	Units	Capacity		BAU	Abundance	Reference	Constrained
Optimized Without CCS Requirement							
CT	8	1,256	Total NPV-$B	14.40	13.50	17.11	
CC	0	0	*$/MWh*	*70.21*	*66.16*	*81.79*	
PC w/CCS	0	0	Fuel NPV-$B	12.22	10.58	13.38	
Wind[a]	5	500	*$/MWh*	*52.29*	*45.13*	*57.23*	
Total		1,296					
DR[b]		313					
Enhanced Renewables							
CT	8	1,256	Total NPV-$B		13.63	17.14	22.69
CC	0	0	*$/MWh*		*66.73*	*81.93*	*105.67*
PC w/CCS	0	0	Fuel NPV-$B		10.73	13.44	15.69
Wind[a]	7	700	*$/MWh*		*45.76*	*57.51*	*67.13*
Total		1,312					
DR[b]		313					
"Green" Plan							
CT	6	942	Total NPV-$B			17.57	22.98
CC	0	0	*$/MWh*			*83.75*	*106.91*
Nuclear	1	400	Fuel NPV-$B			12.91	16.20
Wind[a]	7	700	*$/MWh*			*55.25*	*69.29*
Total		1,398					
DR[b]		313					
Demand Destruction							
CT	8	1,256	Total NPV-$B			15.77	21.03
CC	0	0	*$/MWh*			*81.01*	*105.27*
PC w/CCS	0	0	Fuel NPV-$B			12.32	15.14
Wind[a]	5	500	*$/MWh*			*56.13*	*69.16*
Total		1,296					
DR[b]		152					
Demand Destruction + Unit Retirements							
CT	10	1,570	Total NPV-$B		12.62	15.92	
CC	0	0	*$/MWh*		*66.65*	*81.66*	
PC w/CCS	0	0	Fuel NPV-$B		9.71	12.24	
Wind[a]	5	500	*$/MWh*		*44.24*	*55.77*	
Total		1,610					
DR[b]		152					
High DR/EE Bandwidth							
CT	2	314	Total NPV-$B				22.57
CC	0	0	*$/MWh*				*106.17*
PC w/CCS	2	910	Fuel NPV-$B				15.53
Wind[a]	5	500	*$/MWh*				*67.06*
Total		1,264					
DR[b]		470					
CO2 Limited							
CT	8	1,256	Total NPV-$B			17.06	22.39
CC	0	0	*$/MWh*			*82.30*	*105.28*
PC w/CCS	0	0	Fuel NPV-$B			13.28	15.54
Wind[a]	7	700	*$/MWh*			*57.35*	*67.09*
Total		1,312					
DR[b]		470					

Notes:
a) Wind assumed to contribute 8 MW of summer capacity for every 100 MW of nameplate capacity.
b) Demand Reduction, cumulative DSM peak reduction through 2015.

Source: AEP Resource Planning

Finally, in late-April 2009, prior to the development of the Hybrid Plan, but subsequent to the development of the optimal plans in *Strategist* described above, AEP's Economic Forecasting organization issued an updated load forecast to reflect the results of the recent downturn in the economy, as discussed in Section 5 of this report. It is important to look at this most recent change to the load forecast in the context of previous revisions. The following **Exhibit 11-7** provides a summary of recent peak demand forecasts prepared by AEP. As can be seen from this exhibit, the forecast from one period to the next may be higher or lower, depending on changes in economics or customer behavior both locally (for PSO) and nationally. However, the trend is generally consistent with compound annual growth rates between 0.93 percent and 1.19 percent. This is compared to the historical, weather normalized growth rate of 1.30 percent.

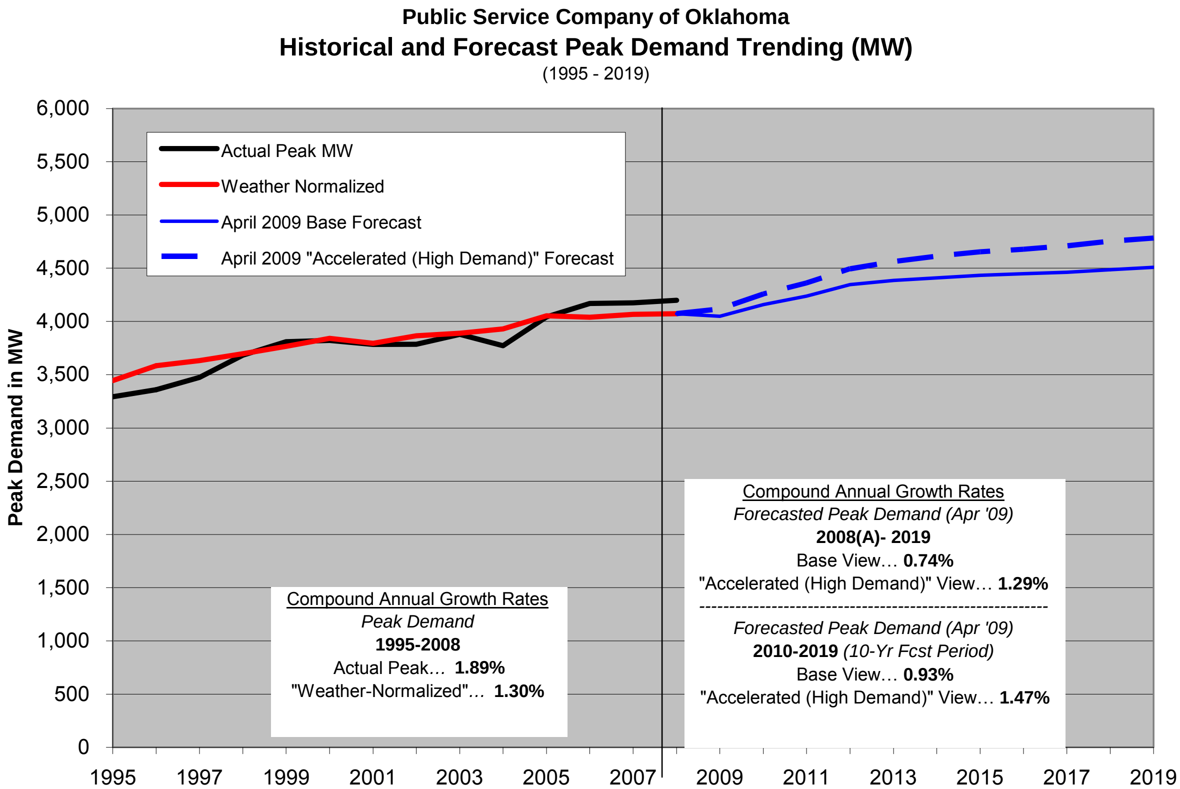
Exhibit 11-7: PSO Load Forecast Trends



Source: AEP Resource Planning

Given this variability in forecasts, and noting that the current forecast grows at a rate lower than what has been PSO's historical experience, an alternate "High Demand" forecast has also been prepared which assumes a more vigorous economic recovery in the near term, but is based on an overall growth rate for the 25 year period, 1995-2020, closely equal to the historical growth rate experienced since 1995 to 2008. This forecast was prepared to ensure that PSO would not find itself in a capacity deficit position should the economy turn around quicker than expected. **Exhibit 11-8** compares the current April 2009 forecast to the "High Demand" forecast.

Exhibit 11-8: PSO Load Forecast Comparison



Source: AEP Resource Planning

As shown earlier in this document in Section 1.2 and repeated here as **Exhibit 11-9**, the embedded Exelon contract provides adequate capacity to meet PSO's peak demand using the April 2009 forecast, however PSO may find itself in a capacity deficit position in 2016 if actual demand growth is closer to the "High Demand" view. This deficiency occurs far enough in the future for PSO to continue to monitor changes in load and react as needed. Note that under both the "Base Demand" and "High Demand" "High Demand" scenarios, if the Exelon PPA is not executed, PSO's capacity position would be deficit in 2012 and beyond. An alternate Capacity, Demand, Reserve table incorporating this High Demand forecast is included in the Appendix.

Exhibit 11-9: PSO Reserve Margin

PSO

Stand-Alone Reserve Margins*

Based on (April 2009) Demand Forecast "Banding"

10-Year 2009 IRP Period: **2010-2019**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reserve Margin										
Under **"Base"** Demand Forecast:										
Per 2009 Resource Plan	13.8%	13.2%	19.2%	19.7%	19.9%	20.3%	19.5%	19.3%	18.7%	18.1%
Exclusive of Exelon PPA (2012)	*13.8%*	*13.2%*	6.9%	7.4%	7.6%	7.9%	7.2%	7.1%	6.5%	6.1%
Under **"Accelerated (High)"** Demand Forecast:										
Per 2009 Resource Plan	11.0%	8.2%	15.2%	14.8%	14.2%	14.2%	13.2%	12.6%	11.6%	10.9%
Exclusive of Exelon PPA (2012)	*11.0%*	*8.2%*	*3.2%*	*3.0%*	*2.5%*	*2.5%*	*1.5%*	*1.1%*	*0.2%*	*-0.5%*
Reserve Margin -- MW Position										
Above / <Below> 13.6% SPP Requirement)										
Under **"Base"** Demand Forecast:										
Per 2009 Resource Plan	6	(18)	232	253	259	275	242	237	211	190
Exclusive of Exelon PPA (2012)	*6*	*(18)*	(280)	(259)	(251)	(235)	(268)	(271)	(297)	(318)
Under **"Accelerated (High)"** Demand Forecast:										
Per 2009 Resource Plan	(108)	(228)	65	51	26	24	(19)	(46)	(92)	(124)
Exclusive of Exelon PPA (2012)	*(108)*	*(228)*	(447)	(461)	(484)	(486)	(529)	(554)	(600)	(632)

* Excludes short-term capacity transfers to/from affiliate Southwestern Electric Power Company

Note: Minimum Reserve Margin Requirement per SPP Criteria is 13.6%

Source: AEP Resource Planning

After reviewing the results of the various optimal plans developed under the price scenarios and other modeling constraints and scenarios, and taking the new load forecast into account, the PSO Hybrid Plan was developed. The specific details and timing of the plan are displayed in **Exhibit 11-10.**

Exhibit 11-10: PSO Hybrid Plan

2009 IRP (Hybrid Plan) *PSO*

MW	*Planned Resource Reductions* [(A)]		*Planned Resource Additions*				
			DSM		RENEWABLE		THERMAL
	Unit Retirements/Expirations (summer-rating)	Environmental Retrofits[(F)]	*Embedded* Demand Reduction[(B)] *(Cumul. Contribution)*	*New* Demand Reduction[(C)] *(Cumul. Contribution)*	Solar (Nameplate)	Wind (Nameplate)	Duty Cycle Type: BL=Baseload INT=Intermediate/Cyclic PKG=Peaking
2009			9	0			
2010			13	31			
2011			16	62		198 [(E)]	
2012			19	94			(Grn Cntry PPA) 512-MW BL
2013			21	125			
2014			22	157			
2015			23	188		67	
2016		NE 3&4 FGD (15)	24	188			
2017			25	188		200	
2018			25	188			
2019			25	188			
2019 Cumul. Contribution/Nameplate	***0***	***(15)***	***25***	***188***	***0***	***465***	***512***
(SPP) Capacity Value (Wind 8%; Solar 70%(est.))					***0***	***37***	
2020			25	188		200	157-MW PKG
2021			25	188			
2022	PPA Expiration (512-MW)[(D)]		25	188			505-MW INT
2023			25	188		100	
2024			25	188			
2025			25	188			157-MW PKG
2026			25	188	17	100	
2027			25	188	17		
2028			25	188	35		157-MW PKG
2029			25	188	35	100	
2030		NE3 CCS (74 MW)	25	188	56		
2030 Cumul. Contribution/Nameplate	***(512)***	***(89)***	***25***	***188***	***160***	***965***	***1,488***
(SPP) Capacity Value (Wind 8%; Solar 70%(est.))					***112***	***77***	
Cumul. (Nameplate) Contribution thru '30			***1%***	***7%***	***6%***	***34%***	***53%***
Cumul. (Capacity) Contribution thru '30			***1%***	***10%***	***6%***	***4%***	***79%***

'NET' CAPACITY RESOURCE ADDITIONS:	
2009-2019	***747***
2009-2030	***1,288***

Peaking	471	*48%*
Intermediate	505	*52%*
Intermediate Contract Expiration	(512)	*-52%*
Baseload	512	*52%*
	976	

(A) Not shown are relatively small unit uprates and derates embedded in the current plan (e.g. FGD retrofit auxiliary load losses)
(B) "Embedded" DSM represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(C) "New" DSM represents incremental activity projected based on estimated contribution & program cost (vs. avoided cost) parameters, from recent Market Potential Studies, and were generally limited to an EPRI Jan. '09 study identifying a "Realistically Achievable Potential"… Note:
(D) PPA term for PSO 2012 baseload capacity & energy: 9 years, 7 months (thru 2021)
(E) Assumes Elk City and Blue Canyon V wind energy available by 2011, but firm transmission delayed until 2013
(F) CCS retrofit technology assumed to be chilled ammonia with a 15% parasitic load

Source: AEP Resource Planning

11.5.5 Observations: PSO Hybrid Plan Composition

Several factors were considered in the development of the various elements of the PSO 2009 Hybrid Plan:

- Thermal Resources – It was determined from the price scenario optimal plans that the most cost effective planned thermal resource addition was generally peaking capacity and energy. It was also determined that the combustion turbine capacity should be provided in single unit/blocks rather than in blocks of two. Due to the reduced load forecast, the timing of the first new block was delayed until 2020. Recall, the Hybrid Plan also reflects the assumed addition of 512 MW of combined cycle capacity from the Exelon PPA starting in June 2012 through February 2022. As such, an intermediate resource is added to the plan in 2022 to replace this contract. The *Strategist* analysis showed that a plan with a combined cycle in 2022 was almost identical in cost to one showing a set of CT's.
- Renewable Resources – The renewable resource portfolio included both wind and solar resources required to achieve the renewable energy sales targets established for 2013, 2020, and 2030. Wind resources are being added throughout the planning period.
- DSM – The four DR/EE programs that were found to be cost effective in the screening process (see Section 9) were included in the Hybrid Plan, but the cumulative demand reduction was reduced from 313 MW to 188 MW to reflect the "Realistically Achievable Potential" identified in the recent EPRI study for the same time frame. Additionally, as identified in Section 4, cumulative demand reduction of 25 MW of "known and measurable" OCC-approved program activity was reflected as part of the most recent load forecast.
- CCS Retrofits – To acknowledge the potential requirement for significant CO_2 emission reductions in the future, that may not be achievable via other means, a CCS technology retrofit is included in the plan at the Northeastern 3 unit in the 2030 out-year. This technology's potentially significant relative CO_2 reduction contribution was viewed as being critical to the prospect of achieving substantive CO_2 reduction requirements such as those set forth by the Waxman-Markey Bill.

11.5.6 Summary and Conclusions for PSO Plans

The PSO resource expansion plan provides a robust and diverse approach to meeting PSO's resource needs in both a cost effective manner and one that considers the long-term prospect of carbon mitigation. This study has shown that with the addition of 512 MW of capacity from the Exelon PPA, no additional thermal resources are required to meet additional capacity needs over the 10 year planning horizon. The plan includes substantial clean energy renewable resources, including wind and, over the long term, solar, to meet aggressive renewable energy targets set by the Company. This study also shows that significant amounts of selected DR/EE programs are potentially cost effective and should be employed on PSO's system. The long-term plan also addresses the issue of potential CO_2 emission limits through retrofitting an existing coal unit with CCS technology.

11.6 SWEPCO Plan Development

The SWEPCO resource expansion plan was developed in a manner similar to the PSO resource plan. The SWEPCO plan was created using many of the same resource addition assumptions and commodity price assumptions as the PSO plan. The PSO and SWEPCO plans are developed simultaneously with both systems adding capacity on an individual company basis to meet respective reserve requirements. However, the ability to transfer economy energy between the respective companies was considered in determining these capacity resources.

The SWEPCO resource plans were based on the assumption that the 509 MW Stall CC would be in service by July, 2010. In addition, it was assumed that SWEPCO would receive its 447 MW share of the 600 MW Turk PC by the end of June, 2012. Both these facilities received certificates of need from the three states that SWEPCO operates within, Arkansas, Louisiana and Texas, and are currently under construction with Stall 60 percent physically complete and Turk 15 percent physically complete as of June 30, 2009.

	Stall	Turk
Arkansas	06-120-U	06-154-U
Louisiana	U-29702/U-27866 B	U-23327 B
Texas	33048	33891

11.6.1 Comparison of SWEPCO Plans for Base Power Price Scenario

Exhibit 11-11 compares some of the suboptimal plans to the optimal SWEPCO plan for the Reference price scenario. This exhibit shows the diversity of plans created by the model, as well as the economic impact created by the addition of each supply alternative. For example, a comparison of the Optimal Plan to the best plan that includes a coal unit, shows that SWEPCO's costs would increase by approximately $212 million.

Exhibit 11-11: Comparison of SWEPCO Optimal and Suboptimal Plans

Comparison of SWEPCO Optimal and Suboptimal Plans
Reference Price Scenario

Plan Description	**Optimal Plan**		**Best Coal Plan**		**Best Nuclear Plan**		**Best Combined Cycle Plan**	
	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)
2010	1 - Com. Cooling	27	1 - Com. Cooling	27	1 - Com. Cooling	27	1 - Com. Cooling	27
	2 - Com. Lighting	38	2 - Com. Lighting	38	2 - Com. Lighting	38	2 - Com. Lighting	38
	1 - Com. Motors	46	1 - Com. Motors	46	1 - Com. Motors	46	1 - Com. Motors	46
	2 - Res. Thermal Env.	52	2 - Res. Thermal Env.	52	2 - Res. Thermal Env.	52	2 - Res. Thermal Env.	52
2011	1 - Com. Cooling	79	1 - Com. Cooling	79	1 - Com. Cooling	79	1 - Com. Cooling	79
	2 - Com. Lighting	90	2 - Com. Lighting	90	2 - Com. Lighting	90	2 - Com. Lighting	90
	1 - Com. Motors	98	1 - Com. Motors	98	1 - Com. Motors	98	1 - Com. Motors	98
	2 - Res. Thermal Env.	104	2 - Res. Thermal Env.	104	2 - Res. Thermal Env.	104	2 - Res. Thermal Env.	104
2012	1 - Com. Cooling	131	1 - Com. Cooling	131	1 - Com. Cooling	131	1 - Com. Cooling	131
	2 - Com. Lighting	142	2 - Com. Lighting	142	2 - Com. Lighting	142	2 - Com. Lighting	142
	1 - Com. Motors	150	1 - Com. Motors	150	1 - Com. Motors	150	1 - Com. Motors	150
	2 - Res. Thermal Env.	157	2 - Res. Thermal Env.	157	2 - Res. Thermal Env.	157	2 - Res. Thermal Env.	157
2013	1 - Com. Cooling	184	1 - Com. Cooling	184	1 - Com. Cooling	184	1 - Com. Cooling	184
	2 - Com. Lighting	194	2 - Com. Lighting	194	2 - Com. Lighting	194	2 - Com. Lighting	194
	1 - Com. Motors	202	1 - Com. Motors	202	1 - Com. Motors	202	1 - Com. Motors	202
	2 - Res. Thermal Env.	209	2 - Res. Thermal Env.	209	2 - Res. Thermal Env.	209	2 - Res. Thermal Env.	209
2014	1 - Com. Cooling	236	1 - Com. Cooling	236	1 - Com. Cooling	236	1 - Com. Cooling	236
	2 - Com. Lighting	246	2 - Com. Lighting	246	2 - Com. Lighting	246	2 - Com. Lighting	246
	1 - Com. Motors	255	1 - Com. Motors	255	1 - Com. Motors	255	1 - Com. Motors	255
	2 - Res. Thermal Env.	261	2 - Res. Thermal Env.	261	2 - Res. Thermal Env.	261	2 - Res. Thermal Env.	261
2015	1 - Com. Cooling	288	1 - Com. Cooling	288	1 - Com. Cooling	288	1 - Com. Cooling	288
	2 - Com. Lighting	299	2 - Com. Lighting	299	2 - Com. Lighting	299	2 - Com. Lighting	299
	1 - Com. Motors	307	1 - Com. Motors	307	1 - Com. Motors	307	1 - Com. Motors	307
	2 - Res. Thermal Env.	313	2 - Res. Thermal Env.	313	2 - Res. Thermal Env.	313	2 - Res. Thermal Env.	313
2016								
2017								
2018								
2019								
2020								
2021								
2022	2 - 164 MW CTs		2 - 164 MW CTs		2 - 164 MW CTs		2 - 164 MW CTs	
2023								
2024								
2025	2 - 164 MW CTs		2 - 164 MW CTs		1 - 400 MW Nuke		2 - 164 MW CTs	
2026								
2027								
2028	2 - 164 MW CTs		1 - 450 MW PC w/ CCS				1 - 538 MW CC	
2029					2 - 164 MW CTs			
2030								
2009 - 2035 CPW ($000)								
SWEPCO Cost	19,082,410		19,294,788		19,634,502		19,202,563	
Cost Over Optimal Plan			212,378		552,092		120,153	

Source: AEP Resource Planning

11.6.2 Optimal SWEPCO Results by Scenario

Strategist was used to develop the above optimal and suboptimal plans under the Reference price scenario along with the constraints summarized in (Sections 2 and 10.3). In addition, optimal plans for each of the other power and CO_2 price scenarios were developed. A summary of these optimal plans can be found in **Exhibit 11-12.**

Exhibit 11-12: SWEPCO Optimal Plan Comparison for Power and CO_2 Price Scenarios

SWEPCO Optimal Plan Comparison for Power and CO2 Price Scenarios

Scenario	BAU		Abundance		Reference		Constrained	
	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)	Supply-side and DSM Additions	Cumulative Peak Reduction (MW)
2010	1 - Com. Cooling	27	2 - Com. Lighting	11	1 - Com. Cooling	27	1 - Com. Cooling	27
	2 - Com. Lighting	38	1 - Com. Motors	19	2 - Com. Lighting	38	2 - Com. Lighting	38
	1 - Com. Motors	46	2 - Res. Thermal Env.	25	1 - Com. Motors	46	1 - Com. Motors	46
	2 - Res. Thermal Env.	52			2 - Res. Thermal Env.	52	2 - Res. Thermal Env.	52
							1- Res. Cooling	67
2011	1 - Com. Cooling	79	2 - Com. Lighting	36	1 - Com. Cooling	79	1 - Com. Cooling	94
	2 - Com. Lighting	90	1 - Com. Motors	44	2 - Com. Lighting	90	2 - Com. Lighting	105
	1 - Com. Motors	98	2 - Res. Thermal Env.	51	1 - Com. Motors	98	1 - Com. Motors	113
	2 - Res. Thermal Env.	104			2 - Res. Thermal Env.	104	2 - Res. Thermal Env.	119
							1- Res. Cooling	134
2012	1 - Com. Cooling	131	2 - Com. Lighting	61	1 - Com. Cooling	131	1 - Com. Cooling	161
	2 - Com. Lighting	142	1 - Com. Motors	70	2 - Com. Lighting	142	2 - Com. Lighting	172
	1 - Com. Motors	150	2 - Res. Thermal Env.	76	1 - Com. Motors	150	1 - Com. Motors	180
	2 - Res. Thermal Env.	157			2 - Res. Thermal Env.	157	2 - Res. Thermal Env.	186
							1- Res. Cooling	201
2013	1 - Com. Cooling	184	2 - Com. Lighting	87	1 - Com. Cooling	184	1 - Com. Cooling	228
	2 - Com. Lighting	194	1 - Com. Motors	95	2 - Com. Lighting	194	2 - Com. Lighting	239
	1 - Com. Motors	202	2 - Res. Thermal Env.	102	1 - Com. Motors	202	1 - Com. Motors	247
	2 - Res. Thermal Env.	209			2 - Res. Thermal Env.	209	2 - Res. Thermal Env.	253
							1- Res. Cooling	268
2014	1 - Com. Cooling	236	2 - Com. Lighting	112	1 - Com. Cooling	236	1 - Com. Cooling	295
	2 - Com. Lighting	246	1 - Com. Motors	120	2 - Com. Lighting	246	2 - Com. Lighting	306
	1 - Com. Motors	255	2 - Res. Thermal Env.	127	1 - Com. Motors	255	1 - Com. Motors	314
	2 - Res. Thermal Env.	261			2 - Res. Thermal Env.	261	2 - Res. Thermal Env.	320
							1- Res. Cooling	335
2015	1 - Com. Cooling	288	2 - Com. Lighting	138	1 - Com. Cooling	288	1 - Com. Cooling	362
	2 - Com. Lighting	299	1 - Com. Motors	146	2 - Com. Lighting	299	2 - Com. Lighting	373
	1 - Com. Motors	307	2 - Res. Thermal Env.	152	1 - Com. Motors	307	1 - Com. Motors	381
	2 - Res. Thermal Env.	313			2 - Res. Thermal Env.	313	2 - Res. Thermal Env.	387
							1- Res. Cooling	402
2016								
2017								
2018								
2019								
2020			2 - 164 MW CTs					
2021								
2022	2 - 164 MW CTs				2 - 164 MW CTs			
2023							2 - 164 MW CTs	
2024			2 - 164 MW CTs					
2025	2 - 164 MW CTs				2 - 164 MW CTs			
2026							2 - 164 MW CTs	
2027			2 - 164 MW CTs					
2028	2 - 164 MW CTs				2 - 164 MW CTs		2 - 164 MW CTs	
2029								
2030								
CPW ($millions)	13,920		14,821		19,082		25,452	

Source: AEP Resource Planning

11.6.3 Observations: SWEPCO Optimal Plan Composition

The economically optimum plans (i.e. lowest study period CPW revenue requirement) under all four discrete price scenarios and sensitivities are very similar. The optimum runs under the BAU and Reference price scenarios and sensitivities produced the same optimum plan adding two 164 MW combustion turbine peaking units/blocks in each of the years 2022, 2025, and 2028. The plan also includes 313 MW of cumulative DSM peak reduction from four program measures. The optimum plan under the Abundance price scenario includes only three DR/EE programs with 152 MW of cumulative peak reduction and advances the blocks of two 164 MW peaking combustion turbines to years 2020, 2024, and 2027. Under the Constrained price scenario, the optimum plan includes five DSM programs with 402 MW of cumulative peak reduction. As a result, the addition of the combustion turbines is delayed to 2023, 2026, and 2028.

