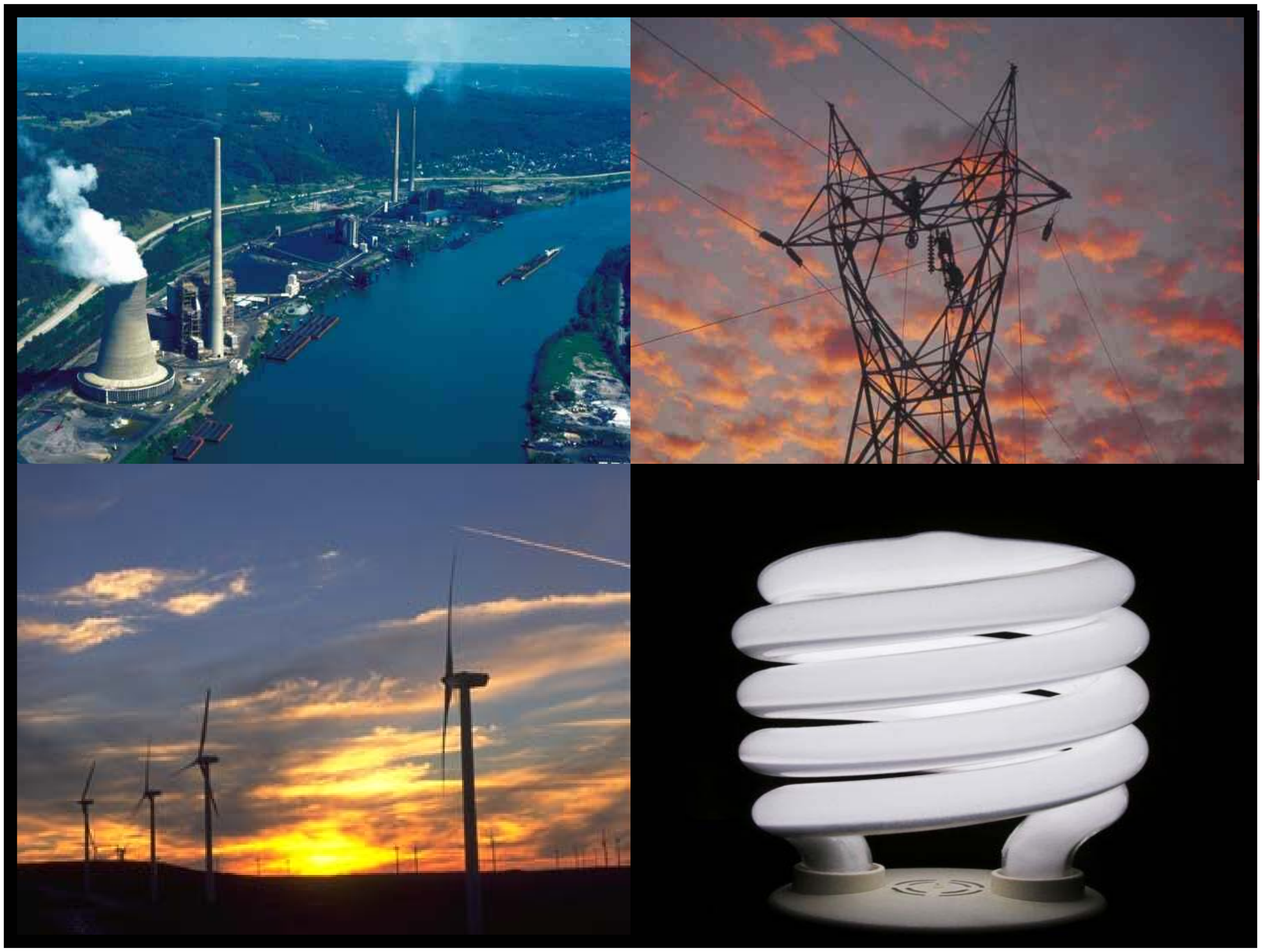
AEP AMERICAN® ELECTRIC POWER

2009 AEP-EAST

INTEGRATED RESOURCE PLAN



2010-2019

Date Issued: July 2009

Business Confidential
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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 PJM 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:

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Table of Contents

Exhibits

Appendices

Acknowledgements

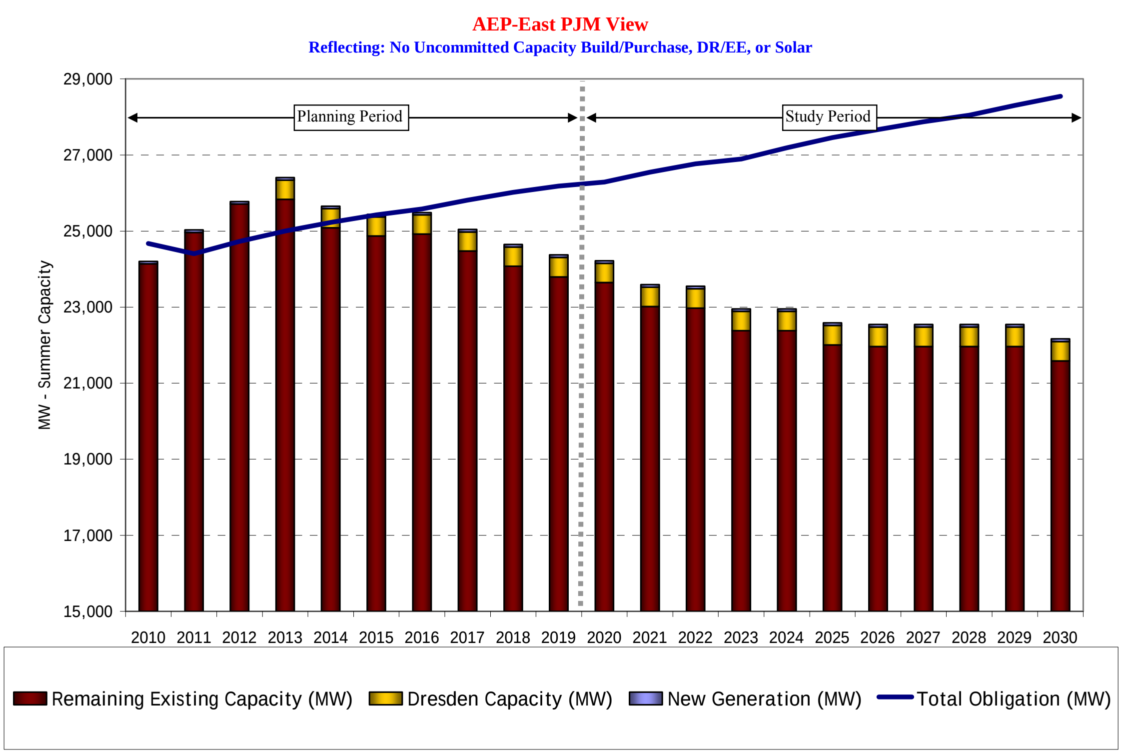
The Resource Planning group appreciates the support and input of the various individuals throughout the Service Corporation who provided input into the development of this Integrated Resource Plan document. In addition, a number of people provided valuable comments as the report was being developed including 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") forecast period (Planning Period), the AEP integrated eastern zone (AEP-East) internal peak demand is expected to grow by about 0.88 percent or 200 MW annually. This growth can be considered as occurring in two phases. In the first phase, through 2014 peak demand is expected to grow at 1.8% annually as the region rebounds from the current recession; thereafter annual peak demand growth of 0.64% is expected, the reduction representing the end of the economic rebound combined with the impact of assumed CO_2 legislation on the price of electricity.

The following **Summary Exhibit 1** offers the "going-in" capacity need of the AEP-East zone prior to *any* uncommitted capacity additions. It amplifies that the region's overall capacity need occurs beginning in the 2015-2018 period. Committed new capacity includes completion of the 540 MW Dresden combined cycle facility in 2013, and executed purchase power agreements for renewable energy (wind) resources.

Summary Exhibit 1

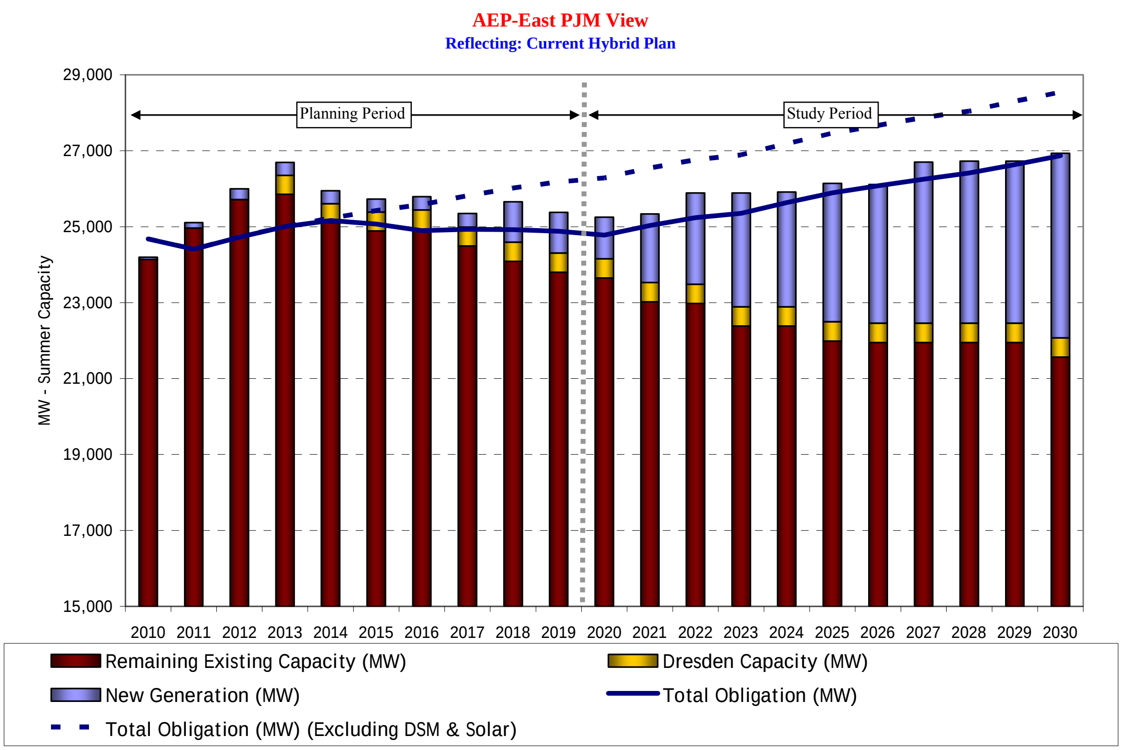


Source: AEP Resource Planning

In spite of the potential retirement of up to 3,470 MW of older, coal-fired units over the planning period due largely to external factors including known or anticipated environmental initiatives as well as the December 2007, stipulated New Source Review (NSR) Consent Decree, this AEP-East IRP requires no new baseload units in the forecast period. Rather, a unit uprate project at Cook Nuclear Plant during the 2014-2018 time period and a 2018 peaking resource, in addition to increased wind purchases and demand response programs are proposed to be added to maintain anticipated minimum PJM nominal reserve margin requirements of approximately 16.2%. Additional peaking and intermediate capacity will be added after 2020 to meet future load obligations.

Summary Exhibit 2 below shows AEP-East's capacity position relative to the PJM requirement, including capacity additions as proposed in this 2009 IRP. As this table shows, the combination of supply side additions and demand side measures that provide demand reductions/energy efficiency (DR/EE or "DSM") allow AEP-East to meet the PJM margin requirements.

Summary Exhibit 2



Source: AEP Resource Planning

Major Drivers:

Global Climate Change

This 2009 IRP for AEP-East is consistent with the AEP 2009 Corporate Sustainability Report with regard to the assumption of emerging legislation related to greenhouse gas (GHG)/carbon dioxide (CO_2) emissions, renewable portfolio standards (RPS), and energy efficiency. The pricing assumptions and requirements for CO_2 used in this IRP were developed prior to the passage of the Waxman-Marley draft. Future IRP's will reflect legislation that is developed or enacted after this report is issued. The driving planning assumptions in this IRP 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 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 Reduction and Energy Efficiency

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-East IRP reflects approximately 537 MW of incremental peak demand reduction (above the current 269 MW of embedded peak demand reduction included in the load forecast and above the 473 MW interruptible load) by 2012, growing to 1,074 by 2015, amounts significantly exceeding those forecasted in prior planning cycles. These incremental reductions in demand result from both energy efficiency programs (474 MW) and demand response (600MW).

In Ohio, Substitute Senate Bill 221 was signed into law on May 1, 2008 and became effective on July 31, 2008. The bill sets significant and aggressive DR/EE benchmarks as well as renewable and advanced energy requirements. These goals, as well as a similar mandate in Michigan, were considered while developing the DR/EE levels recommended in this plan for AEP-East.

Potential Unit Disposition

An AEP-East unit disposition study was undertaken by an IRP Unit Disposition Working Group (WG) involving numerous AEP functional disciplines. This Q4-2008 effort was a follow-up to earlier studies performed annually since 2005. As before, the WG's primary intent was to assess the relative composition and timing of potential retirement "tranches". As in previous reviews, the predominant focus was again on the older-vintage, less-efficient, uncontrolled subcritical units in the AEP-East fleet.

In this cycle review, the WG considered financial implications of the potential (dispatch) cost impacts associated with CO_2 emissions. In addition, factors including PJM operational flexibility, emerging unit liabilities, and workforce/community factors were considered when recommending the relative multi-tier profile of potential unit retirements.

It should be noted that the conclusions of this study are for the expressed purpose of performing this overall long-term IRP analysis and reflect on-going and evolving disposition assessments. ***From a capacity perspective, no formal decisions have been made with respect to specific timing of any such unit retirements***, with the exception of those units that are identified in the stipulated settlement agreement related to the NSR litigation. In fact, the Unit Disposition WG's formal recommendation suggested that the units operate and budget under a "Hold & Maintain" status. These disposition analyses and renderings are deemed necessary so that the *prospects* for such ultimate decisions can be integrated into a capacity replacement plan in a manner that is ratable and practical from both a financial and operational perspective.

In addition, according to the AEP 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 ACI or FGD/SCR emissions control equipment. 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 these older, non-controlled units and ultimately the timing for new capacity.

Carbon Capture and Sequestration Technology

The 2009 plan does not include any coal fired baseload additions but does recognize that the existing fossil fleet may be subject to reduced CO_2 limits in the future. Therefore, the plan includes the continued phase-in of Carbon Capture and Sequestration (CCS) at Mountaineer Plant as a practical and cost-effective method. It is essential that the successful demonstration of this technology will be necessary before it is rolled out on a larger scale.

> "If this technology ultimately is not available to us and the industry, and in fact global warming legislation is passed and we can't address ourselves to the post-combustion answer, our company, our investors and everyone else in this face what I have called an economic brownout, because we simply won't have adequate electricity to energize the U.S. economy."
>
> Mike Morris, AEP Chairman, President and CEO

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 12/31/2011. The largest portion of these purchases (1,926 MW, nameplate) is assumed to be applicable to AEP-East.[1] Placed in addition to current and planned AEP-West region affiliates' (PSO and SWEPCO) long-term wind purchases as well as economically-screened wind and biomass co-firing opportunities beyond

[1] Note: Recognizing also that firm "capacity" attributable to wind would be limited to roughly 13% of that amount for purposes of capacity planning in PJM.

the 10-year IRP period, AEP is positioned to achieving 10% of energy sales from renewable sources, again consistent with Ohio Substitute S.B. 221 and other state mandated renewable goals.

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 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 East Recommended Plan (Including AEP-East Company Ownership):

- ✓ Complete the 540 MW Dresden Combined Cycle Facility by 2013 (APCo)
- ✓ As part of the life extension component replacement program required under the 20 year operating license extension received in August 2005, uprate the D.C. Cook Units 1 and 2 by 417 MW over the 2014 to 2018 timeframe (I&M)
- ✓ Construct or acquire 628 MW of peaking (e.g., Combustion Turbine) capacity by 2018 (APCo & KPCo, 50/50 Ownership)
- ✓ Purchase or construct 2,451 MW (nameplate) of wind generation (Various companies) in addition to 75 MW already in operation by 2009 bringing total nameplate wind capacity to 2,526 MW by 2019
- ✓ Construct or acquire 187 MW of biomass generation by 2018 (CSP & OPCo)
- ✓ Continue the Carbon Capture and Sequestration Demonstration project at the Mountaineer facility (APCo)
- ✓ Implement Demand Response totaling 1,073 MW by 2015 (Various)

On July 28, 2009 AEP was informed that Ormet will shut down its Hannibal, Ohio operations indefinitely. Future AEP-East planning will reflect this change.

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

Summary Exhibit 3

2009 IRP for *AEP-East*

	Planned Resource Reductions (MW) (A)		*Planned Resource Additions (MW)* (A)						
			DSM		RENEWABLE			THERMAL	
	Unit Retirements (summer-rating)	Environmental Retrofits (F)	Embedded Demand Reduction (B) (Cumul. Contribution)	New Demand Reduction (C) (Cumul. Contribution)	Solar (Nameplate)	Wind (Nameplate)	Biomass (Derate / New Facility (D))	Duty Cycle Type: BL=Baseload INT=Intermediate/Cyclic PKG=Peaking	*Ownership*
2009			58	0	0	200			
2010	(440)	MT-Ph1CCS(4 MW) RK1&2 ACI	145	179	10	350			
2011			267	358	3	601			
2012	(560)	AM2 FGD (10 MW)	269	537	2	700	(0) / 60		
2013		AM1 FGD CV5&6 SCR(18MW)	271	716	14	500		(Dresden) 540-MW INT	*APCo*
2014	(395)	MT-Ph2 CCS (31 MW)	272	894	14		(43) / 0	(Cook 2)+45MW BL	*I&M*
2015	(415)	MR5/BS2 FGD (50 MW)	273	1,073	14			(Cook 1&2)+168MW BL	*I&M*
2016			273	1,073	14	100		(Cook 1)+68MW BL	*I&M*
2017	(600)	RK1 FGD	273	1,073	13			(Cook 2)+68MW BL	*I&M*
2018	(580)		273	1,073	17		(41) / 127	(Cook 1)+ 68MW BL and 628-MW PKG	*PKG: APCo/KPCo 50/50; BL: I&M*
2019	(480)	RK2 FGD	273	1,073	17				
2019 Cumul. Contribution/Nameplate	***(3,470)***	***(113)***	***273***	***1,073***	***118***	***2,451***	***103***	***1,585***	
(PJM) Capacity Value (E)					***83***	***319***			
Cumul. (Nameplate) Contribution			***5%***	***19%***	***2%***	***44%***	***2%***	***28%***	
Cumul. (Capacity) Contribution			***8%***	***31%***	***2%***	***9%***	***3%***	***46%***	

'NET' CAPACITY RESOURCE ADDITIONS: Additions - Reductions =	***(147)***

Peaking	628	*40%*
Intermediate (incl. Dresden)	540	*34%*
Baseload (D.C. Cook Uprates)	417	*26%*
	1,585	

(A) Not shown are smaller unit derates and uprates embedded in the current plan which are largely offseting
(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 activity modeled thru 2015 only
(D) Derate represents a blended fuel biomass unit, New Facility reflects a single repowered, (100%) dedicated biomass (e.g. stoker) unit from MR 1-4 and a 60 MW PPA
(E) Capacity value in PJM is initially set at 13% of nameplate for wind and 70% of nameplate for solar
(F) CCS retrofit technology assumed to be chilled ammonia with a 15% parasitic load

Source: AEP Resource Planning

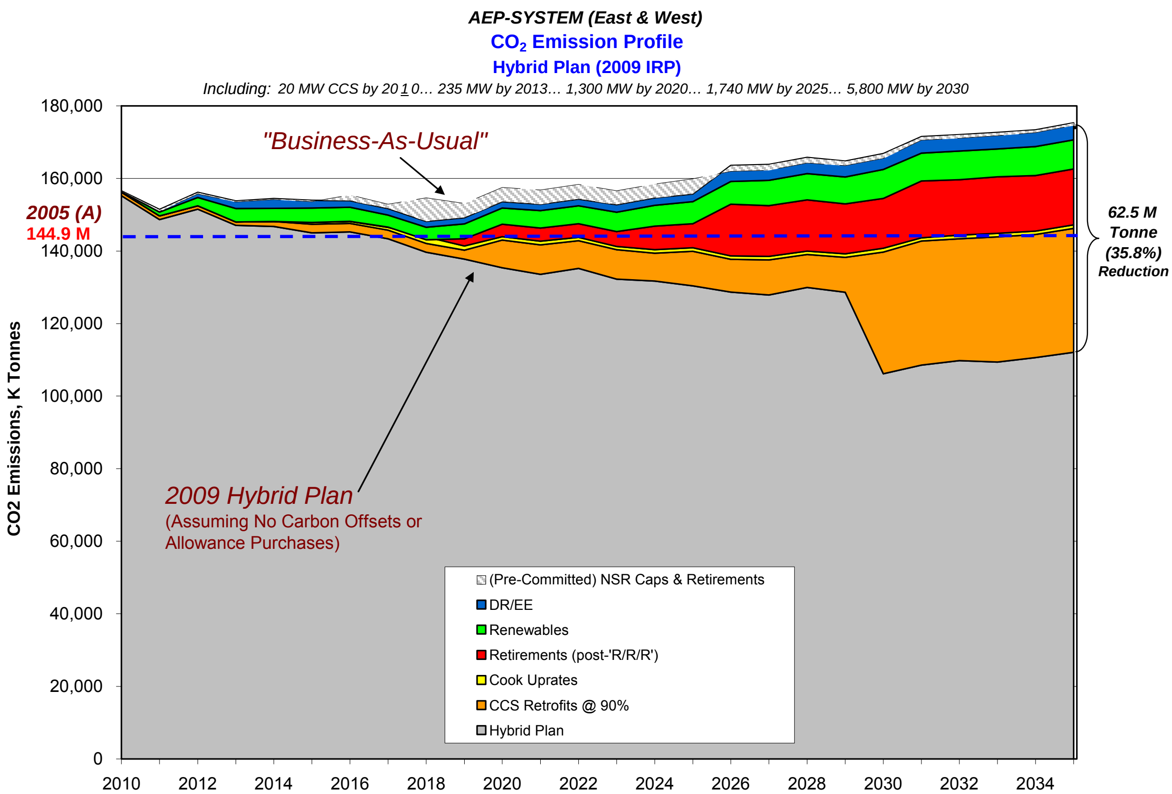
Plan Impact on Carbon Mitigation ("*Prism*" *Analysis*)

Global Climate Change and the prospect for comprehensive CO_2 legislation has had a direct bearing on the outcome of the 2009 AEP-East 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:

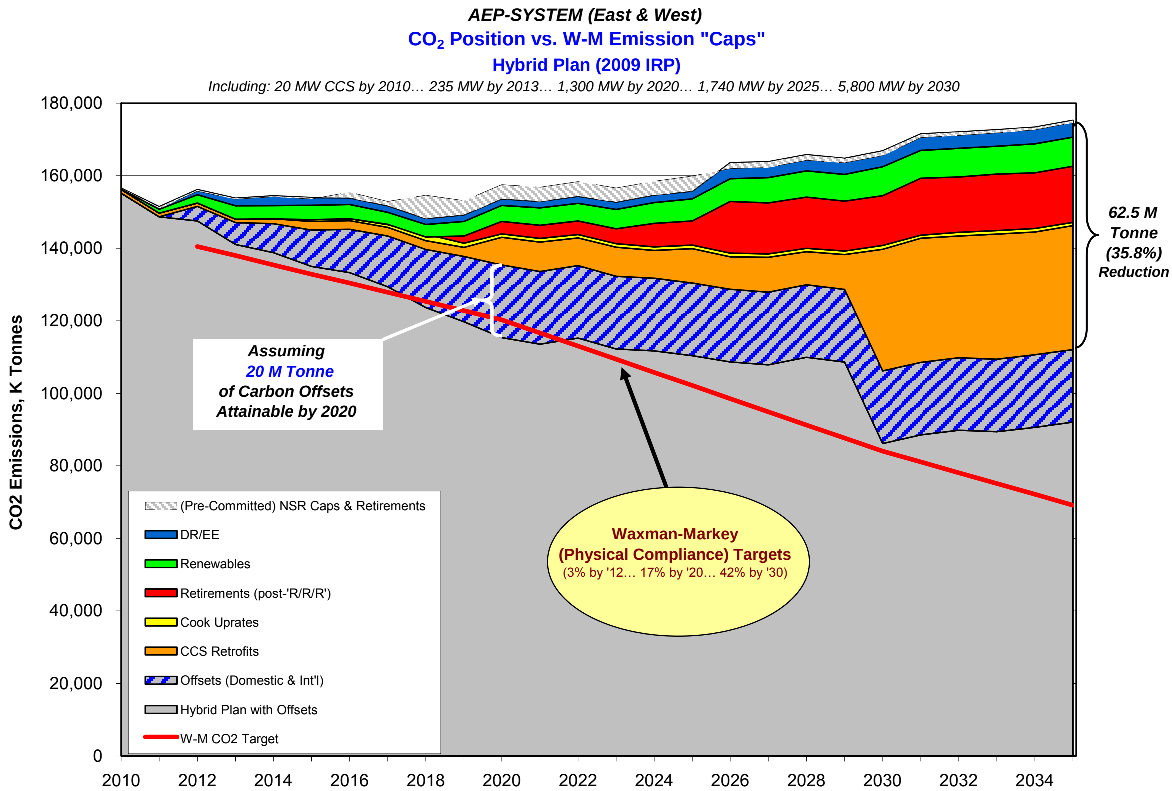
Summary Exhibit 4



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

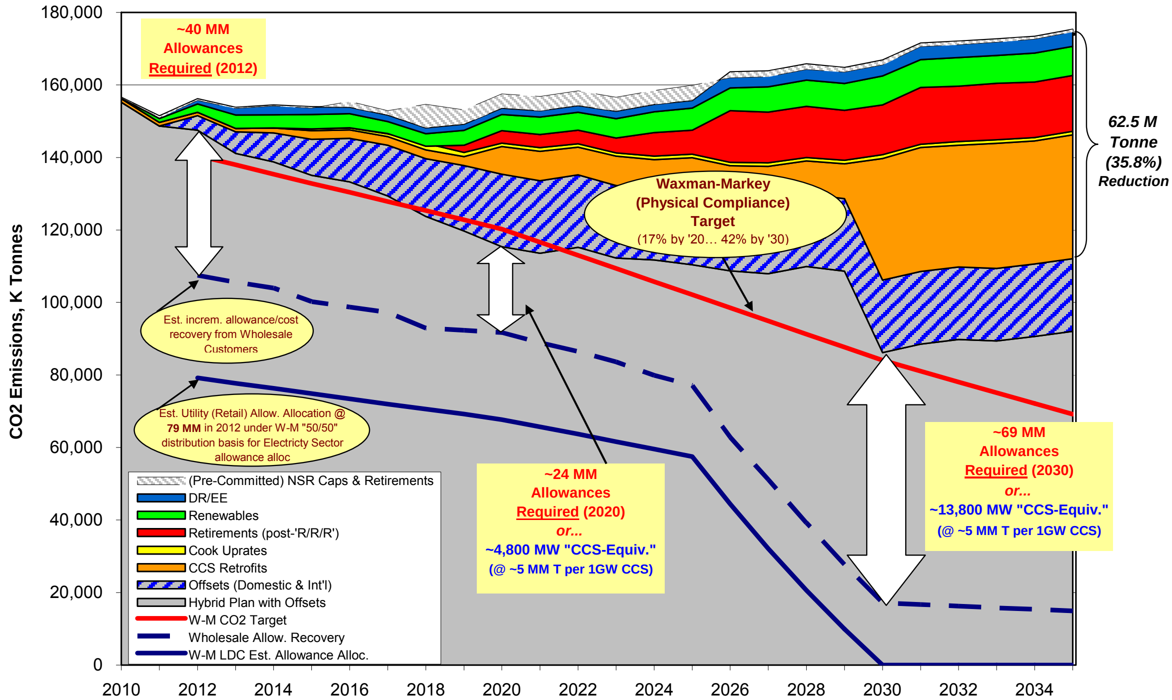


Source: AEP Resource Planning

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

AEP-SYSTEM (East & West)
CO_2 Position vs. Est. W-M LDC Allocations & Wholesale Recoveries
Hybrid Plan (2009 IRP)



Source: AEP Resource Planning

In summary, this prism analysis would suggest that the carbon mitigation requirements in the AEP-East 2009 IRP 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.

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

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.*

Conclusion:

The recommended capacity resource 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 and the uprate of the Cook Nuclear facility allow AEP-East to meet its reserve requirements until 2018, at which point new peaking capacity will be required. No new baseload capacity is required over the term of the forecast period.

The plan positions AEP-East 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.

Keep in mind that the planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and 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. <u>The Plan is not a commitment to a specific course of action</u>, since 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-East 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-East 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. Sections 13 through 15 describe the findings and recommendations (Section 13), plan implications on AEP operating companies (Section 14), and lastly, plan implementation (Section 15).

1.1 IRP Process Overview

This report presents the results of the Integrated Resource Plan (IRP or "Plan") analysis for the AEP East (PJM) zone of the AEP System, covering the period 2010-2019, with additional planning modeling conducted through the year 2030. The information presented with this IRP 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 lowest reasonable cost.*

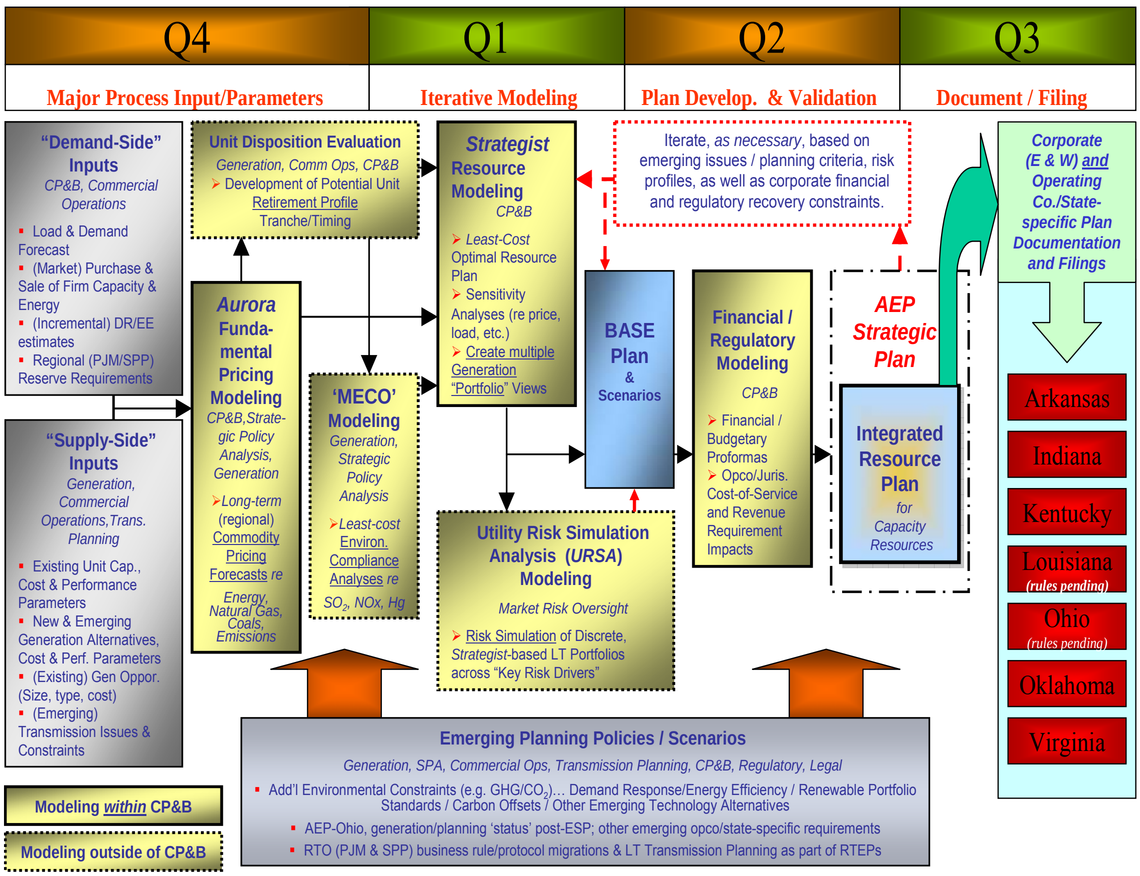
In addition to the need to set forth a long-term strategy for achieving regional reliability/reserve margin requirements, capacity resource planning is critical to AEP due to its impact on:

- **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**— resource planning is naturally integrated with the Company's current and anticipated corporate sustainability goals, environmental compliance—including the prospect for comprehensive Climate Change/CO_2 legislation, 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 (see **Exhibit 1-2**).

Exhibit 1-1: IRP Process Overview



Source: AEP Resource Planning

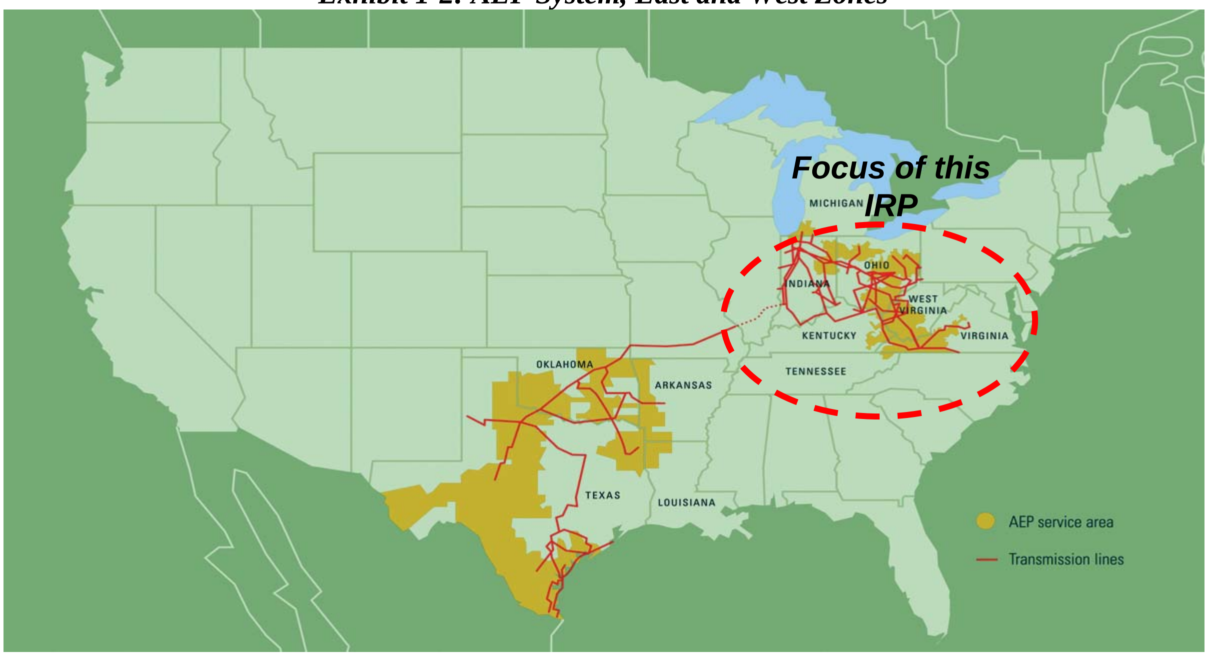
AEP owns and/or operates 58 generating stations in the United States, with a capacity of approximately 37,000 megawatts. AEP's customers are served by one of the world's largest transmission and distribution systems. System-wide there are more than 39,000 circuit miles of transmission lines and more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

AEP's operating companies are managed in two geographic zones: 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); and its western zone, which, for resource planning purposes within the Southwest Power Pool (SPP), comprises the

Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO).[2]

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-East zone. Planning for affiliates PSO and SWEPCO operating in SPP will be communicated in a separate document.