Under all four price scenarios and sensitivities, peaking duty cycle (proxied in the form of combustion turbine units), are the only supply-side resource selected. The only difference is the timing of the additions based on the number of DSM program measures added. The same four DR/EE programs, Commercial Cooling, Commercial Lighting, Commercial Motors, and Residential Thermal Envelope, were found to provide cumulative CPW savings under three of the four discrete price scenarios and sensitivities. This would indicate a high level of confidence in making peaking/combustion turbine and DR/EE additions under future scenarios.

11.6.4 Development of the SWEPCO Hybrid Plan

The Hybrid plan is developed by determining which optimal plan appears to be most "robust" (i.e., least cost) under the various price scenarios and sensitivities. As with the PSO analysis, in order to make this comparison, the SWEPCO optimal plans for each price scenario and sensitivities are forced into the other scenarios. **Exhibit 11-13** summarizes the CPW of each SWEPCO plan under each scenario for the full Study Period and **Exhibit 11-14** shows the differences.

Exhibit 11-13: SWEPCO Full Study Period Revenue Requirements

SWEPCO Full Study Period Revenue Requirement Comparison (2009-2035 CPW $ millions)				
Commodity and CO2 Price Scenario	BAU	Abundance	Reference	Constrained
No CO2 Price Optimal Plan	**13,920**	14,830	19,082	25,356
Low Power Price Optimal Plan	13,924	**14,821**	19,087	25,387
Base Power Price Optimal Plan	13,920	14,830	**19,082**	25,356
High Power Price Optimal Plan	14,012	14,914	19,160	**25,452**

Source: AEP Resource Planning

Exhibit 11-14: SWEPCO Full Study Period Cost over Optimal Plan

SWEPCO Full Study Period Revenue Requirement Comparison (2009-2035 CPW) Cost Over Optimal Plan ($ millions)				
Commodity and CO2 Price Scenario	BAU	Abundance	Reference	Constrained
No CO2 Price Optimal Plan		9	0	(96)
Low Power Price Optimal Plan	4		5	(65)
Base Power Price Optimal Plan	0	9		(96)
High Power Price Optimal Plan	92	93	78	

Source: AEP Resource Planning

In order to provide additional information for use in developing the Hybrid plan, *Strategist* was also used to identify optimal and suboptimal plans under the fundamental pricing scenarios using additional modeling constraints and scenarios. These additional constraints and scenarios were largely identical to those utilized in the PSO analysis that are described in detail in Section 11.5.4 of this report.

Exhibit 11-15 provides a financial comparison of the optimal plans under each of the four price scenarios along with the results of the additional modeling constraints and scenarios run under some or all of the price scenarios over the 2009-2035 extended planning horizon.

Exhibit 11-15: SWEPCO Plan Comparisons

SWEPCO Plan Comparison

New Capacity (Summer Rating)	Units	Capacity		BAU (No CO_2)	Abundance (Low Power)	Reference (Base Power)	Constrained (High Power)
No CO2 Price Optimal Plan							
CT	6	942	Total NPV-$B	13.92	14.83	19.08	25.36
CC	0	0	*$/MWh*	*56.23*	*59.19*	*73.82*	*95.42*
PC w/CCS	0	0	Fuel NPV-$B	11.24	9.65	11.78	13.91
Wind[a]	13	1,300	*$/MWh*	*38.33*	*32.81*	*40.16*	*47.52*
Total		1,046					
DR[b]		313					
Low Power Price Optimal Plan							
CT	6	942	Total NPV-$B	13.92	14.82	19.09	25.39
CC	0	0	*$/MWh*	*56.24*	*59.15*	*73.84*	*95.54*
PC w/CCS	0	0	Fuel NPV-$B	11.28	9.68	11.82	13.96
Wind[a]	13	1,300	*$/MWh*	*38.45*	*32.90*	*40.28*	*47.69*
Total		1,046					
DR[b]		152					
Base Power Price Optimal Plan							
CT	6	942	Total NPV-$B	13.92	14.83	19.08	25.36
CC	0	0	*$/MWh*	*56.23*	*59.19*	*73.82*	*95.44*
PC w/CCS	0	0	Fuel NPV-$B	11.24	9.65	11.78	13.91
Wind[a]	13	1,300	*$/MWh*	*38.33*	*32.81*	*40.16*	*47.52*
Total		1,046					
DR[b]		313					
High Power Price Optimal Plan							
CT	6	942	Total NPV-$B	14.01	14.91	19.16	25.36
CC	0	0	*$/MWh*	*56.54*	*59.47*	*74.09*	*95.42*
PC w/CCS	0	0	Fuel NPV-$B	11.27	9.69	11.83	13.91
Wind[a]	13	1,300	*$/MWh*	*38.41*	*32.94*	*40.34*	*47.52*
Total		1,046					
DR[b]		402					
Best Contrary Coal Plan							
CT	4	628	Total NPV-$B	14.23	15.06	19.29	25.48
CC	0	0	*$/MWh*	*57.27*	*59.98*	*74.55*	*95.84*
PC w/CCS	1	455	Fuel NPV-$B	11.03	9.40	11.44	13.41
Wind[a]	13	1,300	*$/MWh*	*37.59*	*31.98*	*39.01*	*45.81*
Total		1,187					
DR[b]		313					
Best Contrary Nuclear Plan							
CT	4	628	Total NPV-$B	14.68	15.43	19.63	25.75
CC	0	0	*$/MWh*	*58.83*	*61.24*	*75.71*	*96.78*
PC w/CCS	0	0	Fuel NPV-$B	10.78	9.19	11.13	12.98
Nuclear	1	400	*$/MWh*	*36.76*	*31.26*	*37.93*	*44.36*
Wind[a]	13	1,300					
Total		1,132					
DR[b]		313					

Notes:
a) Wind assumed to contribute 8 MW of summer capacity for every 100 MW of nameplate capacity.
b) Demand Reduction, cumulative DSM peak reduction through 2015.

Exhibit 11-15: SWEPCO Plan Comparisons (cont'd):

SWEPCO Plan Comparison

New Capacity (Summer Rating)	Units	Capacity		BAU	Abundance	Reference	Constrained
Optimized Without CCS Requirement							
CT	6	942	Total NPV-$B	13.92	14.82	19.08	
CC	0	0	*$/MWh*	*56.23*	*59.15*	*73.82*	
PC w/CCS	0	0	Fuel NPV-$B	11.24	9.68	11.78	
Wind[a]	13	1,300	*$/MWh*	*38.33*	*32.90*	*40.16*	
Total		1,046					
DR[b]		313					
Enhanced Renewables							
CT	6	942	Total NPV-$B		15.16	19.18	25.28
CC	0	0	*$/MWh*		*60.30*	*74.17*	*95.17*
PC w/CCS	0	0	Fuel NPV-$B		10.07	11.96	14.01
Wind[a]	19	1,900	*$/MWh*		*34.25*	*40.76*	*47.88*
Total		1,094					
DR[b]		313					
"Green" Plan							
CT	4	628	Total NPV-$B			19.54	25.49
CC	0	0	*$/MWh*			*75.37*	*95.89*
Nuclear	1	400	Fuel NPV-$B			11.60	13.36
Wind[a]	19	1,900	*$/MWh*			*39.54*	*45.65*
Total		1,180					
DR[b]		313					
Demand Destruction							
CT	6	942	Total NPV-$B			17.61	23.44
CC	0	0	*$/MWh*			*73.31*	*94.98*
PC w/CCS	0	0	Fuel NPV-$B			10.53	12.22
Wind[a]	13	1,300	*$/MWh*			*38.25*	*44.62*
Total		1,046					
DR[b]		152					
Demand Destruction + Unit Retirements							
CT	10	1,570	Total NPV-$B		13.91	17.79	
CC	0	0	*$/MWh*		*60.02*	*74.15*	
PC w/CCS	0	0	Fuel NPV-$B		8.60	10.37	
Wind[a]	13	1,300	*$/MWh*		*31.30*	*37.74*	
Total		1,674					
DR[b]		313					
High DR/EE Bandwidth							
CT	6	942	Total NPV-$B				25.30
CC	0	0	*$/MWh*				*96.09*
PC w/CCS	0	0	Fuel NPV-$B				13.77
Wind[a]	13	1,300	*$/MWh*				*47.46*
Total		1,046					
DR[b]		603					
CO2 Limited							
CT	8	1,256	Total NPV-$B			19.32	24.56
CC	0	0	*$/MWh*			*75.36*	*93.47*
PC w/CCS	0	0	Fuel NPV-$B			11.86	13.81
Wind[a]	19	1,900	*$/MWh*			*40.88*	*47.60*
Total		1,408					
DR[b]		603					

Notes: a) Wind assumed to contribute 8 MW of summer capacity for every 100 MW of nameplate capacity.
b) Demand Reduction, cumulative DSM peak reduction through 2015.

Source: Resource Planning

The load forecast issued by AEP's Economic Forecast group in late-April 2009 to reflect the results of the downturn in the economy was taken into account in developing the SWEPCO Hybrid Plan along with the results of the various optimal plans developed under the price scenarios and other modeling constraints and scenarios. **Exhibit 11-16** provides the specific details and timing of the plan.

Exhibit 11-16: SWEPCO Hybrid Plan

2009 IRP (Hybrid Plan) *SWEPCO*

MW	***Planned Resource Reductions*** (A)		***Planned Resource Additions***				
			DSM		**RENEWABLE**		**THERMAL**
	Unit Retirements/ Expirations (summer-rating)	**Environmental Retrofits**(E)	***Embedded* Demand Reduction**(B) *(Cumul. Contribution)*	***New* Demand Reduction**(C) *(Cumul. Contribution)*	**Solar** (Nameplate)	**Wind** (Nameplate)	**Duty Cycle Type: BL=Baseload INT=Intermediate/Cyclic PKG=Peaking**
2009			10	0			
2010			16	24		79.5(D)	
2011			20	48		100	(Stall) 509-MW INT
2012			24	72		100	
2013			26	96		150	(Turk) 447-MW BL
2014		FC1 FGD (4)	29	120			
2015		WSH2 FGD (8)	30	144		33	
2016			31	144		100	
2017			32	144			
2018			32	144			
2019			32	144			157-MW PKG
2019 Cumul. Contribution/Nameplate	***0***	***(12)***	***32***	***144***	***0***	***563***	***1,113***
(SPP) Capacity Value (Wind 8%; Solar 70%(est.))					***0***	***45***	
2020			32	144			
2021			32	144		100	157-MW PKG
2022			32	144		100	
2023			32	144			157-MW PKG
2024			32	144		100	
2025		Turk CCS (67 MW)	32	144		100	157-MW PKG
2026			32	144	17		
2027			32	144	17	100	157-MW PKG
2028			32	144	35		
2029			32	144	35	100	
2030		Welsh 1&2 CCS (170 MW)	32	144	56	200	314-MW PKG
2030 Cumul. Contribution/Nameplate	***0***	***(249)***	***32***	***144***	***160***	***1,363***	***2,055***
(SPP) Capacity Value (Wind 8%; Solar 70%(est.))					***112***	***109***	
Cumul. (Nameplate) Contribution thru '30			***1%***	***4%***	***4%***	***36%***	***55%***
Cumul. (Capacity) Contribution thru '30			***1%***	***6%***	***5%***	***4%***	***84%***

'NET' CAPACITY RESOURCE ADDITIONS:	
2009-2020	***1,322***
2009-2030	***2,203***

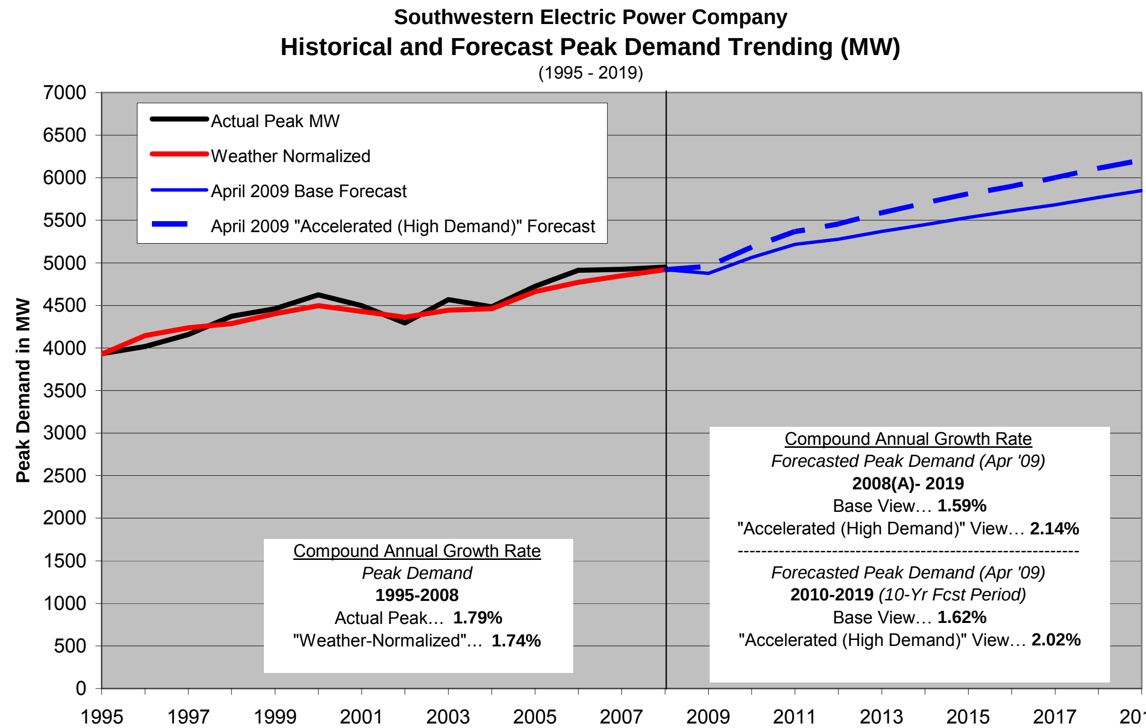
Peaking	1,099	*53%*
Intermediate	509	*25%*
Baseload	447	*22%*
	2,055	

(A) Not shown are relatively small unit uprates and derates embedded in the current plan (e.g. FGD retrofit auxliary load losses)
(B) "Embedded" DSM represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(C) "New" DSM represents incremental activity projected based on estimated contribution & program cost (vs. avoided cost) parameters, from recent Market Potential Studies, and were generally limited to an EPRI Jan. '09 study identifying a "Realistically Achievable Potential"... Note: Such 'New' (increm) DSM-DR activity modeled thru 2015 only
(D) Assumes Majestic wind energy available by 2010, but firm transmission delayed until 2012
(E) CCS retrofit technology assumed to be chilled ammonia with a 15% parasitic load

Source: AEP Resource Planning

As discussed under the development of the PSO Hybrid Plan, a "High Demand" forecast was also prepared for SWEPCO to determine if the plan that was ultimately selected would be sufficient should the economic recovery be more robust than currently predicted. **Exhibit 11-17** shows this "High Demand" forecast relative to historical trends and as compared to the April 2009 forecast used to develop the plan.

Exhibit 11-17: SWEPCO Load Forecast Comparison



Note: *For comparative purposes only,* excludes the shift of the NTEC wholesale contract to a fixed (200 MW) basis eff: 2015 (i.e. assumes continuation of a 'full requirements' demand level over the comparison period)

Source: AEP Resource Planning

As shown earlier in this document in Section 1.2 and repeated here as **Exhibit 11-18**, the embedded Turk and Stall plants provides adequate capacity to meet SWEPCO's peak demand using the April 2009 forecast, however SWEPCO may find itself in a capacity deficit position in 2015 if actual demand growth is closer to the "High Demand" view. This deficiency occurs far enough in the future for SWEPCO to continue to monitor changes in load and react as needed. Note that under both the "Base Demand" and "High Demand" scenarios, if the either Turk and Stall plants are not completed, SWEPCO's capacity position will be deficit (below the 13.6% SPP reserve margin requirement) in 2012 and beyond. An alternate Capacity, Demand, Reserve table incorporating this High Demand forecast is included in the Appendix.

Exhibit 11-18: SWEPCO Reserve Margin With and Without Turk and Stall Plants

SWEPCO

Stand-Alone Reserve Margins*

Based on (April 2009) Demand Forecast "Banding"

10-Year 2009 IRP Period: **2010-2019**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reserve Margin										
Under **"Base"** Demand Forecast:										
Per 2009 Resource Plan	13.8%	14.0%	13.3%	22.0%	20.6%	22.3%	20.9%	19.4%	17.6%	19.2%
Exclusive of Turk (2013)	*13.8%*	*14.0%*	*13.3%*	13.1%	11.9%	12.8%	11.6%	10.1%	8.5%	7.1%
Exclusive of Stall (2011) & Turk (2013)	*13.8%*	3.7%	3.1%	3.1%	1.9%	2.0%	0.9%	-0.4%	-1.8%	-3.1%
Under **"Accelerated (High)"** Demand Forecast:										
Per 2009 Resource Plan	11.0%	10.6%	9.4%	16.9%	14.9%	15.6%	14.0%	12.0%	10.0%	11.2%
Exclusive of Turk (2013)	*11.0%*	*10.6%*	*9.4%*	8.5%	6.6%	6.6%	5.2%	3.4%	1.5%	-0.1%
Exclusive of Stall (2011) & Turk (2013)	*11.0%*	0.6%	-0.4%	-1.2%	-2.9%	-3.6%	-4.9%	-6.5%	-8.2%	-9.6%

* Excludes short-term capacity transfers to/from affiliate Public Service Company of Oklahoma

Note: Minimum Reserve Margin Requirement per SPP Criteria is 13.6%

Source: AEP Resource Planning

11.6.5 Observations: SWEPCO Hybrid Plan Composition

Various factors were considered in the development of the different elements of the SWEPCO Hybrid Plan:

- Thermal Resources – With the addition of the Stall CC and Turk PC units within the next five years, the most cost effective thermal resource additions in the long-term was determined to be peaking capacity and energy. It was determined that the proxied combustion turbine capacity, should be added as a single unit/block rather than in blocks of two. The first unit was added in 2019 to provide adequate reserve margin. Subsequent peaking capacity blocks were assumed over the balance of the longer-term planning horizon.
- Renewable Resources – The renewable resource portfolio included both wind and solar resources required to achieve the renewable energy sales targets established for 2013, 2020, and 2030. Wind resources of 1,363 MW of nameplate capacity are being added throughout the SWEPCO longer-term planning period, while solar resource additions are made during the last five years of the period. The portfolio also includes a biomass fuel Co-Firing option at the Welsh 1 unit beginning in 2017. Under this option, the unit would be assumed to burn approximately 3.0% by weight, of an appropriate biomass resource.
- DSM – The four DR/EE programs found to be cost effective in the screening process were included in the Hybrid Plan, but the cumulative demand reduction was reduced from 313 MW to 144 MW to reflect the "Realistically Achievable Potential" identified in a recent EPRI study. In addition, cumulative demand reduction of 32 MW of "known and measurable" commission approved program activity was embedded in the most recent load forecast.
- CCS Retrofits – To acknowledge the potential for significant CO_2 emission limits in the future, CCS technology retrofits are included in the plan at the Turk plant in 2025 and at

the Welsh 1 and 2 units in 2030. As with the potential for the retrofitting of the PSO Northeastern 3 unit, this technology was viewed as a critical longer-term planning objective to achieve potentially significant federal CO_2 reduction mandates.

11.6.6 Summary and Conclusions for SWEPCO Plans

The SWEPCO resource expansion plan provides a robust and diverse approach to meeting SWEPCO's resource needs in a cost effective manner. This study has shown that peaking capacity and energy is the most cost effective thermal resource to meet future capacity needs. The plan includes substantial clean energy renewable resources, including wind, solar, and biomass to meet aggressive renewable energy targets set by the Company. This study also shows that significant amounts of selected DR/EE programs are potentially cost effective and should be employed on SWEPCO's system. The longer-term plan also addresses the issue of potential CO_2 emission limits through retrofitting a limited number of existing coal units with CCS technology.

12.0 Risk Analysis

Seven portfolios for both PSO and SWEPCO were selected using *Strategist* that were then subjected to rigorous "stress testing" to ensure that none would have outcomes that would be deleterious under a probabilistic array of input variables.

12.1 The URSA Model

Developed internally by AEP Market Risk Oversight, the Utility Risk Simulation Analysis (URSA) model uses Monte Carlo simulation of the AEP–SPP Zone with 1,399 possible futures for certain input variables. The results take the form of a distribution of possible revenue requirement outcomes for each plan. The input variables or risk factors considered by URSA within this IRP analysis were:

- Eastern and Western coal prices,
- natural gas prices,
- power prices,
- SO_2, CO_2, and NO_X emissions allowance prices,
- full requirements loads.

These variables were correlated based on historical data.

For each plan, the difference between its mean and its 95th percentile was identified as Revenue Requirement at Risk (RRaR). This represents a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of 5.0 percent.

Exhibits 12-1A and **12-1B** illustrates for one plan, the "Hybrid Plan," the average levels of some key risk factors, both overall and in the simulated outcomes whose Cumulative Present Value (CPV) revenue requirement equals or exceeds the upper bound of Revenue Requirement at Risk. Note that these CPV's are consistent with the CPW values calculated using the *Strategist* tool. The table is specific to the Hybrid Plan, but the numbers would be very similar under the other plans. (The particular alternative futures producing the highest levels are not the necessarily the same between different plans.)

Exhibit 12-1A: Key Risk Factors–Weighted Means for 2009-2035 (PSO)

	Simulated Outcomes – Hybrid Plan			
	All Outcomes	RRaR-Exceeding Outcomes		
Variable	Mean	Mean	Difference	% Diff
PSO Internal Onpeak Load	2,625	2,626	1.81	0.07%
SPP Onpeak Power Spot	77.67	83.82	6.15	7.92%
PRB Coal Spot	16.61	17.98	1.37	8.25%
Henry Hub Gas Spot	8.37	9.30	0.93	11.11%
CO2 Allowance Spot	24.69	43.03	18.34	74.28%
NOx Allowance Spot	600	603	3.10	0.52%
SO2 Allowance Spot	1,591	2,235	644.22	40.49%

Source: AEP Market Risk Oversight

Exhibit 12-1B: Key Risk Factors–Weighted Means for 2009-2035 (SWEPCO)

	Simulated Outcomes – Hybrid Plan			
	All Outcomes	RRaR-Exceeding Outcomes		
Variable	Mean	Mean	Difference	% Diff
SWEPCo Internal Onpeak	3,564	3,572	7.97	0.22%
SPP Onpeak Power Spot	77.67	83.40	5.73	7.38%
PRB Coal Spot	16.61	17.86	1.25	7.53%
Henry Hub Gas Spot	8.37	9.14	0.77	9.20%
CO2 Allowance Spot	24.69	44.29	19.60	79.38%
NOx Allowance Spot	600	605	4.66	0.78%
SO2 Allowance Spot	1,591	2,279	687.50	43.21%

Source: AEP Market Risk Oversight

The price of CO_2 and SO_2 allowances is greater among the RRaR-exceeding outcomes, suggesting that they are critical sources of risk to revenue requirements. The relative difference between that "tail" and mean outcomes are 70%+ and 40%+, which is significantly greater than the relative difference of other risk factors. On the other extreme, the possible futures associated with the RRaR-exceeding outcomes are characterized by only slightly higher levels for load and NO_X allowance prices.

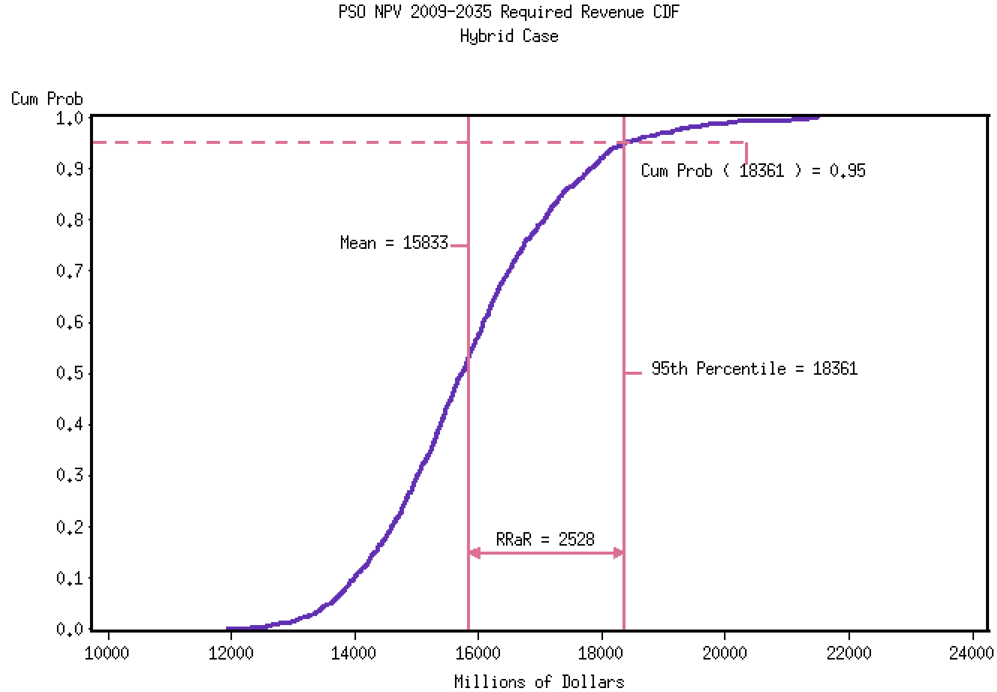
It might be assumed that the very worst possible futures would be characterized by high fuel and allowance prices and low power prices. But according to the analysis of the historical values of risk factors that underlies this study, such futures have essentially no chance of occurring. Any possible future with high fuel prices would essentially always have high power prices. Likewise the risk factor analysis implies an inverse correlation between NO_X allowance prices and some of the other risk factors that determine the tail cases, so that in these tail cases, the average NO_X allowance price is actually less than the average across all possible futures.