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



Source: AEP Internal Communications

1.2.1 AEP-East Zone–PJM:

AEP's eastern zone ("AEP-East" or "AEP-PJM") operating companies collectively serve a population of about 7.2 million (3.26 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. The internal (native) customer base is fairly diversified. In 2008, residential, commercial, and industrial customers accounted for 28.4%, 22.2%, and 35.9%, respectively, of AEP-East's total internal energy requirements of 130,519 GWh. The remaining 13.5% was supplied for street and highway lighting, firm wholesale customers, and to supply line and other transmission and distribution equipment losses.

AEP-East experienced its historic peak internal demand of 22,411 MW on August 8, 2007. The historic winter peak internal demand, 22,270 MW, was experienced on January 16, 2009. AEP-East

[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 regulated generating assets within ERCOT.

reached its all-time peak total demand of 26,467 MW, including sales to nonaffiliated power systems, on August 21, 2003.

1.2.2 AEP-East Pool

The 1951 AEP Interconnection Agreement (AEP Pool) was established to obtain efficient and coordinated expansion and operation of electric power facilities in its eastern zone. This includes the coordinated and integrated determination of load and peak demand obligations for each of the member companies. Further, member companies are expected to "rectify or alleviate" any relative capacity deficits of an extended nature to maintain an "equalization" over time. As such, capacity planning is performed on an AEP-East integrated basis, with capacity assignments made to the pool members based on their relative deficiency within the Pool.

1.2.3 AEP System Interchange Agreement (East and West)

The 2000 System Interchange Agreement (SIA) among AEPSC - as agent for the AEP-East operating companies, and Central and Southwest Services, Inc. (CSW) – including the AEP-West 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 SIA provides for the integration and coordination of AEP's eastern and western companies' zones. In that regard, the SIA provides for the transfer of capacity and energy between the AEP-East zone and the AEP-West zone under certain conditions. 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.

2.0 Current Resource Planning Issues in the Electric Utility Industry

2.1 Regulatory Issues

Currently there are no electric utility restructuring efforts or significant renewable initiatives in Indiana, Kentucky or West Virginia. Following is the current status of electric restructuring initiatives in Virginia, Michigan and Ohio:

- **Virginia**: In April 2007, the Virginia legislature approved amendments to its recently adopted, comprehensive bill providing for the re-regulation of electric utilities' generation/supply rates. This new form of cost-based regulation is more progressive than the traditional method under previous Virginia law and employed by the Virginia State Corporation Commission because voluntary "clean coal", renewable and DR/EE goals have been established. These voluntary goals include an incentive of an incremental 500 basis points return on equity for all jurisdictional assets, not just those assets that are needed to meet the renewable goal.
- **Michigan:** In 2008 the State of Michigan passed legislation that made major changes to its electric industry structure. Its industry remains bifurcated, providing limited customer choice along with a cost based regulated pricing. Additionally a 10% renewable mandate by 2015 was established along with an energy optimization mandate. Several changes were made to provide a utility investment environment that is more favorable, especially for new generating plants. Those changes include: (1) choice is now limited to 10% of a utility's previous year's sales; (2) a certificate of need for new generation and major capacity up-rates was created to provide greater certainty of recovery; (3) a 12 month limit on MPSC rate case decisions was established, with filed rates going into effect if the 12 month limit is not met; and (4) CWIP was established for generation investment financing costs.
- **Ohio**: Legislation setting the regulatory framework for Ohio's electric utility industry was signed into law May 1, 2008 and became effective July 31, 2008. The legislation (Substitute Senate Bill 221, or Sub SB 221) creates two paths for ratemaking – a regulated Electric Security Plan (ESP) and a phased-in Market Rate Option (MRO). ESP filings allow for many ratemaking tools, including automatic cost recovery and increase/decrease mechanisms, construction work in progress (CWIP) recovery for new generation construction or environmental retrofit, a non-bypassable charge for new generation, limitations on customer shopping related to Provider of Last Resort (POLR), phase-ins, deferrals, securitization, and single-issue ratemaking for infrastructure modernization. An MRO may be filed by an Ohio utility at any time, but once approved the utility may not return to an ESP. MRO rates are determined by a competitive bidding process and are blended with the regulated rate over a 5 to 10 year period. Both the ESP and the MRO paths have an "excess earnings" provision that allows the PUCO to adjust rates if it is determined that the utility earnings are significantly above other businesses with a similar risk profile.

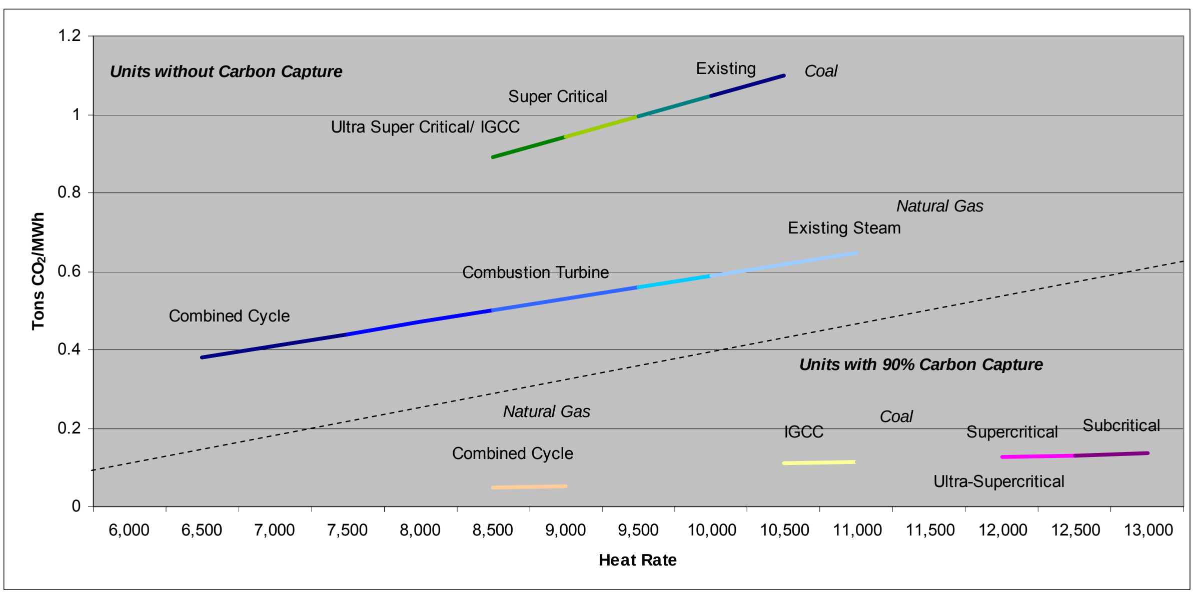
2.2 Climate Change and Greenhouse Gases

A majority of scientists and politicians worldwide have noted that the Earth's climate is warming and that the warming is due, at least in part, to man's production of heat trapping 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. Man-made 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 GHGs (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 make a difference in the quantity of CO_2 produced. **Exhibit 2-1** demonstrates the advantage lower heat rates 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.

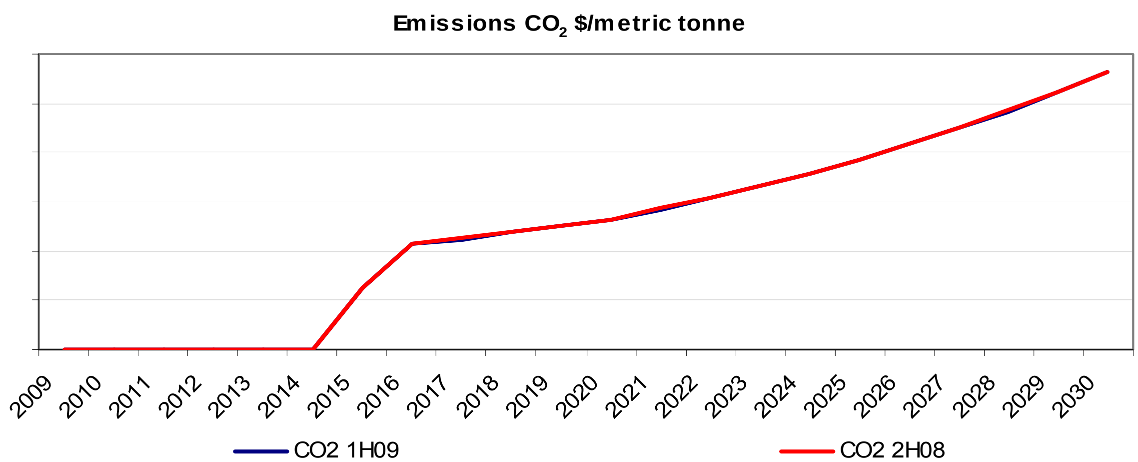
2.2.2 Impact of Environmental Legislation on Industry

Any binding legislation is likely to be "economy-wide"–generally meaning all fossil fuel use will be targeted–because the production of GHGs 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: CO_2 Price Forecast



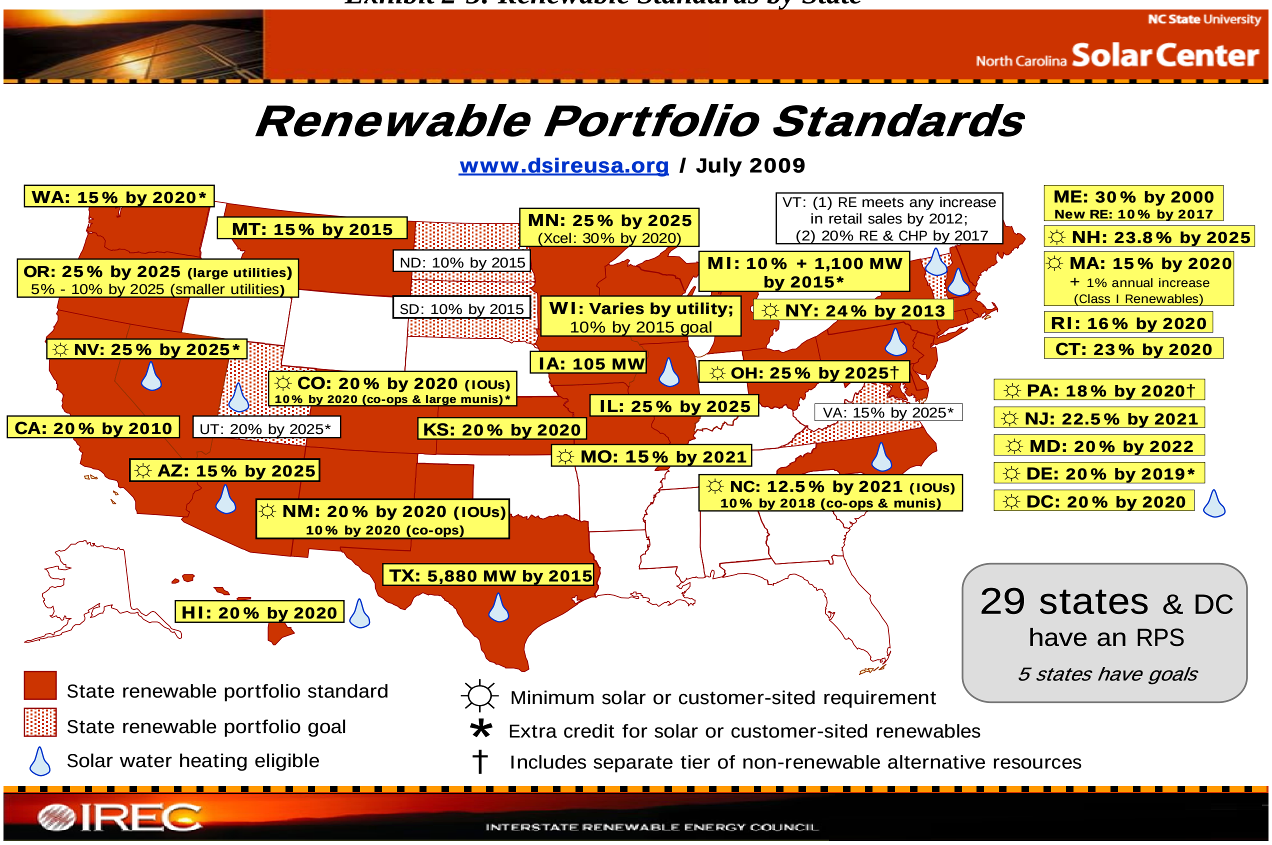
Source: AEP Fundamental Analysis

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% by 2020 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 by 2021 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 for Voluntary Reductions

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. AEP has 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.

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. 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 Production Tax Credit (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.

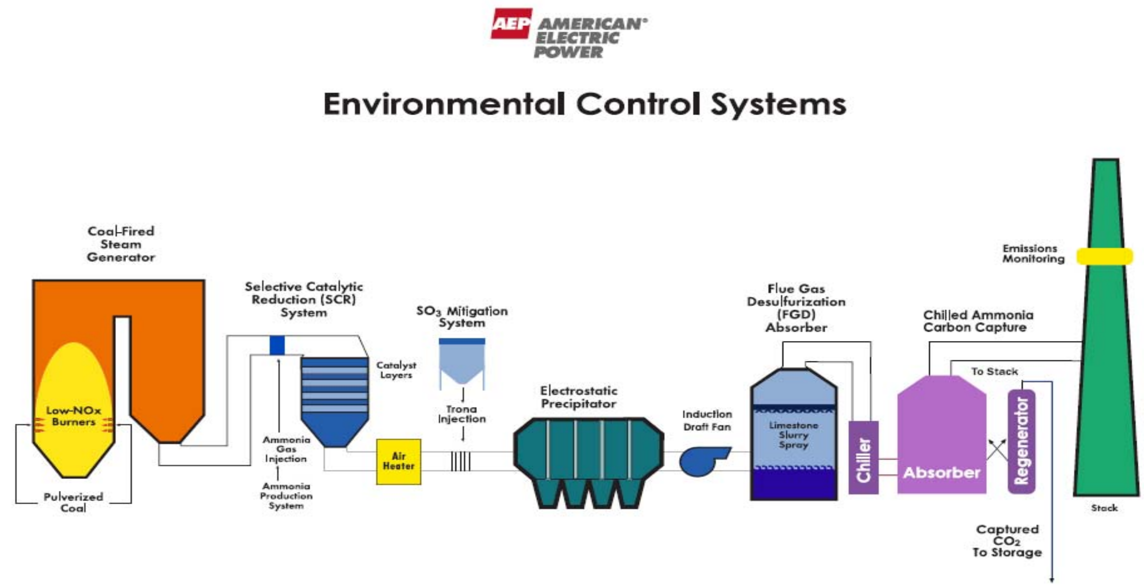
As discussed in the following section, additional actions, including a future carbon capture and storage program, will also help offset the anticipated growth in AEP's carbon footprint.

2.2.3.3 The Role of Technology

Throughout its 100-plus year history, AEP has led the industry in deploying advanced 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 to 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

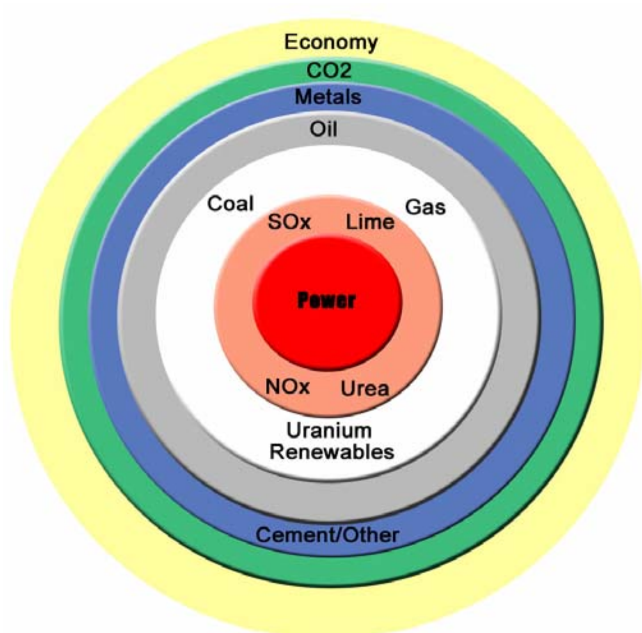
*Note: This section includes excerpts from the "**Long Term Price Forecast 2009-2030: Return to Fundamentals, 2H-2008**" prepared by AEPSC's Strategic & Economic Analysis Group (SEA) and issued February 2009.*

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.**

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.

Exhibit 2-5: Power Price Layers



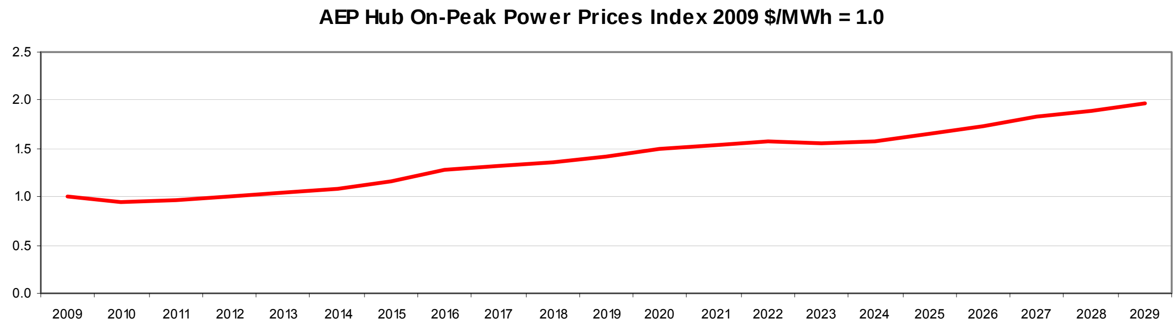
2.3.1 Power Prices

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 Appendix 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 (see Section 10.2) 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 the AEP Hub on-peak prices increase 28 percent compared to 40 percent in the off-peak market over the same period.

Exhibit 2-6 AEP Hub On-Peak Price Index



Source: AEP Fundamental Analysis

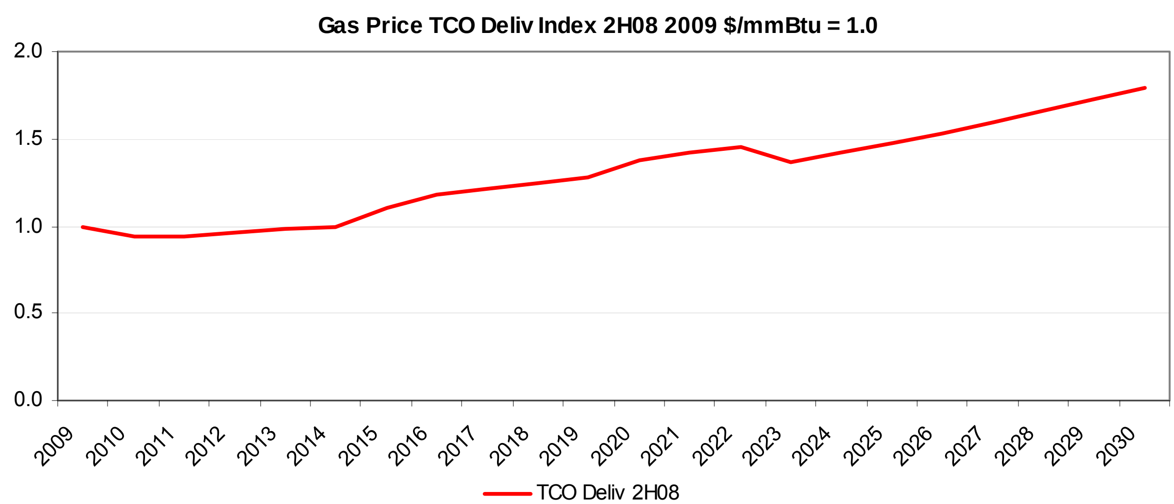
2.3.2 Fuel

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

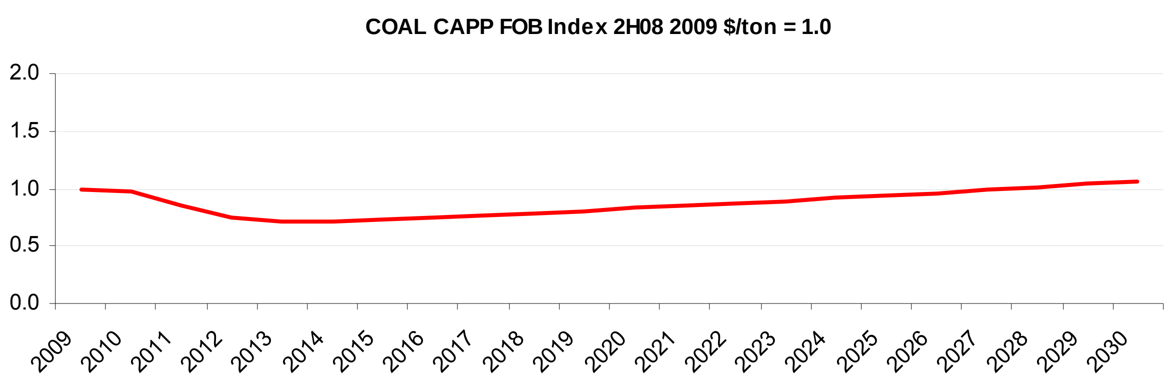
2.3.2.2 Coal

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: CAPP 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

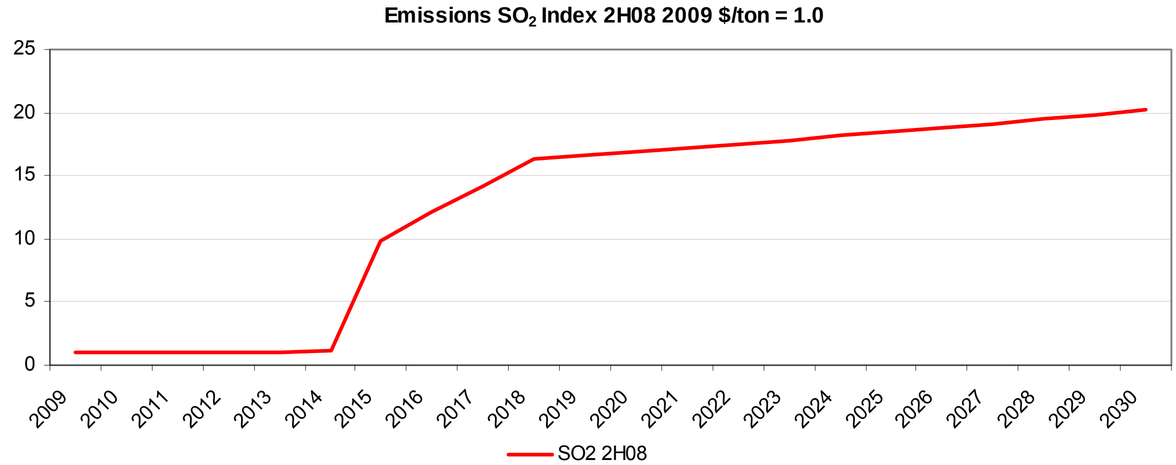
2.3.5.1 SO_2, NO_X and Mercury (Hg)

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 policy could dictate that all coal units 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

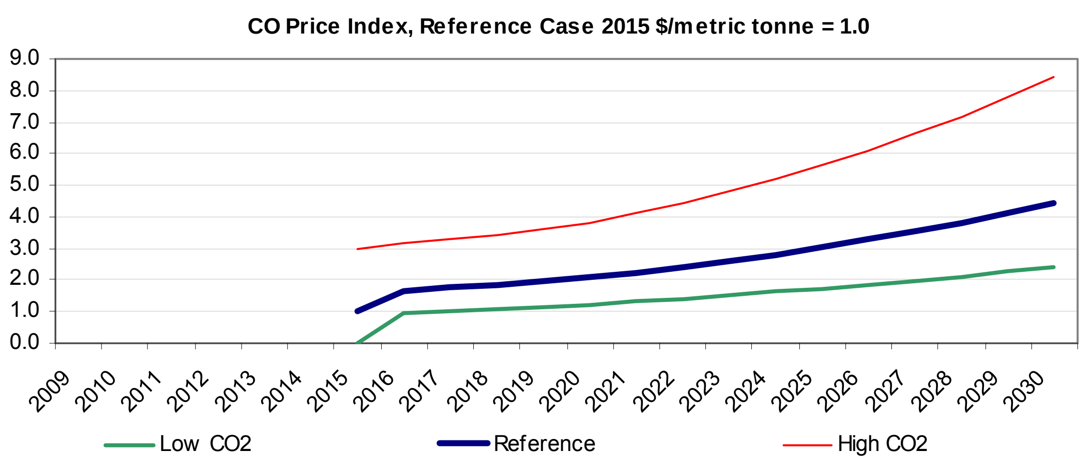


Source: AEP Fundamental Analysis

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. These forecasts attempt to represent a range of potential policy outcomes and resulting pricing to account for the uncertainty. The Abundance (low prices) and Constrained (high prices) Cases (**Exhibit 2-10**) 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 maintain optionality. 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.

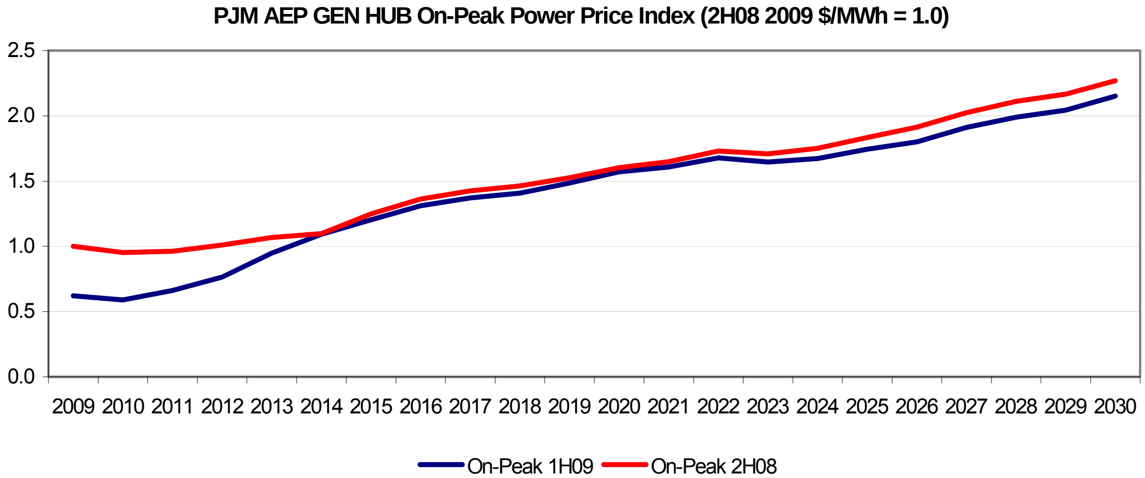
The long-term planning horizon is characterized by several primary variables. First and foremost, the prospect of legislation that in some way regulates GHGs. *Any* system enacted will likely result in:

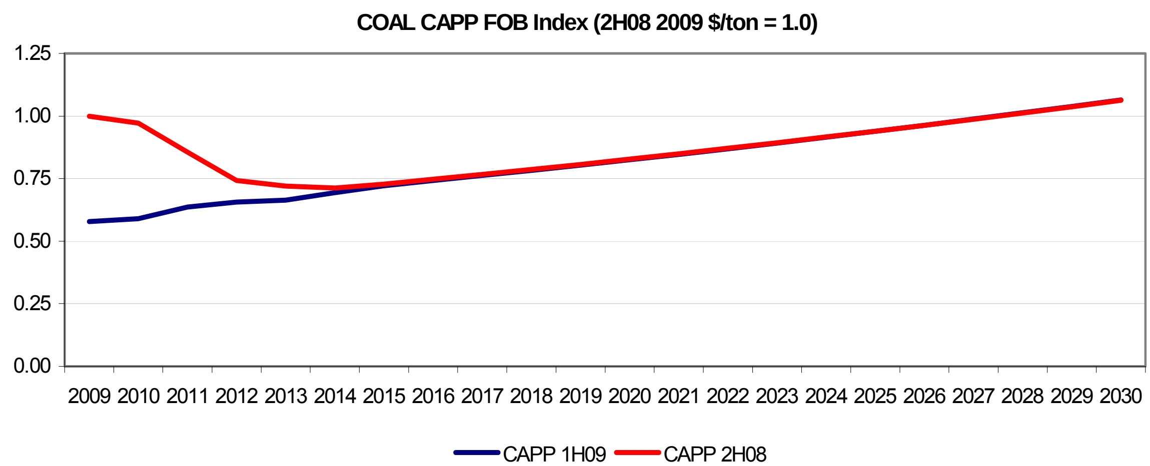
- Ultimate development and implementation of CO_2 capture and sequestration technologies which, in the east where higher-quality bituminous coals are prevalent, could ultimately favor current Integrated Gasification Combined Cycle (IGCC) design technology over traditional Pulverized Coal (PC) plants.
- 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.

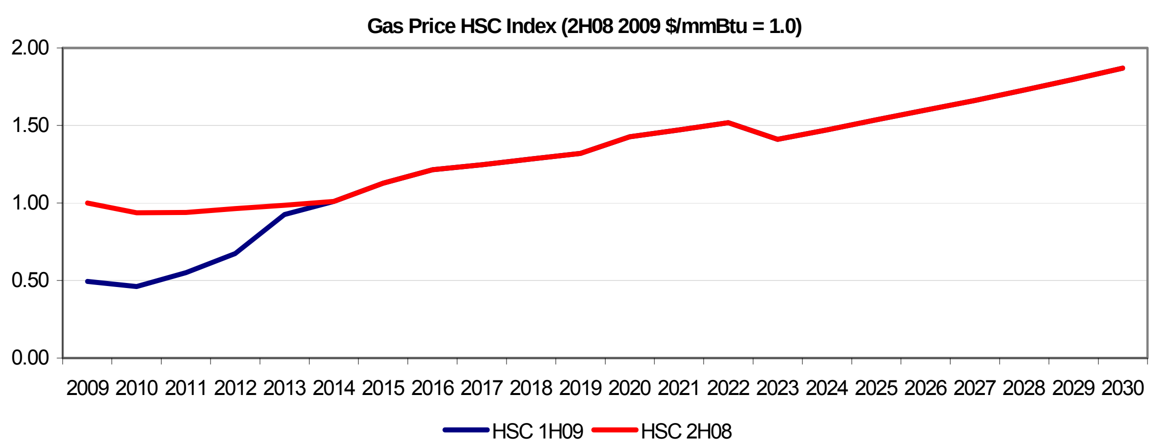
- Emissions allowance prices in light of the as yet unresolved CAIR and CAMR/mercury requirements, assumptions directly affecting the economic viability of uncontrolled coal generation.

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 Unit Disposition and Acquisition

The impact of any potential carbon related cap-and-trade regime will further compound the deteriorating cost profile of some of the older, non-environmentally-controlled, higher heat-rate, coal-fired plants. Also, the Stipulated Agreement that resolved the Company's NSR litigation imposed hard caps on emissions of SO_2 and NOx, and established specific dates to retire, retrofit, or repower named coal units. To that end, a review of affected AEP-East plants was conducted on the basis of cost and other factors, including: engineering and operation; ancillary value within the PJM-RTO; and community and workforce issues. This analysis identified the plants that may be best positioned for possible disposition (including retirement or mothballing) during the planning horizon and provided a logical framework for a staged disposition, while recognizing the need to avoid retiring too many plants over a relatively short time-horizon.

In addition, in continued recognition of both the need for additional capacity beginning in the post-2017 timeframe, other market purchase opportunities are constantly being explored. 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 green field installation. As shown later in Section 8, the cost of these assets now approaches that of a greenfield project.

3.2 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. Within the AEP- East zone, both Ohio and Michigan have statutory benchmarks which take effect in 2009. 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.

3.3 Renewables

Renewable Portfolio Standards and goals have been enacted in over half of the states in the U.S and over two thirds of the PJM states. 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 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 renewable standards is expected to make unnecessary the incentive provided by the PTC. Acquiring this renewable energy and/or the associated Renewable Energy Credit/Certificate (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. AEP operating units I&M and Appalachian Power are already receiving energy from two wind projects with total nameplate ratings of 275 MW and six additional contracts have been executed for APCo, CSP, OPCo and I&M for an additional 351 MW to be placed in service in 2009 and 2010. **Exhibit 3-1** lays out the AEP-East Zone's renewable plan by operating company to meet its share of this target.