The Technical Addendum shows the percentiles of annual average values of key risk factors, estimated for distribution across the 1,399 simulated futures.

12.2 URSA Modeling Results

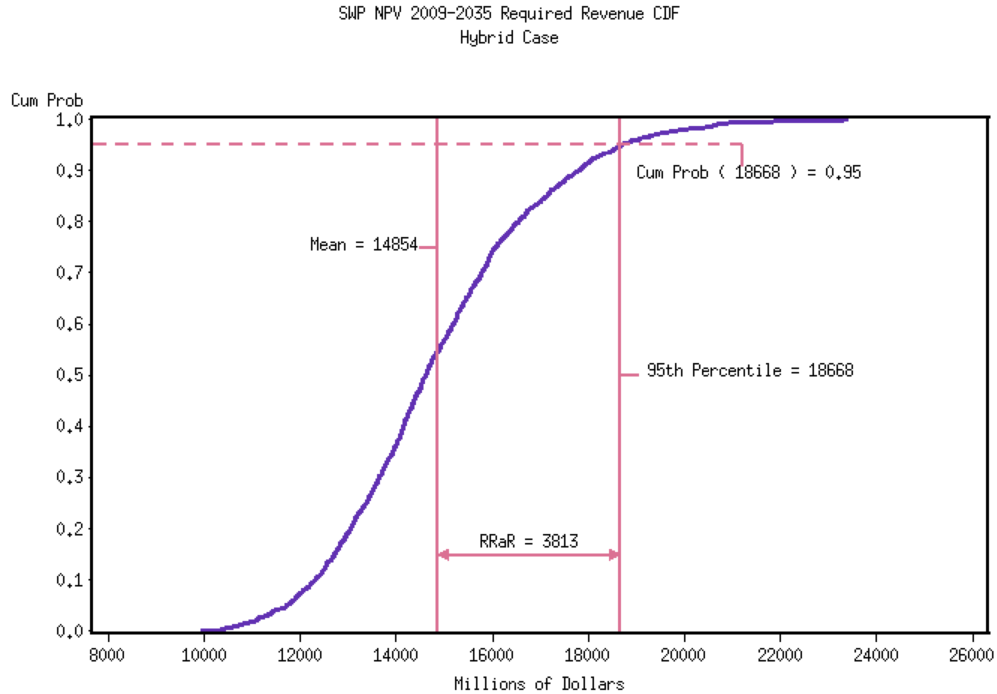
Exhibits 12-2A, 12-2B, 12-3A, and **12-3B** illustrate the distribution of outcomes for the Hybrid Plan on both a cumulative distribution "S-curve" and probability distribution ("bell-curve") basis, respectively. The graphs for the other six plans examined would be quite similar. The costs included in this analysis are the same as were included in the *Strategist* analysis, as described in section 11.1, namely fixed costs of capacity additions; fixed costs of any capacity purchases; installation and administrative costs of DR/EE alternatives; variable costs for the entire fleet; and market revenues netted against costs.

Exhibit 12-2A: Cumulative Probability Distribution of AEP-SPP Revenue Requirement (PSO)



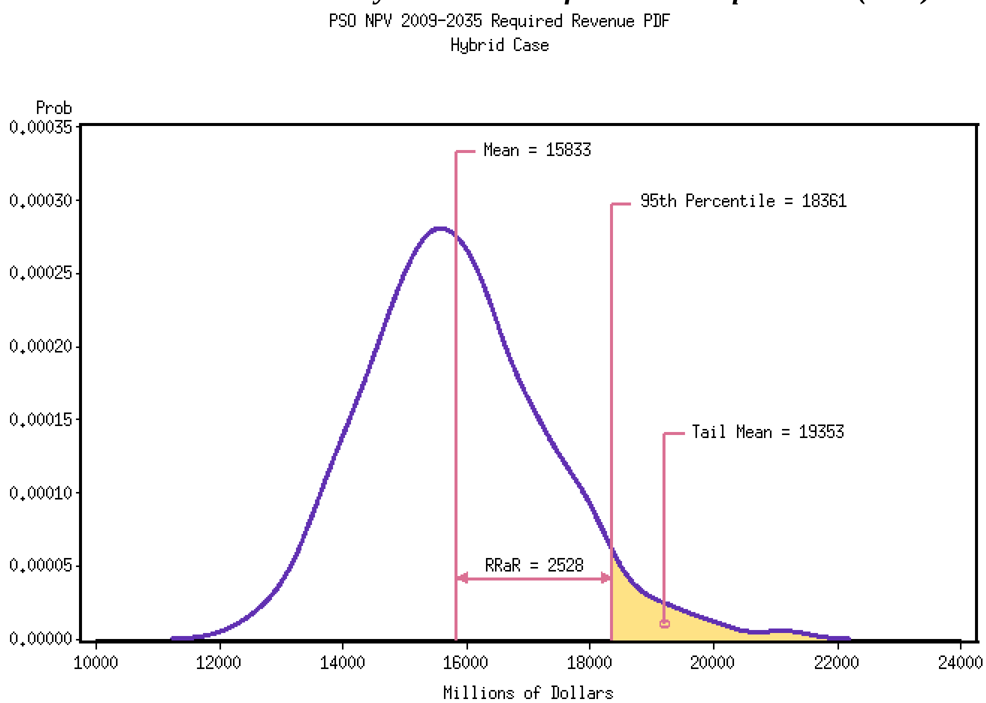
Source: AEP Market Risk Oversight

Exhibit 12-2B: Cumulative Probability Distribution of AEP-SPP Revenue Requirement (SWEPCO)



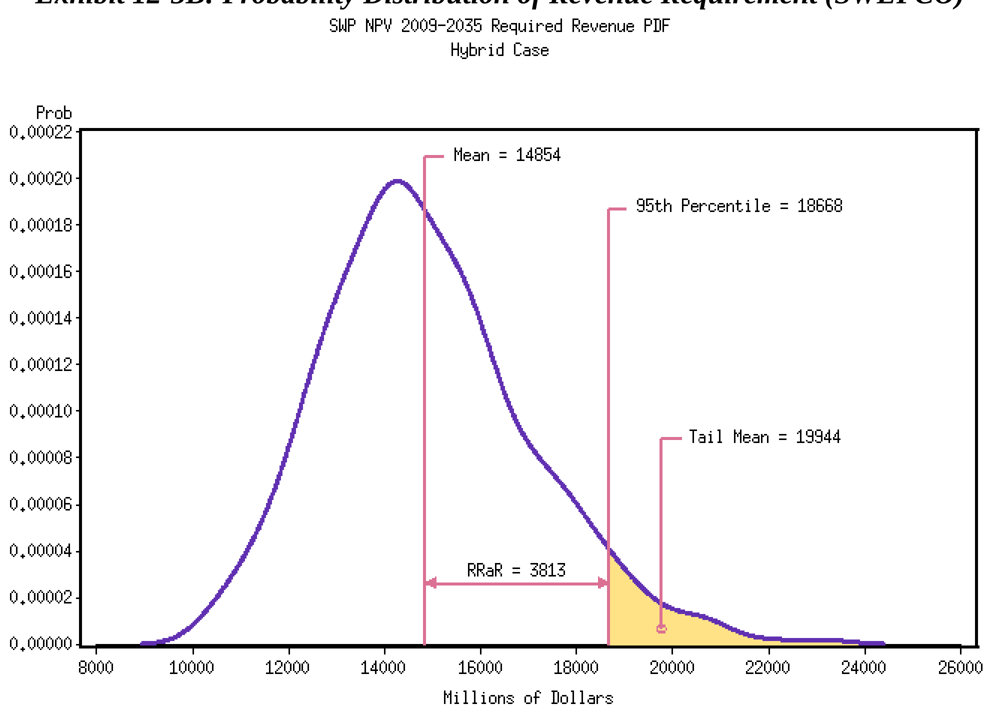
Source: AEP Market Risk Oversight

Exhibit 12-3A: Probability Distribution of Revenue Requirement (PSO)



Source: AEP Market Risk Oversight

Exhibit 12-3B: Probability Distribution of Revenue Requirement (SWEPCO)



Source: AEP Market Risk Oversight

12.3 Capital Cost Risk Assessment

In order to further scrutinize the seven plans under the 1399 possible futures, the impacts of Capital Cost Risk on the URSA results were examined. A six-point capital cost distribution for each of the seven plans was created. (See **Exhibit 12-4** for its basis.) In creating the distribution for each plan, the capital costs of all types of capacity were assumed to be perfectly correlated with each other. The fixed representation of capital costs in URSA was removed from each URSA output distribution and the resulting distributions were convolved with the capital cost distributions.

Exhibit 12-4: Basis of Capital Cost Distributions

Probability of occurrence, **Percent Capital Cost Variance**:	5%	19%	33%	23.67%	14.33%	5%
Solid-fuel Units	-15%	-7%	Base	+10%	+20%	+30%
Gas-fuel Units	-10%	-5%	Base	+6.67%	+13.33%	+20%
Nuclear Units	-15%	-7%	Base	+10%	+20%	+30%

Source: AEP Resource Planning

12.4 Results Including Capital Cost Risk

Exhibits 12-5A and **12-5B** summarizes the Capital Cost Risk-adjusted results for all seven AEP-SPP plans.

Exhibit 12-5A: Capital Cost Risk-Adjusted CPW 2009-2035 Revenue Requirement ($ Millions) (PSO)

PLAN	50th Percentile	95th Percentile	Revenue Requirement at Risk
BASE	15,968	18,928	2,960
CONTRARY NUKE	16,304	19,048	2,744
CONTRARY COAL	15,960	18,728	2,768
ENHANCED RENEWABLES	15,992	18,904	2,912
GREEN	16,352	19,088	2,736
CO2 LIMITED	15,771	18,116	2,345
HYBRID	15,699	18,347	2,648

Source: AEP Market Risk Oversight

Exhibit 12-5B: Capital Cost Risk-Adjusted CPW 2009-2035 Revenue Requirement ($ Millions) (SWEPCO)

PLAN	50th Percentile	95th Percentile	Revenue Requirement at Risk
BASE	14,586	19,437	4,851
CONTRARY NUKE	14,938	19,613	4,675
CONTRARY COAL	14,608	19,349	4,741
ENHANCED RENEWABLES	14,608	19,437	4,829
GREEN	14,938	19,635	4,697
CO2 LIMITED	14,643	18,432	3,789
HYBRID	14,670	18,760	4,090

Source: AEP Market Risk Oversight

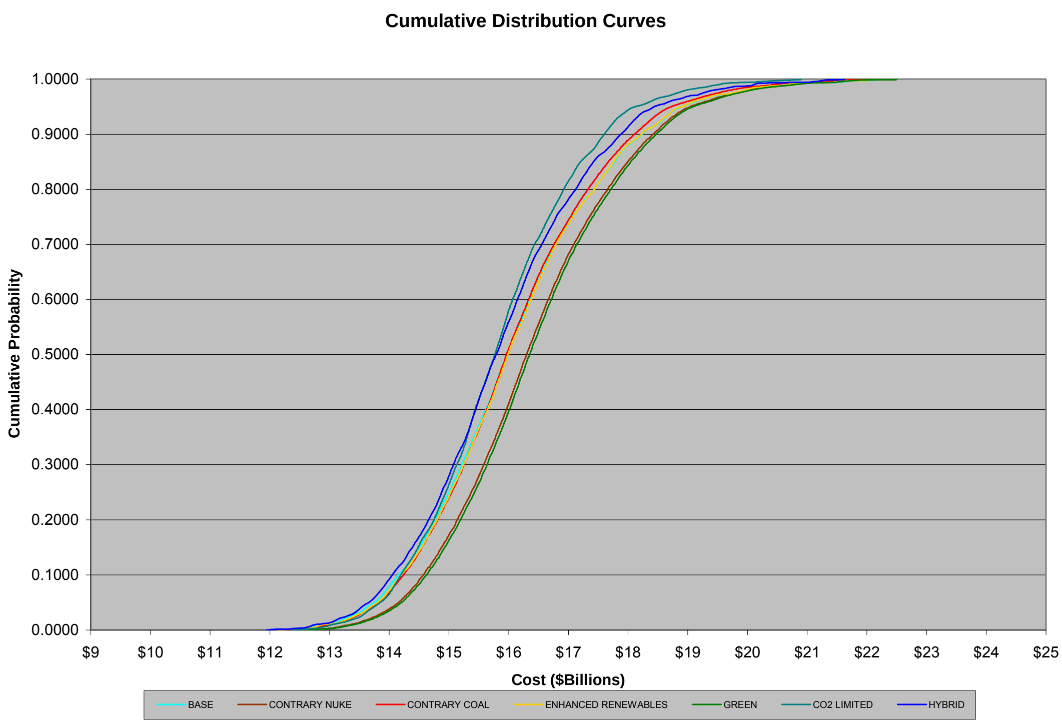
Exhibits 12-5A and **12-5B** show reasonably consistent results across all plans modeled. These comparative results also suggest that, given the fuel/generation diversity of the capacity resource options introduced into the analysis, the relative economic exposure would appear to be small irrespective of the plan selected.

The three lowest-cost plans at the 50th percentile are the CO_2 Limited, Hybrid, and Contrary Coal for PSO and the Base, Contrary Coal, and Enhanced Renewables for SWEPCO. However, the lowest plan at Revenue Requirement at Risk and at the 95th percentile is the CO_2 limited plan, followed by the Hybrid plan.

RRaR measures the risk relative to the 50th percentile, or expected, result of a plan. The plan with the least RRaR is not necessarily preferred for risk avoidance. Instead, low values of required revenue at extreme percentiles, such as the 95th, are preferred.

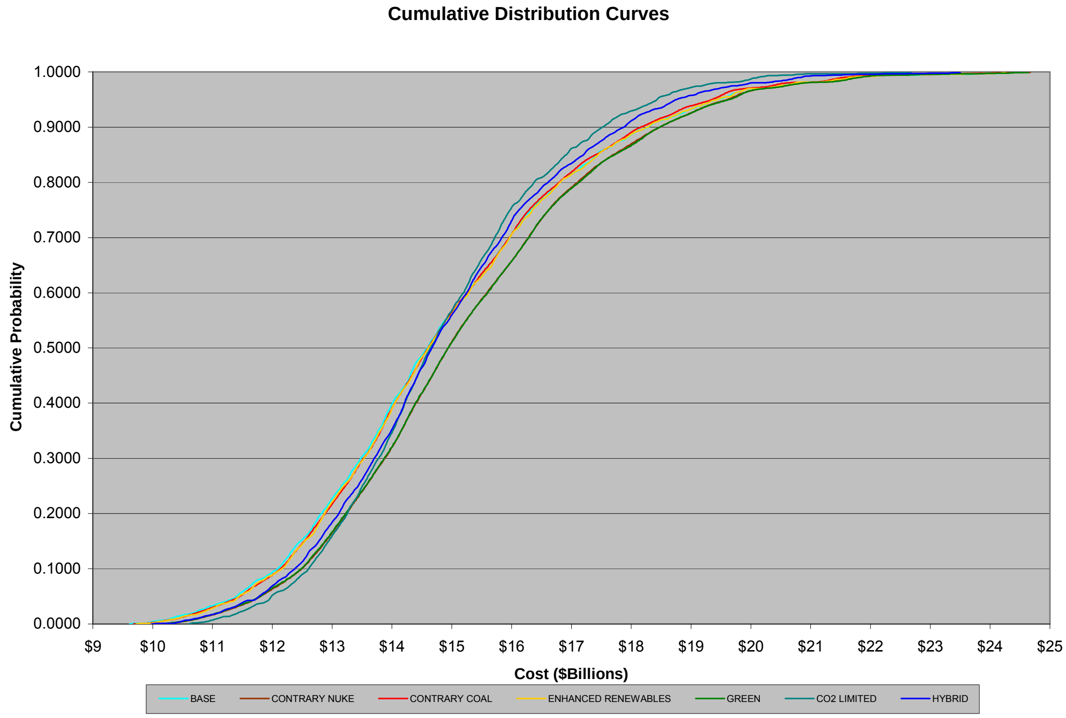
The estimated distributions of revenue required under the seven plans are rather similar. **Exhibits 12-6A, 12-6B, 12-7A,** and **12-7B** show the superimposed graphs of all seven distribution functions.

Exhibit 12-6A: Distribution Function for All Portfolios (PSO)



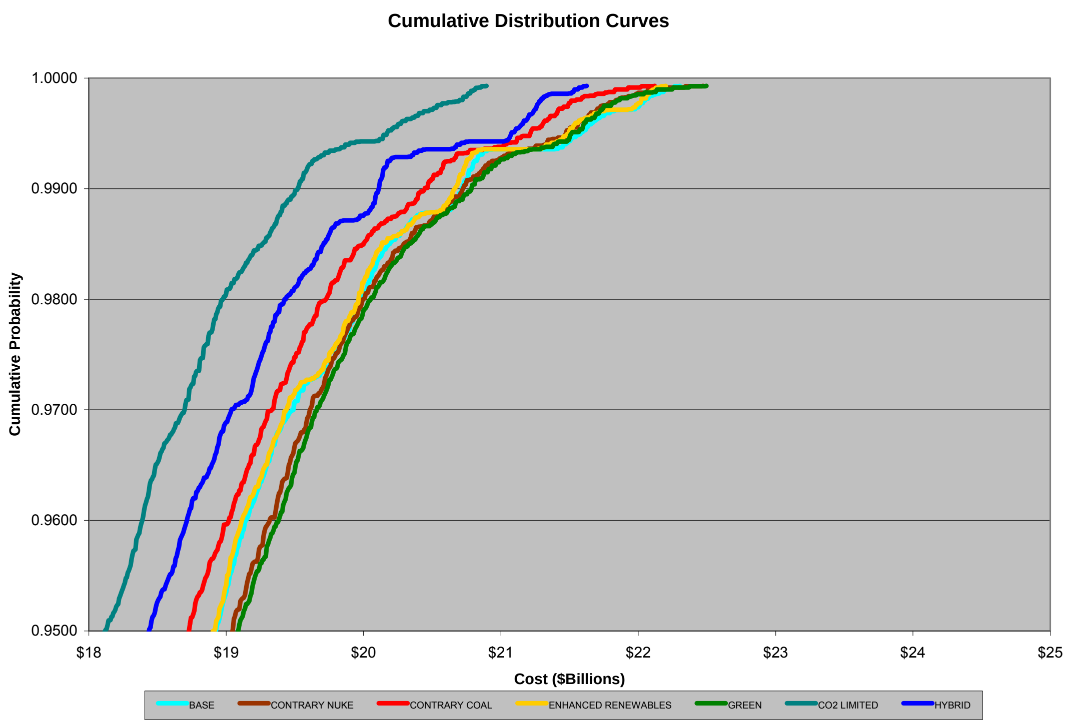
Source: AEP Resource Planning

Exhibit 12-6B: Distribution Function for All Portfolios (SWEPCO)



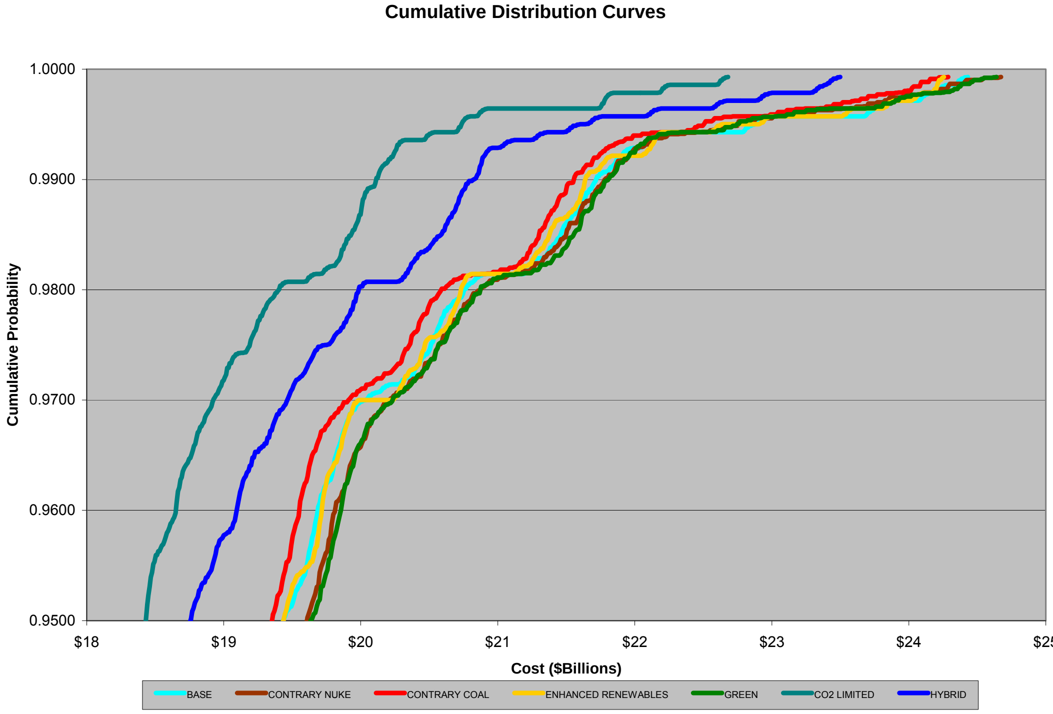
Source: AEP Resource Planning

Exhibit 12-7A: Distribution Function for All Portfolios at > 95% Probability (PSO)



Source: AEP Resource Planning

Exhibit 12-7B: Distribution Function for All Portfolios at > 95% Probability (SWEPCO)



Source: AEP Resource Planning

12.5 Conclusion From Risk Modeling

For both SWEPCO and PSO the Hybrid Plan and the CO_2 Limited Plan had the lowest cost at the 95% probability level. Their RRaR was also among the lowest of all plans. As the CO_2 Limited Plan includes assumptions regarding potential legislation that has not yet been approved by the Senate or signed into law, the Hybrid Plan appears to be the best option. In the near term, these plans are similar and selecting one over the other will have no significant impact prior to any potential legislation passing into law. The Hybrid Plan is a reasonable, lower cost plan across a wide range of potential outcomes.

13.0 Conclusions and Recommendations

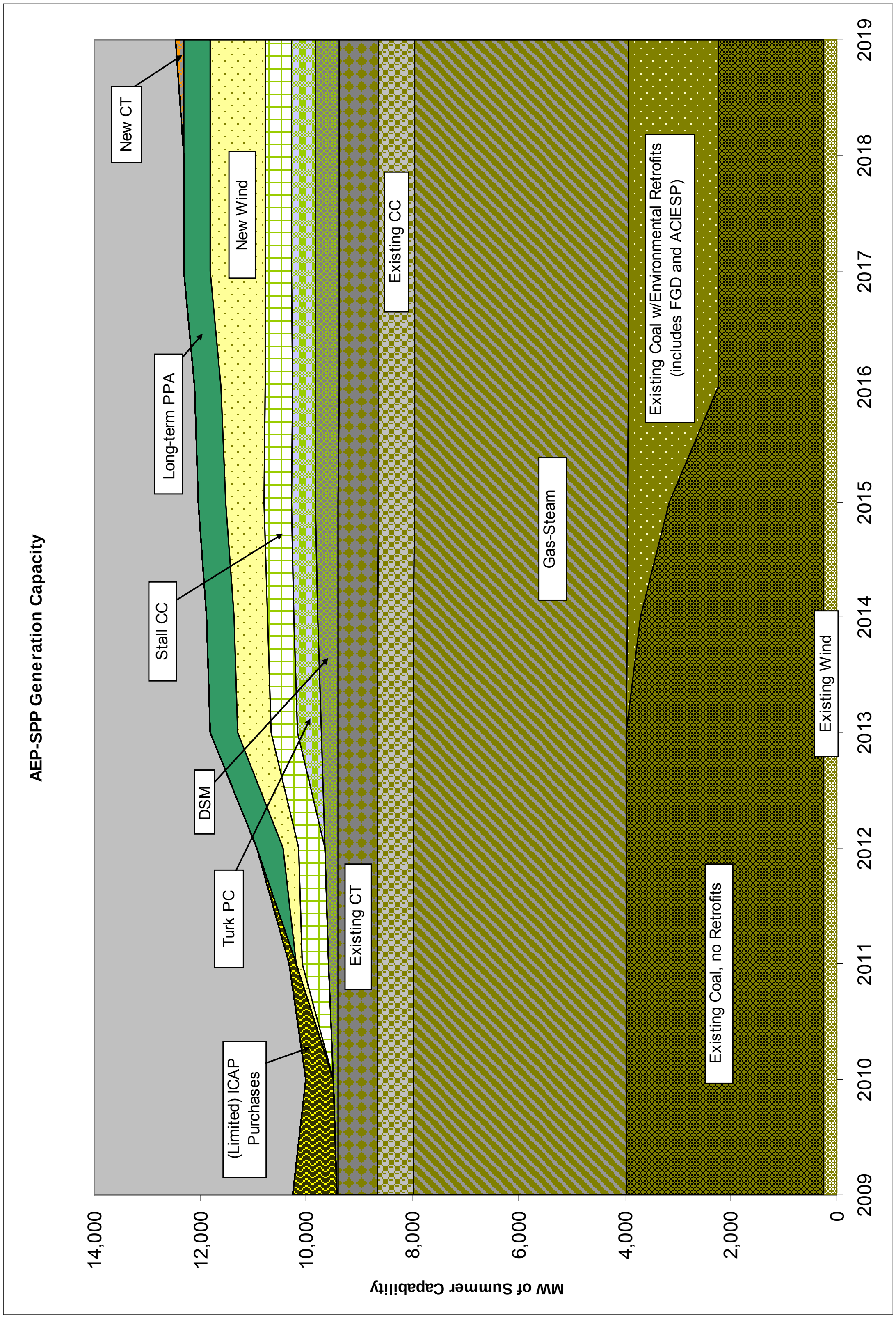
The selection of the Hybrid Plans for both PSO and SWEPCO, which embed the respective Arkansas, Louisiana, and Texas commission-approved Turk baseload facility and Stall combined cycle facility, and the Exelon PPA reflects management's commitment to clean coal technology, renewable energy alternatives, energy efficiency, and the economic vitality of the territories served by AEP. These resource portfolios fare well when compared to the other portfolios when subjected to robust scenario and attendant risk modeling/ analysis. Other benefits include:

- Pre-positioning for the prospects of federal carbon legislation.
- Likewise, with the prospects for a Federal Renewable Portfolio Standard, becoming an early-mover to secure wind power ensures that AEP will be well positioned to ultimately achieve those standards as they become effective.
- Increased DR/EE, assuming customer acceptance and full and contemporaneous rate recovery, could offer an effective means to reduce demand, energy usage and, with that, our attendant carbon footprint.
- Keeping coal as a viable fuel in a carbon-constrained world requires that commercial USC-PC technology be championed and built. AEP's steeped history and core competency surrounding coal-based generation would also naturally support such a commitment. This coal-based technology advancement would also be continued by way of positioning both PSO and SWEPCO for the potential need for introducing CCS retrofits as part of its longer-term planning.

13.1 Capacity and Energy Plan

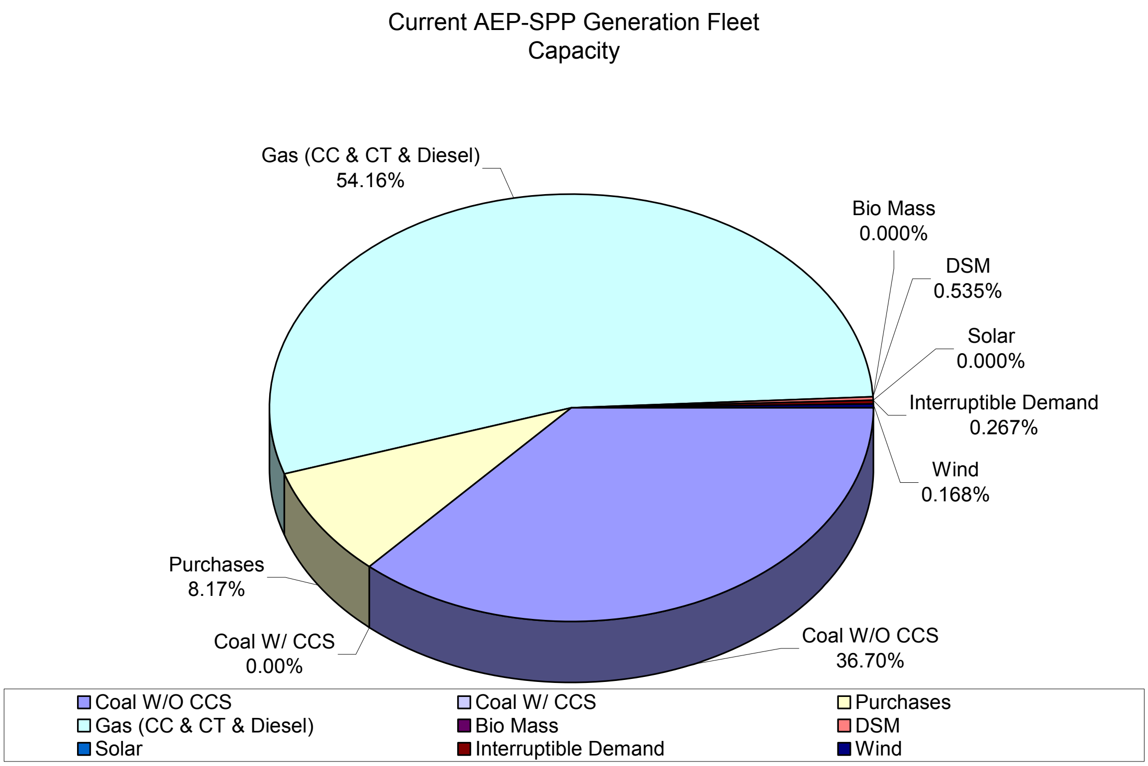
The charts found on **Exhibits 13-1** through **13-3** offer a summary of the resulting AEP-SPP generating fleet. From a capacity mix standpoint, the most significant take-away would be that the profile represents a diverse technology and fuel mix. From an environmental stewardship perspective, note that from **Exhibit 13-1** that the AEP-SPP fleet continues to migrate to a lower carbon emitting portfolio.

Exhibit 13-1: AEP-SPP Generation Capacity



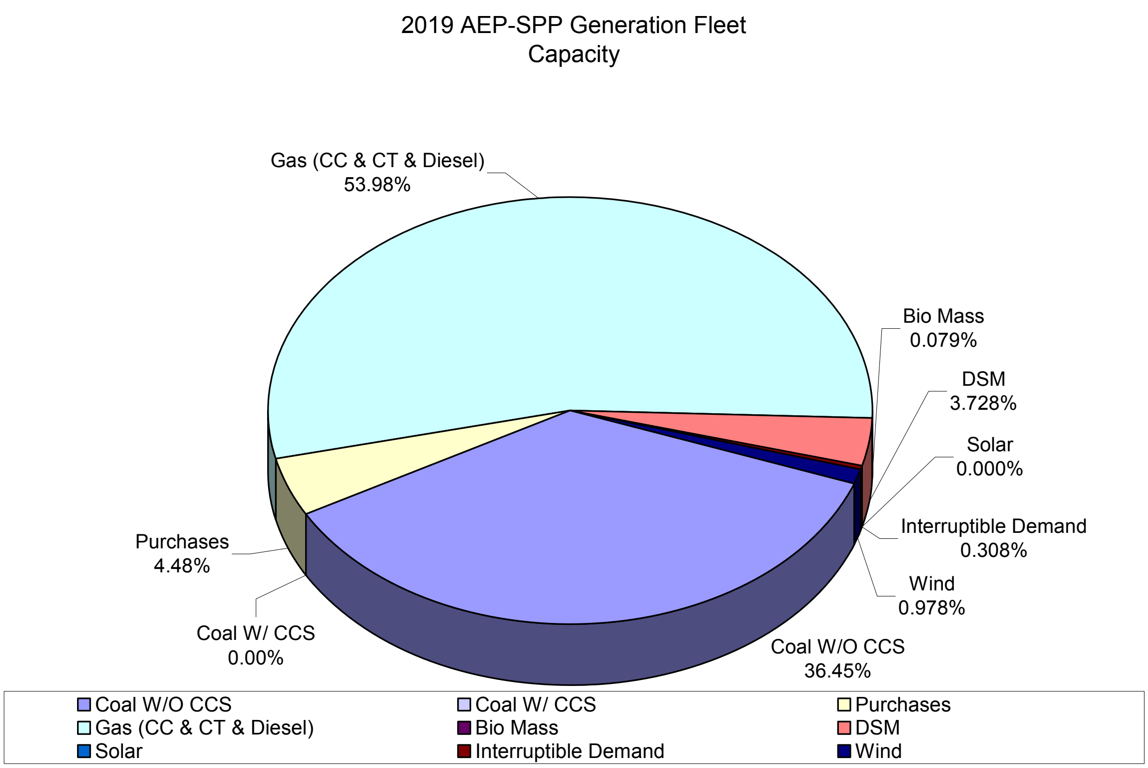
Source: AEP Resource Planning

Exhibit 13-2: AEP-SPP Current Capacity Mix



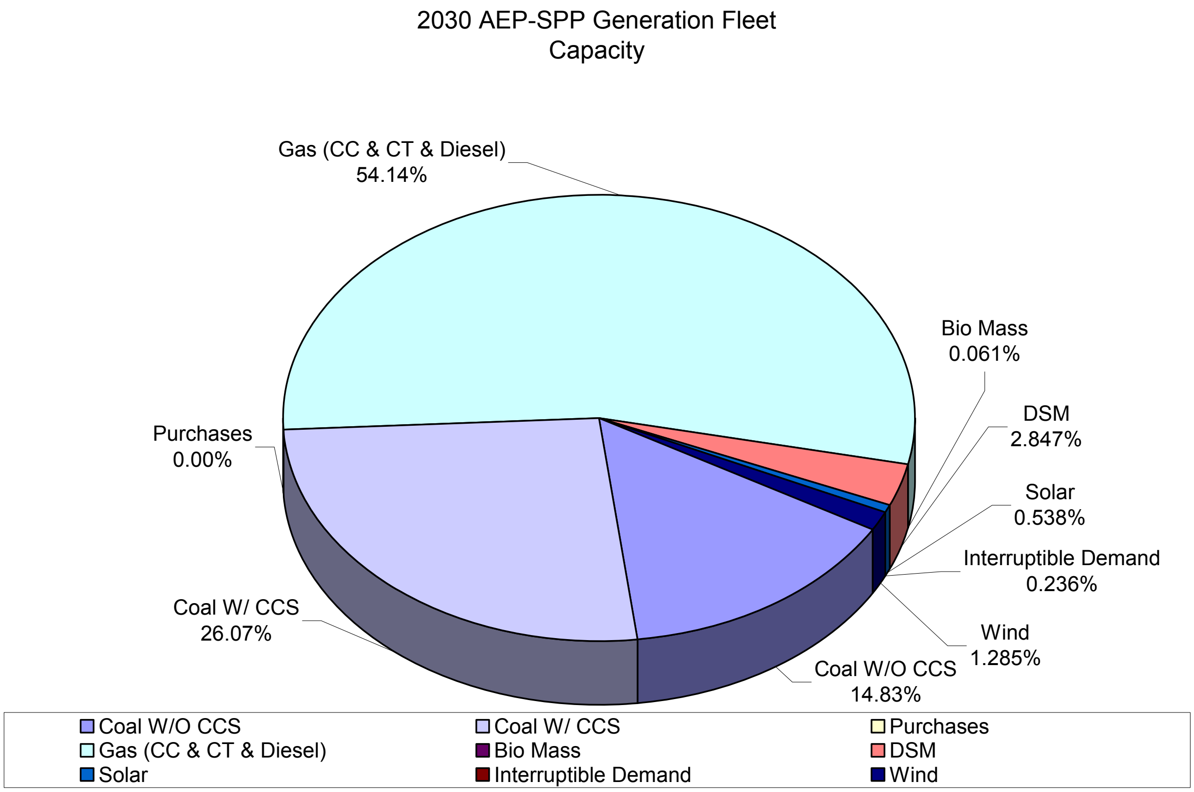
Source: AEP Resource Planning

Exhibit 13-3: AEP-SPP 2019 Capacity Mix



Source: AEP Resource Planning

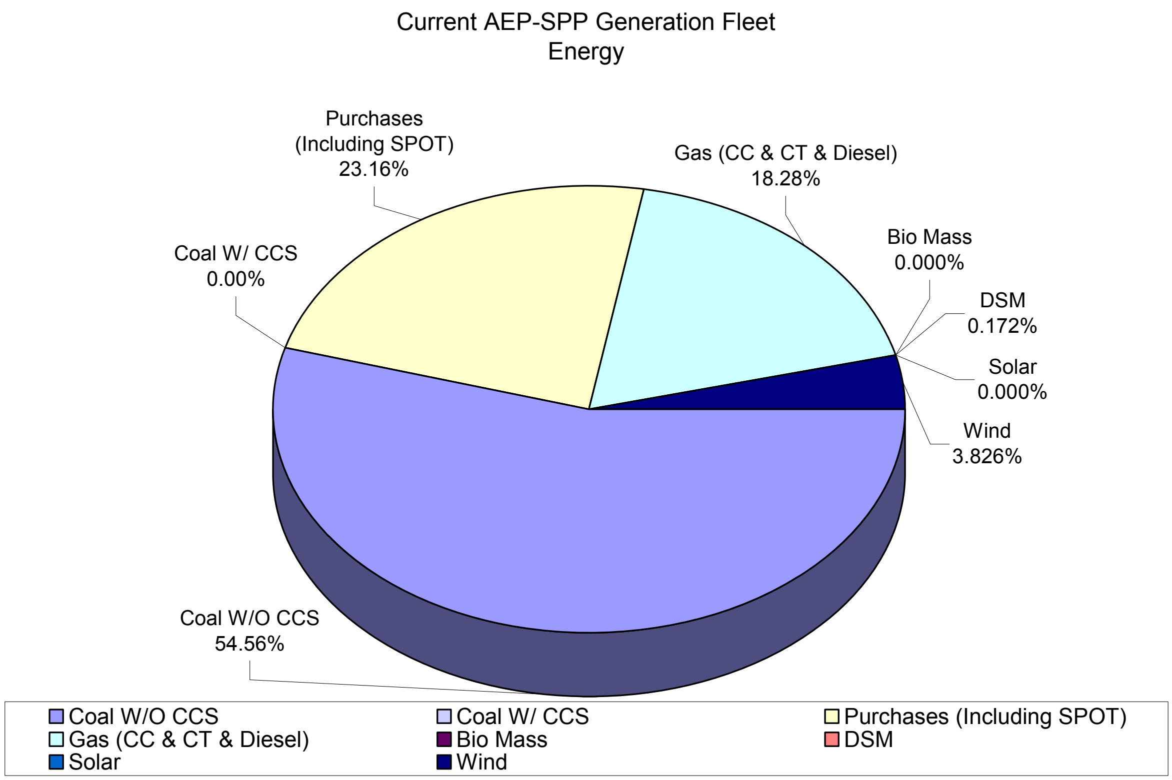
Exhibit 13-4: AEP-SPP 2030 Capacity Mix

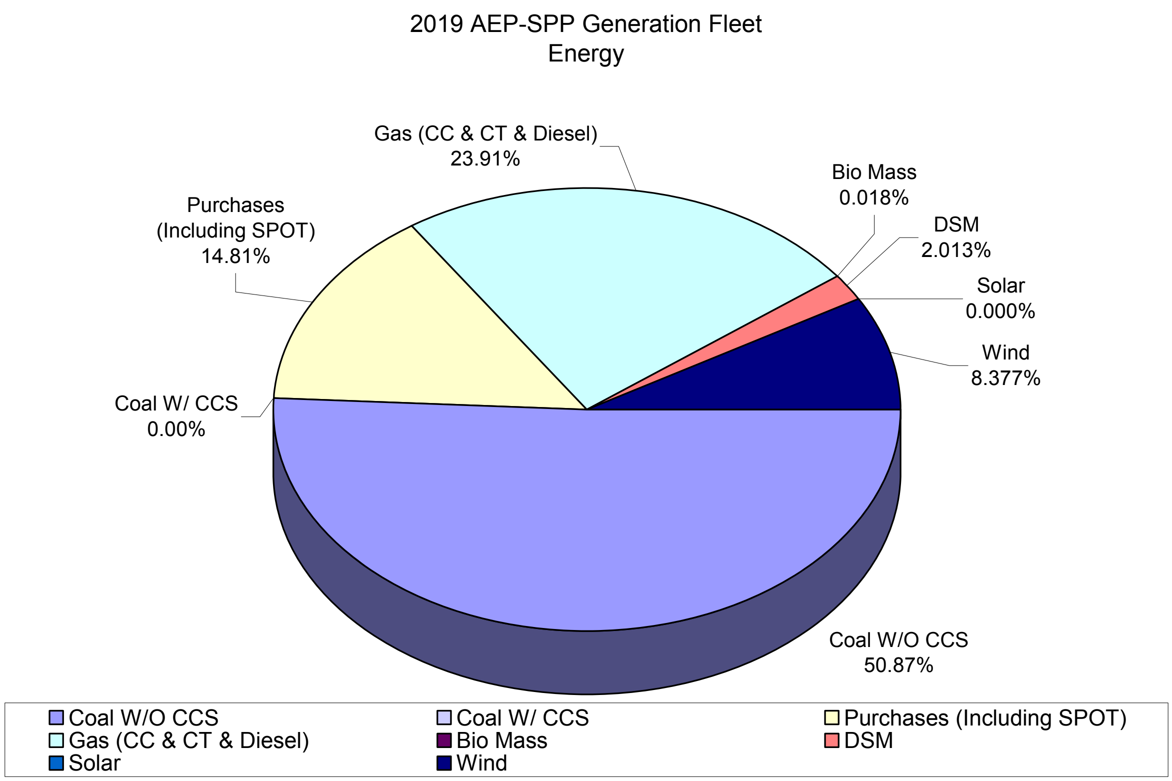


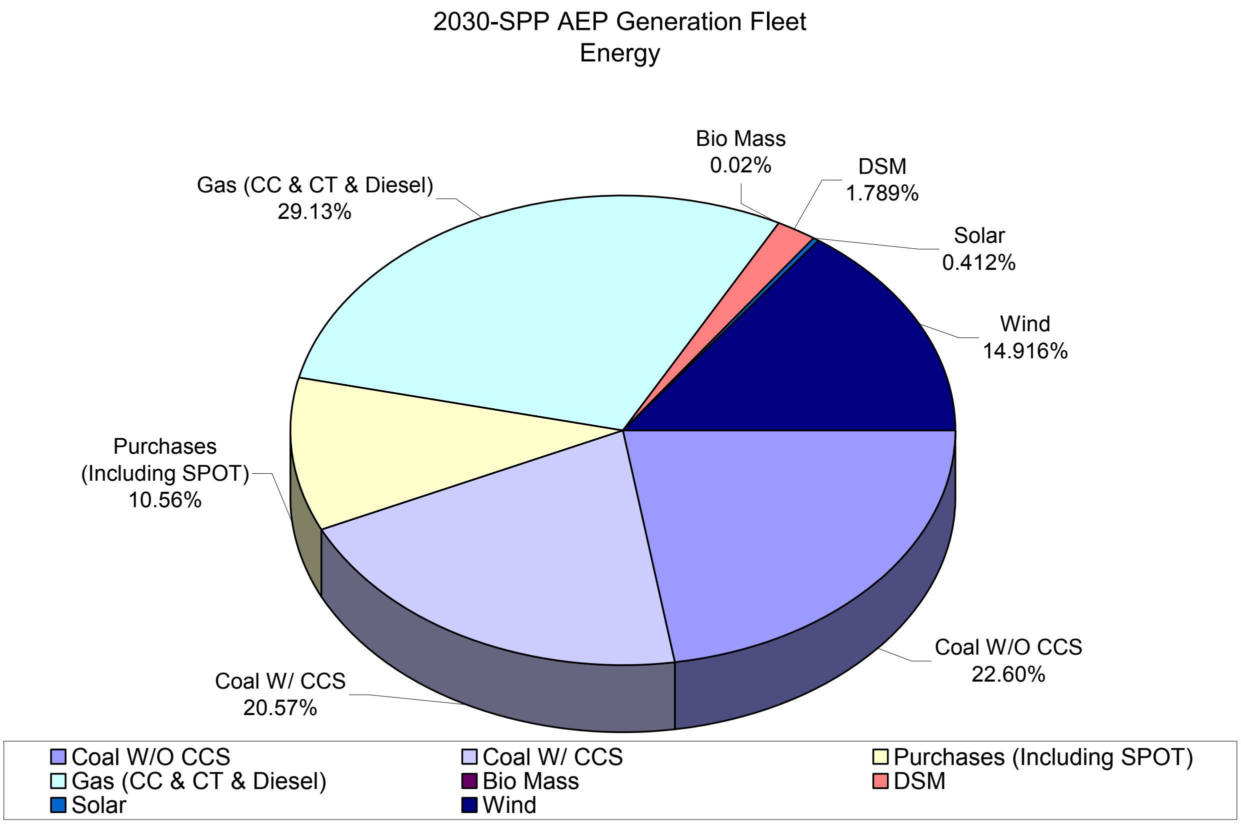
Source: AEP Resource Planning

Exhibit 13-5 incorporates the recommended capacity additions and their attendant energy profiles. Note that the 2019 and 2030 plan relies more heavily on renewable resources and nuclear and less on baseload coal to meet its needs.

Exhibit 13-5: Change in Energy Mix With Hybrid Plan - Current vs. 2019 and 2030







Source: AEP Resource Planning

Exhibit 13-6 incorporates the recommended capacity additions and their attendant energy profiles. Note that the 2009 plan relies more heavily on DR/EE and renewables and less on baseload (coal) to meet its needs.

Exhibit 13-6: 2009 AEP-SPP IRP

2009 AEP-SPP Integrated Resource Plan (Hybrid Plan)

	PSO					SWEPCO				
	Planned Resource Reductions	*Planned Resource Additions (MW)*				Planned Resource Reductions	*Planned Resource Additions (MW)*			
		DSM		RENEWABLE	THERMAL		DSM		RENEWABLE	THERMAL
	Environmental Retrofits[G]	Embedded Demand Reduction[B] (Cumul. Contribution)	New Demand Reduction[C] (Cumul. Contribution)	Wind (Nameplate)	Duty Cycle Type: BL=Baseload INT=Intermediate PKG=Peaking	Environmental Retrofits[G]	Embedded Demand Reduction[B] (Cumul. Contribution)	New Demand Reduction[C] (Cumul. Contribution)	Wind (Nameplate)	Duty Cycle Type: BL=Baseload INT=Intermediate PKG=Peaking
2009		9	0				10	0		
2010		13	31				16	24	79.5[F]	
2011		16	62	198 [E]			20	48	100	(Stall) 509-MW INT
2012		19	94		(Grn Cntry PPA) 512-MW BL		24	72	100	
2013		21	125				26	96	150	(Turk) 447-MW BL
2014		22	157			FC1 (4)	29	120		
2015		23	188	67		WSH2 (8)	30	144	33	
2016	NE3&4 (15)	24	188				31	144	100	
2017		25	188	200			32	144		
2018		25	188				32	144		
2019		25	188				32	144		157-MW PKG
Nameplate Capacity	*(15)*	*25*	*188*	*465*	*512*	*(12)*	*32*	*144*	*563*	*1,113*
(SPP) Capacity Value (Wind 8%;)				*37*					*45*	
Cumul. (Nameplate)		*2%*	*16%*	*39%*	*43%*		*2%*	*8%*	*30%*	*60%*
Cumul. (Capacity) Contribution		*3%*	*25%*	*5%*	*67%*		*2%*	*11%*	*42%*	*83%*

(A) Not shown are relatively small unit uprates and derates embedded in the current plan (e.g. FGD retrofit auxliary load losses)
(B) "Embedded" DSM represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(C) "New" DSM represents incremental activity projected based on estimated contribution & program cost (vs. avoided cost) parameters, from recent Market Potential Studies, and were generally limited to an EPRI Jan. '09 study identifying a "Realistically Achievable Potential". This 'New' (increm) DSM-DR activity modeled thru 2015 only
(D) PPA term for PSO 2012 baseload capacity & energy: 9 years, 7 months (thru 2021)
(E) Assumes Elk City and Blue Canyon V wind energy available by 2011, but firm transmission delayed until 2013
(F) Assumes Majestic wind energy available by 2010, but firm transmission delayed until 2012
(G) Derate associated with the addition of an FGD system

Source: AEP Resource Planning

13.2 Comparison to 2008 IRP

In comparison to the 2008 IRP for AEP-SPP, the 2009 IRP, represented in Exhibit 13-6**,** reflects additional DR (an additional 140 MW by 2015) and renewable resources (an additional 463 MW of wind capacity), the replacement of a (generic) PSO 492 MW CC with the Green Country PPA in 2012, and the elimination of two PSO peaking/combustion turbine blocks in 2016 and 2017. For SWEPCO, a peaking block is now shown in 2019 (the 2008 plan only showed additions through 2017).