Exhibit 3-1: Renewable Energy Plan Through 2030

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				AEP-Ohio				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	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%	-	75	-	0.2%
2010	0	276	0	2.5%	10	100	0	0.7%	0	150	0	2.5%	0	0	0	0.0%	10	525	-	1.5%
2011	0	551	0	4.5%	13	325	10	2.0%	0	300	0	4.7%	0	50	0	1.9%	13	1,226	10	3.2%
2012	0	751	8	6.2%	15	675	101	5.0%	0	400	0	6.2%	0	100	0	3.8%	15	1,926	109	5.5%
2013 [(b)]	0	851	8	6.9%	28	975	101	6.7%	0	500	107	9.3%	0	100	19	4.6%	28	2,426	235	7.0%
2014	0	851	8	6.9%	42	975	101	6.7%	0	500	107	9.2%	0	100	19	4.6%	42	2,426	235	7.0%
2015	0	851	8	6.9%	56	975	159	7.4%	0	500	107	9.2%	0	100	112	12.1%	56	2,426	385	7.8%
2016	0	851	8	6.8%	70	1,015	159	7.6%	0	560	107	10.0%	0	100	112	12.0%	70	2,526	385	8.0%
2017	0	851	8	7.0%	83	1,015	159	7.5%	0	560	107	10.4%	0	100	112	11.9%	83	2,526	385	8.0%
2018	0	851	8	6.7%	100	1,015	286	9.0%	0	560	107	9.8%	0	100	112	11.8%	100	2,526	512	8.6%
2019	0	851	50	7.4%	117	1,015	372	10.0%	0	560	107	9.8%	0	100	112	11.7%	117	2,526	641	9.2%
2020	0	851	50	7.3%	133	1,215	372	11.0%	0	560	107	9.7%	0	100	112	11.7%	133	2,726	641	9.7% [(c)]
2021	0	851	50	7.3%	168	1,215	499	12.5%	0	710	107	11.7%	0	100	112	11.6%	168	2,876	768	10.6%
2022	0	851	50	7.2%	220	1,315	499	13.1%	0	710	107	11.7%	0	100	112	11.5%	220	2,976	768	10.9%
2023	0	851	50	7.1%	220	1,415	499	13.5%	0	710	215	14.8%	0	100	131	12.9%	220	3,076	896	11.6%
2024	0	851	50	7.1%	271	1,415	499	13.5%	0	910	215	17.4%	0	100	131	12.8%	271	3,276	896	12.1%
2025	0	951	50	7.7%	271	1,415	499	13.4%	0	910	215	17.2%	0	100	131	12.7%	271	3,376	896	12.2%
2026	35	951	50	7.8%	271	1,415	499	13.3%	0	1,010	215	18.4%	0	100	131	12.6%	306	3,476	896	12.4%
2027	35	1051	50	8.4%	271	1,415	499	13.2%	0	1,010	324	21.3%	0	100	150	13.9%	306	3,576	1,023	13.1%
2028	69	1151	50	9.1%	271	1,415	499	13.2%	0	1,110	324	22.5%	0	100	150	13.8%	340	3,776	1,023	13.5%
2029	69	1151	50	9.0%	271	1,415	499	13.1%	0	1,110	324	22.2%	0	100	150	13.7%	340	3,776	1,023	13.4%
2030	112	1151	50	9.1%	271	1,415	499	13.0%	0	1,110	324	22.0%	0	100	150	13.6%	383	3,776	1,023	13.3% [(c)]

(a) Data exclude conventional (run-of-river) hydro energy as a renewable source as it has been excluded from certain state and proposed federal RPS criteria.
(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. Establishment of a federal renewables standard would likely eliminate further extension of such PTC opportunities.
(c) What appear to be shortages in meeting the 2020 and 2030 target percentages are made up for in the SPP Zone, where wind resources are more cost-effective.

Source: AEP Resource Planning

The plan summarized in Exhibit 3-1 is intended to meet the requirements of the Ohio Renewable Portfolio Standards, the Michigan Clean, Renewable, and Efficient Energy Act, and the Virginia voluntary renewable portfolio standard.

3.3.1 Ohio Renewable Portfolio Standards

The goal of Ohio Substitute SB 221 Alternative Energy is that 25% of the retail energy sold in Ohio will come from Alternative Energy sources by 2025. Alternative Energy consists of two main constituents, Advanced Energy and Renewable Energy. Advanced Energy includes distributed generation, clean coal technology, advanced nuclear technology, advanced solid waste conversion, plant efficiency improvements and demand side management/energy efficiency. Renewable Energy includes solar (photovoltaic or thermal), wind, hydro, geothermal, solid waste decomposition, biomass, biologically derived methane, fuel cells, and storage resources.

At least half of the retail energy sales goal should be produced from renewable sources in 2025. There is a further sub-requirement that solar constitute at least 0.5 percent of retail sales. There are annual benchmark goals, beginning in 2009, for the Renewable and Solar requirement and sub-requirement, respectively.

Exhibit 3-2: Ohio Renewable Energy Plan

AEP-Ohio Renewables Requirement and Plan

Full Year	Solar Benchmark		Solar Plan	Total Benchmark		Total Plan
	Pct	GWh	GWh	Pct	GWh	GWh
2010	0.004%	1.8	10.5	0.25%	115	313
2011	0.010%	4.5	13.7	0.50%	225	1,025
2012	0.030%	12.8	15.6	1.00%	426	2,591
2013	0.060%	25.3	30.1	1.50%	634	3,467
2014	0.090%	38.6	44.6	2.00%	859	3,481
2015	0.120%	53.6	59.1	2.50%	1,116	3,846
2016	0.150%	67.1	73.6	3.50%	1,566	3,975
2017	0.180%	81.2	87.4	4.50%	2,030	3,989
2018	0.220%	100.0	105.5	5.50%	2,500	4,786
2019	0.260%	119.0	123.7	6.50%	2,975	5,334
2020	0.300%	138.2	140.4	7.50%	3,456	5,925
2021	0.380%	165.3	176.6	9.50%	4,132	6,740
2022	0.420%	195.6	231.0	10.50%	4,890	7,082
2023	0.460%	215.4	231.0	11.50%	5,386	7,369
2024	0.500%	235.4	285.4	12.50%	5,886	7,423
2025	0.500%	236.9	285.4	12.50%	5,923	7,423

Source; AEP Resource Planning

Advanced Energy must provide the balance of the 25 percent goal not attained with renewable energy. Energy Efficiency, within the umbrella of Advanced Energy, must produce prescribed annual reductions in energy usage that add to 22.2 percent of retail energy sold. Additionally, peak demand must be reduced 7.75 percent by 2018. There are no annual benchmark Advanced Energy goals, but there are annual Energy Efficiency and Demand Response benchmark goals beginning in 2009. Exhibit 3-2 shows the results of the current plan for AEP-Ohio in meeting the renewable energy goals.

3.3.2 Michigan Clean, Renewable, and Efficient Energy Act

Michigan's "Clean, Renewable, and Efficient Energy Act" (2008 PA 295) requires that ten percent of sales be met from renewable sources by the year 2015. The initial requirement is for 2012 and the percentage ramps up over the next three years as shown in **Exhibit 3-3**. New sources must be within Michigan or in the retail service territory of the provider, outside of Michigan. Credit is given for existing sources, such as I&M's hydroelectric plants. Renewable Energy Credits will have a three-year life in Michigan.

Exhibit 3-3: AEP I&M-Michigan Renewable Plan through 2020

I&M-Michigan Renewable Plan

	Target for New Renewables GWh	Allocated New Renewables per Plan GWh	Carryover RECs Used GWh	Remaining Carryover GWh
2010		70	0	70
2011		137	0	207
2012	71	182	70	319
2013	118	226	119	426
2014	180	226	180	472
2015	364	226	246	452
2016	367	253	344	361
2017	370	253	249	364
2018	373	253	364	253
2019	376	253	253	243
2020	379	253	243	244
2021	382	319	244	186
2022	385	319	186	184
2023	388	319	184	124
2024	391	408	124	208
2025	394	408	208	145
2026	397	453	145	270
2027	400	453	270	204
2028	404	497	204	370
2029	407	497	370	301
2030	411	497	301	464

Source: AEP Resource Planning

3.3.3 Virginia voluntary renewable portfolio standard

Virginia Code section 56-585.2 creates incentives for utilities to meet voluntary renewable energy goals. The basis of the goals is energy sales in 2007 less energy provided by nuclear plants. The goals are 4% of that sales figure in 2010, 7% by 2016, and 12% by 2022. Double credit is given for energy from solar or wind projects. Including the projects in the current plan along with existing run-of-river hydroelectric plants, APCo should have sufficient credits required to meet the voluntary goals for each year of the planning period.

3.4 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. 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 may be 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

3.5 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. Discussed in greater detail in this report's **Technical Addendum,** the AEP System's strategy for complying with Title IV of the Clean Air Act Amendments (CAAA) of 1990, as well as CAIR and CAMR (or its substitute), take into consideration additional power plant emission reduction requirements for SO_2, NO_X and mercury emissions.

Further, on-going debate over CO_2/GHG emissions, particulate matter, 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.

3.5.1 New Source Review (NSR)—Consent Decree

Congress established the NSR permitting program as part of the 1977 Clean Air Act Amendments (CAAA). NSR is a pre-construction permitting program that serves two important purposes:

- First, it ensures that air quality is not significantly degraded from the addition of new and modified factories, industrial boilers and power plants. In areas with unhealthy air, NSR assures that new emissions do not slow progress toward cleaner air. In areas with clean air, especially pristine areas like national parks, NSR assures that new emissions do not significantly impact air quality.
- Second, the NSR program assures the public that any large new or modified industrial source will be as clean as possible and that advances in pollution control occur concurrently with industrial expansion.

The USEPA, certain special interest groups, and a number of states alleged that AEP-East affiliates APCo, CSP, I&M and OPCo modified certain units at coal-fired generating plants in violation of the NSR requirements of the CAAA. The USEPA filed its complaints against our subsidiaries in U.S. District Court for the Southern District of Ohio. The alleged modifications occurred at our generating units over a 20-year period. A bench trial on the liability issues was held during July 2005. In June 2006, the judge stayed the liability decision pending the issuance of a decision by the U.S. Supreme Court in the Duke Energy case.

In December, 2007 AEP entered into a settlement of this litigation. Under the terms of the settlement, AEP will complete its environmental retrofit program on its Eastern units, operate those units under a "hard cap" on both total SO_2 (beginning in 2010) and NO_X (beginning in 2009) emissions and install additional control technologies at certain units. The most significant additional control project will involve installing flue gas desulfurization systems and selective catalytic reduction systems at Rockport Units 1 & 2 by the end of 2017 and 2019, respectively. In addition, certain units have a schedule for retirement, repowering or retrofitting with pollution control equipment. That schedule is consistent with this IRP.

3.6 Planning Constructs

3.6.1 Ancillary Services

In addition to energy products, PJM provides markets for ancillary services that can be sold by AEP-East generating units in support of the generating and transmission system operated by PJM. Such real-time ancillary markets include (1) regulation, (2) synchronized or spinning reserve, and (3) blackstart.

Regulation is a form of load-following that corrects for short-term changes in electricity use that might affect the stability of the power system. Synchronized reserve supplies electricity if the grid has an unexpected need for more power on short notice. Black-start service supplies electricity for system restoration in the unlikely event that the entire grid would lose power. This service is acquired through a bidding process.

Prior to the formation of RTOs, these services were provided in a routine manner by the generating units; there were no markets for them, but the costs were recovered through regulated rates. Potential revenue streams from these services have not been taken directly into account in the IRP in terms of unique resource offerings, but AEP is beginning to account for them in some special applications, such as the evaluation of battery (storage) technology.

3.6.2 Reliability Pricing Model (RPM)

Effective with its 2007/08 delivery year (June 1, 2007 through May 31, 2008), PJM instituted a new capacity-planning regime, called the Reliability Pricing Model (RPM). Its purpose is to develop a long-term price signal for capacity resources as well as load-serving entity (LSE) obligations that is intended to encourage the construction of new generating capacity in the region. The heart of the RPM is a series of capacity auctions, extending out four planning years, into which all generation that will serve load in PJM will be offered. The required reserve margin under RPM is determined by the intersection of the capacity-offer curve with an administratively-determined demand curve. In steady-state mode, the auction will be held 38 months before the beginning of the plan year, with subsequent auctions to trim up the capacity commitments as forecasts change.

FERC has authorized and PJM has provided for an alternative to the capacity auction, called the Fixed Resource Requirement (FRR), which can be appropriate for vertically integrated utilities to use. Under the FRR, the reserve margin is not dependent upon the intersection of the offer curve and the administratively-set demand curve but is built directly upon the fixed PJM Installed Reserve Margin (IRM) requirement, as it was prior to the introduction of RPM. This alternative allows opting entities to meet their requirements with a lower capacity requirement than might have resulted under the auction model with more cost certainty. AEP has elected to "opt-out" of the RPM (auction) and will be utilizing the FRR (self-planning) construct. That opt-out of the PJM capacity auction currently is effective through the 2012/13 delivery year, for which the auction was held in May, 2009. AEP will determine for each subsequent year whether to continue to utilize FRR for an additional year or to opt-in to the RPM auction for a minimum five-year period.

4.0 Current Supply 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
- Changes in capability due to efficiency and/or environmental retrofit projects
- Changes resulting from decisions surrounding unit disposition evaluations
- Regional capacity and transmission constraints/limitations
- Load and (peak) demand (see Section 5.2.)
- Current DR/EE impacts (see Section 5.3.)
- RTO-specific capacity reserve margin 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 AEP Generation Resources

Exhibit 4-1 offers a summary of all supply resources for the AEP-East zone (with detail appearing in ***Appendix A***). The current (June 1, 2009) AEP-East summer supply of 28,209 MW is composed of the following:

Exhibit 4-1: AEP-East Capacity As of June 2009

Coal (incl. OVEC[3])	**22,559 MW**
Nuclear	**2,064 MW**
Hydro (incl. pumped storage)	**675 MW**
Gas/Diesel	**2,873 MW**
Wind (PJM capacity credit)	**39 MW**
Total	**28,209 MW**

Source: AEP Resource Planning

4.2 Capacity Impacts of Generation Efficiency Projects

As detailed in ***Appendix B***, the capability forecast of the existing AEP-East generating fleet reflects several unit up-ratings over the IRP period, largely associated with various turbine efficiency upgrade projects planned by AEP Engineering Services for selected 1,300 and 800 MW-series coal units. Additionally, AEP continues to work towards improving heat rates of its generating fleet. Such improvements, while not increasing capacity, do improve fuel efficiency.

[3] OVEC is the Ohio Valley Electric Cooperative which operates the Clifty Creek and Kyger Creek Plants. AEP is a part owner of OVEC and is entitled to 951 MW of the OVEC capacity.

A change which is not included in *Appendix B* but which is reflected in the 2009 plan is a new strategic project that will increase the generating capability of Cook Units 1 and 2. Implemented in conjunction with a series of necessary plant modifications to improve design and operating margins and to address component aging issues, a net capacity increase of more than 400 MWe from the two units appears technically and economically achievable. Three interrelated issues challenge the continued economic performance of Donald C. Cook Nuclear Plant Units 1 (Cook-1) and 2 (Cook-2):

1. Design and operating margins of some systems, structures, and components (SSCs) are lower than desirable and should be enhanced to support improved operational flexibility and satisfy regulatory expectations.

2. Many SSCs will reach end-of-life prior to expiration of the extended plant license and need to be replaced to maintain margins and allow continued plant operation.

3. The Nuclear Steam Supply Systems (NSSS) for Cook-1 and Cook-2 were designed and built with substantial conservatism to allow uprating, but with the exception of minor Margin Recovery Uprating of about 1.7% performed on each unit, this conservatism remains largely untapped.

Consequently, the Cook Plant does not produce its maximum potential cost-effective electrical output. License changes and modification of selected systems and components could increase the capacity of both units and effectively decrease ongoing plant production costs. However, if not properly implemented, the analyses and modifications needed for uprating could introduce performance or reliability concerns that would negate the value of the capacity increase.

The problem to be addressed by the Extended Power Uprating (EPU) Project is to integrate necessary margin improvement and on-going life cycle management efforts with an uprating for each Cook unit to the maximum safe and reliable reactor thermal power achievable while demonstrating and achieving cost justification of uprating on a life-cycle basis.

A break even analysis performed using the Strategist model shows that the EPU Project is economical even at costs significantly exceeding the current preliminary estimates and as such has been "embedded" in this IRP.

4.3 Capacity Impacts of Environmental Compliance Plan

As also detailed *Appendix B*, the capability forecast of the existing generating fleet reflects several unit de-ratings associated with environmental retrofits (largely scrubbers) over the IRP period. The net impact to existing units as a result of the planned up-ratings and de-ratings is reflected in that Appendix.

4.4 Existing Unit Disposition

As detailed further in the Technical Addendum of this report, another important initial process within this IRP cycle was the establishment of a long-term view of disposition alternatives facing older coal-steam units in the east region. The Existing Unit Disposition identified 13 sets of aging AEP generating assets consisting of a total of 25 units and 4,820 MW.

- Big Sandy Unit 1 (260 MW, summer rating) KPCo
- Conesville Unit 3 (165 MW) CSP
- Clinch River Units 1-3 (690 MW) APCo

- Glen Lyn Unit 5 (90 MW) APCo
- Glen Lyn Unit 6 (235 MW) APCo
- Kammer Units 1-3 (600 MW) OPCo
- Kanawha River Units 1 & 2 (400 MW) APCo
- Muskingum River Units 1 & 3 (395 MW) OPCo
- Muskingum River Units 2 & 4 (395 MW) OPCo
- Picway Unit 5 (90 MW) CSP
- Sporn Units 1-4 (580 MW) APCo (Units 1 & 3), OPCo (Units 2 & 4)
- Sporn Unit 5 (440 MW) OPCo
- Tanners Creek Units 1-3 (480 MW) I&M

Among this group of units are several that were impacted by the Consent Decree from the settled New Source Review litigation. These units, and the dates by which, according to the agreement, they must be retired, repowered, or retrofitted (R/R/R) with FGD and SCR systems, are:

- ✓ Conesville Unit 3, by **December 31, 2012**
- ✓ Muskingum River Units 1-4, by **December 31, 2015**
- ✓ Sporn Unit 5, by **December 31, 2013**
- ✓ A total of 600 MW from Sporn 1-4, Clinch River 1-3, Tanners Creek 1-3, or Kammer 1-3, by **December 31, 2018**.

A financial analysis, performed by AEP-Generation Business Services, focused on gross margin exposure to various market commodity variables: market energy price and projected SO_2, NO_X and CO_2 post 2015 allowance prices. The allowance prices were of particular importance given that most of the units' high, uncontrolled emission rates were anticipated to hinder future dispatchability, given exposure to assumed emission costs. In addition, the introduction of CO_2 pricing would impact unit dispatch cost, beginning as early as 2015.

Additional analyses were also performed using the *Strategist* model. The model was used to determine the relative impact on overall System (AEP-East) Cumulative Present Worth (CPW) for each unit/unit-set if it were assumed retired in an early or a late year. In general, the early year was 2014 and the late year 2025, but this was modified for units subject to the NSR settlement. Other factors such as unit age, size, design, heat rate, and economics tied to possible environmental retrofit options, have made these eastern coal units potentially vulnerable in the future from a fixed and variable cost-of-service basis.

In order to develop a comprehensive assessment of potential unit disposition recommendations, a team encompassing multiple functional disciplines (engineering, operations, fuels, environmental, and commercial operations) also sought to confirm or challenge the preliminary economic findings by examining additional factors relevant to the units' unique physical characteristics. A decision matrix was employed to assist in that assessment. Relative scores were constructed for each unit under the established criteria. Such scores were based on the analysis and professional judgment surrounding each unit's known (or anticipated) infrastructure liabilities, operational flexibility capabilities in PJM, as well as work force and socioeconomic impacts.

4.4.1 Findings and Recommendations—AEP-East Units

The Unit Disposition Working Group findings are summarized here and in **Exhibit 4-2**. Given the size (nearly 5,000 MW) of the group of AEP-East units potentially exposed to future emission expenses for NO_X and SO_2, possible new mercury rulemaking and certain GHG legislation, it is practical to begin a stepped approach to their disposition–avoiding the need to build and finance multiple replacement facilities simultaneously.

- ✓ Recognize that the retirement date represents the year that the unit is projected to no longer provide firm ***capacity*** value in PJM, however it still may provide ***energy*** value and therefore operate well beyond the planned capacity retirement date.
- ✓ The first three retirement "tranches" include only those R/R/R units designated in the NSR Consent Decree.
- ✓ Tranche 1 includes only Sporn 5, 440 MW, retiring in **2010** (R/R/R date 2013). Tranche 2 units, totaling 560 MW and having a potential retirement date of **2012** include Conesville 3, 165 MW (R/R/R date 2012) and Muskingum River 2 & 4, 395 MW (R/R/R date 2015), and Tranche 3 includes Muskingum River 1 & 3, 395 MW (R/R/R date 2015), with a potential retirement date of **2014**.
- ✓ Tranches 4, 5 and 6 retire 415 MW (2015), 600 MW (2017) and 580 MW (2018) respectively.
- ✓ Tranche 7 units total 480 MW and are slated for potential retirement in **2019**. Similar to the previous groups, these units become increasingly uneconomical with tighter SO_2 and NO_X limits, and the impact of (assumed) increasing CO_2 emission costs.

Outside of the current 10-year IRP cycle window (not shown on Exhibit 4-2):

- ✓ Tranche 8 units total 1,350 MW and are identified for potential retirement in **2021 and beyond**.
- ✓ Finally, while not part of the unit disposition analysis, for long range planning purposes it is assumed that I&M's 500 MW Tanners Creek Unit 4, which is not anticipated to be retrofitted with environmental controls, will retire when it reaches 60 years of service life, in 2025.

In general, the Unit Disposition Working Group recommended that, despite its current findings and recommendations, all of the units identified must continue to be evaluated and scrutinized on a cyclic basis, particularly those early-to-mid next decade (Tranches 4, 5 and 6 units), recognizing:

1) opportunities that may arise in the (PJM) marketplace including improved recognition/monetization of ancillary value contribution,
2) a shift in the units' relative physical condition, and
3) any opportunities, from an environmental compliance perspective, to mitigate emission exposures through affordable and/or emerging compliance technologies.

Exhibit 4-2: AEP East Unit Disposition/Retirement Profile

NSR Mandated R/R/R Units

2010 (Tranche 1)			2012 (Tranche 2)			2014 (Tranche 3)		
	MW Summer	MW Winter		MW Summer	MW Winter		MW Summer	MW Winter
Sporn 5	**440**	450	Conesville 3	**165**	165	MR1&3	**395**	420
			MR2&4	**395**	420			
TOTAL	**440**	450	TOTAL	**560**	585	TOTAL	**395**	420
% of Total	***9%***			***12%***			***8%***	

2015 (Tranche 4)			2017 (Tranche 5)			2018 (Tranche 6)			2019 (Tranche 7)		
	MW Summer	MW Winter		MW Summer	MW Winter		MW Summer	MW Winter		MW Summer	MW Winter
Picway 5	**90**	100	Kammer 1-3	**600**	630	Sporn 1-4	**580**	600	Tanners 1-3	**480**	495
Glen Lyn 6	**235**	240									
Glen Lyn 5	**90**	95									
TOTAL	**415**	435	TOTAL	**600**	630	TOTAL	**580**	600	TOTAL	**480**	495
	9%			***12%***			***12%***			***10%***	

	MW Summer	MW Winter
Capacity Retired Through 2019	***3,470***	*3,615*
Subcritical Capacity Retired Post 2019	***1,350***	*1,365*
Total Capacity to Be Retired (Through 2024)	***4,820***	*4,980*

Source: AEP Resource Planning

4.4.2 Implications of Retirements on Black-Start Plan

The retirement of Conesville Unit 3, and in time other units such as the smaller Muskingum River units, will have implications for the System's plans for black-start capability and Automatic Load Rejection, which are needed to restore the system following a transmission system collapse. In addition, PJM rules have implications on timing, announcement, etc. of the retirements.

Upon the retirement of Conesville units 1 and 2, Unit 3 was designated and accepted by PJM as a black-start unit. In the case of a system collapse, this unit could be started from the small diesel units at the station, and in turn could be used to start the larger units, all without assistance from other stations. It is expected that upon retirement of Unit 3, PJM will require this black-start capability to be replaced.

4.4.2.1 Applicable PJM Rules

Black-start resources maintain a rolling two-year commitment to PJM. The PJM tariff therefore requires up to two years' advance notice of retirement.

If PJM and the Transmission Owner determine there is a need to replace the deactivating black start resource, PJM will seek replacement of the retiring resource as follows:

1) PJM will post on-line a notification about the need for a new black start resource along with the location and capability requirements.
2) This posting opens a market window which will last 90 calendar days.

3) PJM will review each pending Generation Interconnection request, each new interconnection request in the market window, and each proposal from a black start unit to evaluate whether any project could meet the black start replacement criteria.
4) The Transmission Owner will have the option of negotiating a cost-based, bilateral contract in accordance with the existing process outlined in Schedule 6A of the OATT. The Transmission Owner may provide an alternative as one of the bids that will be evaluated by PJM pending FERC approval.
5) If PJM and the Transmission Owner determine more than one of the proposed projects meets the replacement criteria, the most cost-effective source will be chosen.
6) If no projects are received during the 90-day market window, PJM and the Transmission Owner will revisit the definition of the location and capability requirements, to allow more resources to become viable, even if sub-optimal.

After PJM and the Transmission Owner identify the most cost-effective replacement resource, PJM and the TO will coordinate with the Generation Owner for the GO's acceptance under the PJM tariff as a black start unit.

The black start resource will be compensated for provision of black start service in accordance with the existing process in the PJM tariff.

4.4.2.2 AEP's Required Actions and Options

The AEP Commercial Operations and Generation groups are studying this issue and will make a recommendation later this year. If AEP intends to retire Conesville 3 in 2012, PJM should be notified in 2010.

It does not appear that there are any viable replacement units for the black-start service in the vicinity of Conesville. The Dresden plant will not be suitable because of the large size and high minimum load of its combustion turbines, which, according to the manufacturer, have never been used in such service.

In any event, AEP and its customers will pay for the black-start service, either by providing the service or by purchasing it.

Options:

1) Provide replacement black-start capability, consisting of diesel or combustion turbine unit(s) at Conesville or potentially elsewhere such as Dresden when Conesville 3 is retired in 2012.
2) Allow PJM to issue an RFP for replacement black-start capability. Issues with this option are:
    a. the black-start would not be under AEP control,
    b. AEP would be a price-taker for this service.

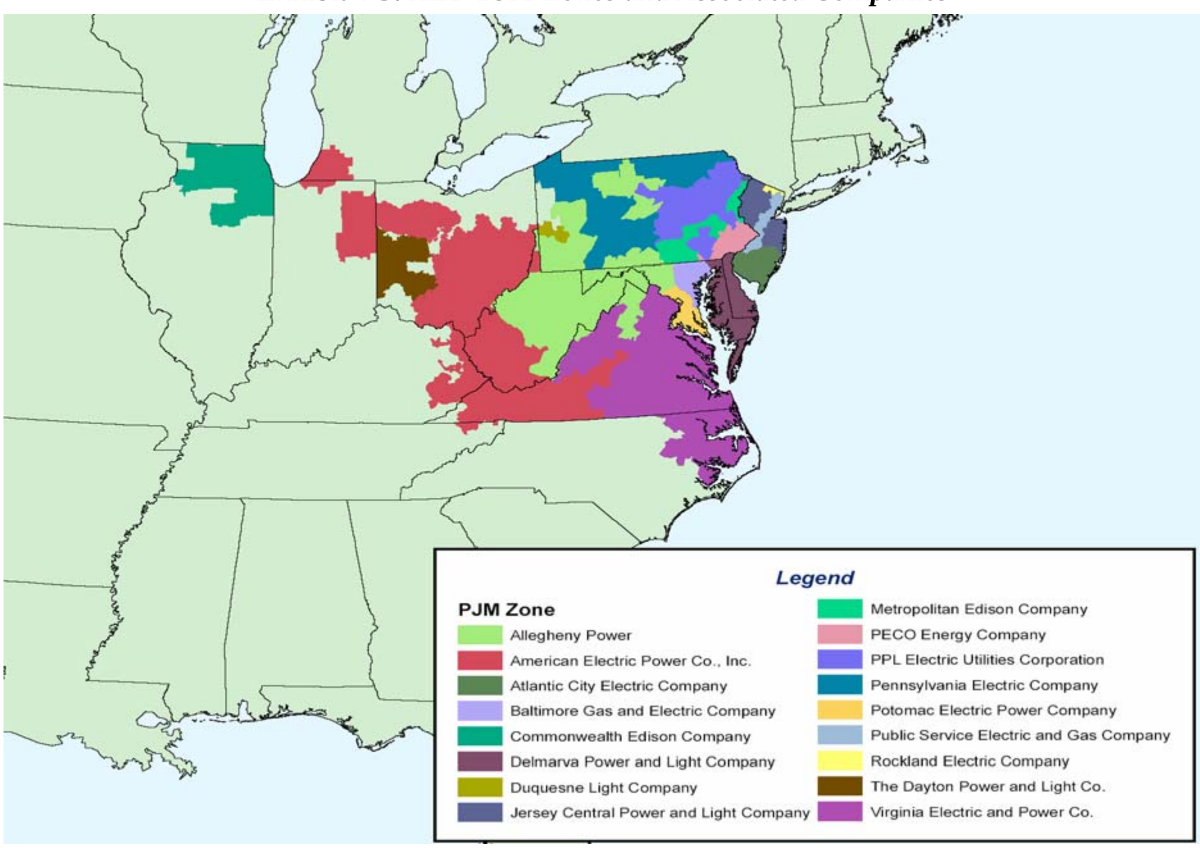
4.5 AEP Eastern Transmission Overview

4.5.1 Transmission System Overview

The eastern Transmission System (eastern zone) consists of the transmission facilities of the seven eastern AEP operating companies. This portion of the Transmission System is composed of approximately 15,000 miles of circuitry operating at or above 100 kV. The eastern zone includes over 2,100 miles of 765 kV overlaying 3,800 miles of 345 kV and over 8,800 miles of 138 kV circuitry. This expansive system allows AEP to economically and reliably deliver electric power to approximately 24,200 MW of customer demand connected to the eastern Transmission System that takes transmission service under the PJM open access transmission tariff.

The eastern Transmission System is the most integrated transmission system in the Eastern Interconnection and is directly connected to 19 neighboring transmission systems at 144 interconnection points, of which 118 are at or above 100 kV. These interconnections provide an electric pathway to facilitate access to off-system resources and serve as a delivery mechanism to adjacent companies. The entire eastern Transmission System is located within the Reliability*First* (RFC) Regional Entity. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization, and now participates in the PJM markets (see **Exhibit 4-3**).

Exhibit 4-3: AEP-PJM Zones and Associated Companies



Source: www.pjm.com

4.5.2 Current System Issues

As a result of the eastern Transmission System's geographical location and expanse - as represented in Exhibit 4-3 - as well as its numerous interconnections, the eastern Transmission System can be influenced by both internal and external factors. Facility outages, load changes, or generation redispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the eastern Transmission System is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern Transmission System conforms to the NERC Reliability Standards and the applicable RFC standards and performance criteria.

AEP's eastern Transmission System assets are aging and some station equipment is obsolete. Therefore, in order to maintain acceptable levels of reliability, significant investments will have to be made over the next ten years to proactively replace the most critical aging and obsolete equipment and transmission lines.

4.5.3 PJM RTO Recent Bulk Transmission Improvements

Despite the robust nature of the eastern Transmission System, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant transmission enhancement to the eastern AEP Transmission System over the last few years was completed in 2006. This was the construction of a 90-mile 765 kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia. In addition, EHV/138 kV transformer capacity has been increased at various stations across the eastern Transmission System.

4.5.4 Impacts of Generation Changes:

Over the years, AEP, and now PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the eastern Transmission System. Currently, there is more than 28,000 MW of AEP-East generation and approximately 6,000 MW of additional merchant generation connected to the eastern Transmission System. AEP, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers for approximately 500 MW of additional generation to be connected to the eastern Transmission System over the next several years. There are also significant amounts of merchant generation under study for potential interconnection.

The integration of the merchant generation now connected to the eastern Transmission System required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. None of these merchant facilities required major transmission upgrades that significantly increased the capacity of the transmission network. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and MISO markets.

The retirement of Conesville units 1 and 2 in 2006 and the potential retirement of Conesville Unit 3 in 2012 will result in the need for power to be transmitted over a longer distance into the Columbus, Ohio metro area. In addition, these retirements will result in the loss of dynamic voltage regulation. Since there is very little baseload generation in central Ohio, these retirements could be significant. The retirement of these units could require the addition of dynamic reactive compensation such as a Static VAR Compensator (SVC) device within the Columbus metro area.

Within the eastern Transmission System, there are two areas in particular that could require significant transmission enhancements to allow the reliable integration of large generation facilities:

- **Southern Indiana**—there are limited transmission facilities in southern Indiana relative to the AEP generation resources, and generation resources of others in the area. Significant generation additions to AEP's transmission facilities (or connection to neighbor's facilities) will likely require significant transmission enhancements, including Extra-High Voltage (EHV) line construction, to address thermal and stability constraints. The Joint Venture Pioneer Project would address many of these concerns.
- **Megawatt Valley**—the Gavin/Amos/Mountaineer/Flatlick area currently has stability limitations during multiple transmission outages. Multiple overlapping transmission outages will require the reduction of generation levels in this area to ensure continued reliable transmission operation, although such conditions are expected to occur infrequently. Significant generation resource additions in the Gavin/Amos/Mountaineer/Flatlick area will also influence these stability constraints, requiring transmission enhancements–possibly including the construction of EHV lines and/or the addition of multiple large transformers–to more fully integrate the transmission facilities in this generation-rich area. Thermal constraints will also need to be addressed. The PATH Transmission Project will partially mitigate these constraints.

Furthermore, even in areas where the transmission system is robust, care must be taken in siting large new generating plants in order to avoid local transmission loading problems and excessive fault duty levels.

5.0 Demand Projections

5.1 Load and Demand Forecast—A 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-East internal long-term load and peak demand forecasts were based on the AEP Economic Forecasting group's load forecast performed in May 2009. The forecast incorporates the effects of energy policy such as the Energy Independence and Security Act of 2007 (EISA) as well as load/price elasticity associated with policy impacts on price.

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 a

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.

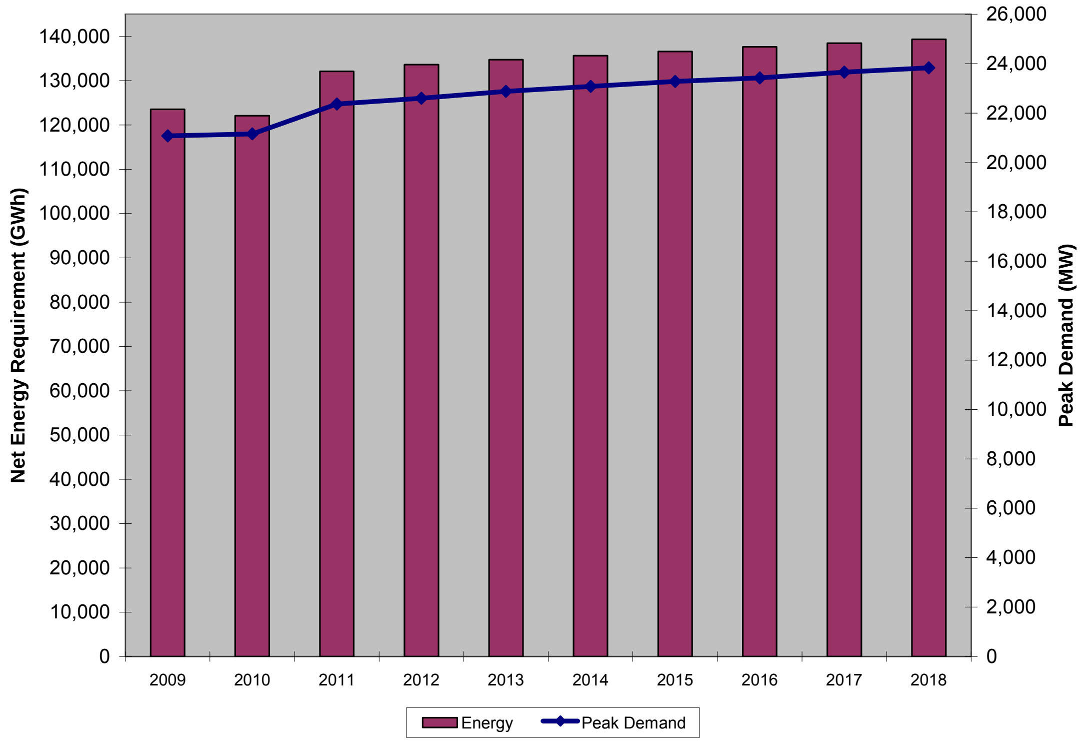
AEP uses processes that take advantage of the relative strengths of each method. The regression models typically used in the shorter-term modeling employ the latest available sales and weather information to represent the variation in sales on a monthly basis for short-term applications. While these 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 method outputs, AEP Economic Forecasting effectively apply the strengths of both load-modeling approaches.

5.2 Peak Demand Forecasts

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

Specifically, **Exhibit 5-2** identifies the AEP-East region's internal demand profile as having 0.88% Compound Annual Growth Rate (CAGR). This equates to roughly a **200 MW per year increase** over the 10-year IRP period through 2019 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 0.58% 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.

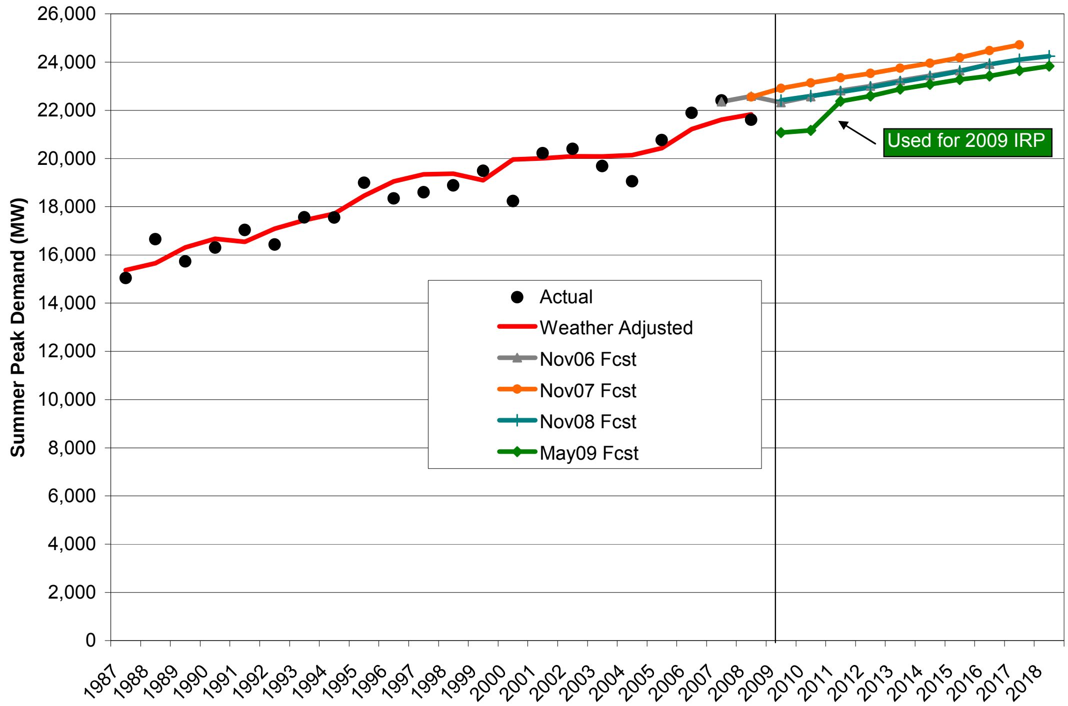
Exhibit 5-2: AEP-East Peak Demand and Energy Projection



Source: AEP Economic Forecasting

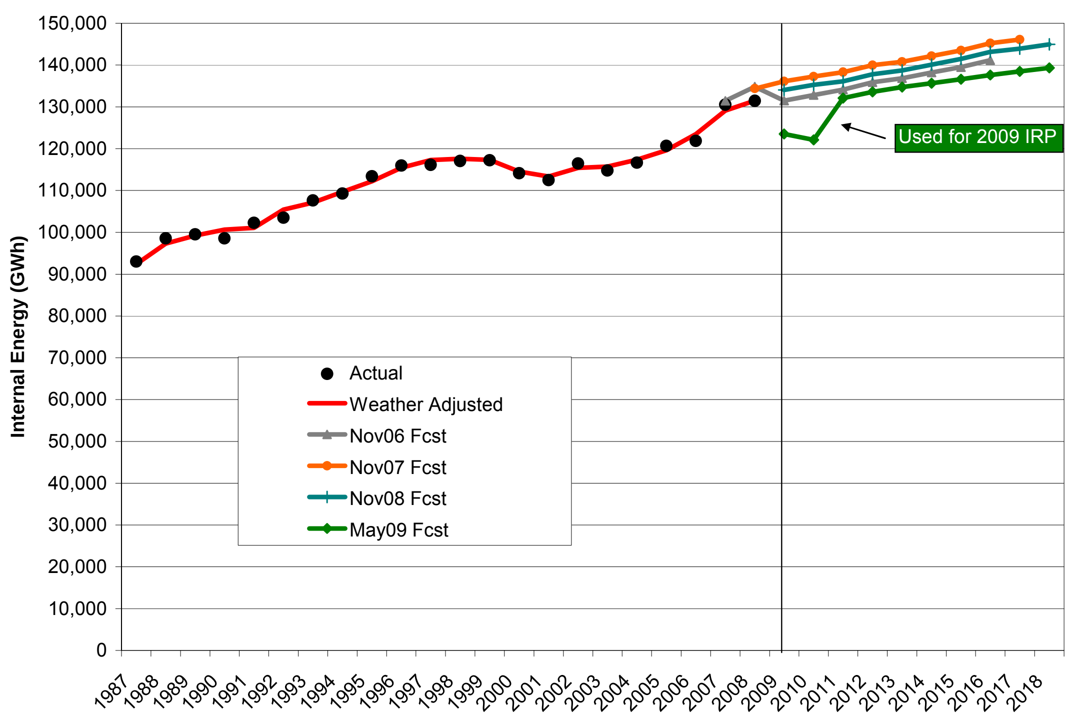
Exhibits 5-3 and 5-4 show the current demand and energy forecasts, respectively, compared to historical actual data and recent forecasts. Note that for both demand and energy, the current forecast is only slightly lower in outer years while significantly lower in 2009 and 2010 as the near term recessionary impacts on demand are being reflected.

Exhibit 5-3: AEP-East Peak Actual and Forecast Trendline



Source: AEP Economic Forecasting

Exhibit 5-4: AEP-East Internal Energy Actual and Forecast Trendline



Source: AEP Economic Forecasting

5.2.1 Load Forecast Drivers

It is critical to note some of the major assumptions driving these demand profiles for the eastern (AEP-PJM) zone:

1) As set forth earlier in this report, it has been assumed for purposes of this IRP cycle that AEP's Ohio operating company legal entities, OPCo and CSP, *will continue to serve those retail loads* for which they have had an historical obligation to serve, beyond the current end of the period set forth under the approved AEP-Ohio Electric Security Plan (ESP) that expires at the end of 2011.
2) The assumption that the load to serve Ormet–a 510 MW industrial load operating six aluminum potlines at its facilities in Hannibal, Ohio– would *continue after the recessionary period.*

On July 28, 2009 AEP was informed that Ormet will shut down its Hannibal, Ohio operations indefinitely. Future AEP-East planning will reflect this change.

3) 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 5-4 is that such firm or "committed" wholesale demand projections are relatively constant over the LT forecast period and, in total, represent a small percentage (< 10%) of the east region's overall load obligation.
4) 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.

The impacts from energy policy such as EISA are expected to be felt on the demand side. These will predominately 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 through 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). These impacts of these acts were being determined at the time of this forecast. The acts do not impact load to the same extent as the 2005 and 2007 acts do.

The economic impacts of a 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

Imbedded in the load forecast are the effects of current programs, including those that have been filed with state commissions in Indiana, Kentucky, Michigan, and Ohio. In Ohio, where mandated benchmarks continue for many years, the Load Forecast reflects only the impacts of the programs filed within the ESP (three years). In Michigan, the forecast assumes compliance with the mandates for the first three years. Subsequent energy and demand reductions are embodied in the general level of DR/EE that is established in Chapter 9 of this IRP. The embedded impacts of current DR/EE programs are shown in **Exhibit 5-5**:

Exhibit 5-5: AEP-East Embedded DR/EE Programs

Load Forecast - Embedded DR/EE Demand Impacts (MW) - Summer							
Operating Company	2009	2010	2011	2012	2013	2014	2015
CSP	25	63	120	120	120	120	120
I&M - Indiana	3	6	9	11	13	14	15
I&M - Michigan	2	5	9	9	9	9	9
KPCo	0.1	0.1	0.2	0.2	0.2	0.1	0.1
OPCo	28	71	129	129	129	129	129
AEP-East (MW)	58	145	267	269	271	272	273

Load Forecast - Embedded DR/EE Energy Impacts (GWh)							
Operating Company	2009	2010	2011	2012	2013	2014	2015
CSP	68	187	356	356	356	356	356
I&M - Indiana	15	29	42	52	60	67	72
I&M - Michigan	10	27	53	53	53	53	53
KPCo	1	3	4	4	4	4	3
OPCo	88	240	453	453	453	453	453
AEP-East (GWh)	183	486	907	917	925	932	937

Source: AEP Resource Planning

6.0 Capacity Needs Assessment

Based on the assessment of AEP-East's current resources as described in Section 4, and its energy and peak demand projections as discussed in Section 5, a capacity needs assessment can be established that will determine the amount, timing and type of resources required for this 2009 IRP Cycle.

- ❖ The 2009 AEP-East load forecast as updated in May, 2009, accounts for:
  1) peak Demand growth of 1.8% annually through 2014, as the region rebounds from the current recession;
  2) peak demand growth of 0.64% thereafter, the reduction representing the end of the economic rebound combined with the impact of CO_2 legislation on the price of electricity;
  3) Ormet demand returns to full capacity (515 MW) by 2011;
  4) 615 MW of demand reduction due to interruptible loads and Advanced Time of Day pricing.
- ❖ The forecast of AEP-East capability additions/deletions reflects through the ten years 2010 through 2019:
  1) the potential retirement of 440 MW in 2010, 560 MW in 2012, 495 MW in 2014, 325 MW in 2015, 600 MW in 2017, 580 MW in 2018, and 485 MW in 2019;
  2) 199 MW of plant derates associated with environmental and biomass retrofits partially offset by plant efficiency and other improvements of 73 MW.

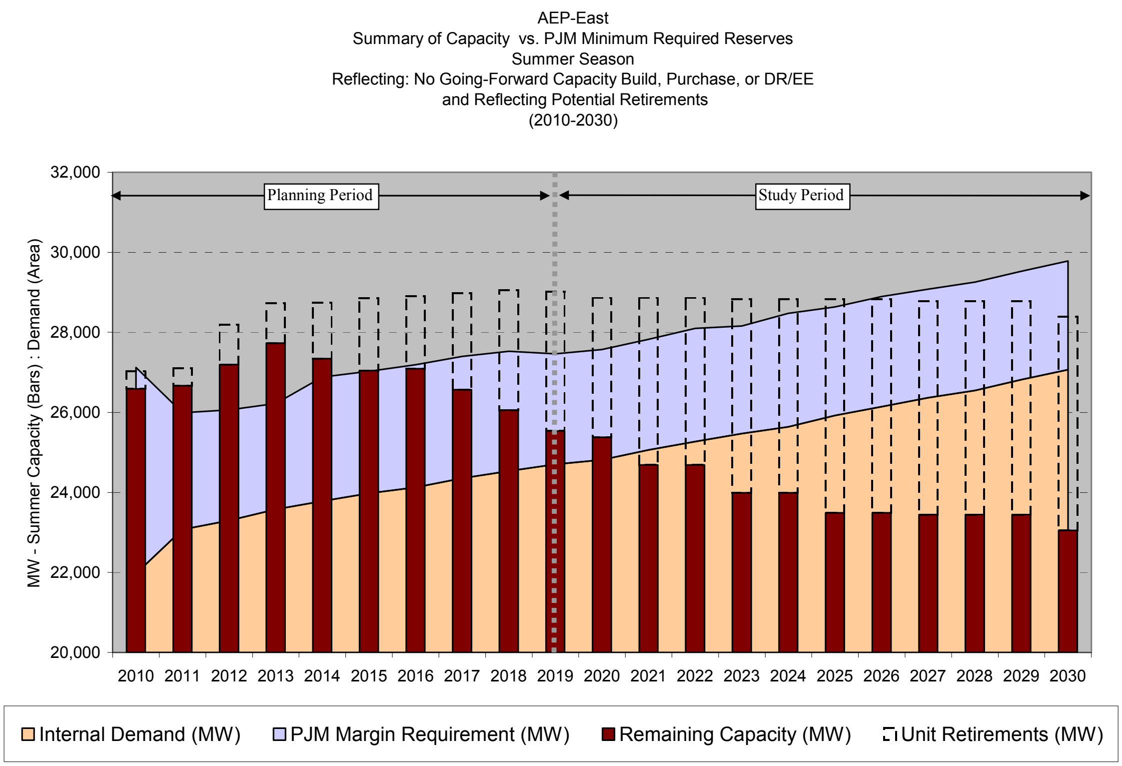
The forecast also considers PJM minimum reserve requirements under PJM's self-planning Fixed Resource Requirements (FRR) capacity alternative and estimated Equivalent Demand Forced Outage Rates (EFORd) of AEP generators.

These demand and resource figures include impacts of existing and approved state/jurisdictional DR/EE programs and existing PPAs for renewable resources. They also include the addition of the 540 MW Dresden combined cycle facility currently under construction. They do not consider new DR/EE programs that were evaluated as part of this year's IRP process or additional renewable resources needed to meet the System's stated goal of 2,000 MW of wind projects by the end of 2011. Also not included in the capacity are any uprates to the D. C. Cook nuclear plant beyond 14 MW scheduled for 2011.

The resultant capacity gap arises in the 2015-2018 timeframe and grows in future years, primarily with projected unit retirements.

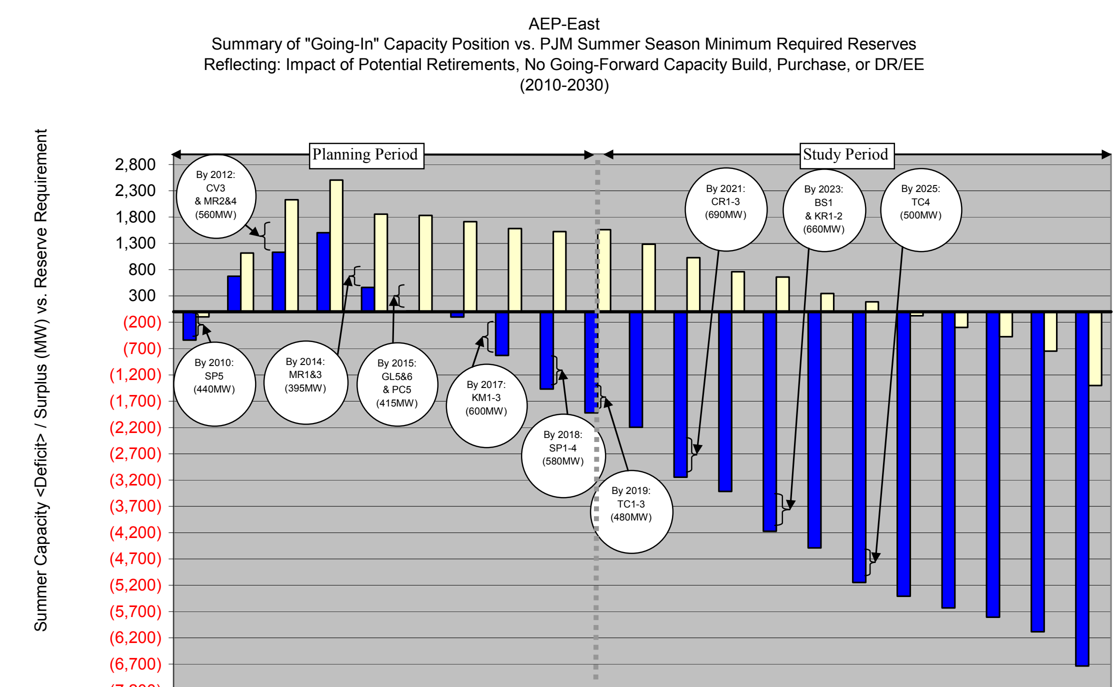
Exhibits 6-1 and 6-2 are companion charts which summarize the need to add about 1,500 MW of installed capacity (ICAP) through the 10-year IRP window, given the current assumptions. Exhibit 6-1 compares the demand (area) and capacity (bar) trends over the period. Exhibit 6-2 then reflects the culmination of these separate impacts, coupled also with the PJM minimum Installed Reserve Margin (IRM) requirement of 15.5% starting in 2010 and 16.2% starting in 2012. Based on the assumptions discussed, the capacity of the AEP-East zone moves to a deficit position beginning in 2016.

Exhibit 6-1: Summary of Capacity vs. PJM Minimum Required Reserves



Source: AEP Resource Planning

Exhibit 6-2: Summary of Capacity Deficiency vs. PJM Minimum Required Reserves



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Position W/ Ret's (MW)	(535)	678	1,132	1,505	463	16	(99)	(831)	(1,468)	(1,924)	(2,197)	(3,143)	(3,415)	(4,174)	(4,489)	(5,147)	(5,410)	(5,632)	(5,809)	(6,082)	(6,737)
Position W/O Ret's (MW)	(95)	1,118	2,132	2,505	1,858	1,831	1,716	1,584	1,527	1,561	1,288	1,032	760	661	346	188	(75)	(297)	(474)	(747)	(1,402)

Source: AEP Resource Planning

6.1 RTO Requirements

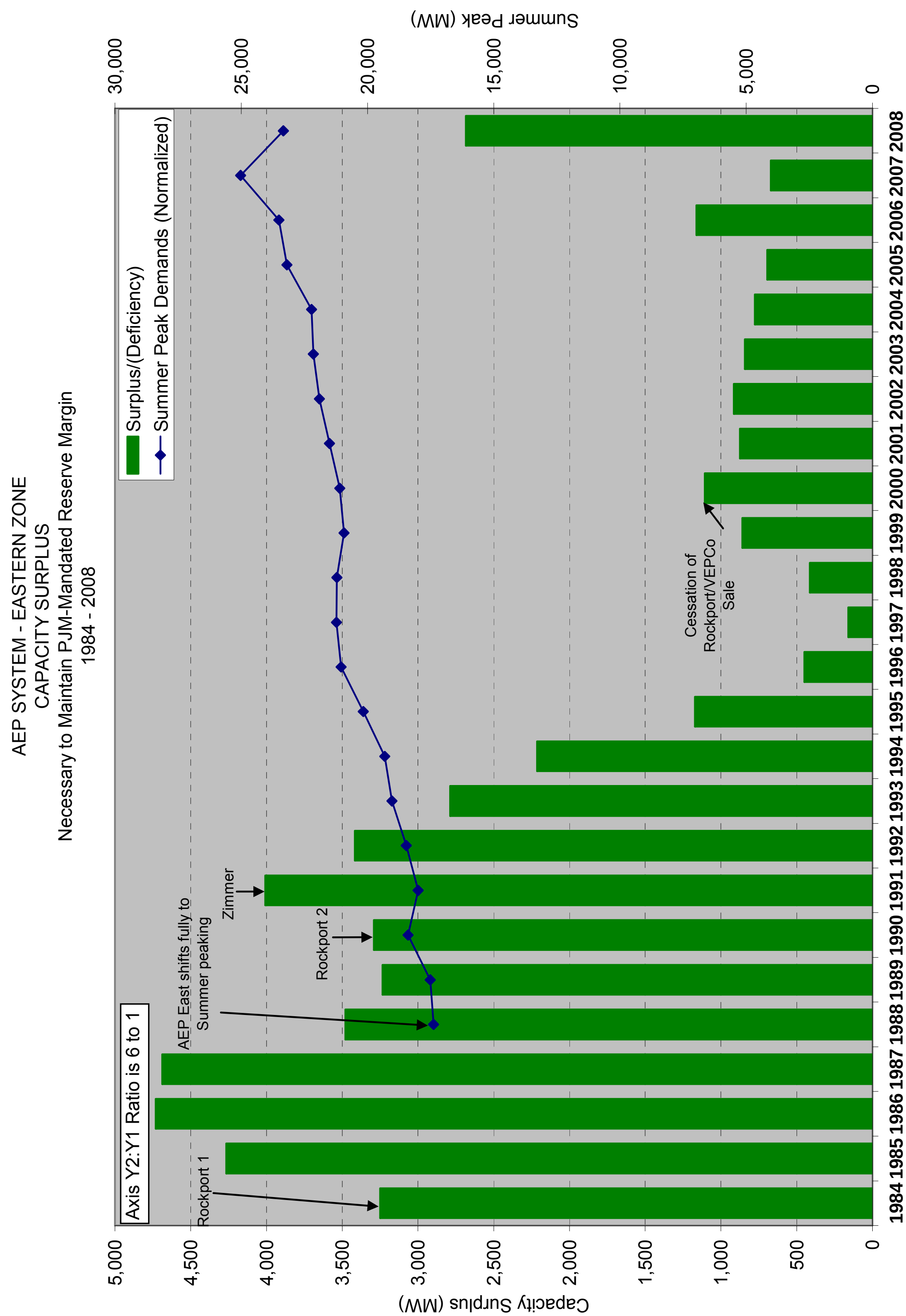
In developing the plans for the AEP-East zone, it was assumed that several factors would remain constant. As indicated, AEP is committed to the FRR alternative to the RPM of PJM through the 2012/2013 delivery year, and *it was assumed that this commitment would continue indefinitely*. Although PJM could contemplate further changes in the IRM, it was also assumed that the PJM IRM would remain constant at 16.2%, as currently set for the 2012/13 delivery year. Finally, it was assumed that both the underlying PJM EFORd for 2012/13 (6.44%) would remain constant into the following years.

On the other hand, it was assumed that the AEP unit EFORd would change through time. Existing unit EFORds were projected to change as unit improvements are made or as units near retirement. Also, the addition of new units and removal of old units from the system changes the weighted average EFORd. With the exception delivery year 2010/11, which is heavily impacted by the current Cook outage, AEP's EFORd is projected to improve from 8.41% in 2009/10 to 6.56% in 2018/19. This assumption tends to reduce the amount of new installed capacity needed to meet PJM requirements.

6.2 Capacity Positions—Historical Perspective

To provide a perspective, an historical relative capacity position for the AEP-PJM zone is presented in **Exhibit 6-3**. AEP's East zone (as part of ECAR) experienced ample capacity reserves throughout the decade of the 1980s and most of the 1990s. The trending, however, clearly suggests that anticipated load growth as previously reflected for the AEP-East zone (**Exhibit 6-1**) will soon result in zonal capacity deficiencies, on a planning basis.

Exhibit 6-3: AEP Eastern 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 a resource planning effort is 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 unique impact on generation of environmental compliance, the planning effort must ultimately be in concert with anticipated long-term 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 the AEP East Zone is faced with a potential capacity deficiency as early as 2016 depending upon the level and extent of DR/EE-inspired demand reduction and the extent and timing of D. C. Cook uprates.

Recognizing that market opportunities–both in the form of 1) limited-term bilateral capacity purchases from nonaffiliated sources, or 2) acquisition of available "distressed generation" assets at a significant discount–will continue to be pursued, it also recognized that such market alternatives will likely be opportunistic in nature. Therefore, the resource modeling and the recommended regional long-term resource plans must maintain sufficient implementation flexibility so as to consider such market/"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 five years, resulting in an overall 2009-2035 period.

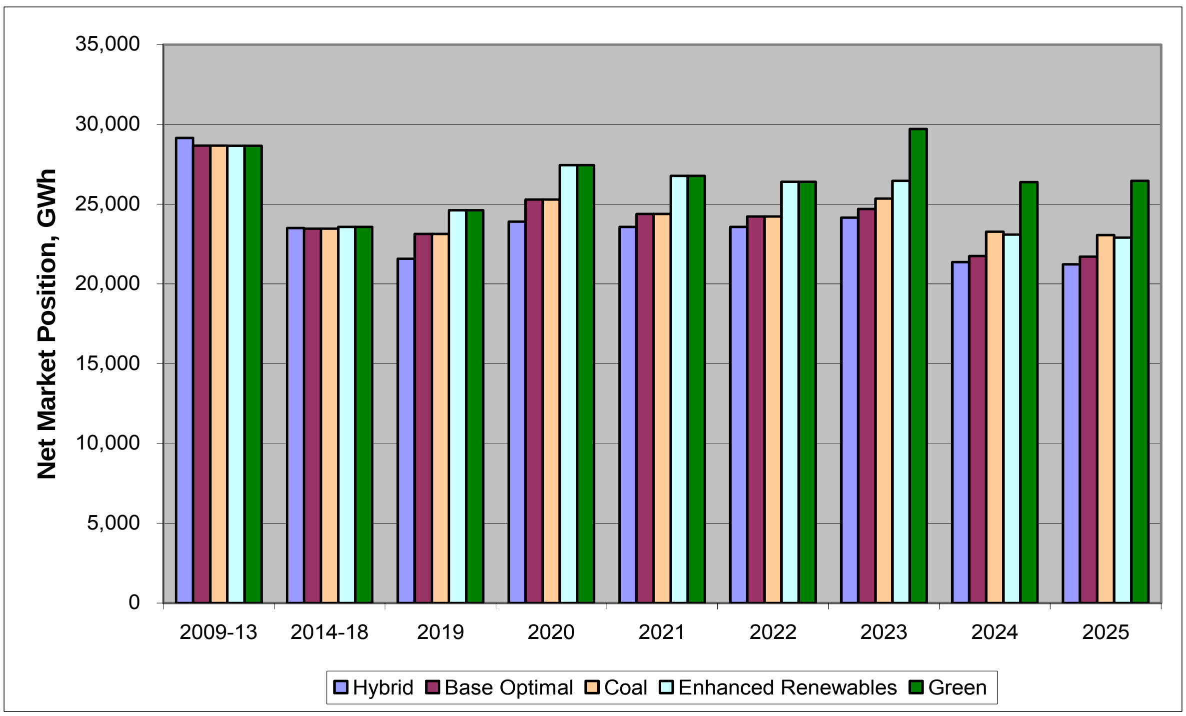
7.3 Establishing the Optimal Asset Mix

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

7.3.1 Market Energy Position of the AEP East Zone

The AEP-East fleet is projected to undergo a change in its operational mix particularly beginning in the year 2015, with the onset of increased environmental-related unit dispatch costs tied to potential new CO_2 legislation. It is anticipated that more output will be coming from units that are then being operated as "quasi-peaking" and intermediate duty cycle units versus units that today perform a traditional baseload function. This is due to the relative increase in production costs, including the costs of emissions, primarily from the subcritical/non-controlled fleet. As these units become relatively more costly they are anticipated to be dispatched less, especially during off peak periods, and will be used more often to load-follow during peak periods. This leaves a smaller number of units available to serve a baseload function. With less baseload capacity, AEP will have more higher priced energy from intermediate and peaking gas fired units accepted into the PJM market. Under some price scenarios this could expose the AEP LSEs to market prices and would cause them to become, in effect, "price takers" from the market. The probability of this occurring in a potential portfolio (see Section 11.4.4) is reduced when AEP maintains a minimum net market (energy) position of approximately 10% of its annual energy requirements, or 12,000 GWH. **Exhibit 7-1** shows that each of the portfolios evaluated meet this criteria.

Exhibit 7-1: Annual Energy Position of Evaluated Portfolios

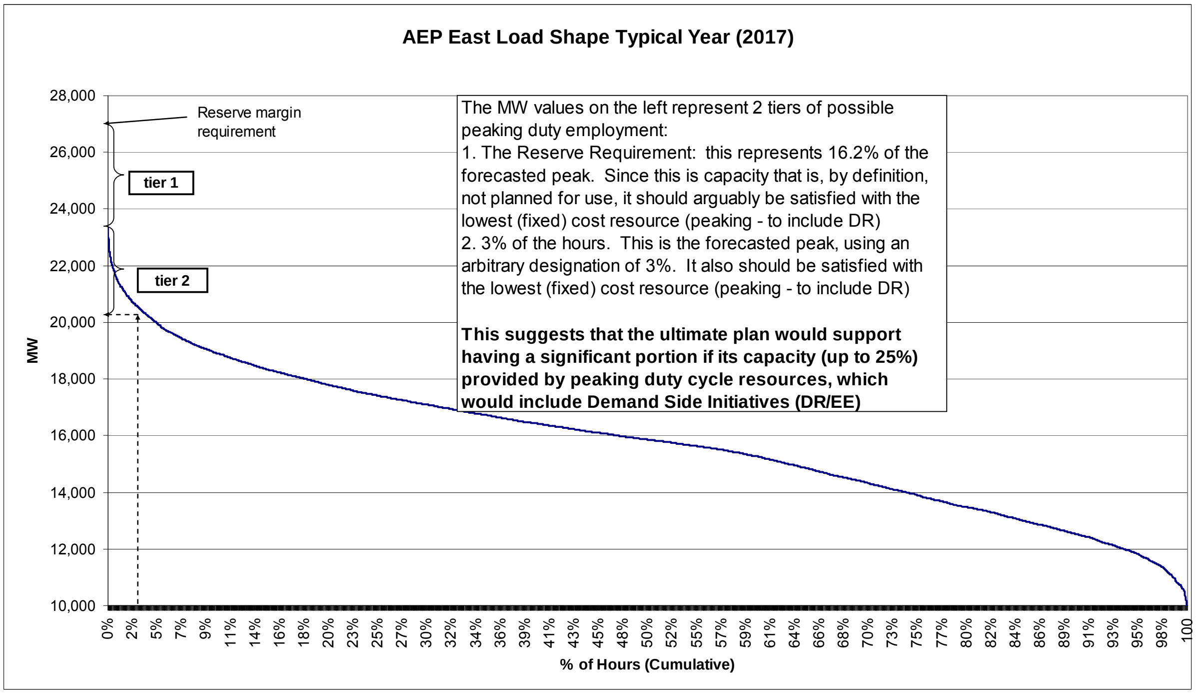


Source: AEP Resource Planning

7.3.1.1 AEP-East Fleet Duty Cycle

In addition to meeting the system energy requirements, the generation fleet must meet the minimum PJM reserve requirements. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide very little energy over an annual load cycle. This capacity should be obtained at the lowest practical cost, despite the fact that such capacity often has very high energy costs. For this reason, acquisition of existing gas assets at below market prices is the preferred choice for meeting peaking requirements. This peaking requirement is manifested in the system load duration curve, an example of which is shown in **Exhibit 7-2**. This curve shows the hourly demand for each hour in a typical year. Note that there is a notable drop off in demand after the highest 3% of the hourly loads. This drop off supports the position that the lowest installed cost investment, or lowest life cycle cost investment when considering the minimal capacity factors these peaking facilities will experience, are selected by optimization modeling.

Exhibit 7-2: AEP East 2017 Load Duration Curve



Source: AEP Resource Planning

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 the on-going operational needs of the system. Given that, the *Strategist* modeling (to be discussed) currently considers traditional commodities including energy, fuels, environmental (allowance) values, and the energy market. Factors often thought of as "ancillary" services/values are not currently considered.

As discussed in this section, in the current PJM RTO pricing structure, such ancillary values could be considerable. In PJM, AEP and the other member companies currently pay for service including, among other things, regulation/load-following, balancing, synchronous/spinning reserves, and black-start capability. In particular, regulation is becoming a more critical component of such RTO services. Under PJM's cost-sharing mechanism, while AEP may capture some of this ancillary market, its Load Serving Entities (LSE) are obligated to pay for a portion of those costs. Therefore, the planning process should also objectively consider these factors when setting forth an ultimate capacity resource plan.

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 through the mechanism of "Allowance for Funds Used During Construction" (AFUDC) (which allows utilities to defer to the balance sheet 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, the AEP Corporate Planning and Budgeting and Corporate Finance departments, among others, will continually assess and iterate planning profiles generated through the IRP cycle process, making recommendations to alter the timing and amount of resource additions specified in the Plan, as warranted.

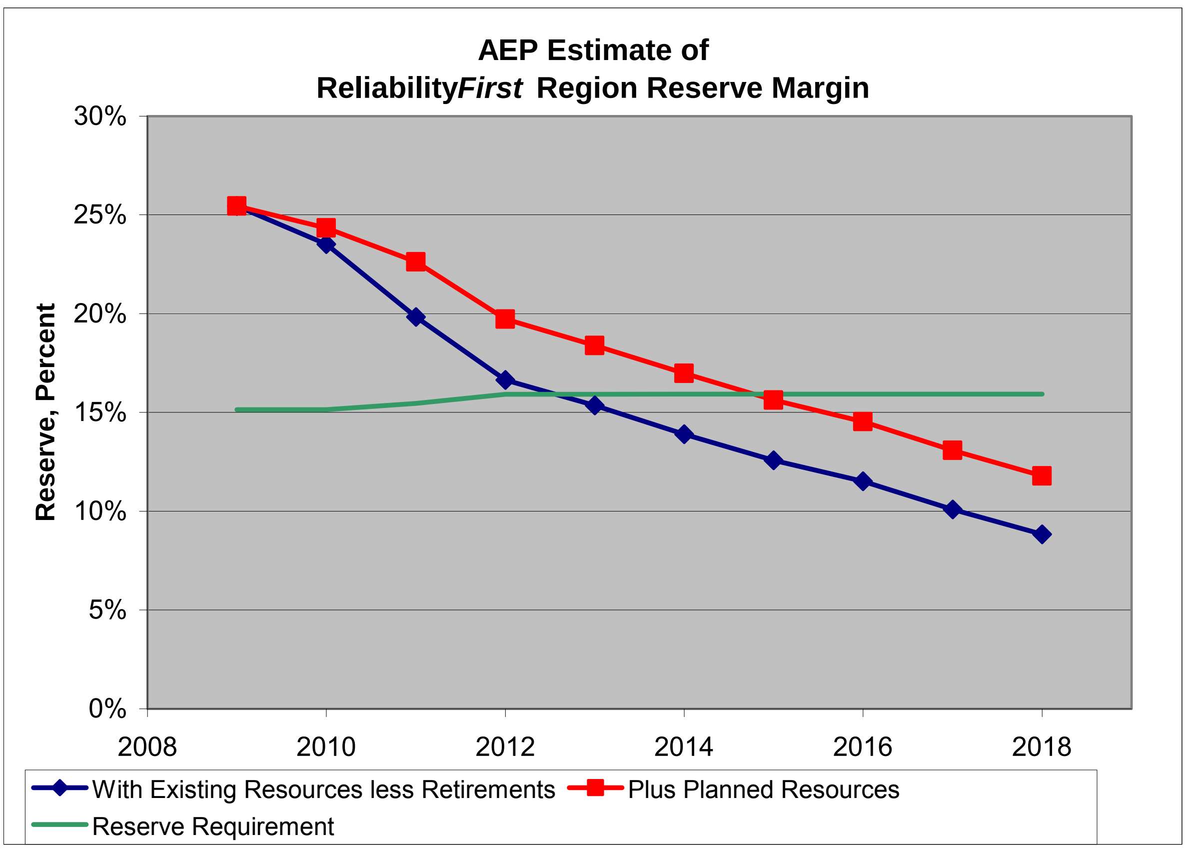
8.0 Resource Options

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–will decline to the point that new assets will have to be built within the next five years in the PJM area that includes the AEP East Zone.