13.3 Plan Impact on Carbon Mitigation ("Prism" Analysis)

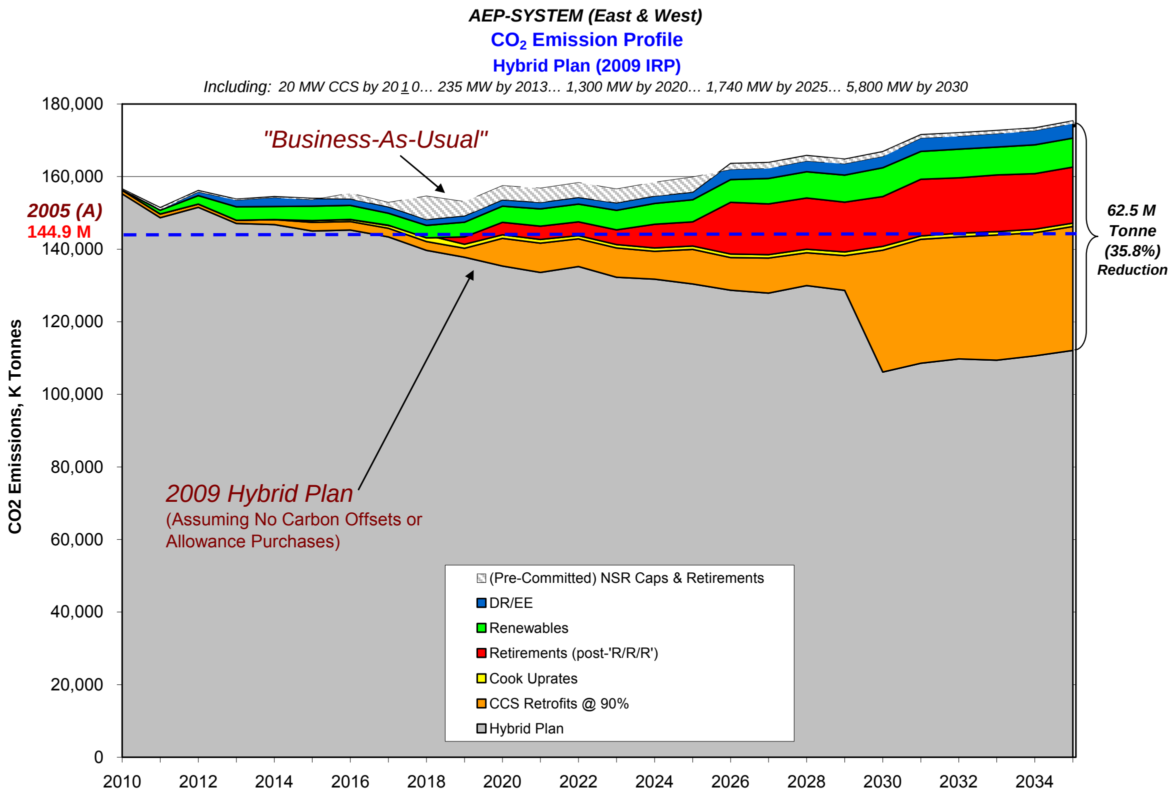
Global Climate Change and the prospect for comprehensive CO_2 legislation has had a direct bearing on the outcome of the 2009 AEP-SPP Plan. To gauge the respective CO_2 mitigation impacts incorporated into this resource planning, an assessment was performed that emulates an approach undertaken by the Electric Power Research Institute (EPRI). This profiling seeks to measure the contributions of various "portfolio" components that could, when taken together, effectively achieve such carbon mitigation:

- Energy Efficiency
- Renewable Generation
- Fossil Plant Efficiency, including coal-unit retirements
- Nuclear Generation

- Technology Solutions, including Carbon Capture and Sequestration

The following **Exhibit 13-7** reflects those comparable components within this 2009 IRP–set forth as uniquely-colored "prisms"—that are anticipated to contribute to the overall AEP System's (*combined East and West regions*) initiatives to reduce its carbon footprint:

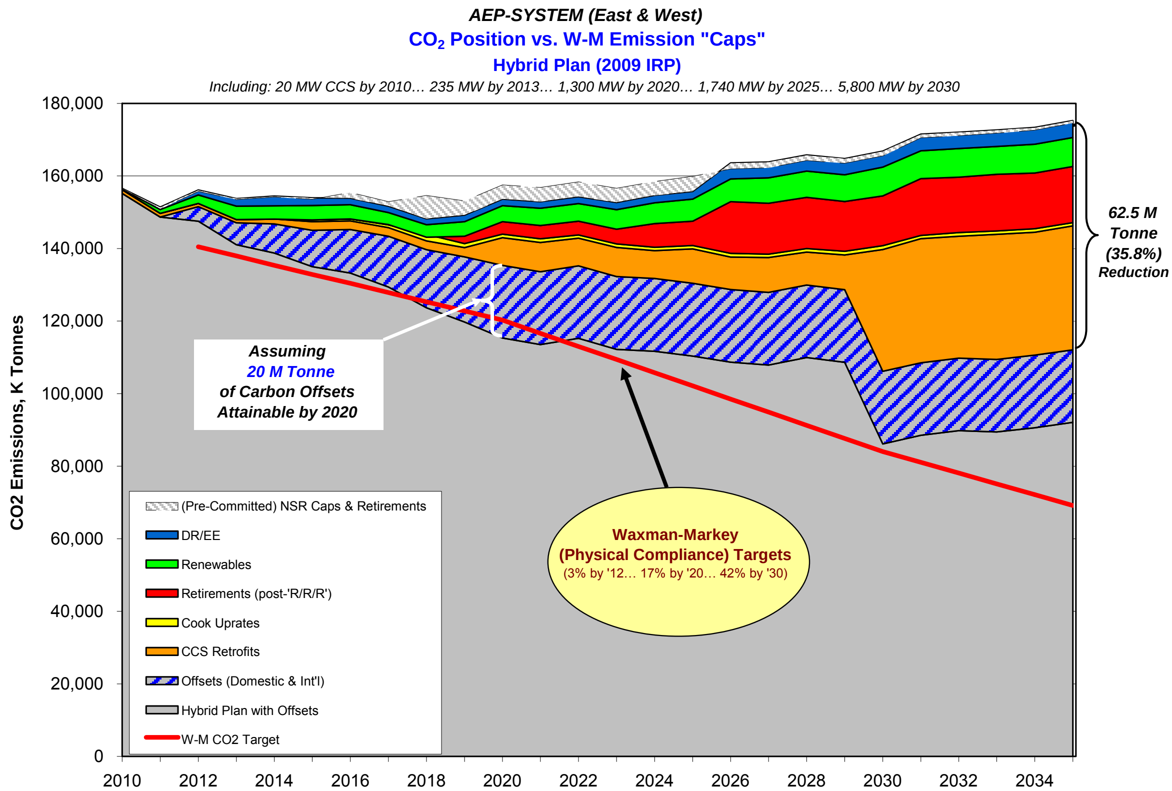
Exhibit 13-7: CO_2 Emission Profile



Source: AEP Resource Planning

While these results would suggest significant improvement in the AEP System CO_2 emission profile over time, it could still fall short of prospective legislation that would attempt to further limit CO_2. Specifically, using H.R. 2454 (the Waxman-Markey Bill) that passed the U.S. House in June, 2009 as a proxy, this profile would require reduction in CO_2 emissions that would have to consider acquisition of carbon "offsets"—financial instruments that represent certified initiative to remove 1 ton of carbon—to begin to approximate the levels of reduction set forth by such mandates. The following **Exhibit 13-8** offers such a comparison for the AEP System:

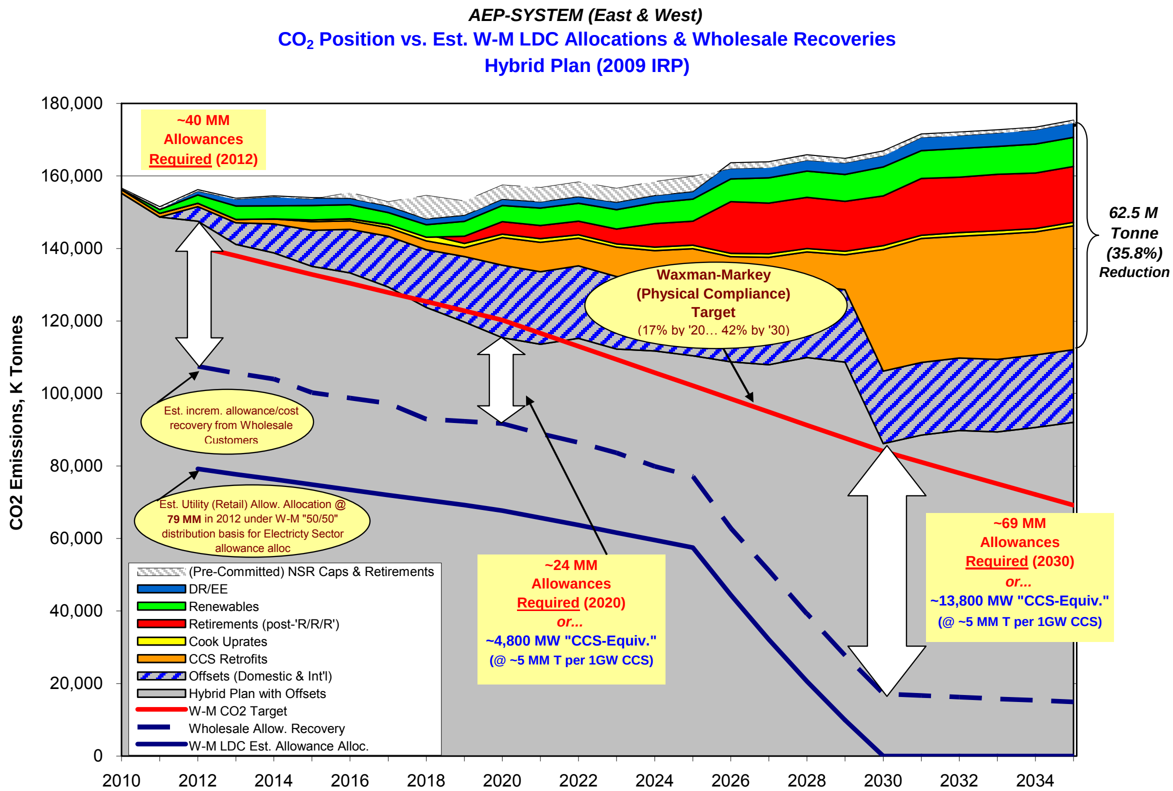
Exhibit 13-8: CO_2 Emission Profile With Caps



Source: AEP Resource Planning

Further, under the assumption that a cap-and-trade mechanism could emerge from any set of carbon legislation, it is reasonable to assume that such CO_2 mitigation efforts, inclusive of offset acquisitions, may not provide for an adequate CO_2 position within that mechanism. Specifically, if the legislation provides for the *allocation* of an insufficient level of (free) CO_2 allowances to the utility, any such remaining CO_2 position "shortfall" must subsequently be borne by the utilities' customers through additional, potentially more costly, CO_2 mitigation efforts, including the purchase of additional allowances. The following **Exhibit 13-9** identifies this potential position based on the current allowance allocation format set forth by the Waxman-Markey Bill:

Exhibit 13-9: CO_2 Emission Profile vs. Estimated Waxman-Markey Allocation



Source: AEP Resource Planning

In summary, this prism analysis would suggest that the carbon mitigation requirements in the AEP System (East and SPP) 2009 IRPs offer a meaningful pathway to the attainment of potential Climate Change/CO_2 legislation, however, **additional** contributions–over-and-above the acquisition of CO_2 allowances—may be required in future planning cycles to protect AEP's customers from significant cost exposures.

13.4 Arkansas Stakeholder Process - SWEPCO

In December 2008 SWEPCO facilitated a meeting of Stakeholders to collect input for this IRP as required by the State of Arkansas. The Stakeholders issued their report in February 2009 and it is included in the Appendix of this IRP. This Plan recognizes the work of the Arkansas Stakeholder group's report and incorporates their priorities into the SWEPCO plan. One of the Stakeholder's priorities was diversification of the resource mix, primarily through adding renewable sources. For SWEPCO, this plan has 300 MW (nameplate) more wind generation than SWEPCO's 2008 plan. The Stakeholder's also stressed reliability at low cost as a priority item. This IRP includes the completion of both Stall and Turk to maintain SWEPCO's reserve margin above the SPP required levels. These projects were selected through a competitive bidding process which assures ratepayers that the lowest reasonable cost option has been selected. The Stakeholders also listed demand side options as a priority item. This IRP increases the level of demand side programs in the forecast well above previous plans. Other Stakeholder concerns were taken into account and addressed throughout the report. SWEPCO appreciated the opportunity to gather input from their Stakeholders and looks forward to working with them again for future IRP filings.

13.5 Conclusion

The recommended plan provides the "least, reasonable cost" solution through a combination of traditional supply, renewable and demand side investments. The tempered load growth combined with additional renewable resources, increased DR/EE initiatives, completion of Stall and Turk plants, and the execution of the Exelon PPA, will allow AEP-SPP to meet its resource requirements through 2019 at which point new peaking capacity will be required. No new uncommitted baseload capacity is required over the term of the forecast period.

Finally, the plan positions AEP to meet state renewable portfolio standards and energy efficiency requirements, and sets in place the framework to meet potential CO_2 reduction targets at the intended least reasonable cost to its customers.

14.0 Implementation

14.1 Current Commitments

While the resource plan described in this report covers an extended time period, the only implementation commitments for which a firm consensus must be drawn at this time are those affecting resources that are timed to enter service roughly "one lead-time" into the future. New generation lead time naturally varies depending upon the resource type being contemplated. Depending on siting, land acquisition, permitting, design, engineering, and construction timetables–and whether certain elements (e.g. land or permitting) are already in-place–such lead-times may vary as follows:

- Simple Cycle Combustion Turbine units – about 18 to 30 months
- Wind Energy Projects – 12 to 36 months from issuance of RFP
- Natural Gas Combined Cycle units – about 30 to 42 months
- Solid Fuel units – about 60 months or more

14.1.1 AEP-SPP Implementation Status

1. **Wind (PSO and SWEPCO)** (2010-2012): An RFP was issued on June 1, 2009 for 1,100 MW of renewable energy for both the AEP-East and AEP-SPP zones to be operational no later than 12/31/2011. Additional RFP's will be issued at a later date for resources required after 2011.
2. **DR/EE**

   Oklahoma:

   - Quick start programs filed and approved June 2008 - Seven programs approved and implementation under way.
   - The Emergency Load Management (ELM) - Currently have 10.5 MW subscribed for summer 2009.
   - Energy Star New Homes program - Completed approximately 150 ES homes to date - plans to complete 700 by December 2009.
   - Low Income Weatherization - Partnering with Department of Commerce, Choctaw Nation and Rebuild Together Tulsa on low- income weatherization program - completed 30 homes with another 68 to be completed July 2009. This results in an energy savings of approximately 160,500 kWh and 28.6 kW.
   - ES Res/Comm appliance rebate program - Began implementation of air conditioner replacement rebate program in April 2009 in partnership with Sears and Kmart.
   - C&I SOP - Have projects completed that resulted in a reduction of 150 kW and 965,800 kWh with projects pending that will provide another 1,100 kW and 6 million kWh in energy savings by December 2009.
   - Model Cities LED Traffic signal change out program - Paid incentives for energy savings of 214 kW and 1.2 GWh but have commitments for remaining 1,400 kW and 6.3 GWh.
   - Higher Education Loan program - Paid incentives to OSU Tulsa and Tulsa Community College for completion of energy audits.

PSO received approval to file new proposed programs 2010-2012 on September 15th.

Texas:

- SWEPCO-Texas is currently operating ten programs, including one demand response program, with a mandated goal to achieve a 20 percent reduction in the five-year average demand growth during 2009. The associated energy goal is derived by applying a 20 capacity factor to the demand goal. SWEPCO-Texas currently has over 5,000 kW subscribed for the summer of 2009.
- An appliance recycling program and an additional comprehensive commercial program (Commercial Solutions) were "kicked off" in late 2008 and are in full swing in 2009. A solar PV pilot program will be initiated in the 3rd quarter of 2009. In addition, SWEPCO-Texas continues to negotiate with Comverge in developing a small scale (250 air conditioners or heat pumps) direct load control R&D project for the summer of 2010 in the City of Longview.

Louisiana:

- SWEPCO - Louisiana is giving consideration to proactively filing a portfolio of programs in 2009 which would include a low-income weatherization program and a solar PV program. The proposed program portfolio would be similar to that in SWEPCO's Arkansas and Texas jurisdictions.

Arkansas:

- As a result of the collaborative that was initiated by the Arkansas Public Service Commission in 2006, energy efficiency rules were adopted in May 2007. To comply with these rules, SWEPCO began one "Quick Start" demand response program and five "Quick Start" energy efficiency programs in late 2007 and will continue these programs through 2009. SWEPCO filed a comprehensive program plan on April 1, 2009 where it proposed two additional energy efficiency programs for 2010 and beyond.
- SWEPCO - Arkansas currently has over 5,000 kilowatts subscribed for the summer of 2009.

3. **Stall Combined Cycle Unit** (by 6/1/2011): All permits have been received and construction continues.
4. **PSO baseload capacity** (by 6/1/2012): PSO and Exelon Generation Company LLC, a subsidiary of Exelon Corporation, have executed a long-term PPA and filed an application seeking its approval with the Oklahoma Corporation Commission (OCC). The PPA is for the purchase of up to 520 megawatts (MW) of electric generation from the 795-MW natural gas-fueled Green Country Generating Station, located in Jenks, Okla.
5. **Turk USC Pulverized Coal** Unit (by 6/1/2013): The Arkansas Court of Appeals overturned the APSC decision granting a CECPN. AEP filed an appeal to Arkansas Supreme Court. The air permit appeal hearings were held in June, and a decision is expected by year-end. As of July 1, 2009, over $713 million has been spent on plant construction, and $1.3 billion of the total $1.6 billion project has been committed.

14.1.2 AEP Capital Expenditures For This Plan

To implement the recommendations included in this plan, significant capital expenditures will be required. These expenditures are outlined in the Confidential Supplement. As stated earlier, this plan, while making specific recommendations based on available data, is not a commitment to a specific course of action.

APPENDICES

Appendix A, Figure 1 Existing Generation Capacity, AEP-SPP Zone

AEP System - SPP Zone
Existing Generation Capacity as of June 1, 2009

Plant Name	Unit No.	In-Service Date	Mode of Operation	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	SCR	CCS	FGD	FGD Upgr	ACI-ESP	ACI-BH	Super critical	Age
PSO														
Northeastern	3	1979	Base	460	455	Coal	--	2030	2016	--	2016	--	Y	30
Northeastern	4	1980	Base	470	470	Coal	--	--	2016	--	2016	--	Y	29
Oklaunion (a)	1	1986	Base	108	101	Coal	--	--	--	--	--	--	N	23
PSO Coal				1,038	1,026									29
Comanche	1	1973	Base/Intermediate	285	255	Gas	--	--	--	--	--	--	--	36
Northeastern	1	1961	Base/Intermediate	470	422	Gas	--	--	--	--	--	--	N	48
Northeastern	2	1970	Intermediate	470	470	Gas	--	--	--	--	--	--	Y	39
Riverside	1	1974	Intermediate	463	454	Gas	--	--	--	--	--	--	Y	35
Riverside	2	1976	Intermediate	465	453	Gas	--	--	--	--	--	--	Y	33
Riverside	3	2008	Peaking	83	75 (b)	Gas	--	--	--	--	--	--	--	1
Riverside	4	2008	Peaking	83	75 (b)	Gas	--	--	--	--	--	--	--	1
Southwestern	1	1952	Intermediate	80	78	Gas	--	--	--	--	--	--	N	57
Southwestern	2	1954	Intermediate	80	78	Gas	--	--	--	--	--	--	N	55
Southwestern	3	1967	Intermediate	315	311	Gas	--	--	--	--	--	--	N	42
Southwestern	4	2008	Peaking	83	75 (b)	Gas	--	--	--	--	--	--	--	1
Southwestern	5	2008	Peaking	83	75 (b)	Gas	--	--	--	--	--	--	--	1
Tulsa	2	1956	Intermediate	165	160	Gas	--	--	--	--	--	--	N	53
Tulsa	3	1958	Intermediate	71	65	Gas	--	--	--	--	--	--	N	51
Tulsa	4	1958	Intermediate	165	155	Gas	--	--	--	--	--	--	N	51
Weleetka	4	1975	Peaking	65	54	Gas	--	--	--	--	--	--	--	34
Weleetka	5	1975	Peaking	65	52	Gas	--	--	--	--	--	--	--	34
Weleetka	6	1976	Peaking	65	52	Gas	--	--	--	--	--	--	--	33
PSO Gas				3,556	3,359									37
Diesels		1962	Peaking	6	6	Oil	--	--	--	--	--	--	--	47
Diesels		1963	Peaking	4	4	Oil	--	--	--	--	--	--	--	46
Diesels		1967	Peaking	8	8	Oil	--	--	--	--	--	--	--	42
Diesels		1968	Peaking	3	3	Oil	--	--	--	--	--	--	--	41
Diesels		1976	Peaking	3	3	Oil	--	--	--	--	--	--	--	33
Diesels		1980	Peaking	1	1	Oil	--	--	--	--	--	--	--	29
PSO Oil				25	25									42
Weatherford Wind (c)		2005	Intermittent	15	15	Wind	--	--	--	--	--	--	--	4
Sleeping Bear Wind (c)		2007	Intermittent	2	2	Wind	--	--	--	--	--	--	--	2
PSO Wind				17	17									4
Total PSO				**4,636**	**4,427**									
SWEPCO														
Flint Creek (d)	1	1978	Base	264	264	Coal	--	--	2014	--	--	--	N	31
Welsh	1	1977	Base	528	528	Coal	--	2030	--	--	--	--	N	32
Welsh	2	1980	Base	528	528	Coal	--	2030	2015	--	--	--	N	29
Welsh	3	1982	Base	528	528	Coal	--	--	--	--	--	--	N	27
SWEPCO Coal				1,848	1,848									30
Dolet Hills (e)	1	1986	Base	262	262	Lignite	--	--	2006	2012	--	--	N	23
Pirkey (f)	4	1985	Base	580	580	Lignite	--	--	2006	--	--	--	N	24
SWEPCO Lignite				842	842									24
Arsenal Hill	5	1960	Intermediate	110	110	Gas	--	--	--	--	--	--	N	49
Knox Lee	2	1950	Intermediate	31	30	Gas	--	--	--	--	--	--	N	59
Knox Lee	3	1952	Intermediate	32	29	Gas	--	--	--	--	--	--	N	57
Knox Lee	4	1956	Intermediate	79	73	Gas	--	--	--	--	--	--	N	53
Knox Lee	5	1974	Intermediate	345	345	Gas	--	--	--	--	--	--	N	35
Lieberman	1	1947	Intermediate	25	25	Gas	--	--	--	--	--	--	N	62
Lieberman	2	1949	Intermediate	26	26	Gas	--	--	--	--	--	--	N	60
Lieberman	3	1957	Intermediate	115	109	Gas	--	--	--	--	--	--	N	52
Lieberman	4	1959	Intermediate	112	108	Gas	--	--	--	--	--	--	N	50
Lone Star	1	1954	Intermediate	50	50	Gas	--	--	--	--	--	--	N	55
Mattison	1	2007	Peaking	83	72	Gas	--	--	--	--	--	--	--	2
Mattison	2	2007	Peaking	83	72	Gas	--	--	--	--	--	--	--	2
Mattison	3	2007	Peaking	83	72	Gas	--	--	--	--	--	--	--	2
Mattison	4	2007	Peaking	83	72	Gas	--	--	--	--	--	--	--	2
Wilkes	1	1964	Intermediate	178	174	Gas	--	--	--	--	--	--	N	45
Wilkes	2	1970	Intermediate	360	355	Gas	--	--	--	--	--	--	N	39
Wilkes	3	1971	Intermediate	359	354	Gas	--	--	--	--	--	--	N	38
SWEPCO Gas				2,154	2,076									37
Total SWEPCO				**4,844**	**4,766**									
TOTAL AEP-West				**9,480**	**9,193**									

(a) PSO owns 15.62% of the 650 MW jointly-owned Oklaunion Unit No. 1.
(b) PSO combustion turbine units were uprated after its IRP was completed early in 2008.
(c) Power purchase agreements.
(d) SWEPCO owns 50% of the 528 MW jointly-owned Flint Creek Unit No. 1.
(e) SWEPCO owns 40.234% of the 650 MW jointly-owned Dolet Hills Unit No. 1.
(f) SWEPCO owns 85.936% of the 675 MW jointly-owned Pirkey Unit No. 1.

Appendix B, Figure 1 Economically Screened Renewable Alternatives

Unit or Series	Renewable Type	$/MWh	Unit or Series	Renewable Type	$/MWh
Hydro, Existing Dam, PTC	Hydro	-$16.08	Mountaineer	Biomass Separate Injection	$25.32
Wind Project, SPP with PTC	Wind	-$10.50	Big Sandy 1	Biomass Separate Injection	$25.49
Amos 3	Biomass Cofire	-$3.60	Conesville 5	Biomass Separate Injection	$25.51
Big Sandy 2	Biomass Cofire	-$1.32	Conesville 6	Biomass Separate Injection	$26.06
Amos 1	Biomass Cofire	$0.14	Pirkey 1	Biomass Separate Injection	$26.08 (a)
Tanners Creek 4	Biomass Separate Injection	$1.71	Kanawha River 1	Biomass Separate Injection	$26.15
Rockport 1	Biomass Cofire	$2.98	Flint Creek 1	Biomass Separate Injection	$26.30
Stoker conversion, 100% biomass	High fuel cost	$4.54	Cardinal 1	Biomass Separate Injection	$26.42 (a)
Muskingum River 5	Biomass Cofire	$4.91	Mitchell 1	Biomass Separate Injection	$29.55 (a)
Stuart 1	Biomass Separate Injection	$7.21	Dolet Hills 1	Biomass Separate Injection	$30.51
Muskingum River 5	Biomass Separate Injection	$9.04 (a)	Tanners Creek 3	Biomass Separate Injection	$32.49
Glen Lyn 6	Biomass Separate Injection	$11.53	Tanners Creek 1	Biomass Separate Injection	$32.70
Big Sandy 2	Biomass Separate Injection	$12.09 (a)	Northeastern 3	Biomass Cofire	$32.79
Mountaineer	Biomass Cofire	$12.69	Clinch River 1	Biomass Cofire	$37.48
Amos 3	Biomass Separate Injection	$13.04 (a)	Northeastern 3	Biomass Separate Injection	$38.64 (a)
Amos 1	Biomass Separate Injection	$13.65 (a)	Clinch River 1	Biomass Separate Injection	$41.79 (a)
Oklaunion 1	Biomass Cofire	$14.47	Wind Project, PJM w/o PTC	Wind	$45.04
Welsh 1	Biomass Cofire	$14.51	Sporn 1	Biomass Separate Injection	$47.21
Mitchell 1	Biomass Cofire	$15.09	Landfill Gas0.8Recip Engine	Gas	$57.00
Wind Project, SPP w/o PTC	Wind	$16.62	Muskingum River 3	Biomass Separate Injection	$75.23
Rockport 1	Biomass Separate Injection	$16.79 (a)	Glen Lyn 5	Biomass Separate Injection	$86.09
Wind Project, PJM with PTC	Wind	$17.94	Muskingum River 1	Biomass Cofire	$104.54
Welsh 1	Biomass Separate Injection	$18.51 (a)	Sporn 5	Biomass Cofire	$130.46
Oklaunion 1	Biomass Separate Injection	$20.45 (a)	Muskingum River 1	Biomass Separate Injection	$135.04
Pirkey 1	Biomass Cofire	$20.80	Picway 5	Biomass Separate Injection	$141.28
Cardinal 1	Biomass Cofire	$21.01	Conesville 3	Biomass Cofire	$316.90
Zimmer	Biomass Separate Injection	$22.04	Residential Wind, PJM w/o PTC	Wind	$394.03
Kammer 1	Biomass Separate Injection	$22.34	Central Station Solar	Solar	$445.00
Conesville 4	Biomass Separate Injection	$22.82			
Gavin 1	Biomass Separate Injection	$24.28			
Beckjord 6	Biomass Separate Injection	$24.32			

Note: (a) The cost of a second technology at a unit is incremental, that is, additional renewable energy divided by additional cost.

Appendix C, Figure 1 Key Supply Side Resource Assumptions

AEP System-West Zone
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)

Type	Capability (MW) Std. ISO	Trans. Cost (c) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Emission Rates SO2 (lb/MMBtu)	Emission Rates NOx (lb/MMBtu)	Emission Rates CO2 (lb/MMBtu)	Capacity Factor (%)	Overall Availability (%)
Base Load								
Pulv. Coal (Subcritical) (PRB)	618	20	9,527	0.0125	0.070	212.70	85	90.7
Pulv. Coal (Subcritical) (PRB)	736	17	9,516	0.0125	0.070	212.70	85	89.6
Pulv. Coal (Supercritical) (PRB)	618	20	9,249	0.0125	0.070	212.70	85	90.7
Pulv. Coal (Supercritical) (PRB)	736	17	9,239	0.0125	0.070	212.70	85	89.6
Pulv. Coal (Ultra-Supercritical) (PRB)	618	20	8,980	0.0125	0.070	212.70	85	89.6
Pulv. Coal (Ultra-Supercritical) (PRB)	736	17	8,970	0.0125	0.070	212.70	85	89.6
IGCC (PRB)	621	20	9,220	0.0193	0.062	212.70	85	87.5
Pulv. Coal (Subcritical) (Lignite)	618	20	10,245	0.0773	0.070	215.40	85	90.7
Pulv. Coal (Subcritical) (Lignite)	736	17	10,235	0.0773	0.070	215.40	85	89.6
Pulv. Coal (Supercritical) (Lignite)	618	20	9,947	0.0773	0.070	215.40	85	90.7
Pulv. Coal (Supercritical) (Lignite)	736	17	9,936	0.0773	0.070	215.40	85	89.6
Pulv. Coal (Ultra-Supercritical) (Lignite)	607	21	9,657	0.0773	0.070	215.40	85	89.6
Pulv. Coal (Ultra-Supercritical) (Lignite)	736	17	9,647	0.0773	0.070	215.40	85	89.6
IGCC (Lignite)	585	21	9,156	0.0773	0.057	215.40	85	87.5
Nuclear (MHI ABWR)	1,606	52	10,500	0.0000	0.000	0.00	85	94.0
Base Load (50% CO2 Capture New Unit)								
Pulv. Coal (Subcritical) (PRB)	515	24	11,432	0.0125	0.070	106.35	85	89.6
Pulv. Coal (Supercritical) (PRB)	515	24	11,099	0.0125	0.070	106.35	85	89.6
Pulv. Coal (Ultra-Supercritical) (PRB)	515	24	10,776	0.0125	0.070	106.35	85	89.6
IGCC (PRB)	569	22	10,058	0.0193	0.062	106.35	85	87.5
Pulv. Coal (Subcritical) (Lignite)	515	24	12,294	0.0773	0.070	107.70	85	89.6
Pulv. Coal (Supercritical) (Lignite)	515	24	11,936	0.0773	0.070	107.70	85	89.6
Pulv. Coal (Ultra-Supercritical) (Lignite)	505	25	11,588	0.0773	0.070	107.70	85	89.6
IGCC (Lignite)	537	23	9,988	0.0773	0.057	107.70	85	87.5
Base Load (90% CO2 Capture New Unit)								
Pulv. Coal (Subcritical) (PRB)	433	29	13,610	0.0125	0.070	21.27	85	89.6
Pulv. Coal (Subcritical) (PRB)	515	24	13,595	0.0125	0.070	21.27	85	89.6
Pulv. Coal (Supercritical) (PRB)	433	29	13,213	0.0125	0.070	21.27	85	89.6
Pulv. Coal (Supercritical) (PRB)	515	24	13,199	0.0125	0.070	21.27	85	89.6
Pulv. Coal (Ultra-Supercritical) (PRB)	433	29	12,829	0.0125	0.070	21.27	85	89.6
Pulv. Coal (Ultra-Supercritical) (PRB)	515	24	12,814	0.0125	0.070	21.27	85	89.6
IGCC (PRB)	528	24	10,847	0.0193	0.062	21.27	85	87.5
IGCC (w/ CCS) (PRB)	528	24	10,847	0.0193	0.062	21.27	85	87.5
Pulv. Coal (Subcritical) (Lignite)	433	29	14,636	0.0773	0.070	21.54	85	89.6
Pulv. Coal (Subcritical) (Lignite)	515	24	14,621	0.0773	0.070	21.54	85	89.6
Pulv. Coal (Supercritical) (Lignite)	433	29	14,210	0.0773	0.070	21.54	85	89.6
Pulv. Coal (Supercritical) (Lignite)	515	24	14,195	0.0773	0.070	21.54	85	89.6
Pulv. Coal (Ultra-Supercritical) (Lignite)	425	29	13,796	0.0773	0.070	21.54	85	89.6
Pulv. Coal (Ultra-Supercritical) (Lignite)	515	24	13,781	0.0773	0.070	21.54	85	89.6
IGCC (Lignite)	498	25	10,772	0.0773	0.057	21.54	85	87.5
IGCC (w/ CCS) (Lignite)	498	25	10,772	0.0773	0.057	21.54	85	87.5
Intermediate								
Combined Cycle (2X1 GE7FA)	507	30	7,040	0.0007	0.008	116.00	85	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	619	24	7,660	0.0007	0.008	116.00	85	89.1
Combined Cycle (2X1 GE7FB)	538	28	6,917	0.0007	0.008	116.00	85	89.1
Combined Cycle (2X1 GE7FB, w/ Duct Firing)	650	23	7,537	0.0007	0.008	116.00	85	89.1
Intermediate (70% CO2 Capture New Unit)								
Combined Cycle (2X1 GE7FA)	447	34	7,969	0.0007	0.008	34.80	85	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	546	27	8,671	0.0007	0.008	34.80	85	89.1
Combined Cycle (2X1 GE7FB)	475	32	7,831	0.0007	0.008	34.80	85	89.1
Combined Cycle (2X1 GE7FB, w/ Duct Firing)	574	26	8,533	0.0007	0.008	34.80	85	89.1
Peaking								
Combustion Turbine (2X1GE7EA)	165	60	12,156	0.0007	0.033	116.00	5	90.1
Combustion Turbine (2X1GE7EA,w/ Inlet Chiller	165	60	12,339	0.0007	0.009	116.00	5	90.1
Combustion Turbine (4X1GE7EA)	329	60	12,156	0.0007	0.033	116.00	5	90.1
Combustion Turbine (4X1GE7EA,w/ Inlet Chiller	329	60	12,339	0.0007	0.009	116.00	5	90.1
Combustion Turbine (6X1GE7EA)	494	60	12,156	0.0007	0.033	116.00	5	90.1
Combustion Turbine (6X1GE7EA,w/ Inlet Chiller	494	60	12,339	0.0007	0.009	116.00	5	90.1
Combustion Turbine (8X1GE7EA)	658	60	12,156	0.0007	0.033	116.00	5	90.1
Combustion Turbine (8X1GE7EA,w/ Inlet Chiller	658	60	12,339	0.0007	0.009	116.00	5	90.1
Combustion Turbine (2X GE7FA)	328	60	10,390	0.0007	0.033	116.00	5	90.1
Combustion Turbine (2X GE7FA, w/ Inlet Chiller	328	60	10,545	0.0007	0.009	116.00	5	90.1
Combustion Turbine (3X GE7FA)	492	60	10,390	0.0007	0.033	116.00	5	90.1
Combustion Turbine (3X GE7FA, w/ Inlet Chiller	492	60	10,545	0.0007	0.009	116.00	5	90.1
Combustion Turbine (4X GE7FA)	657	60	10,390	0.0007	0.033	116.00	5	90.1
Combustion Turbine (4X GE7FA, w/ Inlet Chiller	657	60	10,545	0.0007	0.009	116.00	5	90.1
Aero-Derivative (4X GE LM6000PC)	181	60	9,598	0.0007	0.056	116.00	5	89.1
Aero-Derivative (1X GE LMS100)	96	60	8,402	0.0007	0.056	116.00	5	89.1
Aero-Derivative (1X GE LMS100, w/ Inlet Chiller	96	60	8,528	0.0007	0.009	116.00	5	90.1
Aero-Derivative (2X GE LMS100)	191	60	8,402	0.0007	0.056	116.00	5	89.1
Aero-Derivative (2X GE LMS100, w/ Inlet Chiller	191	60	8,528	0.0007	0.009	116.00	5	90.1

Notes: (a)Capability and heat rate numbers have been rounded.
(b) All costs in 2008 dollars. Assume 2% escalation rate for 2008 and beyond.
(c) Transmission Cost ($/kW,w/AFUDC).

Source: "New Generation Technology Cost and Performance Estimates," 12/03/08, Corporate Technology Development (CTD).

Appendix C, Figure 2 Energy Storage Screening

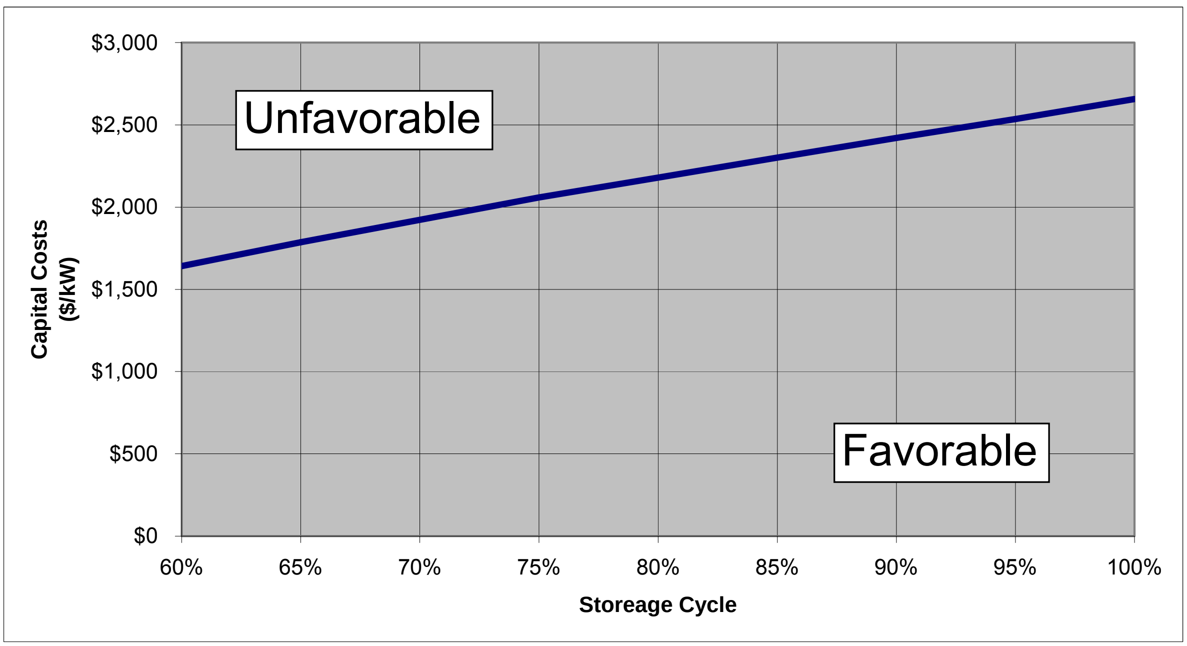
To ascertain a break-even screening curve for energy storage facilities, an hour-by-hour simulation was run. The simulation was based on the forecasted power prices of the reference case as used in this report. The facility was assumed to generate up to six hours per day (the most cost effective hours) in which:

(Generation Price * Cycle Efficiency) – (Charging Price) > 0

The simulation was run for 10 years at various cycle efficiencies while tracking the annual cost, in $/kW-year, and the capacity factor of the facility. For each efficiency the levelized $/kW-year cost was plotted against the average capacity factor. The most recent equivalent data for a combustion turbine (GE7FA) facility was also plotted on the same graph.

The fixed costs for the energy storage facility were then varied to create intercepts with the combustion turbine curve at various capacity factors thus yielding the following chart.

Break-Even Energy Storage Capital Cost and Cycle Efficiency as Compared to a CT (GE7FA)



Source: AEP Resource Planning

This exhibit depicts the break-even capital cost of the storage facility in terms of cycle efficiency. For example a storage facility costing $2,000/kW and having a cycle efficiency of 75% or higher would compare favorably against a CT. However, a facility costing $2,500/kW would need an efficiency of 95% or greater.

This analysis considers only the value of storage as a supply-side resource. Additional value might be provided by the facility's location with respect to the distribution system, if system capital improvements could be delayed.

Appendix D, Figure 1 AEP-SPP Capacity, Demand, Reserve Forecast

AMERICAN ELECTRIC POWER OPERATING COMPANIES IN SOUTHWEST POWER POOL
CAPABILITY, DEMAND AND RESERVES FORECAST
2008 Actual - 2019
(MW)
2009 IRP

Public Service Company of Oklahoma

Capability	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Existing Plants and new additions	4,405	**4,410**	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
Adjustments									-15	-15	-15	-15
New Combustion Turbines												
Wind Purchases	27	17	17	17	17	45	45	50	50	66	66	66
Transfer from SWEPCo				18								
Transfer to SWEPCo					-15							
Other known Purchases w/o Reserves	254	390	138	100	512	512	510	510	510	508	508	508
Unknown Wholesale Purchase				70								
Total Capability	4,686	4,817	4,565	4,615	4,924	4,967	4,965	4,970	4,955	4,969	4,969	4,969
Demand												
Native Load Responsibility	4,152	3,976	4,051	4,100	4,181	4,187	4,180	4,171	4,186	4,203	4,226	4,245
Sales With Reserves												
East to West Transfer w/ Reserves												
Other Purchases With Reserves	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39
Net Demand Responsibility	4,113	3,937	4,012	4,061	4,142	4,148	4,141	4,132	4,147	4,164	4,187	4,206
Reserves												
Reserve Capacity, MW	573	880	553	554	782	819	824	838	808	805	782	763
Capacity Margin, %	12.2	18.3	12.1	12.0	15.9	16.5	16.6	16.9	16.3	16.2	15.7	15.4

Southwestern Electric Power Company

Capability	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Existing Plants and new additions	4,792	4,766	4,766	**5,275**	5,275	**5,722**	5,722	5,722	5,722	5,722	5,722	5,722
Adjustments							-4	-12	-12	-12	-12	-12
New Combustion Turbine												157
Wind Purchases				8	22	34	34	37	45	45	45	45
Transfer from PSO					15							
Transfer to PSO				-18								
East to West Transfer w/o Reserves												
Other known Purchases w/o Reserves	702	816	743	381	381	432	432	42	42	42	42	42
Sales without Reserves	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18
Unknown Wholesale Purchase												
Total Capability	5,476	5,564	5,491	5,628	5,675	6,170	6,166	5,771	5,779	5,779	5,779	5,936
Demand												
Native Load Responsibility	4,920	4,798	4,954	5,082	5,121	5,186	5,239	4,544	4,605	4,666	4,735	4,801
Sales With Reserves	46	46	46	46	48	48	48	248	248	248	250	250
East to West Transfer w/ Reserves												
Other Purchases With Reserves	-175	-175	-175	-175	-175	-175	-175	-73	-73	-73	-73	-73
Net Demand Responsibility	4,791	4,669	4,825	4,953	4,994	5,059	5,112	4,719	4,780	4,841	4,912	4,978
Reserves												
Reserve Capacity, MW	685	895	666	675	681	1,111	1,054	1,052	999	938	867	958
Capacity Margin, %	12.5	16.1	12.1	12.0	12.0	18.0	17.1	18.2	17.3	16.2	15.0	16.1

Total PSO Market + Affiliate Purchase	254	390	138	188								
Total SWEPCo Market + Affiliate Purchase	321	435	362		15							
Total System Purchase	575	825	500	170								

System Unknown Wholesale Purchase				70								
Total Surplus	84	601	14		217	675	616	684	589	515	408	469

Appendix D, Figure 2 AEP-SPP Capacity, Demand, Reserve Forecast (High Demand Scenario)

AMERICAN ELECTRIC POWER OPERATING COMPANIES IN SOUTHWEST POWER POOL
CAPABILITY, DEMAND AND RESERVES FORECAST
2008 Actual - 2019
(MW)
HIGH ECONOMIC FORECAST SCENARIO (2009 IRP EXPANSION PLAN)

Public Service Company of Oklahoma

Capability	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Existing Plants and new additions	4,405	**4,410**	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
Adjustments									-15	-15	-15	-15
New Combustion Turbines												
Wind Purchases	27	17	17	17	17	45	45	50	50	66	66	66
Transfer from SWEPCo									18			
Transfer to SWEPCo					-65							
Other known Purchases w/o Reserves	254	390	138	100	512	512	510	510	510	508	508	508
Unknown Wholesale Purchase			108	228					1	46	92	124
Total Capability	4,686	4,817	4,673	4,755	4,874	4,967	4,965	4,970	4,974	5,015	5,061	5,093
Demand												
Native Load Responsibility	4,152	4,045	4,151	4,223	4,328	4,365	4,385	4,391	4,417	4,453	4,493	4,521
Sales With Reserves												
East to West Transfer w/ Reserves												
Other Purchases With Reserves	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39
Net Demand Responsibility	4,113	4,006	4,112	4,184	4,289	4,326	4,346	4,352	4,378	4,414	4,454	4,482
Reserves												
Reserve Capacity, MW	573	811	561	571	585	641	619	618	597	602	607	611
Capacity Margin, %	12.2	16.8	12.0	12.0	12.0	12.9	12.5	12.4	12.0	12.0	12.0	12.0

Southwestern Electric Power Company

Capability	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Existing Plants and new additions	4,792	4,766	4,766	**5,275**	5,275	**5,722**	5,722	5,722	5,722	5,722	5,722	5,722
Adjustments							-4	-12	-12	-12	-12	-12
New Combustion Turbine												157
Wind Purchases				8	22	34	34	37	45	45	45	45
Transfer from PSO					65							
Transfer to PSO									-18			
East to West Transfer w/o Reserves												
Other known Purchases w/o Reserves	702	816	743	381	381	432	432	42	42	42	42	42
Sales without Reserves	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	-18
Unknown Wholesale Purchase			130	154	153					83	193	128
Total Capability	5,476	5,564	5,621	5,800	5,878	6,170	6,166	5,771	5,761	5,862	5,972	6,064
Demand												
Native Load Responsibility	4,885	4,881	5,076	5,233	5,300	5,403	5,492	4,819	4,895	4,984	5,078	5,159
Sales With Reserves	46	46	46	46	48	48	48	248	248	248	250	250
East to West Transfer w/ Reserves												
Other Purchases With Reserves	-175	-175	-175	-175	-175	-175	-175	-73	-73	-73	-73	-73
Net Demand Responsibility	4,756	4,752	4,947	5,104	5,173	5,276	5,365	4,994	5,070	5,159	5,255	5,336
Reserves												
Reserve Capacity, MW	720	812	674	696	705	894	801	777	691	703	717	728
Capacity Margin, %	13.2	14.6	12.0	12.0	12.0	14.5	13.0	13.5	12.0	12.0	12.0	12.0

Total PSO Market + Affiliate Purchase	254	390	246	328					19	46	92	124
Total SWEPCo Market + Affiliate Purchase	321	435	492	154	218					83	193	128
Total System Purchase	575	825	738	482	153				1	129	285	252

System Unknown Wholesale Purchase			238	382	153				1	129	285	252
Total Surplus	84	429				226	96	120				

Appendix D, Figure 3 PSO Capacity, Demand, Reserve Forecast

PUBLIC SERVICE COMPANY OF OKLAHOMA
CAPABILITY, DEMAND AND RESERVES FORECAST
2008 Actual - 2019
(MW)
2009 IRP

CAPABILITY

	Plant Capabilities	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	11 DIESEL UNITS @ PLANT LOCATIONS	25	25	25	25	25	25	25	25	25	25	25	25
	10 OKLAUNION #1	101	101	101	101	101	101	101	101	101	101	101	101
	9 COMANCHE # 1G1, 1G2, 1S	260	255	255	255	255	255	255	255	255	255	255	255
	8 NORTHEASTERN # 1 & 2	883	892	892	892	892	892	892	892	892	892	892	892
	7 NORTHEASTERN # 3 & 4	930	925	925	925	925	925	925	925	925	925	925	925
	6 RIVERSIDE # 1 & 2	909	907	907	907	907	907	907	907	907	907	907	907
	5 RIVERSIDE CTs	150	150	150	150	150	150	150	150	150	150	150	150
	4 SOUTHWESTERN # 1, 2, 3	467	467	467	467	467	467	467	467	467	467	467	467
	3 SOUTHWESTERN CTs	150	150	150	150	150	150	150	150	150	150	150	150
	2 TULSA # 2, 3, 4	370	380	380	380	380	380	380	380	380	380	380	380
	1 WELEETKA # 4, 5, 6	160	158	158	158	158	158	158	158	158	158	158	158
1	TOTAL	4,405	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
	Adjustments to Plant Capability												
	NEW COMBUSTION TURBINE UNITS												
	NE 3 & 4 Scrubbers, 1.6% (MW) 2016									-15	-15	-15	-15
2	TOTAL	0	0	0	0	0	0	0	0	-15	-15	-15	-15
3	**Net Plant Capability (1 + 2)**	4,405	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,395	4,395	4,395	4,395
	Sales Without Reserves												
	TRANSFER TO SWEPCO					15							
4	TOTAL	0	0	0	0	15	0	0	0	0	0	0	0
	Purchases Without Reserves												
	[redacted]	101	249	138	100								
	TRANSFER FROM SWEPCO				18								
	WEATHERFORD WIND	19	15	15	15	15	15	15	15	15	15	15	15
	SLEEPING BEAR WIND	8	2	2	2	2	2	2	2	2	2	2	2
	BLUE CANYON WIND						20	20	20	20	20	20	20
	ADDITIONAL WIND PROJECTS						8	8	13	13	29	29	29
	EXELON GREEN COUNTRY					512	512	510	510	510	508	508	508
	[redacted]	153	141										
	UNKNOWN WHOLESALE PURCHASE				70								
5	TOTAL	281	407	155	205	529	557	555	560	560	574	574	574
6	**Total Capability (3 - 4 + 5)**	4,686	4,817	4,565	4,615	4,924	4,967	4,965	4,970	4,955	4,969	4,969	4,969

DEMAND

	DEMAND	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
A	**Peak Demand Before Passive DSM**	4,200	4,059	4,171	4,254	4,366	4,406	4,432	4,457	4,473	4,486	4,511	4,532
B	**Passive DSM**												
	APPROVED DSM PROGRAMS		9	13	16	19	21	22	23	24	25	25	25
	NEW DSM			31	62	94	125	157	188	188	188	188	188
	TOTAL	0	9	44	78	113	146	179	211	212	212	212	212
C	**Peak Demand (A - B)**	4,200	4,050	4,127	4,175	4,253	4,260	4,253	4,246	4,261	4,273	4,299	4,320
D	**Active DSM**												
	VALUECHOICE	35	35	35	35	35	35	35	35	35	35	35	35
	INTERRUPTIBLE	13	17	17	17	17	17	17	17	17	17	17	17
	TOTAL	48	52	52	52	52	52	52	52	52	52	52	52
E	**Firm Demand (C - D)**	4,152	3,998	4,075	4,123	4,201	4,208	4,201	4,194	4,209	4,221	4,247	4,268
F	**Other Demand Adjustments**												
	DIVERSITY		22	24	23	20	21	21	22	23	18	20	23
	TOTAL	0	22	24	23	20	21	21	22	23	18	20	23
7	**Native Load Responsibility (E - F)**	4,152	3,976	4,051	4,100	4,181	4,187	4,180	4,171	4,186	4,203	4,226	4,245
	Sales With Reserves												
8	TOTAL	0	0	0	0	0	0	0	0	0	0	0	0
	Purchases With Reserves												
	PSO - SWPA ENTITLEMENT	39	39	39	39	39	39	39	39	39	39	39	39
9	TOTAL	39	39	39	39	39	39	39	39	39	39	39	39
10	**Load Responsibility (7 + 8 - 9)**	4,113	3,937	4,012	4,061	4,142	4,148	4,141	4,132	4,147	4,164	4,187	4,206

RESERVES

	RESERVES	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
11	**Reserve Capacity, MW (6 - 10)**	573	880	553	554	782	819	824	838	808	805	782	763
12	**% Reserve Margin ((11/10) * 100)**	13.9	22.4	13.8	13.6	18.9	19.7	19.9	20.3	19.5	19.3	18.7	18.1
13	**% Capacity Margin (11/(6) * 100)**	12.2	18.3	12.1	12.0	15.9	16.5	16.6	16.9	16.3	16.2	15.7	15.4
14	**Reserve Above 12% Capacity Margin, MW**	12	343	6	0	217	253	259	275	242	237	211	190

Appendix D, Figure 4 SWPCO Capacity, Demand, Reserve Forecast

SOUTHWESTERN ELECTRIC POWER COMPANY
CAPABILITY, DEMAND AND RESERVES FORECAST
2008 Actual - 2019
(MW)
2009 IRP

CAPABILITY

#	Plant Capabilities	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
12	ARSENAL HILL # 5	110	110	110	110	110	110	110	110	110	110	110	110
11	J.L. STALL (ARSENAL HILL) CC				509	509	509	509	509	509	509	509	509
10	DOLET HILL #1	270	262	262	262	262	262	262	262	262	262	262	262
9	FLINT CREEK # 1	264	264	264	264	264	264	264	264	264	264	264	264
8	TURK (HEMPSTEAD) PC						447	447	447	447	447	447	447
7	KNOX LEE # 2, 3, 4, 5	485	477	477	477	477	477	477	477	477	477	477	477
6	LIEBERMAN # 1, 2, 3, 4	268	268	268	268	268	268	268	268	268	268	268	268
5	LONE STAR # 1	50	50	50	50	50	50	50	50	50	50	50	50
4	PIRKEY #1	580	580	580	580	580	580	580	580	580	580	580	580
3	MATTISON (TONTITOWN) CTs	300	288	288	288	288	288	288	288	288	288	288	288
2	WELSH # 1, 2, 3	1,584	1,584	1,584	1,584	1,584	1,584	1,584	1,584	1,584	1,584	1,584	1,584
1	WILKES # 1, 2, 3	881	883	883	883	883	883	883	883	883	883	883	883
1	TOTAL	4,792	4,766	4,766	5,275	5,275	5,722	5,722	5,722	5,722	5,722	5,722	5,722
	Adjustments to Plant Capability												
	NEW COMBUSTION TURBINE UNITS												157
	Adjustments for Environmental Retrofits							-4	-12	-12	-12	-12	-12
2	TOTAL	0	0	0	0	0	0	-4	-12	-12	-12	-12	145
3	Net Plant Capability (1 + 2)	4,792	4,766	4,766	5,275	5,275	5,722	5,718	5,710	5,710	5,710	5,710	5,867
	Sales Without Reserves												
	TRANSFER TO PSO				18								
	Backup contracts [redacted]	18	18	18	18	18	18	18	18	18	18	18	18
4	TOTAL	18	18	18	36	18	18	18	18	18	18	18	18
	Purchases Without Reserves												
	[redacted]	165	165	165	165	165	165	165					
		117	117	117	117	117	168	168					
		30	30	30	30	30	30	30					
		27	27	27	27	27	27	27					
		10	10	10	10	10	10	10	10	10	10	10	10
	ADDITIONAL WIND PROJECTS				8	22	34	34	37	45	45	45	45
	[redacted]	32	32	32	32	32	32	32	32	32	32	32	32
		49	151	362									
	TRANSFER FROM PSO					15							
	[redacted]	272	284										
	UNKNOWN WHOLESALE PURCHASES												
5	TOTAL	702	816	743	389	418	466	466	79	87	87	87	87
6	Total Capability (3 - 4 + 5)	5,476	5,564	5,491	5,628	5,675	6,170	6,166	5,771	5,779	5,779	5,779	5,936