Exhibit 8-1 offers a forecast view by AEP of the RFC region's future reserve margins. This takes into account data in the Reliability*First* draft long term assessment of July, 2009, including recent forecast impacts of the current economic recession. Two points are readily observable. First, despite the recession, the forecasted capacity margins steadily decline. Second, the absolute level of capacity margins (based on existing resources net of retirements) suggests that, in order for the required reserve margin to be maintained, additional capacity will be needed by about 2013. If all capacity projects that PJM and MISO currently classify as "planned" come to fruition, additional capacity will still be needed by 2015.

Exhibit 8-1: Regional Summer Reserve Margin Projections



Source: AEP Resource Planning

These pressures for capacity become more pronounced as the impact of SO_2, NO_X, and mercury emission reduction requirements are likely to negatively impact the utilization of existing (coal-steam) generating units, heightening the potential for regional capacity deficiencies by the 2017 timeframe. Any legislation to control CO_2 will further serve to depress regional capacity resources.

In summary, due to factors discussed here and later in this document, capacity market liquidity cannot be assured significantly beyond the early portion of the next decade. Therefore, unless market opportunities present themselves–as identified in Section 7.1–the intent of this capacity resource planning process is to meet all such requirements with self-planned alternatives.

The future capacity reserve situation is further clouded by the results of the PJM-RPM capacity auctions, for delivery years 2008/09 through 2012/13. The clearing price for capacity was $40 per MW-day for delivery year 2008/09; auction clearing prices for subsequent delivery years have been $112, $102, $174, and $110 per MW-day. This year's auction, for delivery year 2012/13, resulted in the lowest price yet seen, $16.46 per MW-day. Factors that influenced this low clearing price included a rule change by which PJM moved a class of existing interruptible loads totaling over 6,000 MW into the auction process; and another change that removed over 3,300 MW from the forecasted load (to be covered in future interim auctions).

Although on one hand this indicates plentiful capacity resources and demand response in the PJM footprint, the low price bodes ill for the incenting of new capacity construction. The cost of a new combustion turbine, for comparison, net of energy and other revenues, is currently almost $260 per MW-day (net cost of new entry).

8.1.1 Market Purchases

AEP's planning position for its East Zone is to take advantage of market opportunities when economical, both in the form of limited-term bilateral capacity purchases from non-affiliate sources and by way of available, discounted 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.

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:

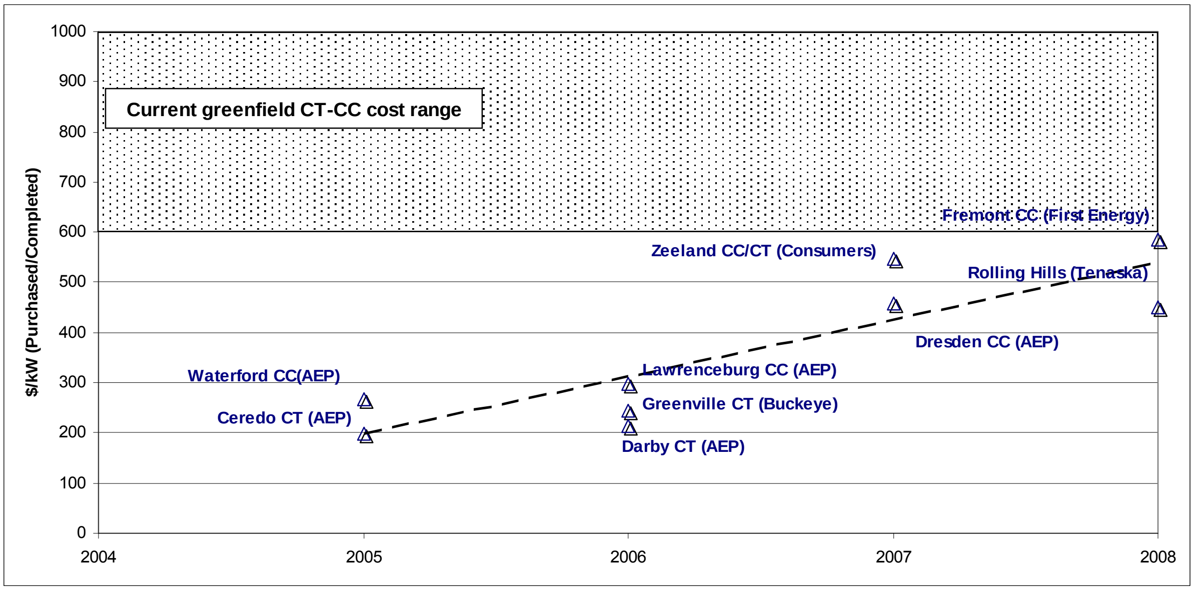
- this IRP assumes the need to ultimately build generating capability to meet the requirements of its customers for which it has assumed an obligation to serve (including Ohio);
- the regional market price of capacity could, as represented above, begin to approach the fixed cost of new-build generation; and
- the planning flexibility that market purchases enable is critical to the process.

Another critical element ultimately impacting the availability of (bilateral) market capacity purchases is the PJM RPM construct. As discussed, AEP has opted out of the RPM capacity auction. With that, however, comes the fact that the capacity supply available to AEP would be limited to other "FRR" entities within PJM or to (potentially expensive) capacity not lifted in those capacity auctions.

8.1.2 Generation Acquisition Opportunities

In addition, in continued recognition of both the need for additional capacity beginning in the post-2016 timeframe, other market purchase opportunities are constantly being explored. 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 *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 green field 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, and *integrated gasification combined cycle* facilities. 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 the current view of AEP 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 some scenarios and sensitivities, but ultimately was not included in the final resource plan being recommended.

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 1,000-1,000°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 temperatures exceeding 1,100°F.

The initial capital costs of subcritical units are lower than those of a comparable supercritical unit by about 4 to 6%, but the overall efficiency of the supercritical design is higher than the subcritical design by approximately 3%. Due to cycle design improvements, the new variable pressure ultra supercritical units are projected to have–at commercial quantities–an initial capital cost of about 4% greater than a comparable supercritical unit. While the overall efficiency remains approximately 3% 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 such as IGCC. The assessment of such technologies is based on cost and performance estimates from commonly cited public sources, consortia where AEP is actively engaged, and vendor relationships, as well as AEP's own experience and expertise.

IGCC is of particular interest to AEP in light of the abundance, accessibility, and affordability of high rank coals for the company–particularly in its eastern zone. 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, yet with the low fuel cost associated with coal. As discussed in this IRP report, 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.

The IGCC process employs a gasifier in which coal is partially combusted with oxygen and steam to form what is commonly called "syngas"–a combination of carbon monoxide, methane, and hydrogen. The syngas produced by the gasifier then is cleaned to remove the particulate and sulfur compounds. Sulfur is converted to hydrogen sulfide and ash is converted into glassy slag. Mercury is removed in a bed of activated carbon. The syngas then is fired in a gas turbine. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG), where it produces steam that drives a steam turbine as would a natural gas-fired combined cycle unit.

IGCC enjoys comparable thermal efficiencies to USC-PC. Its ability to utilize a wide variety of coals and other fuels positions it extremely well to address the challenges of maintaining an adequate baseload capability with efficient, low-emitting, low-variable cost-generating technology. Further, IGCC is in a unique position to be pre-positioned for carbon capture as, unlike PC technologies, it has the ability to perform such capture on a "pre-combustion" basis. This could ultimately lead to improved net energy efficiency than would be required by PC technology utilizing post-combustion carbon capture technology.

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. A CFB boiler is 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.

Fuel 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. Currently, the largest CFB unit in operation is 320 MW, but designs for units up to 600 MW have been developed by three of the major CFB suppliers. A 500 MW unit is in initial stage of operations in Poland. AEP has no commercial operating experience with generation utilizing circulating fluidized bed boilers but is familiar with the technology through prior research, including the Tidd pressurized fluidized bed demonstration project.

8.2.2.4 Nuclear

Although new reactor designs and ongoing improvements in safety systems make nuclear power an increasingly 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. For these stated reasons, among others, AEP does not view nuclear as a viable candidate to meet the capacity resource needs of AEP-East within this near-term period (2010-2019). However, portfolios that include nuclear capacity beyond the near-term period and into the expected second wave of new builds are comparable with the hybrid portfolio that was ultimately selected. Both the economic and political viability of nuclear power and energy will continue to be explored given:

1) the AEP-East zones ultimate need for baseload capacity;
2) the cost uncertainty surrounding the advancement and commercialization of IGCC technology
3) the cost and performance of CCS technology, and
4) the continued push to address AEP's carbon footprint and the mitigating impact nuclear power clearly has in that regard.

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. Historically, many generators, such as AEP's eastern fleet, have relied on older, less-efficient, subcritical coal-fired units to serve such load-following roles. These coal units' staffs have also worked to improve ramp rates, regulation capability, and reduce downturn (minimum load capabilities). As the fleet continues to age and units are retired over time, other generation alternatives will have to be considered for this duty cycle's operating characteristics.

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, 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 multiple gas turbines 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 gas then expands and cools 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 fluctuating 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 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.

(References: Turbomachinery International, Jan/Feb. 2008; Gas Turbine World; EPRI TAG)

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.

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 capacity planning.

8.3 Renewable Alternatives

Renewable generation alternatives use nontraditional energy 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). Numerous renewable energy sources are under development or exist, but many sources like solar, geothermal, new hydro 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 more than half the states and 9 of 13 PJM states plus the District of Columbia, a mandatory RPS exists today in Ohio, West Virginia and Michigan, and a voluntary RPS exists in Virginia. This being said, the notion of a potential Federal RPS and additional state standards 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 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 not practical 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 to achieve emerging state or federal mandates.* A complete list of screened renewable technologies and their levelized costs is included in ***Appendix D***.

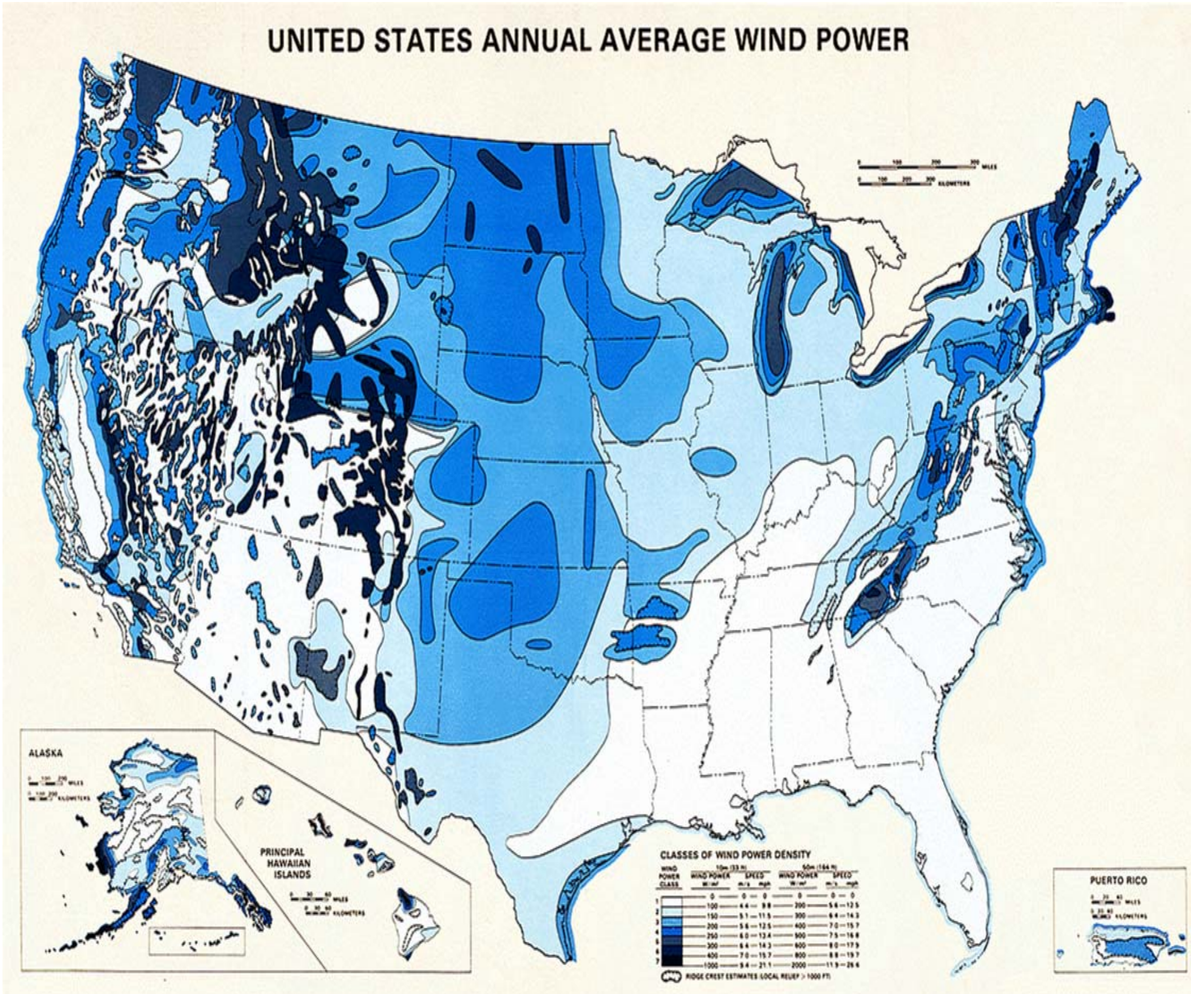
8.3.1 Wind

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 AEP service territory *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 30 to 40 percent; 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 U.S.

Exhibit 8-3: United States Wind Power Locations

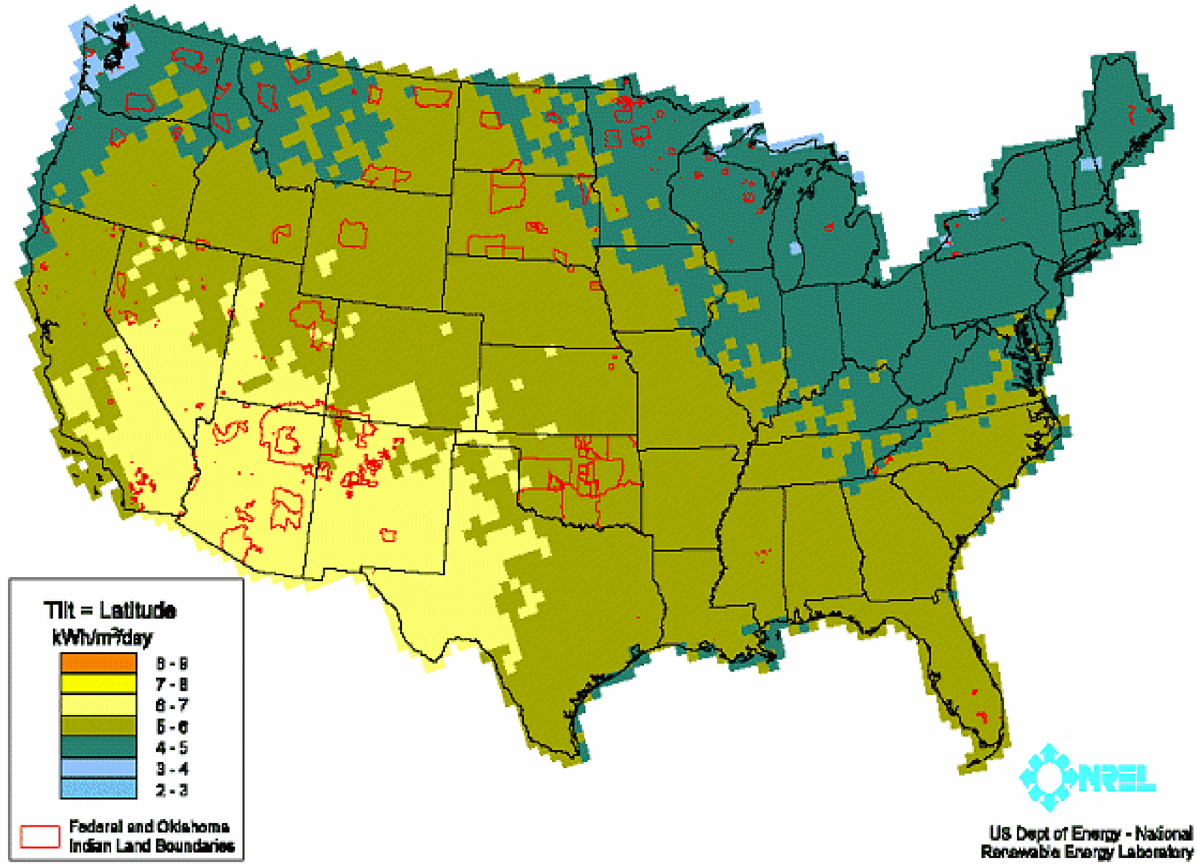


Source: NREL

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 (2kW to 2MW per installation) and are distributed throughout the grid. In the AEP-East zone, solar has limited application as large scale units, but opportunity for distributed generation. The appeal of solar is broad and legislation in Ohio has made its pursuit mandatory subject to price caps, beginning in 2009. Solar photovoltaics are represented in this IRP as if they were not subject to price caps in Ohio. However, the amounts of solar prescribed in the law, while substantial, will not have a significant effect on the timing or amount of other supply assets within a ten-year planning period. **Exhibit 8-4** shows the potential solar resource locations in the U.S.

Exhibit 8-4: United States Solar Power Locations



Source: NREL

8.3.3 Biomass

Biomass is a term that includes organic waste products (sawdust or other wood waste), organic crops (corn, 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

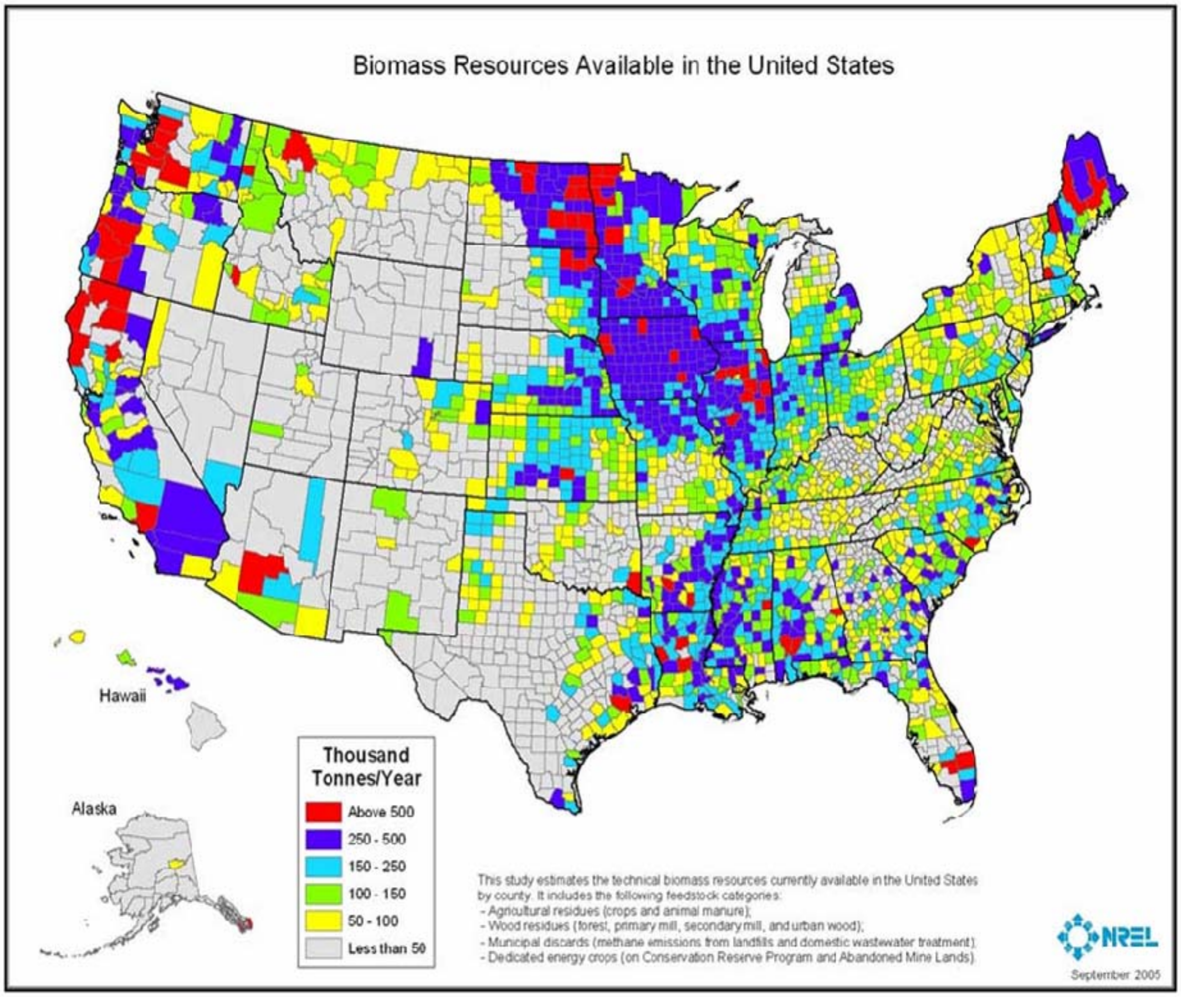
Switchgrass	**Wood Chips / Sawdust**
(per Purdue University Study) o 6 -to- 8 tons /yr. per acre yield o @ 6700 Btu/lb (non-dried, as harvested) *A 200-MW Dedicated Biomass Facility (70% C.F.) would require…* **110k -to- 150k harvested acres** *(172 - 234 sq. mi,)*	*(per AEP-Forestry)* o 70 -to-100 tons /yr. per acre yield* * "clear cutting" on a <u>*40-year cycle*</u> 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 utilization 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 utilization is not a substitute for additional generation. Because it simply substitutes "carbon-neutral" fuel for fossil fuels, it does not eliminate the need for building generation as demand grows and assets are retired. However, if and when GHGs 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 East and West zones) from renewable resources by 2020 (see Appendix F). Based on current AEP renewable resources, and considering an additional 1,000 MW of renewable resources committed to by the year-end 2011, together with the prospective renewable projects listed in **Exhibit 8-7**, included in the 2009 IRP (AEP-East and SPP), this internal commitment is projected to be satisfied.

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

AEP System

Existing and Projected Renewables for 2009 IRP

Unit, Plant, or Contract	Size (MW)	Operating Company (Existing or Awarded Contracts)	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 (Wyandot)	10.0	CSP/OPCo	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		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		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		2013	15	12,096	8.0%	
Solar (Distributed)	14		2014	15	12,110	8.0%	
West Wind	100		2015	377	12,487	8.2%	
Solar (Distributed)	14		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		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		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		2018	18	15,720	10.1%	
Amos 3	0		2019	792	16,512	10.5%	Note 4
Solar (Distributed)	17		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		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

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 will achieve 90% CO_2 capture with a 15% parasitic loss 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 programs" (demand response or "DR"), 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 AEP's respective East (PJM) and West (SPP) zones, 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.

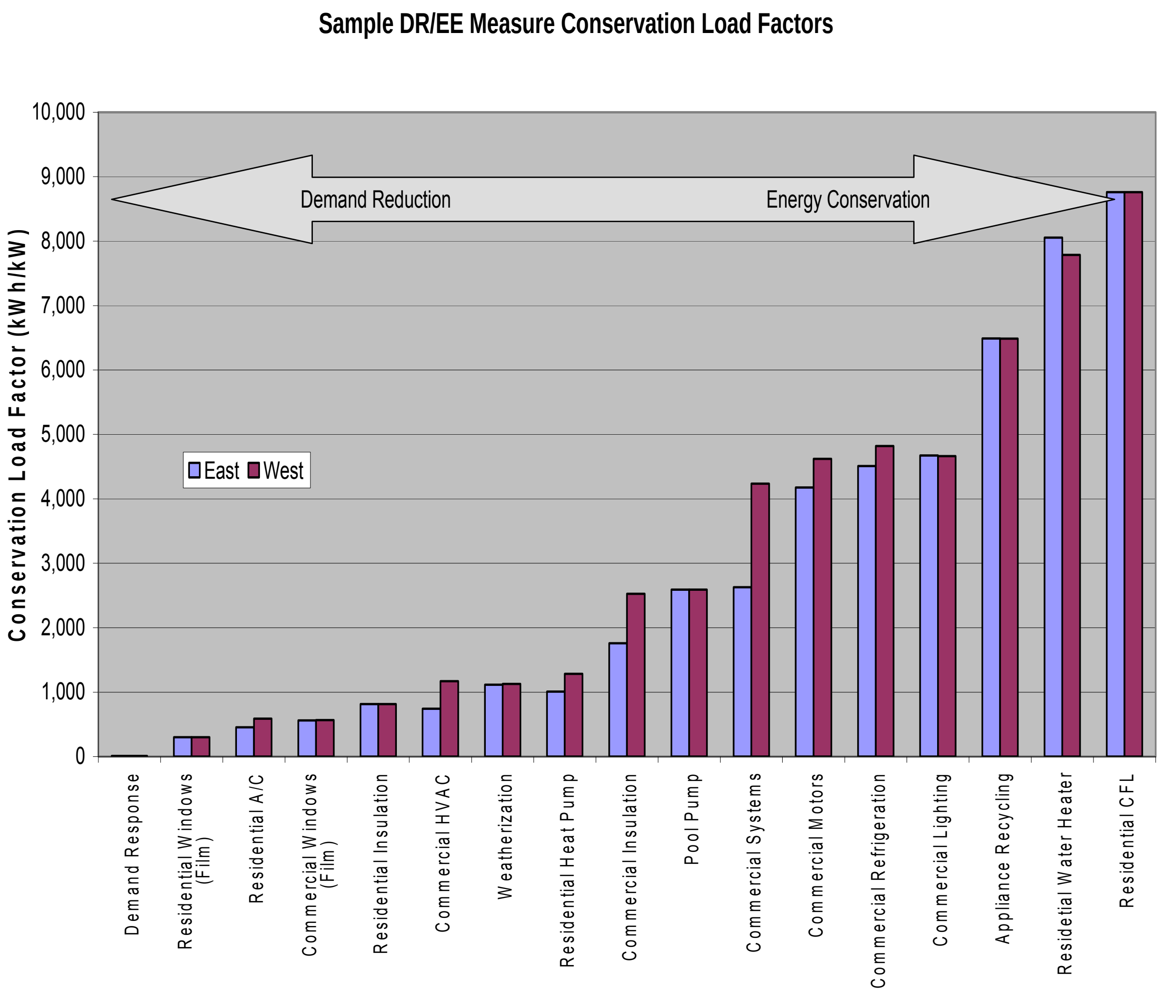
Some examples will illustrate this point. First, a more efficient air conditioner will likely reduce consumption at the peak; the same amount of cool air is being generated with less energy. A more efficient refrigerator will have a lesser impact on the peak as the chance of it running consistently at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

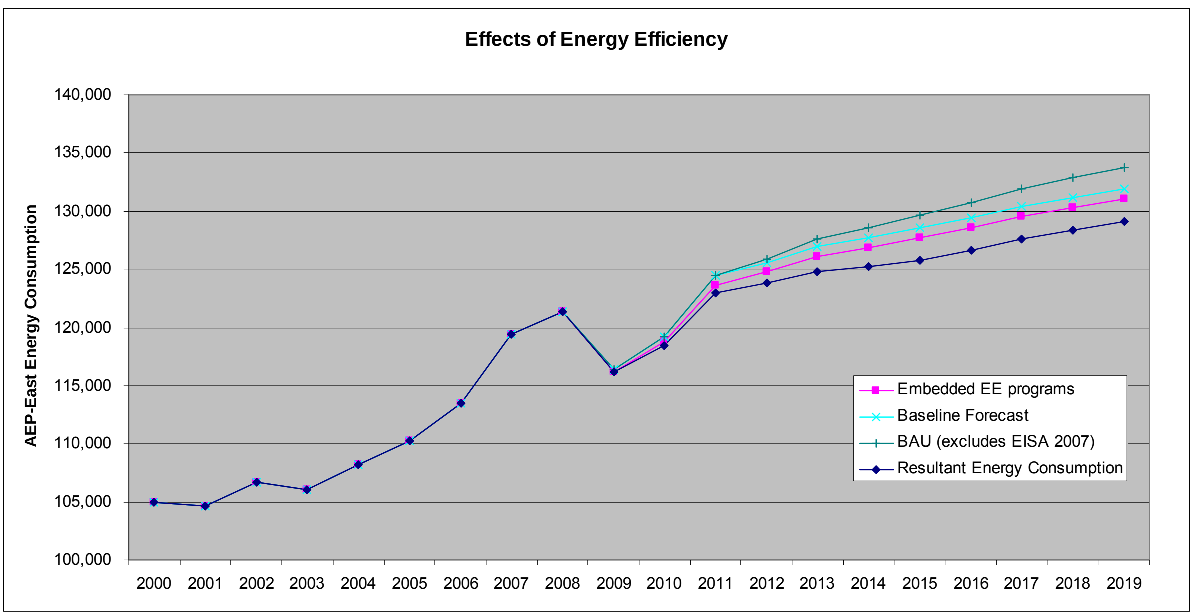
Pilot programs employing smart meters are currently underway in Ohio, Indiana, and Texas. The results of these pilots will greatly inform the impacts assigned to larger roll-outs of these meters, should they ultimately be approved.

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**.

Exhibit 9-1: Impact of Legislation on Energy Consumption



Source: AEP Resource Planning

As Exhibit 9-1 indicates, by 2019 AEP-East energy consumption will be about 3.5 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 Ohio and Michigan in the AEP-East Zone, and Texas in the AEP-West Zone. The Ohio standard, if cost-effective criteria are met, will result in installed efficiency assets equal to over 20 percent of all energy otherwise supplied by 2024. Michigan's standard achieves 10.55% in 2020. Other states in the AEP-East zone are contemplating standards, including Virginia, which has a voluntary 10% by 2020 target.

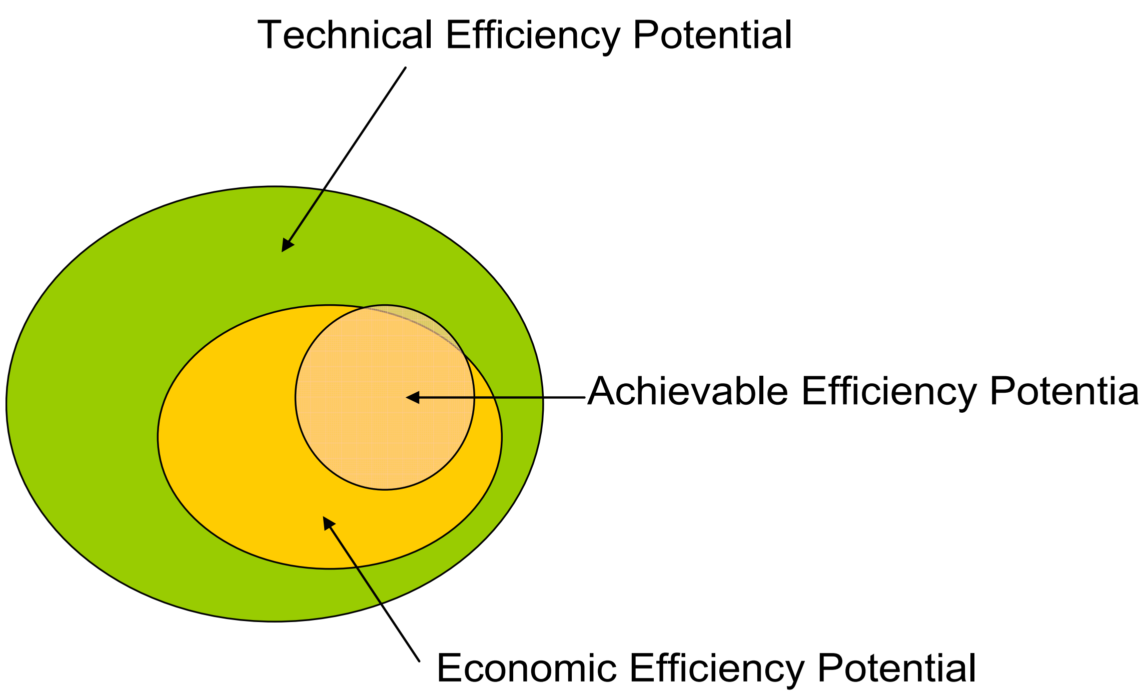
As identified in this document, AEP has internally committed to system-wide peak demand reductions of 1,000 MW by year-end 2012 and energy reductions of 2,250 GWh, approximately 60-65% of which is in the AEP-East zone.

The IRP does not necessarily assume that these state DR/EE targets will be explicitly met over the longer 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 Energy Efficiency and Demand Response 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 by state governing bodies.

9.4 Determining Programs for the IRP

Market Potential Studies (MPS) have been commissioned for 10 of AEP's 11 jurisdictions. In the East zone, at the time the analysis for this IRP was performed, only the Indiana 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 this IRP.

The economic potential for Energy Efficiency lies in the 10-16% 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 1.7% reduction after five years (Indiana MPS) and 3.3% 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 either are currently in place or have been filed with the appropriate regulatory commission. Primarily, these impacts result from the mandates in Ohio and Michigan.