DEMAND

#	Item	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
A	Peak Demand Before Passive DSM	4,950	4,840	5,032	5,188	5,253	5,346	5,427	5,512	5,588	5,660	5,745	5,826
	NTEC								-754	-767	-782	-796	-809
	Peak Demand Before Passive DSM Adjusted	4,950	4,840	5,032	5,188	5,253	5,346	5,427	4,758	4,821	4,878	4,950	5,018
B	**Passive DSM**												
	Approved Passive DSM		10	16	20	24	26	29	30	31	32	32	32
	NEW DSM		0	24	48	72	96	120	144	144	144	144	144
	TOTAL	0	10	40	68	96	122	149	174	175	176	176	176
C	Peak Demand (A - B)	4,950	4,830	4,992	5,120	5,158	5,224	5,278	4,584	4,645	4,702	4,773	4,842
D	**Active DSM**												
	INTERRUPTIBLE		10	14	15	16	17	18	18	18	18	18	18
	TOTAL	0	10	14	15	16	17	18	18	18	18	18	18
E	Firm Demand (C - D)	4,950	4,820	4,978	5,105	5,142	5,207	5,260	4,566	4,627	4,684	4,755	4,824
F	**Other Demand Adjustments**												
	DIVERSITY	30	22	24	23	20	21	21	22	23	18	20	23
	TOTAL	30	22	24	23	20	21	21	22	23	18	20	23
7	Native Load Responsibility (E - F)	4,920	4,798	4,954	5,082	5,121	5,186	5,239	4,544	4,605	4,666	4,735	4,801
	Sales With Reserves												
	TEX-LA ERCOT	46	46	46	46	48	48	48	48	48	48	50	50
	NTEC								200	200	200	200	200
8	TOTAL	46	46	46	46	48	48	48	248	248	248	250	250
	Purchases With Reserves												
	[redacted]	102	102	102	102	102	102	102					
		50	50	50	50	50	50	50	50	50	50	50	50
		23	23	23	23	23	23	23	23	23	23	23	23
9	TOTAL	175	175	175	175	175	175	175	73	73	73	73	73
10	Load Responsibility (7 + 8 - 9)	4,791	4,669	4,825	4,953	4,994	5,059	5,112	4,719	4,780	4,841	4,912	4,978

RESERVES

#	Item	08 ACT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
11	Reserve Capacity, MW (6 - 10)	685	895	666	675	681	1,111	1,054	1,052	999	938	867	958
12	% Reserve Margin ((11/10) * *100*)	14.3	19.2	13.8	13.6	13.6	22.0	20.6	22.3	20.9	19.4	17.6	19.2
13	% Capacity Margin (11/(6) * *100*)	12.5	16.1	12.1	12.0	12.0	18.0	17.1	18.2	17.3	16.2	15.0	16.1
14	Reserve Above 12% Capacity Margin, MW	32	258	8	0	0	422	357	409	347	278	197	279

Appendix E, Figure 1 AEP Plan to Meet 10% of Renewable Energy Target by 2020

AEP System - East Zone
Renewables to Achieve a 7% System Target by 2013 and 10% by 2020 [(a)]
Together with Known or Emerging State-Specific Mandates
2009 IRP

	APCo				CSP				OPCo				AEP-Ohio			
	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	75	0	0.8%	0	0	0	0.0%	0	0	0	0.0%	0	0	0	0.0%
2010	0	276	0	2.5%	1	50	0	0.8%	2	50	0	0.6%	10	100	0	0.7%
2011	0	551	0	4.5%	2	150	0	2.0%	4	175	10	2.0%	13	325	10	2.0%
2012	0	751	8	6.2%	6	276	57	5.1%	9	400	45	4.9%	15	675	101	5.0%
2013 [(b)]	0	851	8	6.9%	11	426	57	7.0%	17	550	45	6.4%	28	975	101	6.7%
2014	0	851	8	6.9%	17	426	57	7.0%	25	550	45	6.4%	42	975	101	6.7%
2015	0	851	8	6.9%	22	426	57	7.0%	34	550	102	7.6%	56	975	159	7.4%
2016	0	851	8	6.8%	28	466	57	7.5%	42	550	102	7.6%	70	1,015	159	7.6%
2017	0	851	8	7.0%	33	466	57	7.7%	50	550	102	7.7%	83	1,015	159	7.5%
2018	0	851	8	6.7%	41	466	57	7.4%	59	550	229	10.3%	100	1,015	286	9.0%
2019	0	851	50	7.4%	49	466	57	7.4%	69	550	315	12.0%	117	1,015	372	10.0%
2020	0	851	50	7.3%	56	666	57	9.8%	78	550	315	12.0%	133	1,215	372	11.0%
2021	0	851	50	7.3%	77	666	57	9.8%	91	550	442	14.6%	168	1,215	499	12.5%
2022	0	851	50	7.2%	90	766	57	11.0%	130	550	442	14.7%	220	1,315	499	13.1%
2023	0	851	50	7.1%	90	866	57	12.1%	130	550	442	14.7%	220	1,415	499	13.5%
2024	0	851	50	7.1%	115	866	57	12.1%	156	550	442	14.7%	271	1,415	499	13.5%
2025	0	951	50	7.7%	115	866	57	12.0%	156	550	442	14.6%	271	1,415	499	13.4%
2026	35	951	50	7.8%	115	866	57	11.9%	156	550	442	14.5%	271	1,415	499	13.3%
2027	35	1051	50	8.4%	115	866	57	11.7%	156	550	442	14.5%	271	1,415	499	13.2%
2028	69	1151	50	9.1%	115	866	57	11.7%	156	550	442	14.4%	271	1,415	499	13.2%
2029	69	1151	50	9.0%	115	866	57	11.6%	156	550	442	14.4%	271	1,415	499	13.1%
2030	112	1151	50	9.1%	115	866	57	11.5%	156	550	442	14.3%	271	1,415	499	13.0%

	I&M				KPCo				AEP-East			
	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	0	0	0.0%	0	0	0	0.0%	-	75	-	0.2%
2010	0	150	0	2.5%	0	0	0	0.0%	10	525	-	1.5%
2011	0	300	0	4.7%	0	50	0	1.9%	13	1,226	10	3.2%
2012	0	400	0	6.2%	0	100	0	3.8%	15	1,926	109	5.5%
2013 [(b)]	0	500	107	9.3%	0	100	19	4.6%	28	2,426	235	7.0%
2014	0	500	107	9.2%	0	100	19	4.6%	42	2,426	235	7.0%
2015	0	500	107	9.2%	0	100	112	12.1%	56	2,426	385	7.8%
2016	0	560	107	10.0%	0	100	112	12.0%	70	2,526	385	8.0%
2017	0	560	107	10.4%	0	100	112	11.9%	83	2,526	385	8.0%
2018	0	560	107	9.8%	0	100	112	11.8%	100	2,526	512	8.6%
2019	0	560	107	9.8%	0	100	112	11.7%	117	2,526	641	9.2%
2020	0	560	107	9.7%	0	100	112	11.7%	133	2,726	641	9.7%
2021	0	710	107	11.7%	0	100	112	11.6%	168	2,876	768	10.6%
2022	0	710	107	11.7%	0	100	112	11.5%	220	2,976	768	10.9%
2023	0	710	215	14.8%	0	100	131	12.9%	220	3,076	896	11.6%
2024	0	910	215	17.4%	0	100	131	12.8%	271	3,276	896	12.1%
2025	0	910	215	17.2%	0	100	131	12.7%	271	3,376	896	12.2%
2026	0	1,010	215	18.4%	0	100	131	12.6%	306	3,476	896	12.4%
2027	0	1,010	324	21.3%	0	100	150	13.9%	306	3,576	1,023	13.1%
2028	0	1,110	324	22.5%	0	100	150	13.8%	340	3,776	1,023	13.5%
2029	0	1,110	324	22.2%	0	100	150	13.7%	340	3,776	1,023	13.4%
2030	0	1,110	324	22.0%	0	100	150	13.6%	383	3,776	1,023	13.3%

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.

Appendix F: DSM By Operating Company

Demand (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
APCO Va	0	45	90	113	140	168	195	195	195	195
APCO WV	0	45	90	113	140	168	195	195	195	195
KngsP	0	9	16	22	27	33	38	38	38	38
I&M - I	3	50	97	125	152	179	206	206	206	206
I&M - M	2	5	9	25	31	36	42	42	42	42
KPCo	1	19	39	51	63	76	88	88	88	88
OPCo	30	81	147	186	225	264	303	303	303	303
CSP	25	68	130	160	191	222	252	252	252	252
WP	0	9	16	22	27	33	38	38	38	38
AEP-East Zone	**61**	**330**	**635**	**816**	**997**	**1,177**	**1,357**	**1,357**	**1,357**	**1,357**
PSO	10	45	80	114	148	181	213	213	213	213
SWEPCO	11	41	70	98	125	152	177	177	177	177
AEP-SPP Zone	**21**	**87**	**150**	**212**	**273**	**332**	**391**	**391**	**391**	**391**

Energy (GWh)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
APCO Va		98	199	233	266	299	332	332	332	332
APCO WV		98	199	233	266	299	332	332	332	332
KngsP		17	28	30	31	33	35	35	35	35
I&M - I	15	113	213	225	235	244	250	250	250	250
I&M - M	10	27	53	56	60	63	67	67	67	67
KPCo	1	38	77	88	98	109	119	119	119	119
OPCo	88	240	453	604	754	905	1055	1055	1055	1055
CSP	68	187	356	469	583	697	811	811	811	811
WP		17	28	30	31	33	35	35	35	35
AEP-East Zone	**183**	**836**	**1,607**	**1,967**	**2,325**	**2,682**	**3,037**	**3,037**	**3,037**	**3,037**
PSO	40	128	214	297	378	457	534	534	534	534
SWEPCO	38	112	184	252	317	379	440	440	440	440
AEP-SPP Zone	**78**	**240**	**397**	**549**	**695**	**836**	**974**	**974**	**974**	**974**

AEP/Southwestern Electric Power Company
Integrated Resource Plan
Stakeholder Report

Created During SWEPCO Hosted Stakeholder Meeting
December 3-4, 2008
Little Rock, Arkansas

Table of Contents

I. Executive Summary

On December 3-4, 2008, AEP hosted an IRP Stakeholder Committee Meeting. The meeting was attended by Stakeholders and members of the Utility Commission, the Arkansas Energy Office and the Attorney General's office. The first day of the meeting consisted of presentations by AEP on the objectives and goals of the Integrated Stakeholder Committee Meeting consisting of Resource Planning Guidelines, AEP Integrated Resource Planning Process, Transmission Overview, and Incorporating Renewable Energy into the AEP IRP Process.

Prior to the beginning of the meeting, stakeholders were asked to complete worksheets addressing Key Issues to be addressed in the IRP process. We then broke into three randomly selected groups in which stakeholders developed pro's and con's of pre-submitted key issues. Then the Stakeholders were grouped based on segment representation. The three group segments were: Independent Power Producers (IPP), Renewable Energy, and the Wholesale, Retail and Municipal Users. Each group then prioritized the Key Issues based on their segment perspective.

II. Stakeholder Authors

The following were present during the two day AEP/Southwestern Electric Power Company IRP Stakeholder Meeting.

Name	Company	E-mail
John Alhen	Arkansas Science & Technology Authority	john.alhen@arkansas.gov
Ken Baker	Wal-Mart	Ken.baker@wal-mart.com
Karen Bassett	ADEQ	bassett@adeq.state.ar.us
Chris Benson	Arkansas Energy Office	Cbenson@ArkansasEDC.com
Frank Costanza	Tradewind Energy	fcostanza@tradewindenergy.com
Clark Cotten	Arkansas Public Service Commission	clark_cotten@psc.state.ar.us
Kelly Crouch	Domtar, Inc.	kelley.crouch@domtar.com
Don Erbach	Entegra Power Group	don@paschallstrategic.com
David Fincher	Hope Water and Light	dfincher@hope-wl.com
Mike Hughes	City of Bentonville	mhughes@bentonvillear.com
Paul Kelso, P.E	Fibrowatt	paul.kelso@fibrowattusa.com
Forrest Kessinger	AECC	FKessinger@aecc.com
Andrew Lachowsky	AECC	ALachowsky@aecc.com
Shawn McMurray	Attorney General	shawn.mcmurray@arkansasag.gov
Mak Nagle	Southwest Power Pool	mnagle@spp.org
Wally Nixon	Arkansas Public Service Commission	Wnixon@psc.state.ar.us

David Ozment	Wal-Mart	James.Ozment@wal-mart.com
Kevin Smith	Tenaska Power Services	ksmith@tnsk.com
Sarah Tacker	Attorney General	sarah.tacker@arkansasag.gov
Scott Turley	University of Arkansas	lturley@uark.edu
Becky Turner	Entegra Power Group	rturner@entegrapower.com

III. Pros and Cons of Stakeholder Issues

The order that these issues are presented in does not indicate any prioritization by the stakeholders.

Issue #1 DSM, Energy Efficiency, & Conservation

The Issue:	◦ Expand $ DSM programs and options ◦ Energy efficiency programs should be ramped up ◦ Role of conservation and demand side response
Description of the Issue:	◦ Current DSM programs and tariffs in general seem to discourage participation in DSM, Dist, Gen, and other load management tools ◦ EE is the least cost energy resource available to a utility. However, goals are not being set and resources are inadequate to realize the returns on investment ◦ Historical lack of serious conservation and demand response goals ◦ Ownership of environmental attributes: customer, utility, both ◦ Program flexibility, simplicity, customer opt-out, self direct options
Why is this issue important?	◦ Potential lower cost ◦ Maximize portfolio of possible solutions ◦ Needed for "balanced" IRP outcome
Risks of failing to address:	◦ May miss opportunities to meet load needs with alternative supply options ◦ Reduced roles long term supply plans ◦ Negative environmental impacts ◦ Continued in efficient use of energy
Possible Obstacles:	◦ Concerns over administering complex tariffs ◦ Reliability of load coverage and complexity of dispatch ◦ Old Arkansas rules ◦ Lack of "true commitment" to conservation and demand response
Pros of Addressing this Issue:	◦ May provide a lower cost of service – brings additional competition and intellectual capital to meet resources requirements ◦ Can be the cheapest alternative - Must remove disincentive

	◦ Subcontract programs to experts
Cons of Addressing this Issue:	◦ Currently no profit incentive ◦ Difficult to measure its value ◦ Utility may not be experienced in implementing programs ◦ Difficult to evaluate its effectiveness ◦ Sustainability issues ◦ Is it a results of what people are doing currently or should certain goals / targets be required

Issue #2 Combined Heat & Power (CHP) & Distributed Gen

Description of the Issue:	CHP and some distributed generation is cost effective to implement given the right signals from the market and government. It has clear additional benefits for reduced CO_2 emissions and increased efficiency and reliability for the customer
Why is this issue important?	See above
Risks of failing to address:	This is a missed opportunity to capture important efficiency and technology potential.
Possible Obstacles:	Regulatory policies are a disincentive and should be changed, but there is much a utility can do in the marketplace primarily in the industrial sector.
Pros of Addressing this Issue:	CHP can be an important resource in terms of additional capacity that could be dispatchable under certain circumstances as well as dramatic reductions in energy and demand requirements for the utility.
Cons of Addressing this Issue:	NA

Issue #3 Options for renewable supply purchasing

The Issue:	Green Power Program (customer buying green power through utility)
Description of the Issue:	Currently there is a very limited quantity of renewable energy on system – and it is “blended” into the portfolio.
Why is this issue important?	Certain customers may choose to set internal environmental objectives related to GHG reduction. The LDC/utility needs to be a partner in achieving these objectives.
Risks of failing to address:	◦ Will not meet customer’s requirements. ◦ Will not drive renewable market (RPS?)
Possible Obstacles:	Regulatory Issues, Operational Issues
Pros of Addressing	◦ There are no real external options as the energy must come across

this Issue:	the utility. ◦ Allows customers to achieve internal objective of carbon neutral ◦ Allow utility to directly assign renewable energy costs.
Cons of Addressing this Issue:	◦ May not meet need if renewable energy credits not included. ◦ Administrative burden.

Issue #4 Jointly procure larger base load with other utilities

The Issue:	Consideration of partnerships with surrounding utilities where economy of scale makes sense.
Description of the Issue:	Economy of scale can exist with new coal or nuclear plants. Co-ownership may allow for a larger plant and overall lower cost of energy
Why is this issue important?	Possible opportunity for lower cost.
Risks of failing to address:	Potential lost opportunity if not included.
Possible Obstacles:	Additional participants in a project makes decision making process more complex. Additional risks w/co-owners. Possibly additional time required to develop contracts.
Pros of Addressing this Issue:	• Potential lower cost. • Economy of scale • Cost savings • Cost sharing
Cons of Addressing this Issue:	• Anti-trust issue • Prices more complex • Regulatory issues • Address Transmission issues

Issue #5 How will plan address the need for ensuring high level of reliability of supply to the customer

Description of the Issue:	Have experienced multiple power failures – wires breaking, capacitors blowing, etc. which is extremely costly to our facility in terms of equipment & downtime and lost production.
Why is this issue important?	Is a high cost issue for our facility; includes damage to equipment and lost production.

Risks of failing to address:	Continuing power failures
Possible Obstacles:	Power/transmission lines replacement could/would cause additional downtime for reliability improvement. However, on planned basis, costs would be mitigated.
Pros of Addressing this Issue:	Would be evidence that resolving reliability issues is a priority for SWEPCO.
Cons of Addressing this Issue:	Transmission issue – Not seen as an IRP Issue.

Issue #6 Consider poultry litter power plant for power purchases

Description of the Issue:	Poultry litter is considered biomass, and therefore a renewable carbon neutral energy, and besides GHG credit benefits, it provides benefits to the poultry industry and the water system.
Why is this issue important?	The poultry industry is extremely large and important for Arkansas. Helping to sustain the industry will also maintain a large group of power purchases. Water quality issues have also been raised in both Arkansas and Oklahoma.
Risks of failing to address:	Governmental mandates may eventually dictate renewable energy, and waiting could negatively impact projects with potential increased costs.
Possible Obstacles:	Cost of renewable energy from poultry litter is higher than gas or coal power pricing.
Pros of Addressing this Issue:	This provides additional base load renewable energy to the SWEPCO system. Renewable. Carbon neutral Lowers TMDL (oxygen issue in waterways)
Cons of Addressing this Issue:	Cost. Transmission access for rural location.

Issue #7 For year 2012 on slide #12, planned capacity is less than demand

Description of the Issue:	Is this a data error as slide #32 indicates enough capacity margin for year 2012?
Why is this issue important?	IRP not meeting demand for certain years.

Risks of failing to address:	Not meeting SPP criteria
Possible Obstacles:	None
Pros of Addressing this Issue:	Ensure that supply forecast meets demand in the final IRP.
Cons of Addressing this Issue:	

Issue #8 Renewables

The Issue:	Renewable energy supply & customer access to supplies Integration of renewable/sustainable resources into SWEPCO generation resource mix
Description of the Issue:	Historical lack of renewable energy goals; goals too low. Customer owned renewable energy vs. utilities owned renewable energy. Ownership of environmental attributes. Renewable resources provide sustainable energy and further diversify traditional fossil fuel generation resources. Many renewable resources also have the benefit of eliminating greenhouse gas and other emissions (SO_2, NO_x, particulates) Properly sited wind generation is competitive with other forms of generation on a delivered to busbar basis (new plant to new plant comparison basis.)
Why is this issue important?	Need "balance" of supply alternatives Need to leverage with customers; not compete with customers. Bad outcome: renewable energy not being fully utilized. Renewable resources (e.g. wind, solar) eliminate fuel costs and provide a hedge re: generation that require fuel inputs and have the potential for cost increases over time. Historically, the societal impacts of emissions from conventional fossil fuel plants (e.g. health impacts) are not normally captured as a cost in the when decision are made to add capacity. These costs wile hard to quantify are real. Renewable energy helps obviate some portion of these emission related impacts.

What are the risks of failing to address this issue in the IRP?	Bad IRP outcome Negative environmental outcome Higher costs State of Arkansas suffers Additional dependence on expensive fossil fuel sources and continued environmental degradation. Costs of new generation sources will continue to rise for all types of generation. Planning for the introduction and transition to multiple resources today will ultimately result in fewer impacts to utility customers and the general public at a lower cost.
Possible Obstacles to Addressing the issue and How to Overcome:	Overcome "Renewable energy costs more" mentality Potential Existing Rules: Net Metering Limitations Interconnection Agreements Ability of customers to use 3rd party Purchased power Agreements Lack of financial Incentives Reluctance to utilize customer resources Risks to REC ownership Cost of renewable energy is often cited as an impediment. Integrating the most cost effective resources initially (e.g. wind) and phasing in promising but not yet low cost alternatives (e.g. solar) can be done over time. Mixing renewable from the most productive regions of the country could also provide the lowest cost approach, but it would also require investment in new high capacity transmission lines.
Pros of Addressing this Issue	A mix of generation assets/resources is important to hedge future costs/need for rate increases. Further, a reduction of emissions is important to promote a healthy environment particularly in the face of growth in energy consumption. Planning for additions of a variety of generation sources will allow for the introduction of next generation of power sources at the lowest possible cost. Renewables can provide economic development benefits and are usually distributed across the utility's service territory. • End result should be good balance. • Energy security • Low fuel costs (wind, solar, hydro & geothermal) • Environmental attributes • Portfolio diversity • Health
Cons of Addressing this Issue	• Cost • Environmental (siting and transmission) • Transmission infrastructure (wind, solar, geo) • Intermittent supply

Issue #9 Demand capacity through pumped hydro

The Issues:	Peak demand load (and Daily Peaking) of Pump Hydro
Description of the Issue:	Meet peak demand
Why is this issue important?	Allows use of lower cost/more-efficient base load units at night and off-peak to pump water. Displaces costs of peaking units (gas, etc.)
What are the risks of failing to address this issue in the IRP?	Higher cost of operating gas peaking units.
Possible Obstacles to Addressing the issue and How to Overcome:	FERC license – Study & File Environmental permits – Assessments Transmission Access – Study • Very effective peaking units (pump hydro) used by GRDA. • There was (may still be) a license to develop 500+/- MW pump hydro near Russellville, AR
Pros of Addressing this Issue	• Option for cost models. • Lower cost on peak power • Quick response/dispatch • Integrates well w/other renewables (wind)
Cons of Addressing this Issue	• Initial high capacity cost. • Environmental elements – physical, CO_2, etc.

Issue #10 Incentivize Utilities to consider PPA's.

The Issue:	Utility owning assets (generation) vs. long term power supply controls.
Description of the Issue:	Utilities earn money via rate basing, traditional regulation only allows utility to pass through costs incurred through contracts, therefore no return element.
Why is this issue important?	Utilities need to be neutral and allowed to select cost effective solutions.

What are the risks of failing to address this issue in the IRP?	Non-utility solutions are ignored.
Possible Obstacles to Addressing the issue and How to Overcome:	Tradition. At the PSC/Legislators utility has no interest to push this concept due to lack of profit potential.
Pros of Addressing this Issue	• Broadens supply options and can lower cost. • Places PPA on equal footing w/self build from IOU's stockholder perspective. • May reduce power rates.
Cons of Addressing this Issue	• May drive up power rates.

Issue #11 Including External Costs (Env. Societal Costs) in Cost Model

The Issue:	Distinguish methodology for determining low cost – This traditional driver and historical methods will lead to same answers – fossil plants. Value all externalities of supply options – that includes environmental, health, economic, societal
Description of the Issue:	Conventional power vs. Renewables vs. DSM All "costs" including externalities must be incorporated in a more dynamic way and alter past low cost determination approaches. Traditional cost analysis is usually focused only on capey, O&M, Fuel – impacts of emissions are (admittedly) hard to quantify) but must be addressed.
Why is this issue important?	Until renewable technology is mainstream (i.e. production increase to lower cost of mfg, or technology is further improved – solar,) they will not be low cost. Need to address GHG, Hg other impacts from fossil vs. using non-polluting renewable options.

What are the risks of failing to address this issue in the IRP?	Status quo on supply side – fossil fuel translates to no change environmentally, fuel dependency, etc. Improved environmental, health, long term economic benefits to the state & public.
Possible Obstacles to Addressing the issue and How to Overcome:	Cost of renewables may cost slightly more in the near term. Solution integrate renewables over reasonable period of time 5-10 years. Hidden costs of externalities are easy to ignore because they are difficult to quantify in typical fashion used by engineers.
Pros of Addressing this Issue	• Indicates to regulators that utility needs latitude to adopt broader supply options. • Regulation needs to reward utilities for taking steps to incorporate new technology. • Improved environmental, health, long term economic benefits to the state & public. • Power rate considers all societal costs • Health benefits • Reduction in GHG • Reduced air emission pollutants • Broader supply options.
Cons of Addressing this Issue	• Very hard to quantify • Inclusion will show higher rates • Redistribution of wealth • Additional risk elements in model • National perspective Required / Not local • Do not connect rebate to environmental attribute waiver.

Issue #12 Economic development benefits related to renewable project development inside SWEPCO/Arkansas

Description of the Issue:	Economic development benefits are rarely if ever considered in selecting location for power projects.
Why is this issue important?	A 100 MW NINO Project in Arkansas (vs. another state) will bring $10’s of million in local economic spending, tax payments, jobs, etc.