9.4.1 Use of EPRI and Indiana Studies to Construct DR/EE Program Blocks

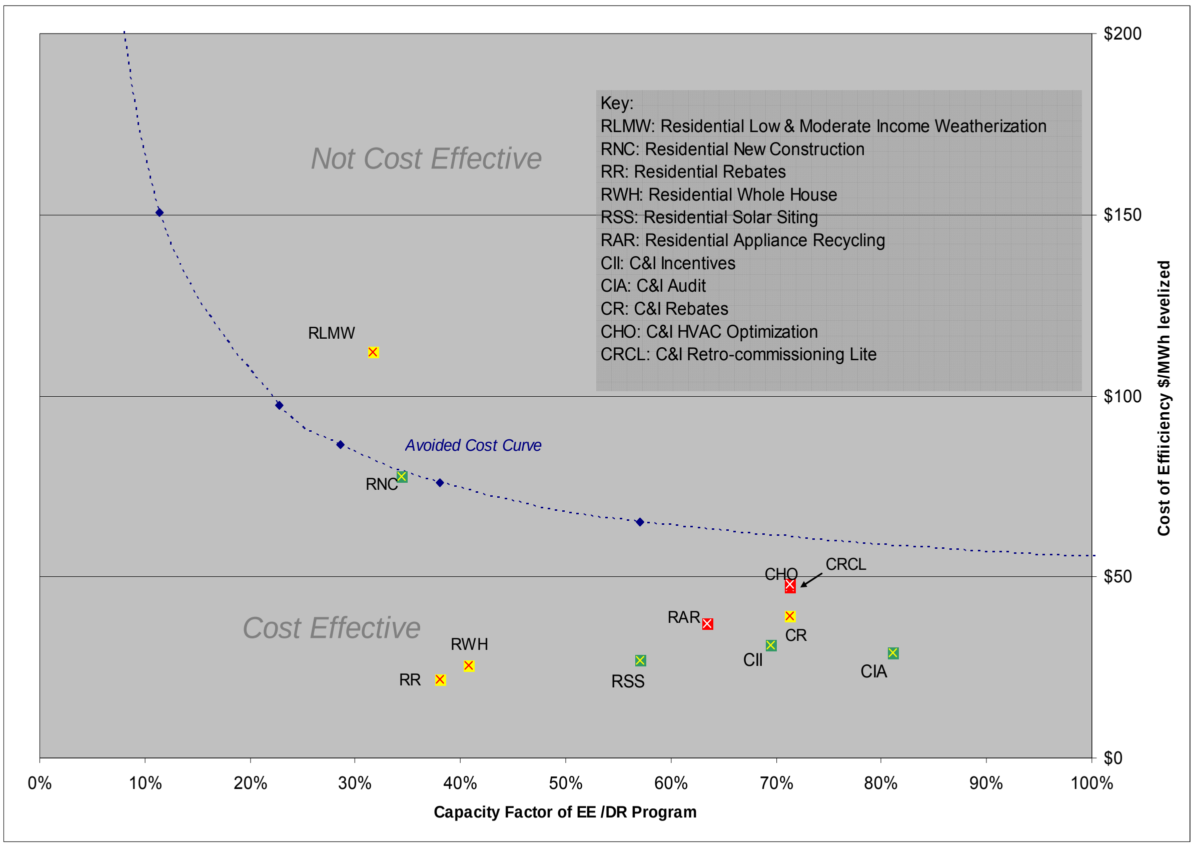
The Indiana study was used as the basis for the construction of DR/EE "blocks" to be used in the modeling process. The blocks are proxies for actual programs that are likely to be implemented in any of the AEP-East jurisdictions, incremental to the programs that have already been filed. The blocks have the cost, energy, and peak demand reduction characteristics of the recommended programs in the Indiana study.

The EPRI study, *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.*, "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.

9.4.1.1 Validating the DR/EE Program Blocks

Because the blocks represent possible programs as recommended by the Indiana 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 included all resource alternative types, 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: Cost Effectiveness of Relative Programs



Source: AEP Resource Planning

Note all of the resources are cost effective with the exception of the Residential Low and Moderate Income Weatherization (RLMW). Because these programs are typically required in jurisdictions where energy efficiency is being implemented, its costs and impacts were included outside of the optimization process.

Not shown on the chart are the C&I Demand Response (CIDR) resource which would be off the chart on the upper left side, but still cost effective, and the Residential Peak Reduction which was not cost effective.

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.

Descriptions of the programs used to develop the proxy resources are included in the Technical Addendum.

9.4.2 Optimizing the Incremental DR/EE resources

Using the red and yellow program characteristics, "blocks" were constructed of equal energy impacts, corresponding demand impacts and costs. The proxy blocks available for optimization and their characteristics are summarized in **Exhibit 9-4**

Exhibit 9-4: DR/EE Proxy Blocks

Monthly Peak Reduction (MW)									
	CR	CRCL	CHO	RWH	RR	RAR	RLMW	CIDR	RPR
Jan	7.17	7.09	7.07	11.61	12.32	7.92	14.59	-	-
Feb	7.16	7.06	7.04	10.28	10.83	7.36	12.66	-	-
Mar	7.37	7.31	7.30	8.48	8.79	6.64	10.03	-	-
Apr	6.83	6.70	6.68	7.09	7.20	6.16	7.94	-	-
May	7.36	7.30	7.28	7.77	7.98	6.38	8.97	-	-
Jun	7.96	7.96	7.95	10.98	11.62	7.66	13.68	50.00	50.00
Jul	7.97	7.97	7.96	14.00	15.00	9.00	18.00	50.00	50.00
Aug	8.00	8.00	8.00	12.22	13.01	8.19	15.46	50.00	50.00
Sep	8.00	8.00	8.00	10.70	11.29	7.53	13.27	-	
Oct	6.96	6.84	6.82	6.85	6.93	6.08	7.59	-	
Nov	6.70	6.55	6.52	8.57	8.89	6.67	10.16	-	
Dec	6.78	6.64	6.62	11.15	11.81	7.73	13.93	-	
Peak	8.00	8.00	8.00	14.00	15.00	9.00	18.00	50.00	50.00

Monthly Energy Reduction (GWh)									
	CR	CRCL	CHO	RWH	RR	RAR	RLMW	CIDR	RPR
Jan	4.20	4.19	4.18	4.96	5.10	4.39	5.38	-	-
Feb	3.84	3.85	3.85	4.30	4.39	3.91	4.58	-	-
Mar	4.31	4.33	4.33	4.09	4.07	4.16	4.04	-	-
Apr	4.01	3.98	3.98	3.48	3.36	3.96	3.13	-	-
May	4.13	4.10	4.09	3.46	3.30	4.08	3.00	-	-
Jun	4.24	4.27	4.28	3.96	3.92	4.09	3.86	-	-
Jul	4.43	4.47	4.48	4.97	5.10	4.46	5.35	-	-
Aug	4.43	4.47	4.48	4.67	4.75	4.38	4.89	-	-
Sep	4.18	4.20	4.20	3.58	3.48	4.01	3.27	-	-
Oct	4.17	4.16	4.15	3.44	3.27	4.08	2.96	-	-
Nov	3.95	3.91	3.91	3.98	3.97	4.04	3.94	-	-
Dec	4.11	4.07	4.07	5.11	5.28	4.44	5.60	-	-
	50.00	50.00	50.00	50.00	50.00	50.00	50.00	-	-

Source: AEP Resource Planning

To reflect the presence of market barriers with the optimization process, the following constraints (**Exhibit 9-5**) were placed on the blocks:

Exhibit 9-5: DR/EE Modeling Constraints

DR/EE Proxy Blocks	Incremental Blocks Allowed Per Year	Block Annual Energy (MWh)	Block Annual Peak Demand (MW)	Annual Cost ($MM)	Initial Cost ($MM)	Block Type
C&I Rebates	4	50,000	8		16	DR
C&I Retro-Commissioning Lite	4	50,000	8		10	DR
C&I HVAC Optimization	1	50,000	8		10	EE
Residential Whole House	1	50,000	14		9	EE
Residential Rebates	1	50,000	15		4	EE
Residential Appliance Recycling	1	50,000	9		7	EE
Residential Low & Moderate Income Weatherization	1	50,000	18		48	EE
C&I Peak Reduction	2	0	50	1	3	EE
Residential Peak Reduction	1	0	50	1	30	EE

Year	Maximum Total EE Blocks Allowed	Maximum DR Blocks Allowed
2010	6	2
2011	12	4
2012	19	6
2013	23	8
2014	29	10
2015	35	12

Source: AEP Resource Planning

These constraints keep the resource modeling process 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 Indiana MPS recommendations and the EPRI Reasonably Achievable level of demand side resources.

Exhibit 9-6 shows the blocks selected annually by the resource modeling process. 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: DR/EE Blocks Selected During Resource Modeling

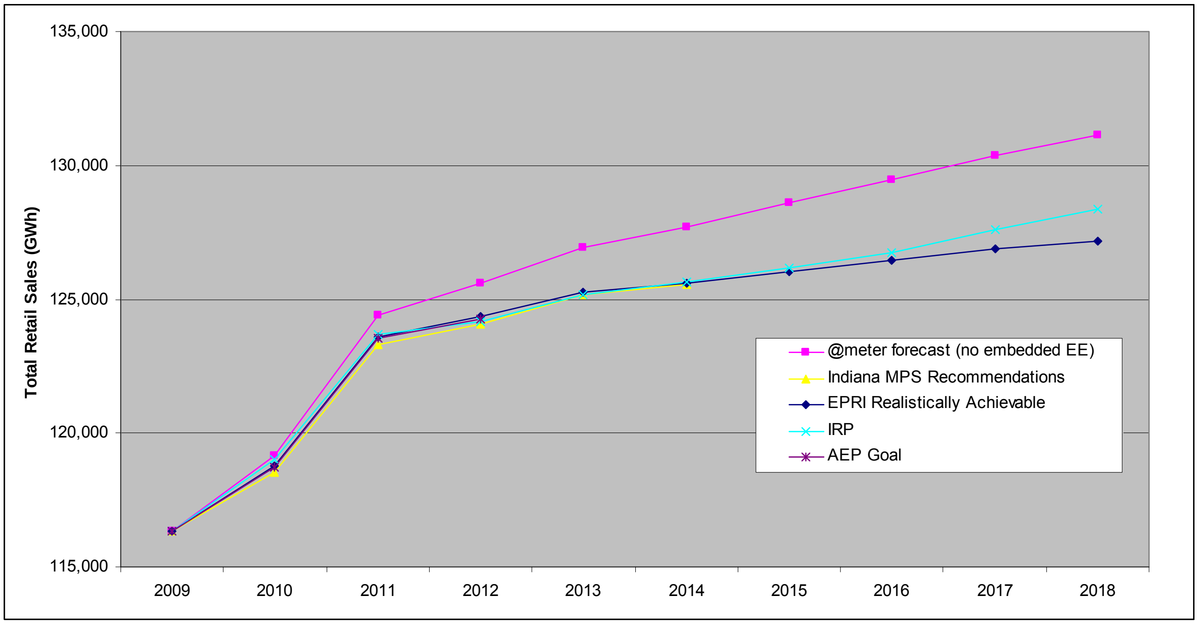
Strategist Optimized Demand Side Proxy Resources (MW)							
	CIDR	RLMW	CR	RWH	RR	Total	Cumulative Total
2010	100	18	32	14	15	179	179
2011	100	18	32	14	15	179	358
2012	100	18	32	14	15	179	537
2013	100	18	32	14	15	179	716
2014	100	18	32	14	15	179	894
2015	100	18	32	14	15	179	1,073

Strategist Optimized Demand Side Proxy Resources (GWh)							
	CIDR	RLMW	CR	RWH	RR	Total	Cumulative Total
2010	0	50	200	50	50	350	350
2011	0	50	200	50	50	350	700
2012	0	50	200	50	50	350	1,050
2013	0	50	200	50	50	350	1,400
2014	0	50	200	50	50	350	1,750
2015	0	50	200	50	50	350	2,100

Source: AEP Resource Planning

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

Exhibit 9-7: AEP Internal EE Target vs. 2009 IRP



Source: AEP Resource Planning

Results:
By 2015, peak demand at the generator is reduced by 1,357 MW in the AEP-East zone; consumption is reduced by 3,037 GWh at the generator. These reductions are consistent with studies performed in the AEP East zone and internal goals.

9.5 Discussion and Conclusion

The assumption of aggressive peak demand reduction and energy efficiency achievements reflect not only mandated levels of DR/EE in Ohio and Michigan, but 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 benefiț.
- Increased interest in demand response from the introduction of emergency capacity programs from PJM. Because AEP-East has historically not been able to count the demand assets of customers who participate in the PJM program, the Company seeks to broaden its interruptible tariffs to accommodate customers who have previously not been eligible, primarily because of size.

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-East 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: DR/EE Assumption Summary

	Energy Efficiency Impacts (GWh)			Peak Demand Impacts (MW)		
Year	Forecast (Embedded)	IRP Blocks	Total	Forecast (Embedded)	IRP Blocks	Total
2009	183		183	58		58
2010	486	350	836	145	179	324
2011	907	700	1,607	267	358	624
2012	917	1,050	1,967	269	537	806
2013	925	1,400	2,325	271	716	986
2014	932	1,750	2,682	272	894	1,167
2015	937	2,100	3,037	273	1,073	1,347

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 10-1.** 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.

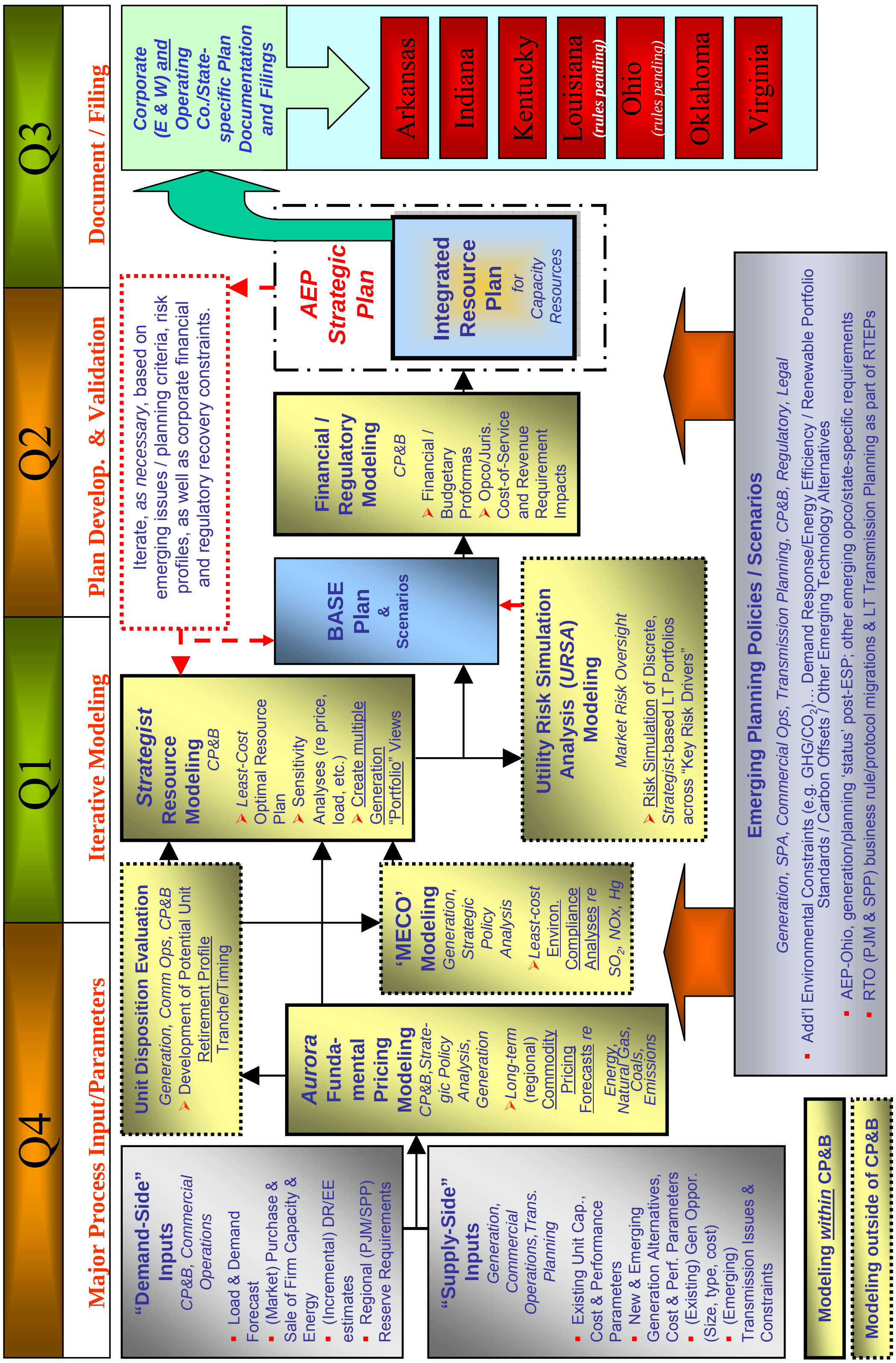
Further impacting this process are growing numbers of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability planning. Currently, fulfilling a regulatory obligation to serve native load customers (including Ohio customers) represents one of the cornerstones of this 2009 AEP-East 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-East integrated resource plan. 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 4). 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*–a Ventyx Co., long term resource optimization tool utilized extensively in the utility industry for over two decades–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.

Exhibit 10-1: IRP Modeling and Planning Process Flow Chart



Source: AEP Resource Planning

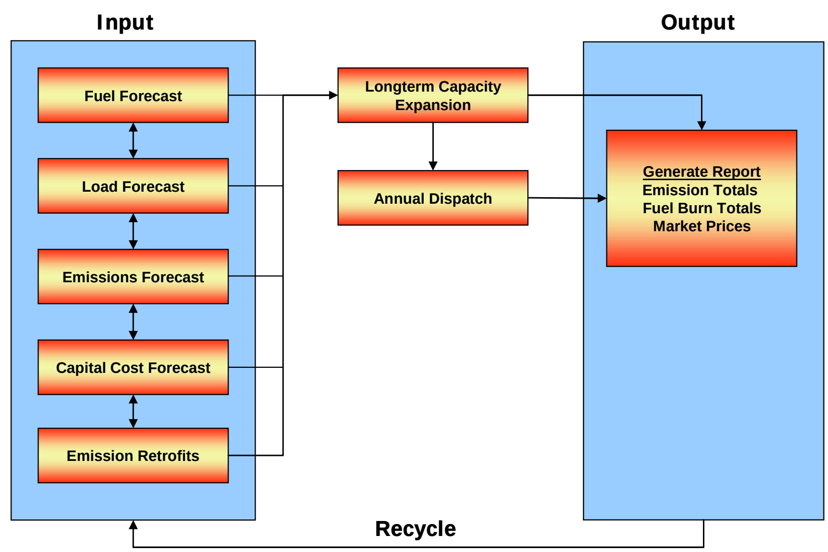
10.3 Key Fundamental Modeling Input Parameters

This section includes excerpts from the "Long Term Price Forecast 2009-2030: Return to Fundamentals, 2H-2008" *prepared by AEPSC's Strategic & Economic Analysis (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 10-2 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 10-2: 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 10-3** presents the key inputs for the scenarios and how they have changed relative to the Reference Case.

Exhibit 10-3: Input Scenarios

	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 carbon policy becomes a long forgotten initiative.

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. Strategic Policy Analysis has developed three potential CO_2 price forecasts for each of the cases. 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. *As the political and economic situation changes so will the politically acceptable pricing range and likely pricing trajectory.*

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. These forecasts, which were developed at the beginning of 2009, do not reflect the recent passage of the Waxman-Markey legislation.

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 it is assumed 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 relative weighting of these two bills. This forecast represents a pricing scenario which likely could occur under some level of political compromise within the U.S. government.

11.0 Resource Portfolio Modeling

11.1 The *Strategist* Model

The *Strategist* optimization model served as the empirical calculation basis from which the AEP-East zonal capacity requirement evaluations were examined and recommendations were made. As will be identified, as part of this iterative process, *Strategist* offers unique portfolios of resource options that can be assessed not only from a discrete, revenue requirement basis, but also for purposes of performing additional risk analysis outside the tool.

As its objective function, *Strategist* determines the regulatory least-cost resource mix for the generation (G) system being assessed.[4] The solution is bounded by user-defined set of resource technologies, commodity pricing, and prescribed sets of constraints.

As described in the IRP Technical Addendum, *Strategist* develops a discrete macro (zone-specific) least-cost resource mix for a system by incorporating 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, unit minimum downturn levels, must-run status, etc.) of existing and new units.
- Unit dispositions (retirement/mothballing).
- Delivered fuel prices.
- Prices of external market energy and capacity as well as SO_2, NO_X, and CO_2 emission allowances.
- Reliability constraints (in this study, minimum reserve margin targets).
- Emission limits and environmental compliance options.

These assumptions, and others, are considered in the development of an integrated plan that best fits the utility system being analyzed. *Strategist* does not develop a full regulatory cost-of-service (COS) profile. Rather, it typically considers only (G)-COS that changes from plan-to-plan, not fixed 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 typically not incorporate significant capital spends for transmission interconnection costs.

Specifically, *Strategist* includes and recognizes in its "incremental (again, largely (G)) revenue requirement" output profile:

- Fixed costs of capacity additions, i.e. carrying charges on capacity and associated transmission (based on a weighted average AEP system cost of capital), and fixed O&M;
- Fixed costs of any capacity purchases;
- Installation and administrative costs of DR/EE alternatives

[4] *Strategist* also offers the capability to address incremental transmission ("T") options that may be tied to evaluations of certain generating capacity resource alternatives.

- Variable costs associated with the entire fleet of new and existing generating units (developed 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) are netted against these costs under this ratemaking/revenue requirement format.

In the PROVIEW module of *Strategist*, the least-cost expansion plan is empirically formulated from potentially hundreds of thousands of possible resource alternative combinations created by the module's chronological dynamic programming algorithm. On an annual basis, each capacity resource alternative 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

The model's algorithm has the potential for creating such a vast number of alternative combinations and feasible states; it can become 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 further limit or constrain the size of the problem. There were numerous other known physical and economic issues that needed to be considered and, effectively, "constrained" during the modeling of the long-term capacity needs so as to reduce the problem size within the tool.

- Maintain an AEP-PJM installed capacity (ICAP) minimum reserve margin of roughly 15.5% per year as represented in the east region's "going-in" capacity position (which itself assumed a PJM Installed Reserve Margin [IRM] of 15.5% throughout the 2011/2012 planning year and 16.2% for remaining years of the planning period).
- All generation installation costs represent AEP-SEA view of capacity build prices that were predicated upon information from AEP Generation Technology Development.
- Under the terms of the New Source Review (NSR) Consent Decree, AEP agreed to annual SO_2 and NO_X emission limits for its fleet of 16 coal-fueled power plants in Indiana, Kentucky, Ohio, Virginia and West Virginia. These emission limits were met by adjusting the dispatch order of these units during *Strategist's* economic dispatch modeling.

11.2 Resource Options/Characteristics and Screening

11.2.1 Supply-side Technology Screening

There are many variants of available supply and demand-side resource types. 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 with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for each of the major duty cycle "families" (baseload, intermediate, and peaking) and are reflected in the **Technical Addendum** of this report.

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 that will determine the ultimate technology type (e.g. choices for "peaking" technologies: GE frame machines "E" or "F", GE LMS100 aeroderivative machines, etc.). The full list of screened supply options is included in **Appendix C**.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Strategist* for each designated duty cycle:

- *Peaking capacity* was modeled as blocks of four, 165 MW GE-7FA Combustion Turbine units (summer rating of 157 MW x 4 = 628 MW), available beginning in 2017.
- *Intermediate capacity* was modeled as single natural gas Combined Cycle (2 x 1 GE-7FB with duct firing platform) units, each rated 650 MW (611 MW summer) available beginning in 2017.
- *Baseload capacity* burning eastern bituminous coals was modeled. The potential for future legislation limiting CO_2 emissions beginning in the 2020 timeframe was considered in selecting the solid fuel baseload capacity alternatives,. Two solid fuel alternatives were made available to the model:
  - ✓ 618 MW Ultra Supercritical PC unit (summer rating of 612 MW) where the unit is assumed to be <u>retrofitted</u> with a chilled ammonia carbon capture and sequestration (CCS) technology by 2020 that would capture 90% of the unit's CO_2 emissions. The addition of the CCS retrofit would reduce the unit's capacity to 525 MW (520 MW summer). This alternative could be added by Strategist from 2017 through 2019. Under the scenario where CO_2 prices did not exist, this unit without the CCS retrofit was available for selection beginning in 2017;
  - ✓ 735 MW Ultra Supercritical PC unit/625 MW net of CCS (summer rating of 619 MW). **CCS** equipment would reduce 90% of the unit's carbon emissions <u>installed during the unit's construction</u>. This alternative could be added by Strategist beginning in 2020.and;

In addition, beginning in the year 2020:

- ✓ Strategist could select an 800 MW share of a 1,600 MW nuclear, Mitsubishi Heavy Industries (MHI) Advanced Pressurized Water Reactor (760 MW summer)

In order to maintain a balance between peaking, intermediate and baseload capacity resources, only four Combustion Turbine (CT) units could be added in any year. If the addition of four CTs was not sufficient to meet reliability requirements in a particular year, the model was required to add either intermediate and/or baseload capacity to meet the reliability targets.

11.2.2 Demand-side Alternative Screening

As described in Section 9, eighteen "blocks" of DR/EE programs were developed and evaluated in *Strategist*. The economics of the DR/EE blocks were screened in order to minimize the problem size of the full *Strategist* optimization. The DR/EE blocks were evaluated under all of the economic scenarios described in Section 10. The results of this screening analysis showed that ~375 MW were selected under all of the economic scenarios. The total DR impact assumed in the full optimization analysis for AEP-East was 1,073 MW.

11.3 *Strategist* Optimization

11.3.1 Purpose

Strategist should be thought of as a tool used in the development of potentially economically viable resource portfolios. It doesn't produce "the answer;" rather, it produces or suggests many portfolios that have different cost profiles under different pricing 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 a low-cost, or even a viable portfolio in other scenarios. Portfolio selection may reflect strategic decisions embraced by AEP leadership, including a commitment to DR/EE, renewable resources and clean coal technology. *Strategist* results, both "optimum" and "suboptimum," serve as a starting point for constructing model portfolios.

For example, if a scenario dictates an unconstrained *Strategist* consistently picks a CT option to the point that such peaking capacity is being added in large quantities, a portfolio that substitutes a 650 MW combined cycle plant for four, 165 MW CTs might be constructed and tested through *Strategist* to see if the resultant economic answer (i.e., CPW of revenue requirements) is significantly different. Intervening in the algorithm of *Strategist* to insert some additional practical constraints or conform to an AEP strategy yields a solution that is more realistic and not injuriously more expensive. The optimum or least expensive portfolio under a scenario may have practical limitations that *Strategist* does not take into full account.

11.3.2 Strategic Portfolios

Management commitments as outlined in the *AEP 2009 Corporate Sustainability Report* that were considered when constructing the underlying AEP-East 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 mandatory state RPS in Ohio, Texas, Michigan, and West Virginia and voluntary RPS in Virginia.
- **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.

As will be described, additional sensitivities were then contemplated to determine the effects of the optimum portfolios, as well as to build additional portfolios. The build plans that were suggested by *Strategist* under the various scenarios and sensitivities are described in the following sections.

11.4 Optimum Build Portfolios for Four Economic Scenarios

11.4.1 Optimal Portfolio Results by Scenario

Given the four fundamental pricing scenarios developed by AEP-FA from Section 10.3, as well as the modeling constraints and certain planning commitments, *Strategist* modeling was used to develop the incremental portfolios identified in **Exhibit 11-1**:

Exhibit 11-1: Model Optimized Portfolios Under Various Power Pricing Scenarios

	Business As Usual Case Optimization	Abundance Case Optimization	Reference Case Optimization	Constrained Case Optimization
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018	4 - 165 MW CTs, 1 - 625 MW PC w/o CCS	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC
2019				
2020				
2021	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs
2022				
2023	4 - 165 MW CTs, 1 - 625 MW PC w/o CCS	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	1 - 800 MW Nuke
2024				4 - 165 MW CTs
2025	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs
2026	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	
2027				4 - 165 MW CTs
2028	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	1 - 800 MW Nuke
2029				
2030	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	
2009-2035 Total East System Cost				
CPW ($M)	75,102	81,155	97,264	127,927
Levelized ($/MWh)	65.76	69.48	79.43	98.37
Number of Units Added				
CT	28	28	28	20
CC	0	2	2	1
PC	2	0	0	0
Nuclear	0	0	0	2
Total Capacity (MW)	5,856	5,920	5,920	5,550
Total Optimized DSM (MW Reduced)	1,074	984	1074	1,128

Source: AEP Resource Planning

Notes:

1) *Because Renewable assets and a base level of incremental DR/EE are included in all portfolios, Strategist did not represent them as incremental resources within these comparative portfolio views.*
2) *The total capacity of the supply-side additions assumes that the* ***540 MW Dresden CC*** *unit would become operational in April 2013.*

3) *The IRP planning horizon extends to 2019 as represented by the horizontal line. For modeling purposes Strategist constructs portfolios through 2030.*

11.4.2 Observations: Baseload Need Assessment

As shown in Exhibit 11-1, baseload capacity (Nuclear or Coal) was added in only the extreme pricing scenarios. In the Business As Usual (BAU) Case, no cost was assumed for CO_2 emissions and the coal alternative benefited from not incurring the increased cost of CCS equipment. Under the BAU Case conditions, coal additions were made to help replace the significant amount of existing capacity being retired in the 2015 to 2025 timeframe. Nuclear additions become an economic means of replacing the retired capacity under the Constrained Case where commodity prices are the highest of the four scenarios and costly CCS equipment is required on the PC additions. However, even with the additional cost of the CCS equipment a suboptimal plan that includes PC additions is only $70 million more expensive than the plan with nuclear additions.

Under the Reference Case, the 2018 and 2023 combined cycle additions operate over a broad range of capacity factors from 20% - 40% prior to all of the older coal unit retirements (2018-2025) and 40%-60% once all of the older coal units have been retired (post 2025). Under the Reference Case conditions, a plan that adds a PC with CCS equipment in 2023 is $65 million more expensive than the optimal plan with CC additions.

Under the Abundance Case, the commodity prices are low enough that the additional cost of a PC with CCS equipment is not justifiable. The cost of a PC with CCS under these conditions is $160 million more expensive than the optimal plan.

11.4.3 Additional Portfolio Evaluation

As an extension of the optimal portfolios created under the four pricing scenarios, nine additional portfolios were tested, or developed around defined objectives. These nine portfolios were created with the goal of examining the economics of portfolios created under factors and influences other than commodity prices. These nine portfolios can be defined as follows:

- "Best Contrary" Base/High Plan for Baseload Coal Solution
- "Best Contrary" Base/High Plan for Nuclear Solution
- Optimization without post 2020 CCS Requirement on New Coal
- Enhanced Renewables
- "Green Plan" – Best Enhanced Renewables Plan that includes Nuclear
- Demand Destruction
- Demand Destruction plus "Accelerated" Coal Unit Retirements
- High DR/EE Bandwidth
- CO_2 Limited

Exhibit 11-2 provides a summary of these portfolios under Reference Case conditions.

Exhibit 11-2: Portfolio Summary

	Contrary Coal	Contrary Nuclear	No CCS Requirement on Coal Additions	Enhanced Renewables	Green Plan	Demand Destruction	Demand Destruction with Accelerated Retirements	High DR/EE Bandwidth Under Constrained Case	CO_2 Limited
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC		4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs,
2019									
2020							4 - 165 MW CTs		Mountaineer 90% CCS
2021	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs		4 - 165 MW CTs	4 - 165 MW CTs,
2022						4 - 165 MW CTs	4 - 165 MW CTs		
2023	4 - 165 MW CTs, 1 - 625 MW PC w/ CCS	1 - 800 MW Nuke	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs	1 - 800 MW Nuke	4 - 165 MW CTs		4 - 165 MW CTs 1 - 800 MW Nuke	4 - 165 MW CTs, 1 - 650 MW CC
2024		4 - 165 MW CTs		4 - 165 MW CTs			4 - 165 MW CTs		
2025	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs
2026	4 - 165 MW CTs		4 - 165 MW CTs		4 - 165 MW CTs			4 - 165 MW CTs	4 - 165 MW CTs
2027		4 - 165 MW CTs		4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs		4 - 165 MW CTs	4 - 165 MW CTs
2028	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs				4 - 165 MW CTs		4 - 165 MW CTs
2029				4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs		4 - 165 MW CTs	
2030	4 - 165 MW CTs	4 - 165 MW CTs	1 - 618 MW PC w/o CCS				4 - 165 MW CTs		4 - 165 MW CTs, Gavin 1&2 90% CCS Retrofit
2009-2035 Total East System Cost									
CPW ($M)	97.329	97.627	97.319	97.843	98.423	85.188	84.214	127.288	97.905
Levelized ($/MWh)	79.47	79.65	79.46	79.79	80.14	81.34	80.66	98.28	80.06
Number of Units Added									
CT	28	28	24	28	24	24	28	28	32
CC	1	1	2	1	1	1	0	0	1
PC	1	0	1	0	0	0	0	0	0
Nuclear	0	1	0	0	1	0	0	1	0
Total Capacity (MW)	5,895	6,070	5,878	5,270	5,410	4,610	4,620	5,420	5,930
Total Optimized DSM (MW Reduced)	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,692	1,692

Source: AEP Resource Planning

11.4.3.1 "Best Contrary" Base/High Plan for Baseload Coal Solution

The objective behind examining this portfolio was to determine the increased cost of a portfolio that contained solid fuel addition(s) under Reference Case conditions, as well as under the other three pricing scenarios. A selected portfolio (Contrary Coal) containing solid fuel addition(s) was chosen from the suboptimal portfolios created under the Reference and Constrained Cases. The Contrary Coal portfolio was then "forced" into the other pricing scenarios (with the focus on the Reference Case) and its costs were determined and compared to the optimal portfolio from that scenario. Under Reference Case conditions, the Contrary Coal portfolio shown in Exhibit 11-2 was only $65M more expensive than the Reference Case optimal portfolio.

11.4.3.2 "Best Contrary" Base/High Plan for Baseload Nuclear Solution

Similar to the Contrary Coal portfolio, the objective behind examining a Contrary Nuclear portfolio was to determine the increased cost of a nuclear addition under the various pricing scenarios, again with the focus on the Reference Case conditions. Under Reference Case conditions, the Contrary Nuclear portfolio was approximately $365 million more expensive than the optimal portfolio for that scenario.

11.4.3.3 Optimization without post 2020 CCS Requirement on New Coal

The objective of this optimization was to test the viability of solid fuel additions without the burden of increased cost due to CCS equipment. Under Reference Case conditions, the optimization produced an optimal portfolio that added a PC at the very end of the planning period (i.e., 2030). This result indicates that even without the increased cost of the CCS equipment, that the commodity prices under the Reference Case conditions are not sufficiently high enough to warrant the additional capital cost of a solid fuel addition early in the planning period. As seen in Exhibit 11-2, the cost of this portfolio is $55 million more than the optimal portfolio for the Reference Case.

11.4.3.4 Enhanced Renewables

The Enhanced Renewable portfolio was created based on meeting increased AEP system-wide renewable energy targets. The renewable energy targets set for this scenario require that 7% of system-wide energy sales be met with renewable energy resources by 2013, 15% (versus 10%) by 2020 and 20% (versus 15%) by 2030. As shown in Exhibit 11-2, the Enhanced Renewable portfolio adds one less CC than the Reference Case optimal portfolio. However, the cost of the Enhanced Renewable portfolio is approximately $580 million more expensive than the Reference Case optimal portfolio. These results indicate that increasing the amount of renewable energy is not cost effective, at least under Reference Case conditions. However, under the Constrained Case conditions, the Enhance Renewable portfolio does provide some savings over the Constrained Case optimal portfolio.

11.4.3.5 "Green Plan"

The Green Plan portfolio was created from the Enhanced Renewables optimization run under the Reference Case conditions. The Green Plan maintained the same renewable energy targets as the

Enhanced Renewables run, but included a nuclear unit in the early 2020 timeframe, in this instance 2023. The purpose of creating the Green Plan was to test the economics of a portfolio with a very low emissions profiles. As shown in Exhibit 11-2, the Green Plan is approximately $1.2 billion more expensive than the Reference Case optimal portfolio. These results indicate that increasing the amount of renewable energy and the addition of a nuclear unit to offset emissions is not cost effective, at least under Reference Case conditions.

11.4.3.6 Demand Destruction

The Demand Destruction portfolio was created based on a load forecast that reflects a 2.8% reduction in 2008 peak and energy levels through 2010. Beginning in 2011, the peak and energy was assumed to have no growth through 2013. From 2014 through 2035, the peak and energy was assumed to grow at an annual rate of 1%. As shown in Exhibit 11-2, the impact of the load forecast reductions resulted in capacity additions from the Reference Case being delayed from 2018 to 2021 and one less CC being added.

11.4.3.7 Demand Destruction plus "Accelerated" Coal Unit Retirements

In this scenario, there was a three year acceleration in the timing of the coal unit retirements identified during the 2009 Unit Disposition Study. The acceleration in retirements was made possible due to the reduction in peak loads and energy from the Demand Destruction forecast. The purpose of this scenario was to evaluate the economics of accelerating the coal unit retirements. As seen in Exhibit 11-2, accelerating the coal unit retirements provides almost $1 billion in savings over the Demand Destruction optimal portfolio. The majority of these savings are driven by the fact that this portfolio does not add the CC unit found in the Demand Destruction optimal portfolio.

11.4.3.8 High DR/EE Bandwidth

The High DR/EE Bandwidth scenario was developed by increasing the DR/EE impacts from the Reference Case optimal plan by 50%. The DR/EE impacts were increased to determine if adding additional DR/EE was cost beneficial under the high prices of the Constrained Case. The additional DR/EE saves approximately $640 million over the Constrained Case optimal portfolio. These savings are generated primarily by the additional DR/EE impacts avoiding a CC addition found in the Constrained Case optimal portfolio.

11.4.3.9 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/CO2 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, or a limit of approximately 110 million (metric) tonnes for the AEP System. 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, the CO_2 Limited optimizations were made under the High DR/EE Bandwidth and Enhanced Renewables assumptions. The reason for making this assumption was that under a CO_2 limited environment, AEP would make additional investments in DR/EE and renewables to reduce their CO_2 footprint. In addition, Mountaineer was assumed to receive a 90% CO_2 CCS retrofit in 2020 in light of the fact that this unit will be a site of some preliminary testing of CO_2 reducing technologies over the next 5 years.

As a first step in the optimization process, an economic screening of 50%, 70% and 90% CCS retrofits was performed on all of the 800 MW and 1,300 MW units in the East system's generation fleet. The CCS retrofits were screened assuming a 2020 and a 2030 in-service date to coincide with the implementation of CO_2 emission limits in 2020 and the further reduction of those limits in 2030. In general, the screening indicated that the 50% CCS retrofits were the most economic. The next step was to perform a full optimization of screened CCS retrofit alternatives to determine how the CO_2 limits could be met in the most economic manner. Prior to the full optimization, it was determined that in order to meet the CO_2 limits it was necessary to optimize around only the 90% CCS retrofits at 1,300 MW units. *Strategist* results indicated that the 2020 CO_2 targets could be met with the just the 90% CCS retrofit at Mountaineer that was assumed to be present in the existing system. Therefore, an optimization of other CCS retrofits in 2020 was not necessary. In 2030, the model was given the choice of the 90% CCS retrofits at Gavin 1&2, Rockport 1&2 and Amos 3 to meet the 2030 CO_2 emission target. From that optimization, the 90% CCS retrofits at Gavin 1&2 were determined to be the most economic means of meeting the 2030 CO_2 emission target.

A summary of each plan's costs over the full (2009-2035) extended planning horizon, and under the various pricing scenarios is shown in **Exhibit 11-3**.

Exhibit 11-3: Optimized Plan Results (2009-2035) Under Various Pricing Scenarios

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	28	4,620	Total NPV-$B	75.10	81.35	97.48	128.79
CC	0	0	*$/MWh*	*65.76*	*69.60*	*79.56*	*98.87*
PC w/CCS	2	1,250	Fuel NPV-$B	52.02	44.96	50.49	55.22
New Wind[a]		3,220	*$/MWh*	*32.08*	*27.72*	*31.14*	*34.06*
Solar[b]		496					
Total		6,636					
DR[c]		1,074					
Low Power Price Optimal Plan							
CT	28	4,620	Total NPV-$B	75.22	81.55	97.27	128.19
CC	2	1,340	*$/MWh*	*65.82*	*69.48*	*79.41*	*98.48*
PC w/CCS	0	0	Fuel NPV-$B	53.47	46.52	52.53	58.22
New Wind[a]		3,220	*$/MWh*	*32.97*	*28.68*	*32.39*	*35.90*
Solar[b]		496					
Total		6,726					
DR[c]		984					
Base Power Price Optimal Plan							
CT	28	4,620	Total NPV-$B	75.22	81.16	97.26	128.18
CC	2	1,340	*$/MWh*	*65.83*	*69.50*	*79.43*	*98.50*
PC w/CCS	0	0	Fuel NPV-$B	53.46	46.50	52.51	58.20
New Wind[a]		3,220	*$/MWh*	*32.97*	*28.68*	*32.39*	*35.89*
Solar[b]		496					
Total		6,726					
DR[c]		1,074					
High Power Price Optimal Plan							
CT	20	3,300	Total NPV-$B	76.43	81.99	97.81	127.93
CC	1	670	*$/MWh*	*66.60*	*70.03*	*79.79*	*98.37*
Nuclear	2	1,600	Fuel NPV-$B	51.69	44.80	50.24	55.07
New Wind[a]		3,220	*$/MWh*	*31.89*	*27.64*	*31.00*	*33.98*
Solar[b]		496					
Total		6,336					
DR[c]		1,128					
Best Contrary Coal Plan							
CT	24	3,960	Total NPV-$B	75.56	81.32	97.33	128.02
CC	1	670	*$/MWh*	*66.04*	*69.60*	*79.47*	*98.40*
PC w/CCS	2	1,250	Fuel NPV-$B	52.92	45.89	51.72	57.02
New Wind[a]		3,220	*$/MWh*	*32.64*	*28.30*	*31.90*	*35.17*
Solar[b]		496					
Total		6,646					
DR[c]		1,074					
Best Contrary Nuclear Plan							
CT	28	4,620	Total NPV-$B	76.00	81.71	97.63	128.06
CC	1	670	*$/MWh*	*66.32*	*69.84*	*79.65*	*98.42*
Nuclear	1	800	Fuel NPV-$B	52.35	45.45	51.09	56.15
New Wind[a]		3,220	*$/MWh*	*32.29*	*28.03*	*31.51*	*34.63*
Solar[b]		496					
Total		6,856					
DR[c]		1,074					

Notes: a) New wind not in service by year-end 2009. Allowed a summer rating of 13% of nameplate.
b) Solar is allowed a summer rating of 70% of nameplate.
c) Demand Reduction, cumulative DSM peak reduction through 2015.

Exhibit 11-3: (Cont'd) Optimized Plan Results (2009-2035) Under Various Pricing Scenarios

			PRICING SCENARIOS											
			BAU			AbundanceCase			Reference Case			Constrained Case		
	Capacity Categories	Cost Categories	Capacity No.	Capacity MW	Cost	Capacity No.	Capacity MW	Cost	Capacity No.	Capacity MW	Cost	Capacity No.	Capacity MW	Cost
Optimized *without* CCS (post '20) requirement on new coal	Nuclear	Total CPW-$B	0	0	$75.10	0	0	$81.21	0	0	$97.32			
	PC	*$/MWh*	2	1,250	$65.76	0	0	$69.51	1	625	$79.46			
	CC	CPW Fuel-$B	0	0	$52.02	2	1,340	$46.23	2	1,340	$52.15			
	CT	*$/MWh*	28	4,620	$32.08	28	4,620	$28.51	24	3,960	$32.16			
	New Wind[a]			3,220			3,220			3,220				
	Solar[b]			496			496			496				
	Total			6,636			6,726			6,691				
	DR[c]			1,074			984			1,074				
Enhanced Renewables	Nuclear	Total CPW-$B				0	0	$82.23	0	0	$97.84	1	800	$127.92
	PC	*$/MWh*				0	0	$70.14	0	0	$79.79	0	0	$98.37
	CC	CPW Fuel-$B				1	670	$47.63	1	670	$53.24	1	670	$57.29
	CT	*$/MWh*				28	4,620	$29.37	28	4,620	$32.84	24	3,960	$35.35
	New Wind[a]						3,695			3,695			3,695	
	Solar[b]						715			715			715	
	Total						6,271			6,271			6,411	
	DR[c]						984			1,074			1,128	
Green Plan: Best Enhanced Renewables including nuclear	Nuclear	Total CPW-$B							1	800	$98.42	1	800	$128.09
	PC	*$/MWh*							0	0	$80.14	0	0	$98.47
	CC	CPW Fuel-$B							1	670	$51.83	1	670	$56.38
	CT	*$/MWh*							24	3,960	$31.96	24	3,960	$34.78
	New Wind[a]									3,695			3,695	
	Solar[b]									715			715	
	Total									6,411			6,411	
	DR[c]									1,074			1,128	
Demand Destruction	Nuclear	Total CPW-$B							0	0	$85.19	2	1600	$111.52
	PC	*$/MWh*							0	0	$81.34	0	0	$99.72
	CC	CPW Fuel-$B							1	670	$42.58	0	0	$42.59
	CT	*$/MWh*							24	3,960	$29.67	20	3,300	$29.69
	New Wind[a]									3,220			3,220	
	Solar[b]									496			496	
	Total									5,396			5,666	
	DR[c]									1,074			1,128	
Demand Destruction with Accelerated Unit Retirements	Nuclear	Total CPW-$B				0	0	$70.93	0	0	$84.21			
	PC	*$/MWh*				0	0	$71.38	0	0	$80.66			
	CC	CPW Fuel-$B				0	0	$39.04	0	0	$42.80			
	CT	*$/MWh*				28	4,620	$27.20	28	4,620	$29.83			
	New Wind[a]						3,220			3,220				
	Solar[b]						496			496				
	Total						5,386			5,386				
	DR[c]						984			1,074				
High DR/EE Bandwidth	Nuclear	Total CPW-$B										1	800	$127.29
	PC	*$/MWh*										0	0	$98.28
	CC	CPW Fuel-$B										0	0	$55.65
	CT	*$/MWh*										28	4,620	$34.44
	New Wind[a]												3,220	
	Solar[b]												496	
	Total												6,186	
	DR[c]												1,692	
CO2 Limited, utilizing all available options including retrofiting CCS on existing units	Nuclear	Total CPW-$B							0	0	$97.90	2	1600	$125.37
	PC	*$/MWh*							0	0	$80.06	0	0	$97.09
	CC	CPW Fuel-$B							1	670	$53.92	0	0	$57.03
	CT	*$/MWh*							36	5,940	$33.35	32	5,280	$35.29
	New Wind[a]									3,220			3,220	
	Solar[b]									496			496	
	Total									7,376			7,646	
	DR[c]									1,611			1,692	

Notes: a) New wind not in service by year-end 2009. Allowed a summer rating of 13% of nameplate.
b) Solar is allowed a summer rating of 70% of nameplate.
c) Demand Reduction, cumulative DSM peak reduction through 2015.

Source: AEP Resource Planning

11.4.4 Development of the Hybrid Plan

Using the intelligence gained from the *Strategist* runs for various pricing and sensitivity scenarios, a "Hybrid" plan was created that primarily focused on the following:

- While the IRP process was taking place, the Economic Forecasting group prepared a revised load forecast in April, 2009 that was formally issued in May, 2009. The revised forecast reflected a downturn in economic conditions over AEP's service area and in turn, a reduction in AEP's peak and energy requirements compared to the forecast used in the IRP process. The "April" forecast showed a reduction in energy requirements of 4% - 5% and a 2% reduction in peak demand over the planning period compared to the load forecast used in the IRP process. In recognition of the April forecast's lower peak loads, the Hybrid Plan deferred the amount of capacity that had been added in the various IRP optimization runs.
- During the course of the IRP analysis in the Spring of 2009, it became apparent that reducing the size of AEP's significant carbon footprint would be necessary over the long-term due to the emerging likelihood of some level of CO_2 emission limits in the future. Based on the analysis performed within the "CO_2 Limited" sensitivity view, CCS retrofits were introduced into the AEP-East plan so as to accelerate this further migration to a reduced CO_2 position.
- Further, the Renewable Energy Plan that was used in all of the resource optimization runs was revised to reflect an acceleration of wind resource additions. This acceleration was likewise envisioned due to the growing prospect of a Federal Renewable Portfolio Standard either within comprehensive Climate Change/CO_2 legislation or that would be stand-alone. This revised Renewable Energy Plan was used in the development of the Hybrid Plan.

Based on the array of discrete results from varying pricing scenarios and strategic portfolios, the Reference Case Optimal Portfolio was determined to be a reasonable basis for the development of the final AEP-East Hybrid Plan shown in **Exhibit 11-4**. This portfolio generally provided the lowest CPW across the various scenarios when compared to the alternative plans. Also, no portfolio called for baseload capacity prior to 2022, which is outside of the 10 year planning horizon. This provides a level of certainty that any short term decisions made based on the Optimal Portfolio would be equally valid under other portfolios as well.

As stated above, during the development of the Hybrid Plan the timing and number of units added in the Reference Case Optimal Plan was adjusted to reflect the reduction in peak loads found in the April 2009 revised load forecast. In addition, the CCS retrofits identified in the CO_2 Limited optimization runs were also added as part of the Hybrid Plan, as well as the revised Renewable Energy Plan. The reduction in peaking requirements with the April load forecast allowed the number of peaking resources beyond 2018 to be reduced from 24 in the Reference Case to 12 in the Hybrid Plan, however an intermediate resource was added in place of four of these CT's to diversify the energy mix.

The Hybrid Plan identifies thermal capacity additions by duty cycle. With the exception of committed capacity additions, such as Dresden, or enhancements to existing resources, such as the

Cook uprate, *the thermal capacity identified is intended to represent "blocks" of capacity that fit that duty cycle and do not imply a specific solution or configuration.*

Exhibit 11-4: Hybrid Plan

2009 IRP (Hybrid Plan) *AEP-East*

MW	*Planned Resource Reductions* (A)		*Planned Resource Additions* (A)						
			DSM		RENEWABLE			THERMAL	
	Unit Retirements (summer-rating)	Environmental Retrofits(E)	Embedded Demand Reduction(B) (Cumul. Contribution)	New Demand Reduction(C) (Cumul. Contribution)	Solar (Nameplate)	Wind (Nameplate)	Biomass (Derate/ New Facility(D))	Duty Cycle Type: BL=Baseload INT=Intermediate/Cyclic PKG=Peaking	*Ownership*
2009			58	0	0	200			
2010	(440)	MT-Ph1CCS(4 MW) RK1&2 ACI	145	179	10	350			
2011			267	358	3	601			
2012	(560)	AM2 FGD (10 MW)	269	537	2	700	(0) / 60		
2013		AM1 FGD CV5&6 SCR(18MW)	271	716	14	500		(Dresden) 540-MW INT	*APCo*
2014	(395)	MT-Ph2 (31 MW)	272	894	14		(43) / 0	(Cook 2)+45MW BL	*I&M*
2015	(415)	MR5/BS2 FGD (50 MW)	273	1,073	14			(Cook 1&2)+168MW BL	*I&M*
2016			273	1,073	14	100		(Cook 1)+68MW BL	*I&M*
2017	(600)	RK1 FGD	273	1,073	13			(Cook 2)+68MW BL	*I&M*
2018	(580)		273	1,073	17		(41) / 127	(Cook 1)+ 68MW BL and 628-MW PKG	*PKG: APCo/KPCo 50/50; BL: I&M*
2019	(480)	RK2 FGD	273	1,073	17				
2019 Cumul. Contribution/Nameplate	***(3,470)***	***(113)***	***273***	***1,073***	***118***	***2,451***	***103***	***1,585***	
(PJM) Capacity Value (Wind 13%; Solar 70%(est.))					***83***	***319***			
2020		MT-Ph3 (160)	273	1,073	16	200			
2021	(690)		273	1,073	35	150	(0) / 127	611-MW INT	*APCo*
2022			273	1,073	52	100	(41) / 0	628-MW PKG	*APCo*
2023	(660)		273	1,073	0	100		611-MW INT	*APCo/KPCo 50/50*
2024			273	1,073	52	200			
2025	(500)		273	1,073	0	100		628-MW PKG	*APCo/CSP 50/50*
2026			273	1,073	35	100	(41) / 0		
2027			273	1,073	0	100		611-MW INT	*I&M*
2028			273	1,073	35	200			
2029			273	1,073	0				
2030		GV1&2 (390)	273	1,073	43			628-MW PKG	*APCo*
2030 Cumul. Contribution/Nameplate	***(5,320)***	***(663)***	***273***	***1,073***	***384***	***3,701***	***148***	***5,302***	
(PJM) Capacity Value (Wind 13%; Solar 70%(est.))					***269***	***481***			
Cumul. (Nameplate) Contribution thru '30			***3%***	***10%***	***4%***	***34%***	***1%***	***49%***	
Cumul. (Capacity) Contribution thru '30			***4%***	***14%***	***4%***	***6%***	***2%***	***70%***	

10 Year IRP Period (2009–2019)

Extended Planning Horizon (2020–2030)

'NET' CAPACITY RESOURCE ADDITIONS:		
2009-2020	***(147)***	
2009-2030	***1,563***	

Peaking	2,512	*47%*
Intermediate (incl. Dresden)	2,373	*45%*
Baseload (D.C. Cook Uprates)	417	*8%*
	5,302	

(A) Not shown are smaller unit derates and uprates embedded in the current plan which are largely offseting

(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) Derate represents a blended-fuel biomass w/ separate injection, New Facility reflects a single repowered, (100%) dedicated biomass (e.g. stoker) unit from MR 1-4 and a 60 MW PPA

(E) CCS retrofit technology assumed to be chilled ammonia with a 15% parasitic load

Source: AEP Resource Planning

For comparison purposes, a Reference Case plan was created using the same Renewable Plan as the Hybrid Plan. The Hybrid Plan was shown to be approximately $425 million less expensive than this adjusted Reference Case plan. The Hybrid Plan savings are due to many factors including a shift in resource needs due to the updated load forecast as well as the reduction in CO_2 emission costs due to the introduction of CCS retrofits in the extended planning horizon.

11.4.5 Portfolio Views Selected for Additional Risk Analysis

The following summarizes the seven portfolio views as set forth by the discrete AEP East capacity resource modeling performed using *Strategist* that were analyzed further in the Utility Risk Simulation Analysis (URSA) model described in Section 12.

- Reference Case Optimal Plan
- "Best Contrary" Base/High Plan for Baseload Coal Solution
- "Best Contrary" Base/High Plan for Nuclear Solution
- Enhanced Renewables
- "Green Plan" – Best Enhanced Renewables Plan that includes Nuclear
- CO_2 Limited
- Hybrid Plan

These resource portfolio options created in Strategist and their revenue requirements offer modeled economic results based on specific, discrete "point estimates" of the variables that could affect these economics. These portfolios were evaluated over a *distributed range* of certain key variables in URSA, which provided a probability-weighted solution that offers additional insight surrounding relative cost/price risk.

12.0 Risk Analysis

Seven portfolios 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 East 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,
- forced outages of AEP's units.

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.

Exhibit 12-1 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 is roughly equal to 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 12-1: Key Risk Factors–Weighted Means for 2009-2035

	Simulated Outcomes – Hybrid Plan			
	All Outcomes	RRaR-Exceeding Outcomes		
Variable	Mean	Mean	Difference	% Diff
AEP Internal Onpeak Load	17,114	17,111	(2.66)	-0.02%
AEP Onpeak Power Spot	73.95	78.29	4.34	5.87%
NYM Coal Spot	65.63	70.96	5.33	8.12%
Henry Hub Gas Spot	8.37	9.09	0.72	8.60%
CO2 Allowance Spot	24.69	42.46	17.77	71.97%
NOx Allowance Spot	734	736	1.58	0.22%
SO2 Allowance Spot	1,591	2,202	610.60	38.38%
Megawatts Forced Out	2,261	2,258	(2.54)	-0.11%

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 71.97% and 38.38%, 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 slightly lower levels of load and megawatts forced out.

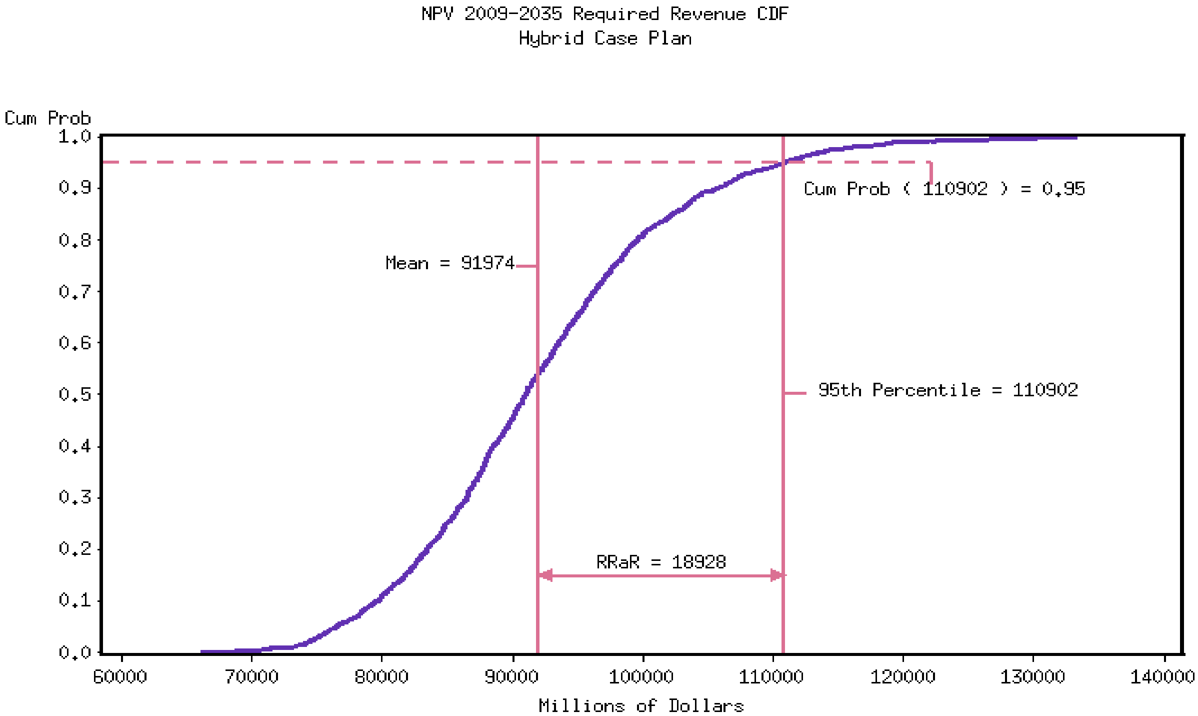
It might be assumed that the very worst possible futures would be characterized by high fuel and allowance prices and low power prices. But according to the analysis of the historical values of risk factors that underlies this study, such futures have essentially no chance of occurring. Any possible 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

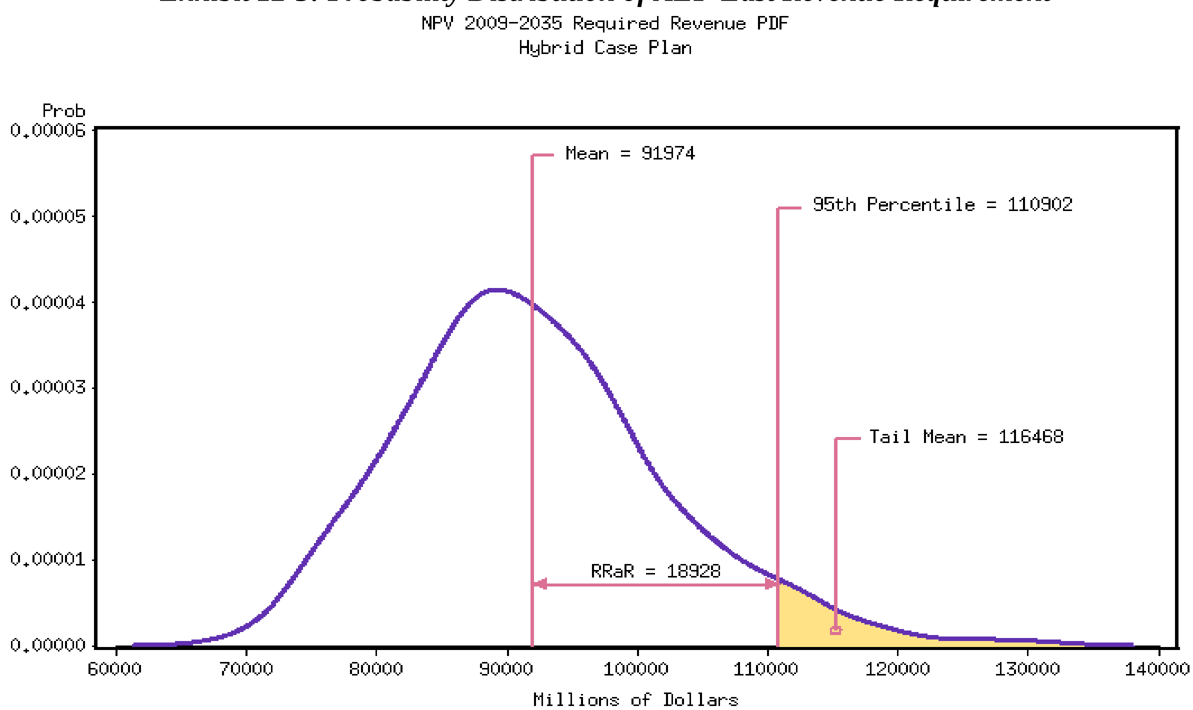
Exhibits 12-2 and **12-3** illustrate the distribution of outcomes for the Hybrid Plan on both a cumulative distribution "S-curve" and probability distribution ("bell-curve") basis, respectively. The graphs for the other six plans examined would be quite similar. The costs included in this analysis are 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 12-2: Cumulative Probability Distribution of AEP-East Revenue Requirement



Source: AEP Market Risk Oversight

Exhibit 12-3: Probability Distribution of AEP-East Revenue Requirement



Source: AEP Market Risk Oversight

12.3 Installed Capital Cost Risk Assessment

In order to further scrutinize the seven plans under the 1399 possible futures, the impacts of Installed 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 installed capital costs of all types of generating capacity were assumed to be perfectly correlated with each other. The fixed representation of installed capital costs in URSA was removed from each URSA output distribution and the resulting distributions were convolved with the installed capital cost distributions.

Exhibit 12-4: Basis of Installed 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 Installed Capital Cost Risk

Exhibit 12-5 summarizes the Installed Capital Cost Risk-adjusted results for all seven AEP-East plans.

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

PLAN	50th Percentile	95th Percentile	Revenue Requirement at Risk
BASE	91,854	114,210	22,356
CONTRARY NUKE	92,016	114,426	22,410
CONTRARY COAL	92,070	114,455	22,385
ENHANCED RENEWABLES	92,934	115,074	22,140
GREEN	92,988	115,128	22,140
CO_2 LIMITED	92,736	112,608	19,872
HYBRID	91,924	111,867	19,943

Source: AEP Resource Planning

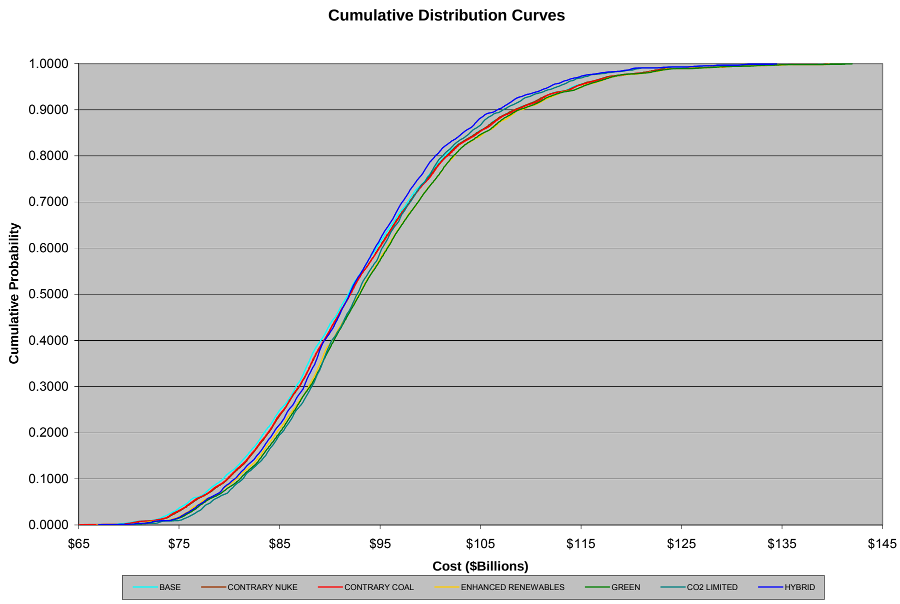
Exhibit 12-5 shows reasonably consistent results across all plans modeled. These comparative results also suggest that, given the fuel/generation diversity of the capacity resource options introduced into the analysis, the relative economic exposure would appear to be small irrespective of the plan selected.

The three lowest-cost plans at the 50^{th} percentile are the Base, Hybrid, and Contrary Nuke plans. However, the lowest Revenue Requirement at Risk plan is the CO_2 limited plan, followed by the Hybrid plan, while the lowest cost plan at the 95^{th} percentile is 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 95^{th}, are preferred.

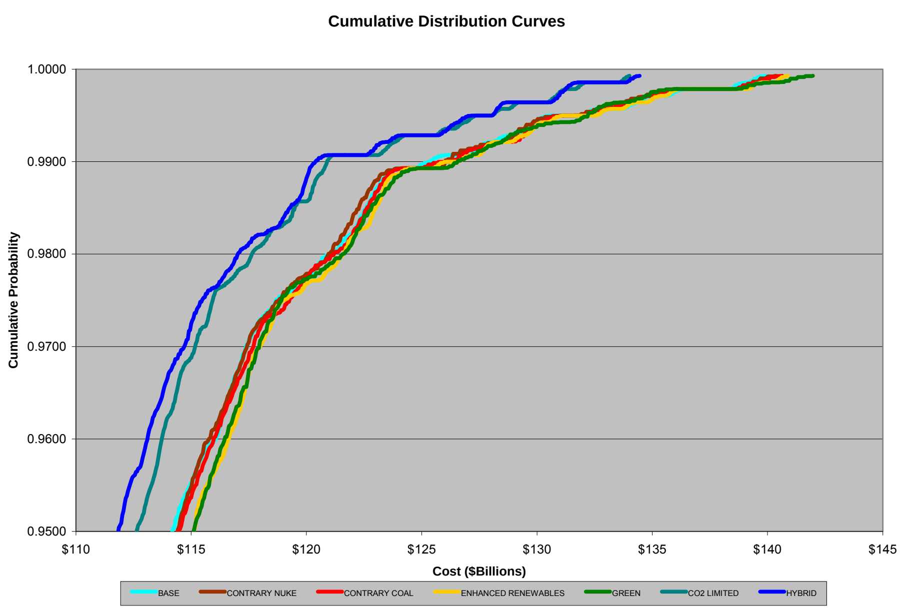
The estimated distributions of revenue required under the seven plans are rather similar. **Exhibits 12-6** and **12-7** show the superimposed graphs of all seven distribution functions. **Exhibit 12-6** shows entire distributions; **Exhibit 12-7** shows only the region at or above the 95th percentile.

Exhibit 12-6: Distribution Function for All Portfolios



Source: AEP Resource Planning

Exhibit 12-7: Distribution Function for All Portfolios at > 95% Probability



Source: AEP Resource Planning

12.5 Conclusion From Risk Modeling

The Hybrid Plan had the lowest cost at both the 50% probability level and the 95% probability level. Its RRaR was the second lowest, slightly behind the CO_2 limited plan. Therefore, it can be concluded that the Hybrid Plan is the least, reasonable cost plan across a wide range of potential outcomes.