What are the risks of failing to address this issue in the IRP?	Energy consumed in Arkansas and produced in Arkansas may bring greatest overall economic benefit.
Possible Obstacles to Addressing the issue and How to Overcome:	Power cost for in state may be higher is viewed alone, but when local economic impacts are added it could be the better solution.
Pros of Addressing this Issue	• This issue should be part of the "lost" determination process used by utilities & APSC in approving new supply options • Increases positive economic benefits in-state. • Redistribution of wealth
Cons of Addressing this Issue	• An increase in power rates • Redistribution of wealth • No most efficient use of resources when viewed nationally

Issue #13 Maintaining reasonable costs to customers

Description of the Issue:	Increasing costs of power are passed to total manufacturing cost of product.
Why is this issue important?	Higher manufacturing costs could end up putting facility operation in question.
Risks of failing to address:	The concern of prices increasing beyond reasonable.
Possible Obstacles:	Fuel sources and pricing fluctuations.
Pros of Addressing this Issue:	Keep business running. Low cost for industry. Low cost for customers.
Cons of Addressing this Issue:	How to define reasonable cost as a balance with renewables.

Issue #14 Greenhouse Gas Mitigation Options

Description of the Issue:	GHG emissions are a concern for our facility (Domtar) as well because when we market our products, we have to consider impacts on the environment from the source of the power we buy.
Why is this issue important?	It supports the company's sustainability goals.

Risks of failing to address:	Might not receive attention/focus that is required to have impact.
Possible Obstacles:	Cost of alternative fuels could compete with out fuel costs; could cause our costs for power increase.
Pros of Addressing this Issue:	Supports environmental goals NERC top concern Good for environment
Cons of Addressing this Issue:	Difficult to get a carbon footprint baseline. Cost.

Issue #15 Long Term Pricing Constraints

The Issue:	If customer made decision to expand operations, increasing the demand for power, how will that be addressed by IRP to ensure costs remain effective?
Description of the Issue:	If increase in cost to purchase additional power is too great, would possibly halt expansion activities
Why is this issue important?	Increasing production at facility insures jobs are maintained because are low cost producers for company and improves economy in SW Arkansas
Risks of failing to address:	May not account for increase (potential) in demand
Possible Obstacles:	Is "potential" concern: not present "actual" concern
Pros of Addressing this Issue:	◦ Would offer guidance for company as work on business plan ◦ Benefit customer by being able to forecast retail power cost ◦ Promotes economic development ◦ Adds jobs
Cons of Addressing this Issue:	◦ Cost of credit associated with fixed prices ◦ Exposure to market margins ◦ Long term hedges difficult

Issue #16 CO_2 Mitigation

Description of the Issue:	SWEPCO's portfolio consists of significant amounts of coal/lignite based resources. Displacing coal/lignite resources with efficient natural gas resources is an effective CO_2 mitigation strategy.
Why is this issue important?	Natural gas resources existing on the SPP/Entergy systems are under utilized. The resources emit significantly lower CO_2 emissions per MWh that coal/lignite resources and can be a low cost alternative (as compared to wind resources) to meet future CO_2 regulations

	(anticipated)
Risks of failing to address:	Higher costs to ratepayers.
Possible Obstacles:	Transmission congestion across the SPP/Entergy Seam. See previous sheet 1 for implementation strategy.
Pros of Addressing this Issue:	Low cost alternative to mitigate CO_2 output for SWEPCO Use existing gas resource Reduces CO_2 Could replace construction a coal plant
Cons of Addressing this Issue:	Transmission access Fuel price volatility

Issue #17 Transmission Constraints

The Issue:	◦ Transmission congestion ◦ Transmission constraints – Today all supply assets inside he constraint are required limiting other supply options ◦ Transmission expansion in conjunction with purchase power alternatives to meet incremental capacity needs
Description of the Issue:	◦ Need for adequate transmission to meet AEP load and loads that rely on AEP for transmission ◦ Lower cost supply options can't be sourced due to deliverability / reliability ◦ Significant unsubscribed generation existing on the Entergy system (built in the ~2000 timeframe) should be considered a viable alternative to self-build alternatives. Natural gas prices have stabilized and significant volumes of natural gas. Frame shale sources are being produced and should stabilize gas prices in the future.
Why is this issue important?	◦ Transmission affects reliability and cost ◦ Lower cost options (eg: wind) exists within the SPP but can't be delivered to SWEPCO. ◦ Natural gas fired generation is clean, efficient alternative to meet base, intermediate and peaking needs of the utility. ◦ Existing generation was built at a lower cost than new build alternatives and this economic benefit can be realized by the utility under purchase power arrangements.
Risks of failing to address:	◦ Limitations for supply options from siting constraints, cost, environmental, etc ◦ Higher cost to ratepayers
Possible Obstacles:	◦ Planning done at SPP, difficulty with seams agreements ◦ Issues with cost recovery

	◦ Near term cost to build transmission solutions vs. cost recovery ◦ Transmission ownership conflicts. The ASPC has an open docket to address transmission congestion across Entergy / SPP seam. SWEPCO should consider addressing improving imports / exports from / to the Entergy system in this docketed proceeding
Pros of Addressing this Issue:	◦ Improved reliability and potential for lower cost ◦ Highlights need for PSC / Legislators to adopt, pressure, and accelerate transmission solutions ◦ Lower all end costs to rate payers
Cons of Addressing this Issue:	◦ Without addressing cost constraints, end result could be forgoing low cost energy outside of the constraint area ◦ There seems to be no pressure to address transmission constraints. It seems very far out into the future. SPP, AEP, and SWEPCO seem to be making legitimate efforts but it is being bogged down by other parties ◦ Cost recovery of transmission costs for IPP dis-incentivizes transmission solutions to new capacity needs. ◦ IPP doesn't have power of eminent domain ◦ Issues with NERC
Suggestions:	◦ Participate in APSC Docket 08-136-U ◦ Any IRP should consider transmission constraint-free options – if there were no constraints what options would be available ◦ When considering new build options, consider transmission upgrades as well ◦ AEP should buy EAI and then fix the seams issues ◦ IRP should consider cost-sharing options re: transmission upgrade to make existing IPP a more viable option <u>Solution</u> ◦ Cost evaluation ◦ Spirit of cooperation among various players

Issue #18 Transparency of Modeling Assumptions

Description of the Issue:	The assumptions utilized in the evaluation process are the basis upon which the final resource selections will be made.
Why is this issue important?	Understanding these assumptions as a potential supplier allows the supplier to better structure a product to meet SWEPCO's needs.
Risks of failing to address:	SWEPCO may not receive the best supply products to meet their needs in the most cost effective manner.
Possible Obstacles:	May provide ammunition for opponents.
Pros of Addressing this Issue:	Should result in meeting SWEPCO's needs in a more cost effective manner.

	Confidence of stakeholders in process because it is very complicated Encourage participation of stakeholders Consider working with SPP on DR since IRP model is also used in RFP process. Transparency of modeling assumptions allows the market to more fairly compete with self build options
Cons of Addressing this Issue:	How do you value non-traditional resources in modeling (e.g. no emissions, etc.)? Is it quantifiable? How do you value/quantify diversity of fuel.

IV. Prioritization of Issues by IPP Stakeholder Group

The above working group evaluated the consolidated 18 issues compiled by the general stakeholders group for evaluation and prioritization with respect to the specific concerns, operational issues, and priorities of this customer group of AEP / SWEPCO.

Members of the Independent Power Producer (IPP) working group were:

Don Erbach	Entegra Power Group	don@paschallstrategic.com
Kevin Smith	Tenaska Power Services	ksmith@tnsk.com
Becky Turner	Entegra Power Group	rturner@entegrapower.com

The approach for this group was as follows:
1st – Created 3 buckets of priorities (A=highest, C=lowest)
2nd – Created priorities within buckets

A1	17	Access to market
A2	18	Fairness of competition against self-build, lower cost
A3	10	Fairness of competition against self-build
A4	4	Lower cost
A5	11	Fairness of competition between technologies
A6	16	Lower cost, Environmental
A7	2	Reliability, Environmental
B1	8	Environmental, Reliability
B2	14	Environment, lower cost
B3	9	Reliability
B4	3	Customer Service
B5	6	Environmental
C1	13	Cost, Customer Service
C2	1	Environmental, Lower cost, Customer Service

C3	15	Cost
C4	12	Economic Development, Environmental
C5	5	Reliability
C6	7	N/A

V. Prioritization of Issues by the Renewable Energy Stakeholder Group

The above working group evaluated the consolidated 18 issues compiled by the general stakeholders group for evaluation and prioritization with respect to the specific concerns, operational issues, and priorities of this customer group of AEP / SWEPCO. Members of the Renewable Energy working group were:

Frank Costanza	Tradewind Energy	fcostanza@tradewindenergy.com
Ken Baker	Wal-Mart	Ken.baker@wal-mart.com
Paul Kelso, P.E	Fibrowatt	paul.kelso@fibrowattusa.com
David Ozment	Wal-Mart	James.Ozment@wal-mart.com

SWEPCO's existing generation capacity is dominated by a mix of fossil fuel generation resources, with approximately 90 percent of system energy production/ consumption derived from these company-owned generating resources. SWEPCO will need to add generation resources to meet future demand and energy needs, and these resources should include renewable energy in order to provide greater diversity and reliability, along with many environmental and societal benefits, including the use of "home grown" fuels for greater energy independence and security.

Attaining reduced environmental impacts upon its service territory constituents and the broader regions surrounding the company's service territories is strongly urged through a process that recognizes and quantifies the external costs associated with environmental degradation, health and other impacts, including future carbon regulation, to the highest extent possible when evaluating the addition of new generation. Reliance upon cost of service approaches that only consider low cost via employment of traditional Integrated Resource Plan, rate making and other embedded planning paradigms that do not incorporate costs to address broader and more complex environmental and externalities, will lead to continued reliance upon fossil fuel generation that may not be in the best long term interest of the broader constituents living within and adjacent to the utility's service territories.

SWEPCO stakeholders strongly urge utility management, state regulators, and elected officials which oversee SWEPCO's operations to adopt policies, procedures and potentially legislation which will:

1. Establish targets for incorporating and diversifying SWEPO's current generation mix to include renewable/alternative energy resources, that:
    a. reduce environmental and external impacts
    b. provide some level of fuel hedging and related risk mitigation
    c. provide for and promote to the largest extent possible the addition of resources within SWEPCO's service territory in Arkansas to promote further in- state economic development

2. Promote and incorporate the addition of new electric transmission infrastructure, as the current high voltage transmission system constraints within the SPP, and Entergy RTO regions adjacent to SWEPCO, may limit SWEPCO's ability to locate or purchase generation from facilities in otherwise cost effective locations
3. Consider expansion of the classic definition of renewables to include demand side management resources. For example, the State of Pennsylvania treats demand response as a tier 2 renewable and allows part of a utility's alternative energy goal to be achieved through demand reduction.

New resource additions should also encourage non-utility owned options which can demonstrate their ability to deliver reliable and competitively priced renewable energy when compared to other renewable resources that would otherwise be developed and owned by the utility company. Processes to add any new generation resources should be managed through transparent sourcing processes run by non-biased third parties.

Increases in cost of electric service to customers is likely as the need to construct and / or purchase additional generation continues to grow in order to meet growing customer needs. Adding renewable energy to the mix will help to provide the desired energy security, diversity, and reliability, along with the many environmental and societal benefits to the people of Arkansas, Louisiana, Texas and the surrounding states.

What follows is how the Renewable Energy Stakeholder subgroup prioritized the individual issues developed at the session. A, B, and C issues represent prioritization, but the individual items within the A, B, and C groups are not in any particular order.

A Issues	3,6,8	Renewable Resources, Sustainability, Diversity, Cost, Environmental
A Issues	13	Reasonable cost – Affordability to end users
A Issues	11	Externalities considered – Environment / Societal benefits / Recreation / Health
A Issues	14, 16	Emissions – Environment / Cost / Health
A Issues	1	DSM – Diversity / Cost / Emissions / Timing / Environmental
B Issues	12	Economic Development Renewables
B Issues	17	Transmission – Cost / Environment / Diversity
B Issues	18	Transparency modeling – Cost
B Issues	10	IOU vs. IPP ownership - Cost
B Issues	4	Partnerships with other utilities – Cost / Environmental / Diversity / Timing
C Issues	5	Reliability - Given
C Issues	2	CHP
C Issues	9	Pumped Hydro
C Issues	15	Expansion – Cost Effectiveness

VI. Prioritization of Issues by Wholesale / Retail / Municipal Stakeholder Group

Discussion of Approach

The above working group evaluated the consolidated 18 issues compiled by the general stakeholders group for evaluation and prioritization with respect to the specific concerns, operational issues, and priorities of this customer group of AEP / SWEPCO. Members of the Wholesale/Retail/Municipal (WRM) working group were:

Kelly Crouch	Domtar, Inc.	kelley.crouch@domtar.com
David Fincher	Hope Water and Light	dfincher@hope-wl.com
Mike Hughes	City of Bentonville	mhughes@bentonvillear.com
Forrest Kessinger	AECC	FKessinger@aecc.com
Andrew Lachowsky	AECC	ALachowsky@aecc.com
Scott Turley	University of Arkansas	lturley@uark.edu

As the working group evaluated the 18 issues, some were combined as they a shared common basis, while one was deleted, as it was not an issue but a question about the presentation. After consolidation, this left 13 key issues for the working group to prioritize. The issues were discussed by the group and through a process of consensus prioritization; the sub-group arrived at an overall ranking of the issues. The overall ranking of the issues is presented at the end of this section.

Discussion of the Ranking and Priorities

RELIABILITY

Priority Ranking #1: *"ensuring a high level of reliability of supply to the customer"* (issue #5)

The first priority of the Wholesale/Retail/Municipal (WRM) working group is the reliability of the supply and delivery systems, as this is fundamental to meeting the needs of the working group's direct customers. While it is understood that "reliability" is implicit in every aspect of planning, the Retail group wanted to re-state the importance of reliability by making it their number one priority ranking. The consumer relies on electricity for life safety as well as modern conveniences, and outages are costly for commercial, retail and manufacturing. Baseload, intermediate, and peaking resources must remain adequate to ***reliably*** meet present and future demand for power, including reserves and contingency planning.

COSTS; ECONOMIC DEVELOPMENT

Priority Ranking #2: *"maintaining reasonable costs to customers"* (issue #13) and ***"long term pricing constraints"*** (issue #15)

Not surprisingly the second highest priority of the WRM group is the ability of the utility to provide adequate power supply at a reasonable market competitive cost. The group felt this was fundamental to sustained economic development. Consumers living on a fixed income suffer economic distress from rising power costs. Manufacturing facilities that are energy intensive may no longer be viable if power costs increase beyond certain economic thresholds. Economic development and job growth depend on long-term stability of power costs with minimal escalation. Demand-side management, greenhouse gas mitigation, and renewable energy are all issues advocated by the WRM group (see priority rankings 5, 6 & 7 respectively), but with a strong emphasis on reasonable low cost.

PARTNERSHIPS

Priority Ranking #3: ***"jointly procure larger base load with other utilities"*** (issue #4).

The working group recognized that certain future power supply issues can only be addressed through integrated partnerships between the various state agencies, suppliers, and regional transmission entities. Specific examples are redevelopment of nuclear generation capabilities and the expansion of regional and national transmission capacity. Nuclear, although costly to develop, may, in the long-term, address both the drive for low-cost reliable power and sustainability initiatives. Nuclear power avoids greenhouse gases, and avoids the cost of mitigating greenhouse gases. Nuclear, although costly to develop, may, in the long-term, address both the drive for low-cost reliable power and sustainability initiatives. Nuclear power avoids greenhouse gases, and avoids the cost of mitigating greenhouse gases. Another area where partnership and cooperation can benefit the end user is through the economy of scale when looking at new generation capacity. Co-ownership may allow for a larger plant and overall lower cost of energy. Potential opportunities may be missed if joint development of large baseload plants is not explored with other utilities.

TRANSMISSION

Priority Ranking #4: ***"transmission constraints"*** (issue #17)

Although perhaps not a direct IRP issue, transmission constraints continue to plague our industry, to wit:

- The "seams" issue needs to be addressed between Entergy and the SPP. The separation of Entergy from the SPP as a whole frustrates the ability to move power economically through the system.
- Lack of adequate transmission frustrates the ability of IPP's to sell into the market. Further, IPP's are not granted the right to develop and extend transmission.
- Additional national transmission infrastructure is needed to move renewable power from areas of renewable generation to the load centers.

Mandates from FERC and the PSC are needed to address transmission constraints.

Though these issues extend beyond the scope of the specific IRP for SEP/SWEPCO, they do affect the power supply options and choices available to the company for the IRP.
Issues such as these are too costly, entail too much risk or exceed jurisdictional authority for any singular partner to overcome. In fact, it was the consensus of the group that resolution of these issues will likely require leadership at the federal level. Resolution of transmission issues was considered the top priority with respect to more global issues.

DEMAND-SIDE MANAGEMENT

Priority Ranking #5: ***"DSM; Energy Efficiency; & Conservation"*** (issue #1)

The fifth highest priority as ranked by the WRM sub-group concerned SWEPCO's Demand Side Management (DSM) programs. As major end users of energy and power, the group felt that they could have a much larger impact on the IRP through a more broadly implemented and aggressive DSM program. Below are two examples of specific areas of recommendation though there are certainly others.

- Expansion of traditional DSM programs using financial incentives to encourage conservation and demand reduction.
- Encourage the use of tariffs, rate options, and other regulatory options to facilitate more private capital investment in DSM technologies. Instruments must be fixed over a long enough term to justify capital investment, and that send more timely and accurate price signals will encourage more aggressive large scale DSM investment.

Energy efficiency may be the least cost energy resource available to a utility. Demand Side Management may offset the need to build additional expensive generation facilities. Conservation lowers cost and lowers greenhouse gas production. SWEPCO should continue the investment at the current level, and consider additional investment and additional rate incentives.

The WRM stakeholder sub-group does recognize and appreciate SWEPCO's recent DSM efforts and expects this to be a precursor of greater things to come. SWEPCO is encouraged to look to other of its operating units, the Arkansas PSC and the Arkansas Energy Office for best in class DSM programs.

GREENHOUSE GAS MITIGATION & RENEWABLE ENERGY

Priority Ranking #6: ***"greenhouse gas mitigation"*** (issue #14) and ***"CO_2 mitigation"*** (issue #16); ***"customer options for renewable supply purchasing"*** (issue #3); ***"poultry litter biomass power plant"*** (option #6); and ***"renewables (wind; solar)"*** (option #8)

The final grouping of issues assigned a specific priority by the WRM sub-group concerned Green House Gas (GHG) issues and Renewable Energy technologies. The discussion centered around how these emerging group of issues will factor into the IRP from a long term environmental stewardship standpoint as well as the near term cost of service impact to the rate base.

The WRM sub-group did not advocate unilateral GHG reduction actions on the part of SWEPCO in Arkansas, as this could likely have major cost of service and economic development implications. The WRM sub-group's recommended approach for implementation of GHG controls or reduction targets was that these should come from the federal level so as to not disadvantage any one specific service territory, group of consumers, or State.

At the stakeholder meeting, several retail customers expressed interest in greenhouse gas (GHG) mitigation, including:

- Dotmar Mill; Ashdown, Arkansas
- University of Arkansas, Fayetteville
- Wal-Mart

Options for limiting GHG may include generation options that have a lower carbon footprint, for example:

- Displacing coal/lignite resources with natural gas.
- Displacing coal/lignite/gas with nuclear power.

SWEPCO should continue to pursue a "cap and trade" program, and should continue to explore cost effective means of CO_2 sequestration, in the context of the above priorities.

As different customers have different objectives as relates to approaching or achieving "carbon neutrality", customers' desire additional options for purchasing power from renewable energy sources. What the WRM sub-group would advocate is the implementation of special tariffs, green power purchasing rates, or other regulatory tools that will allow consumers to make green power purchasing choices. This will encourage development of renewable sources of energy supply without disadvantaging the broader rate base, while federal regulatory efforts concerning green house gas emissions are worked out.

Renewable energy resources were viewed by the group as a positive addition to the IRP in terms of supply diversity and long term cost stability. SWEPCO should continue pursuing cost effective renewable wind and solar power. Although the cost of renewable power is currently high, increments of renewable energy allow for a reasonable blended cost approach.

The remaining six issues were placed in rank order (#9,10,2,18,12,11), but the consensus of the group was that they were less significant with respect to those listed above, and should be weighted accordingly by AEP/SWECPO as it prepares its Integrated Resource Plan.

Ranking of the Issues

Priority	Issue & ID Number		Criteria
1	#5	Reliability	Reliability, economic development
2	#13, 15	Costs to Customers	Economic development
3	#4	Partnerships	Costs-nuclear
4	#17	Transmission	Cost & reliability
5	#1	Demand side mgmt	Cost, environmental, energy efficiency
6	#14,16	Green House Gas Issues	Cost, environmental
7	#3,6,8	Renewable Energy	Diversity, environmental, cost
8	#9	Pump Hydro	Diversity, cost
9	#10	Generation vs. supply contracts	
10	#2	Combined Heat & Power	
11	#18	Transparency of model	
12	#12	Economic development inside Arkansas/Renewables	
13	#11	Externalities	

VI. Comments from Other Invited Parties

Several other constituent groups were invited to participate in the IRP Stakeholder process. However several members either were unable to attend the meeting or chose not to take an active role in the three representative working groups. This section is provided as a means for those stakeholders to provide input to the final IRP Stakeholder Report with respect to their issues and priorities, to make comments on the process, or otherwise provide input to the final report appropriate to their perspective. They are included as-received with only minimal formatting to fit the overall report format.

Audubon Arkansas

1423B South Main St.
Little Rock, AR 72201
December 23, 2008

SWEPCO IRP Process

Dear SWEPCO IRP Stakeholders:

Please find below comments from Audubon Arkansas relative to the ongoing Integrated Resource Planning process. While we regret being unable to attend the first IRP meeting, we hope that these comments can be taken into consideration.

The fundamental purpose of an IRP is to provide an "informational report" that can be used for "planning" by the Commission.[5]

Among the objectives of an IRP is "comparable consideration of demand and supply resources."[6] Such consideration includes "development of a range of outcomes that complement the long-term forecasts of electricity demand (MW) and energy consumption (kWh).[7] The range of demand response activities, such as efficiency, conservation, demand-side management, interruptible load, and price-responsive demand "should be identified" and should be "investigated" to determine costs, effectiveness, and other attributes such as future emission control or allowance costs to the extend they are monitizable."[8] The APSC Guidelines contemplate development of "multiple" IRP's, each of which meets reliability criteria. The multiple IRP's demonstrate, among other things,

[5] APSC Resource Planning Guidelines, § 1.
[6] *Id.*, § 4.1.
[7] *Id.* § 4.2.
[8] *Id.* § 4.3.

different ways to respond to potential different levels of load growth, first fuel cost forecasts, and other parameters.[9]

Because the fundamental purpose of the IRP is to provide information useful to the Commission, and because a probing analysis of efficiency and demand response scenarios is an essential objective, Audubon Arkansas suggests that more complete information about demand, energy consumption, and the potential for demand response and efficiency efforts to meet varying levels of potential demand should be included from the earliest stages of the public involvement process.

- For instance, what is the sensitivity of overall demand and energy consumption in Arkansas and in the SWEPCO territory to economic downturn, federal efficiency and carbon legislation, and fuel cost?
- Graphs in the initial SWEPCO handouts do not isolate or distinguish the impact of efficiency and demand response from the overall demand curve. We suggest that such impacts should be graphically represented, in combination with supply resources over the period studied, in such a way that their comparative impact can assessed by public stakeholders.
- More importantly, what is the potential, if favorable cost recovery and incentives were available to SWEPCO, for future demand and energy consumption to be served through efficiency and demand response? Smart metering alone has been estimated at several percentage points of capacity in some jurisdictions. The overall potential for demand and energy consumption reductions should be explored under a reasonable range of carbon cost, fuel cost, and cost recovery scenarios.
- As SWEPCO is aware, FERC and some state PSC's are considering the use of efficiency and demand response to provide transmission benefits. What is the potential for such efforts to benefit Arkansas?
- What would be the emissions benefits of these potential efficiency and demand response scenarios?

The information needed to answer these questions would help to meet the objectives identified in the IRP guidelines. This information would allow stakeholders to understand how overall demand might be affected by market and regulatory signals, and what the potential is for SWEPCO to respond with programs that reduce or manage demand and energy consumption.

Audubon Arkansas appreciates this opportunity to provide initial comments in the SWEPCO IRP process.

Thank you.

Sincerely,

[9] *Id.* § 4.4.

Ken Smith
Executive Director
Audubon Arkansas

Eddy Moore
Audubon Arkansas

VII. Conclusion

All stakeholders were allowed the opportunity to provide key issues both prior to and during the session. These issues became the basis for further discussion, analysis and prioritization, with the objective of communicating to AEP/SWEPCO the importance of these issues with respect to development of their Integrated Resource Plan.

In order to come to conclusions that could be captured in a cohesive Stakeholder Report, the consensus decision of the group was to look at the issues from three broad interest perspectives. The stakeholders decided to divide into three groups to discuss and ultimately rank the issues as to their relevance and importance to that constituency group. The three groups were:

- Retail / Wholesale / Municipal Customers
- Renewable Interests
- Independent Power Producers

The consensus of the attendees at this first IRP Stakeholder's Meeting was:

- The experience was overall a positive one, and offered the opportunity to provide meaningful input with respect each constituent's priorities and issues.
- That it was educational, both from the information provided by AEP/SWEPCO, and with respect to the perspectives and priorities of the other representatives at the meeting.

On behalf of the attendees at the IRP Stakeholders Meeting, we appreciate the efforts of AEP/SWEPCO, and of the Arkansas Public Service Commission for the opportunity to participate in the process. This concludes the report of the stakeholders.

Respectfully Submitted,

Lawrence Scott Turley, PE
Director, Utility Operations
The University of Arkansas
Acting Secretary for the Stakeholder Group