13.0 Findings and Recommendations

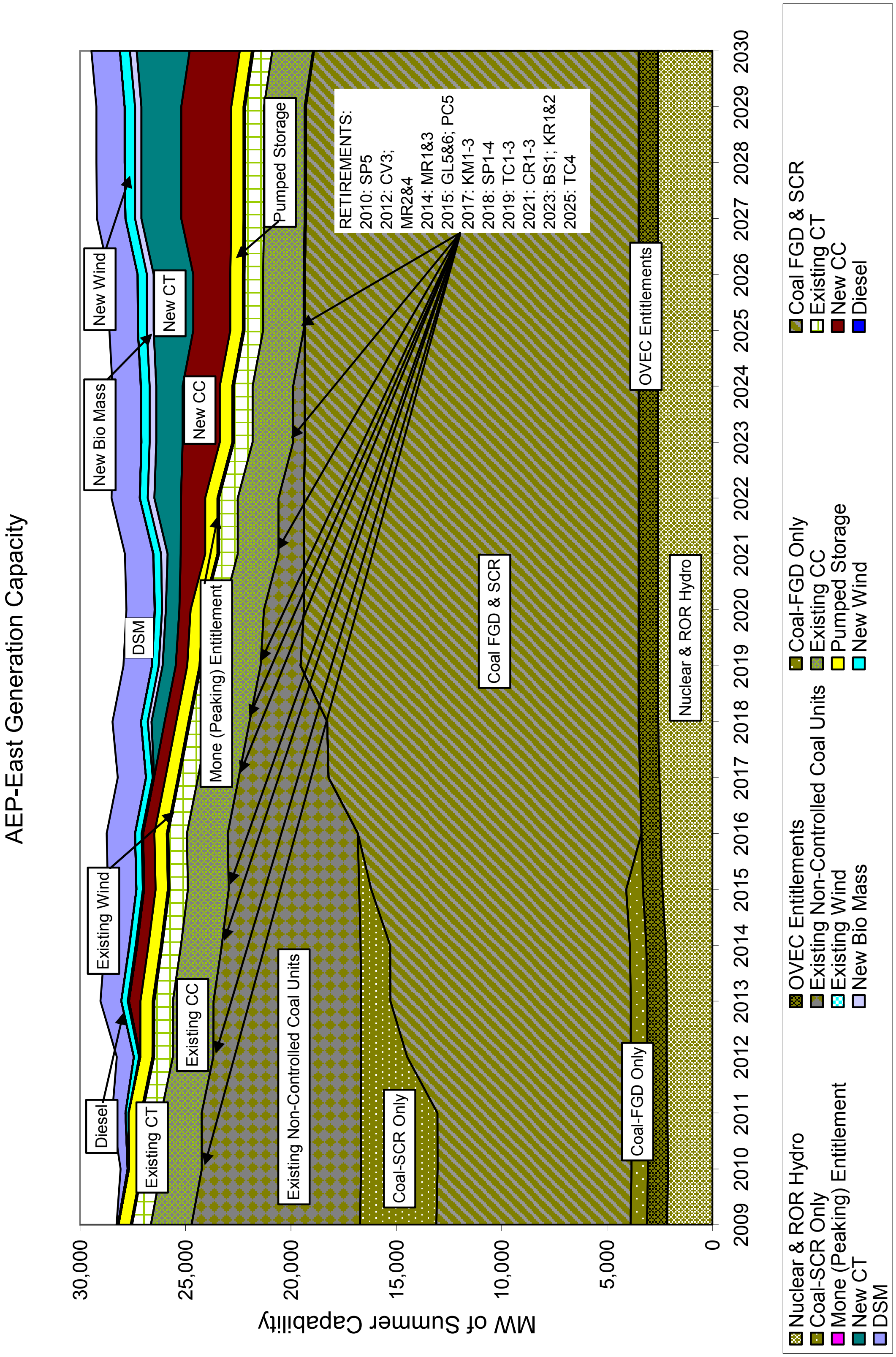
The selection of the Hybrid Plan reflects management's commitment to a diverse portfolio including renewable energy alternatives and demand reduction/energy efficiency. This resource portfolio fares well when compared to the other portfolios when subjected to robust statistical analysis, providing the lowest reasonable life-cycle cost on average, and the least risk to its customers, as measured by required revenue at risk. Other benefits include:

- The Mountaineer Carbon Capture and Sequestration project pre-positions AEP for carbon legislation. Keeping coal as a viable fuel in a carbon-constrained world requires that commercial CCS technology be championed and built. AEP service territory encompasses some of the most prolific coal producing regions in the nation. AEP's steeped history and core competency surrounding coal-based generation would also naturally support such a commitment.
- With mandatory Renewable Portfolio Standards in force in Michigan, West Virginia, and Ohio, and a voluntary standard in Virginia, becoming an early-mover to secure wind power ensures that AEP will be well positioned to achieve those standards.
- Increased DR/EE, consistent with state objectives, assuming customer acceptance and full and contemporaneous rate recovery, could offer an effective means to reduce demand, energy usage, and as a result, our carbon footprint.
- Ability to meet emission caps set forth in the NSR case Stipulated Agreement.

The charts found on **Exhibits 13-1** through **13-4** offer a summary of the resulting AEP-East generating fleet. From a capacity mix standpoint, the most significant take-away would be that the profile represents a diverse technology and fuel mix. That being said, the Plan would continue to reflect as much as a 75% "baseload" (i.e. coal & nuclear) profile by 2019, declining to 62% by 2030.

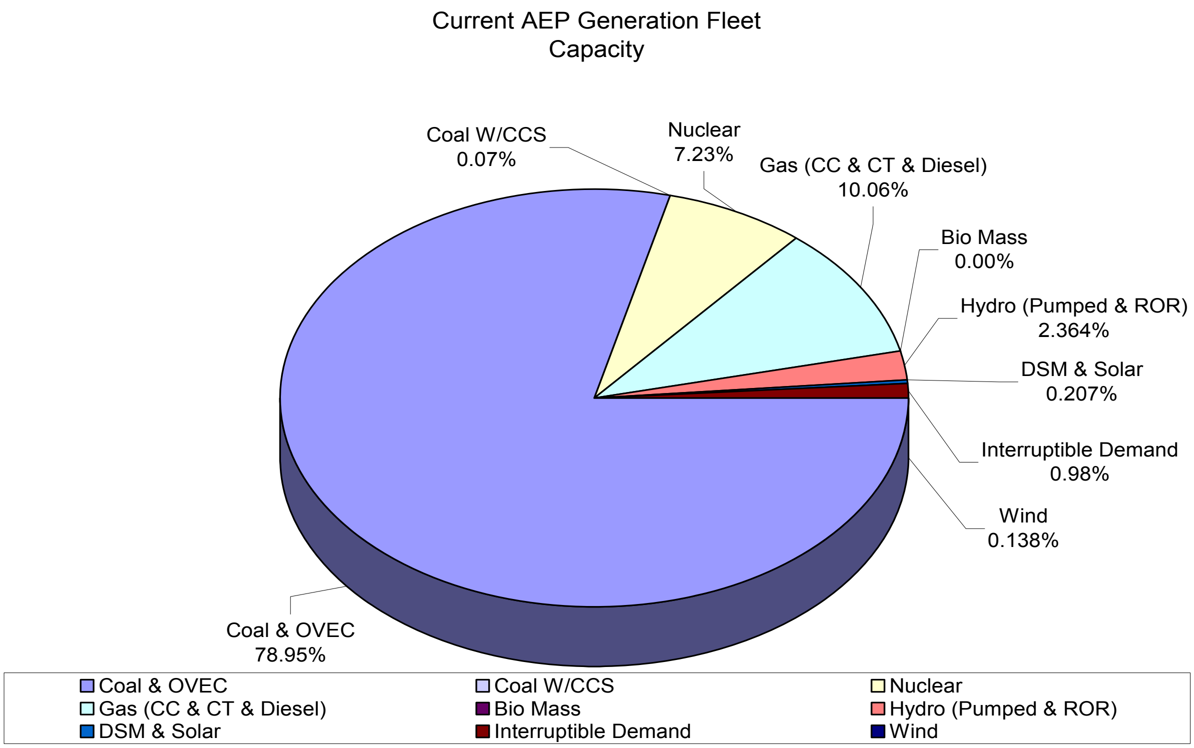
From an environmental stewardship perspective, note that from **Exhibit 13-1** that the AEP-East fleet continues to migrate to a lower carbon emitting portfolio.

Exhibit 13-1: AEP-East Generation Capacity



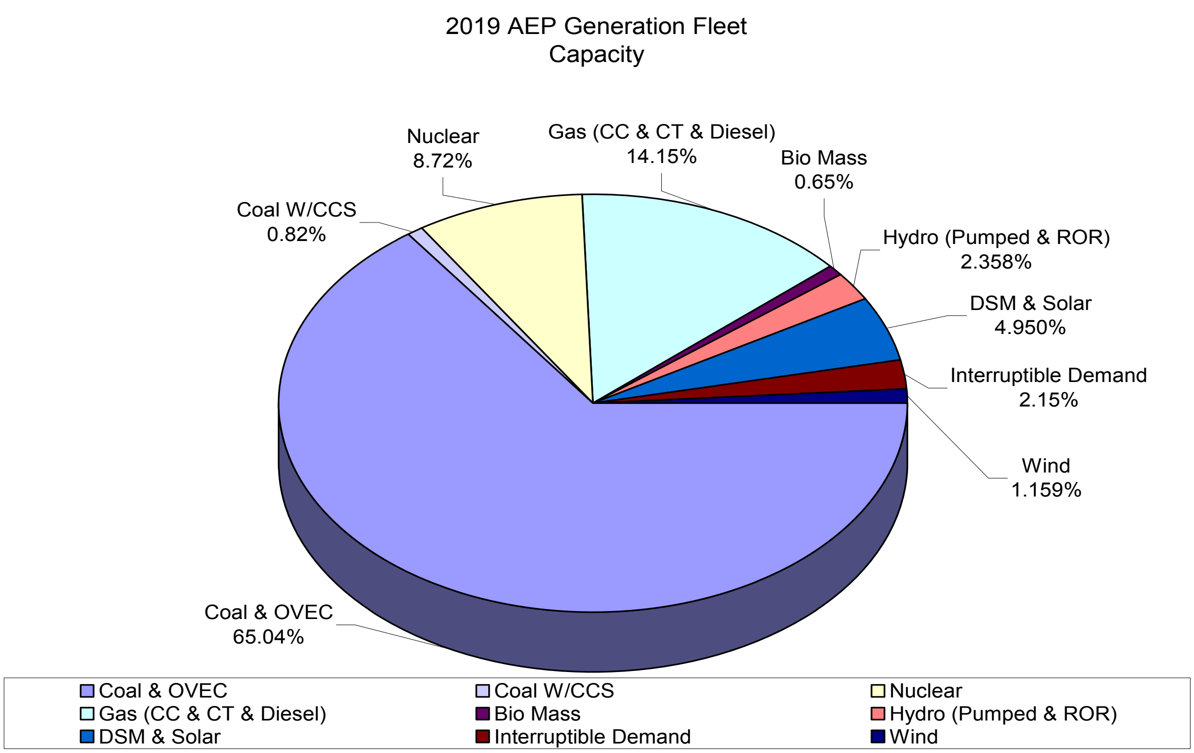
Source: AEP Resource Planning

Exhibit 13-2: AEP-East Current Capacity Mix



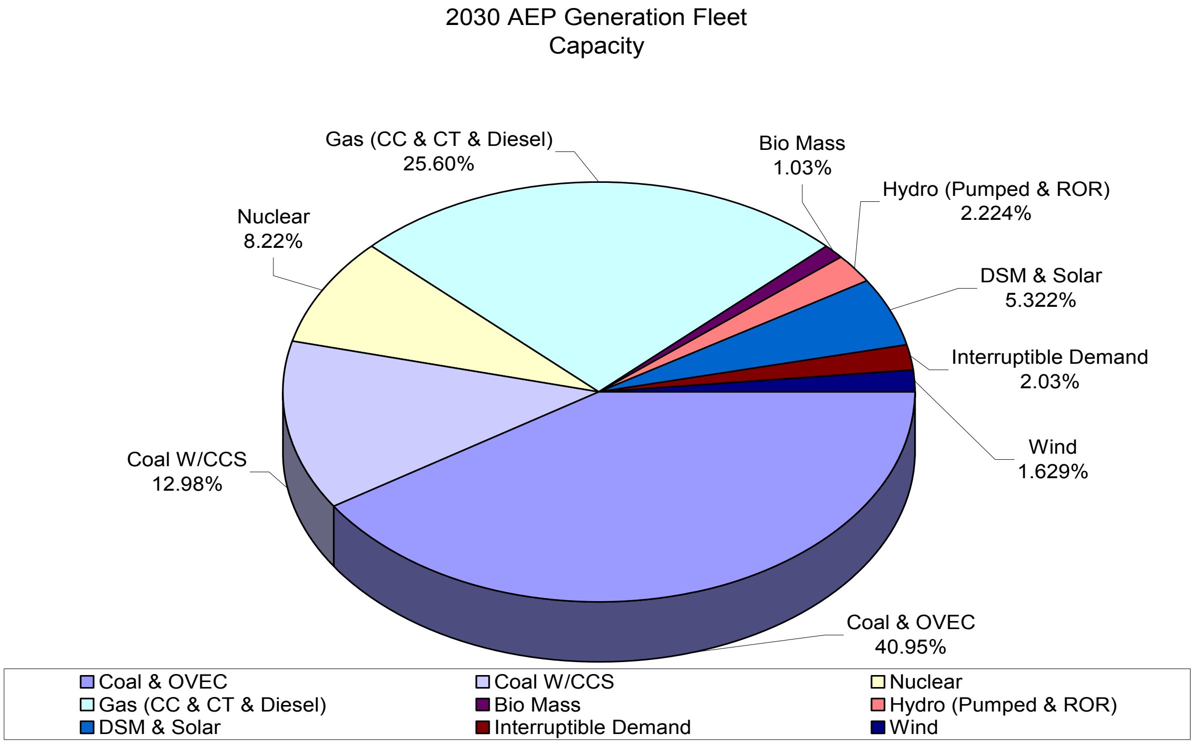
Source: AEP Resource Planning

Exhibit 13-3: AEP-East 2019 Capacity Mix



Source: AEP Resource Planning

Exhibit 13-4: AEP-East 2030 Capacity Mix

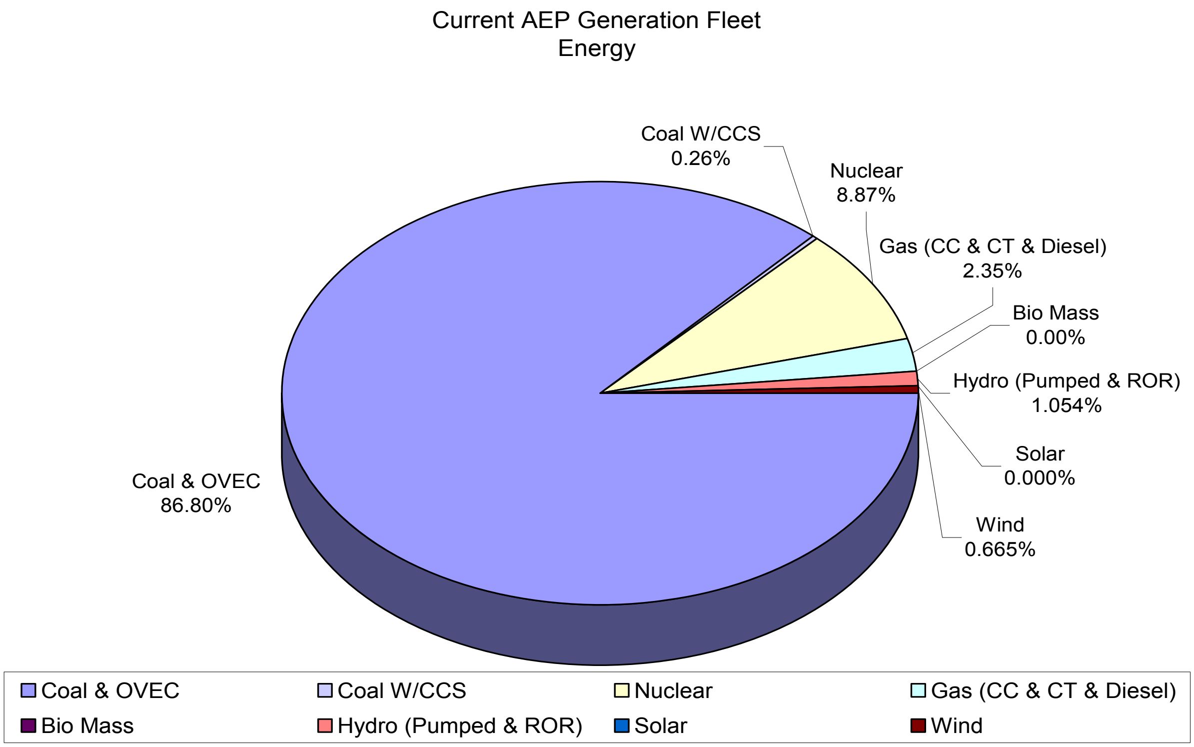


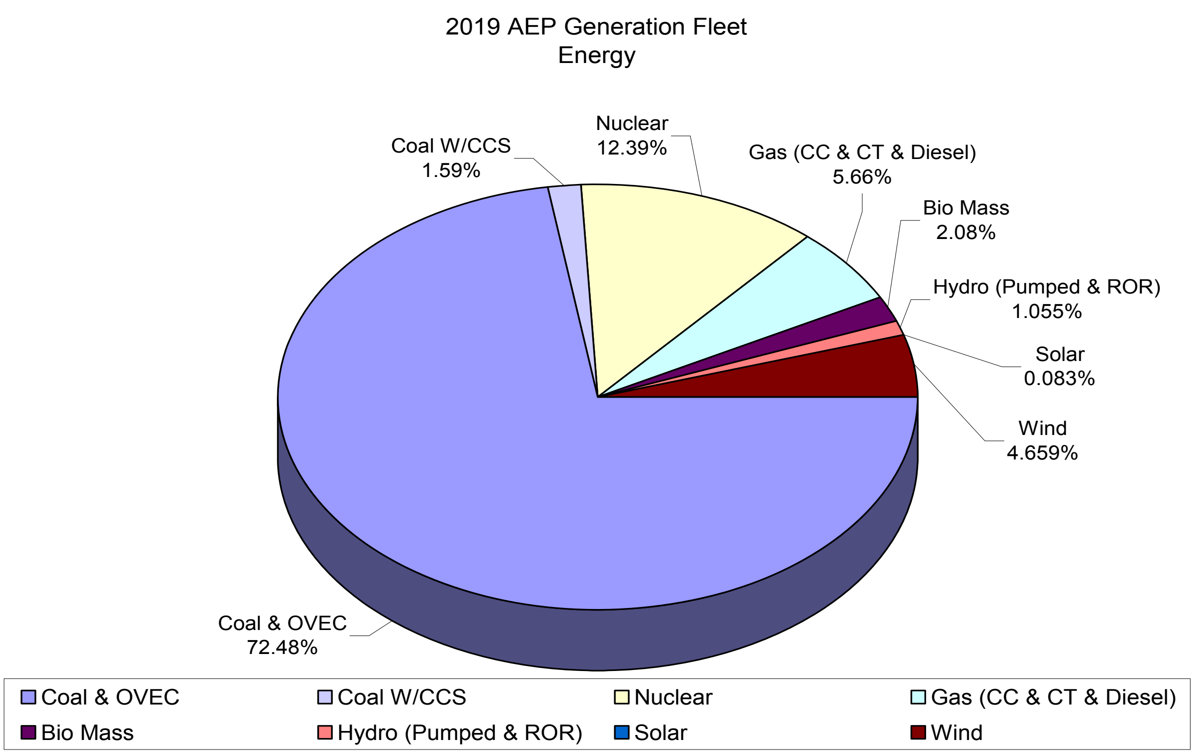
Source: AEP Resource Planning

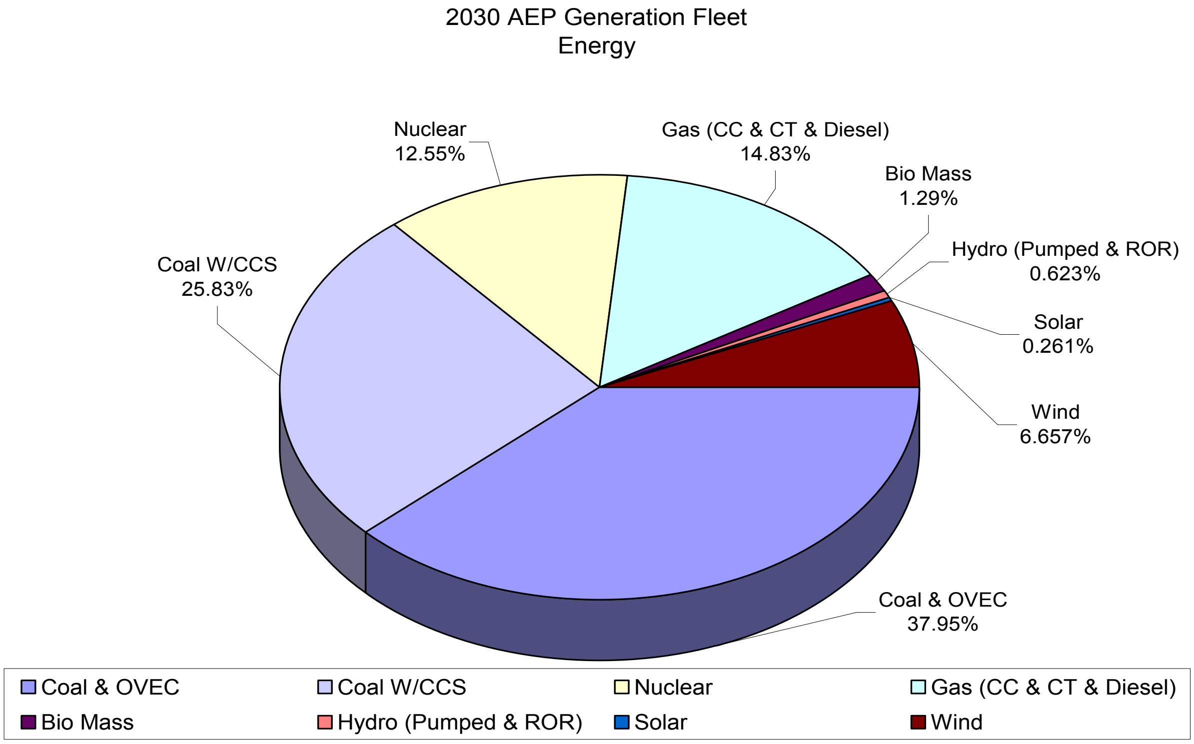
13.1 Capacity and Energy Plan

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.

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







Source: AEP Resource Planning

13.2 Comparison to 2008 IRP:

The 2008 IRP for AEP-East recommended an earlier build profile than the current 2009 IRP. The most notable differences between the two plans are the elimination of the 2017 IGCC unit due to a combination of the addition of the Cook Unit Uprate and additional demand response; deferral of the Dresden facility to 2013; and additional renewable generation sources. The fleet capacity reductions associated with retiring older coal fired units now extend to 2019 so are greater than projected in 2008, which projected retirements to 2017. A summary of the plan differences is presented in **Exhibit 13-6**.

Exhibit 13-6: Comparison of 2008 IRP to 2009 IRP

2008 Vs 2009 IRP for AEP-East

All Units in MW	*Planned Resource Reductions*		*Planned Resource Additions*						
			DSM		RENEWABLE				THERMAL
	Unit Retirements (summer-rating)	Environmental Retrofits	Embedded Demand Reduction *(Cumul. Contribution)*	New Demand Reduction *(Cumul. Contribution)*	Solar (Nameplate)	Wind (Nameplate)	Biomass (Derate / New Facility	NAS Batteries	Peaking/ Intermediate/ Baseload
2008 Plan	*(3,125)*	*(131)*		950	0	1,395		6	*2,132*
2009 Plan	*(3,470)*	*(113)*	273	1,073	118	2,451	103	0	*1,585*
Difference	*(345)*	***18***	**273**	**123**	**118**	**1,056**	**103**	*(6)*	*(547)*

Source: AEP Resource Planning

13.3 Plan Impact on CO_2 Emissions (*"Prism" Analysis)*

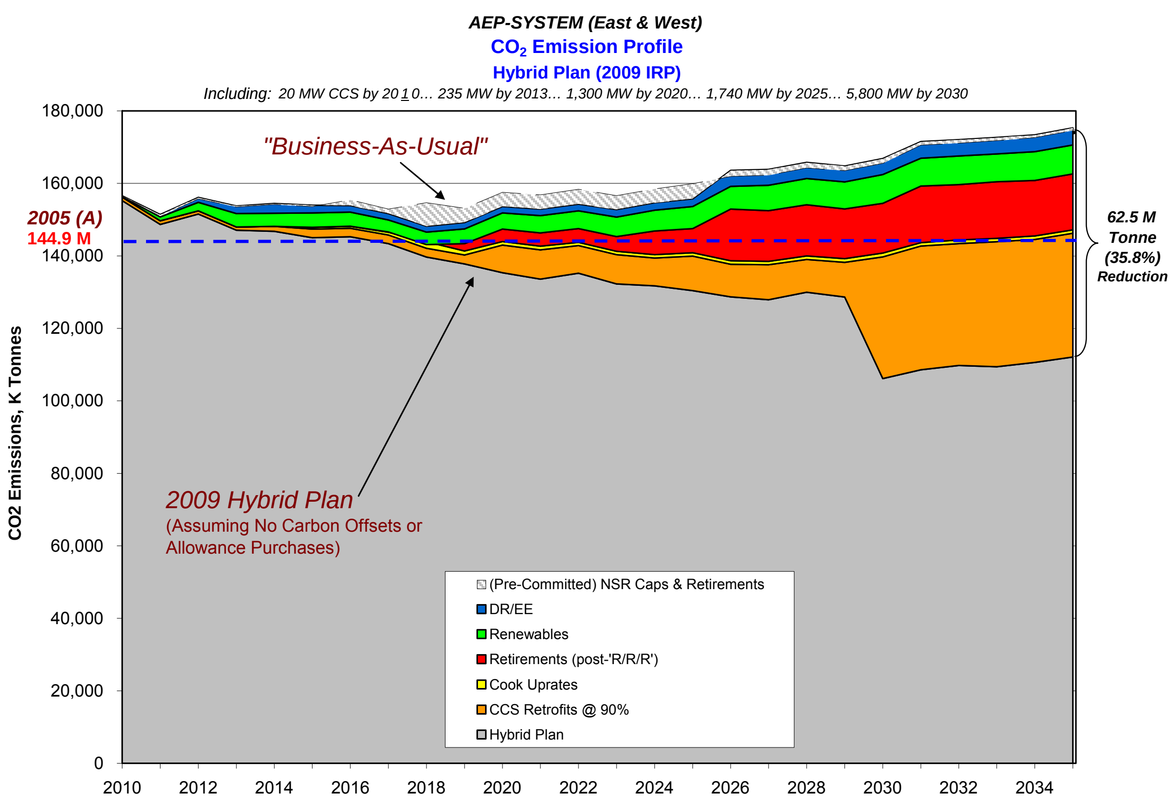
The Hybrid Plan includes resource additions that will result in lowering AEP's carbon emissions over the next 20 years. By retiring older, less efficient coal fired units, increasing nuclear capacity at the Cook plant, adding wind and solar resources, adding carbon capture and sequestration to larger coal units, and implementing energy efficiency programs, AEP has laid out a plan that is consistent with pending legislation and corporate sustainability.

To gauge those 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 through:

- 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:

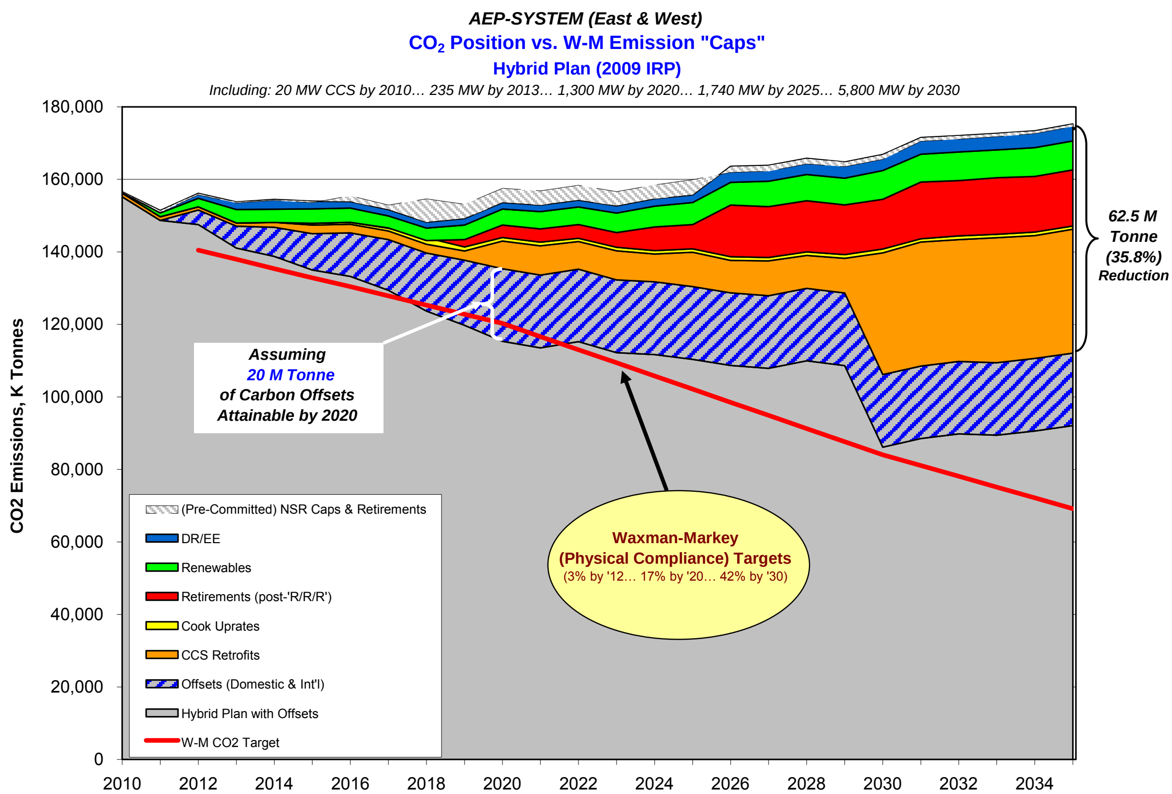
Exhibit 13-7: AEP System CO_2 Emission Reductions, by "Prism" Component



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:

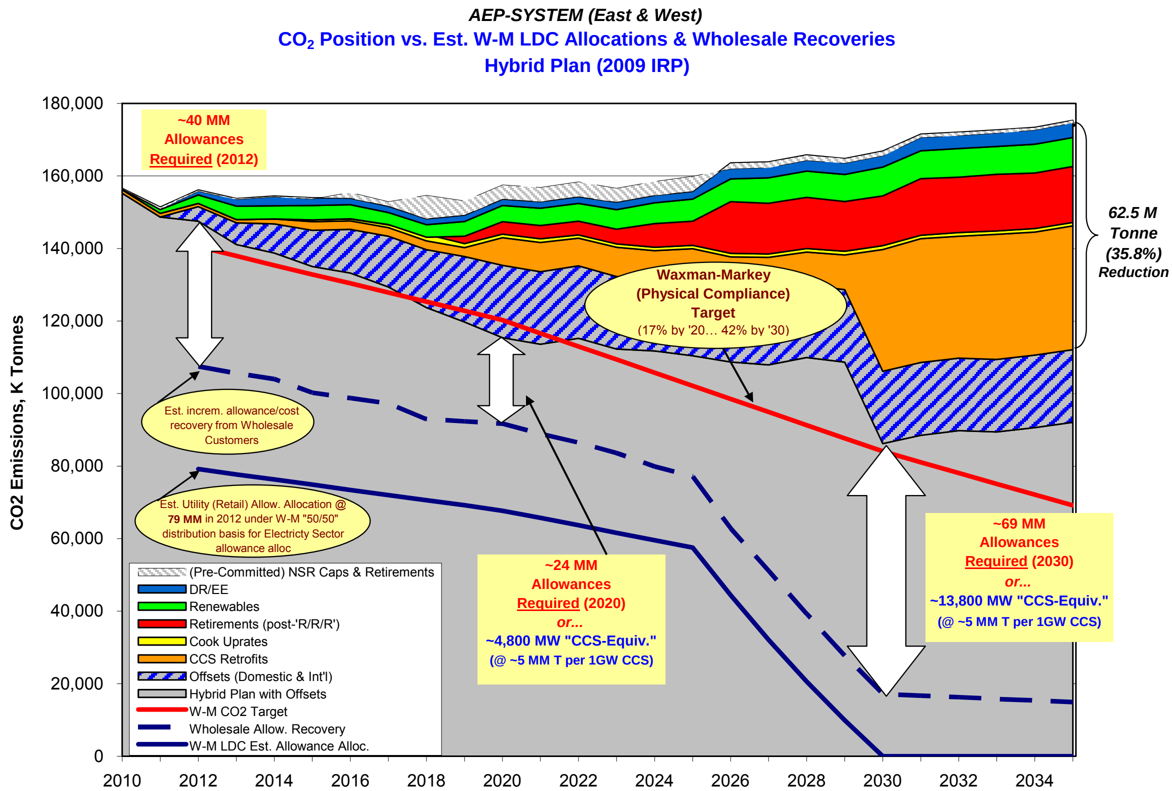
Exhibit 13-8: Comparison of CO_2 Emission Levels vs. W-M "Targets"



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-Market Bill:

Exhibit 13-9: Comparison of CO_2 Emission Levels vs. W-M Allowance Allocations



Source: AEP Resource Planning

In summary, this prism analysis would suggest that the carbon mitigation requirements in the AEP-East 2009 IRP 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 process to protect AEP's customers.

14.0 AEP-East Operating Companies—Plan Implications

Once the recommended overall AEP-East resource plan was selected, it was next evaluated from the perspective of its implementation across the region's five member companies. This process involved consideration of:

- Specific operating company resource assignment/allocations based on relative capacity positions; and
- Attendant capacity settlement ("Pool") effects.

14.1 AEP-East—Overview of Potential Resource Assignment by Operating Company

As described throughout this report, the recommended resource plan for AEP's Eastern (PJM) zone was formulated on a region-wide view, recognizing that AEP plans and operates its eastern fleet on an integrated basis, as outlined in the AEP Interconnection ("Pool") Agreement. As specified in the Pool Agreement, each Member Company (APCo, CSP, I&M, KPCo & OPCo) is required to provide an equitable contribution to the incremental capacity resource requirements of AEP-East. This contribution has been historically based on its relative percentage surplus/deficit reserve margin of each company.

Exhibit 14-1 identifies the Member Company timing and type of new capacity–CT, D (Dresden) CC, Biomass, Wind, – represented in the recommended ("Hybrid") AEP-East capacity resource plan.

Exhibit 14-2 identifies the resulting Member Company Reserve Margins over the next 20 years. As reflected in the chart, the result of this ownership regiment serves to:

- Reduce the absolute capacity deficiency for each Member Company
- Cause the reserve margins of all Member Companies to begin to converge over the 10-year IRP period.

Exhibit 14-1: AEP-East New Capacity Resource Assignments

Summer*	Winter	AEP					APCo					CSP				
		CC	CT	D CC2	Bio Mass	Wind**	CC	CT	D CC2	Bio Mass	Wind**	CC	CT	D CC2	Bio Mass	Wind**
2009	2009/10					5					2.0					1.0
2010	2010/11					14					5.5					2.0
2011	2011/12					14					4.0					2.5
2012	2012/13				60	10					2.0				45	3.0
2013	2013/14			1					1							
2014	2014/15															
2015	2015/16					2										0.8
2016	2016/17															
2017	2017/18															
2018	2018/19		4		127			2								
2019	2019/20					4										4.0
2020	2020/21					3										
2021	2021/22	1			127	2	1.0									2.0
2022	2022/23		4			2		4								2.0
2023	2023/24	1				4	0.5									
2024	2024/25					2					2.0					
2025	2025/26		4			2		2					2			
2026	2026/27					2					2.0					
2027	2027/28	1				4					2.0					
2028	2028/29															
2029	2029/30															
2030	2030/31		4					2					2			

Summer*	Winter	I&M					KPCo					OPCo				
		CC	CT	D CC2	Bio Mass	Wind**	CC	CT	D CC2	Bio Mass	Wind**	CC	CT	D CC2	Bio Mass	Wind**
2009	2009/10					1.0										1.0
2010	2010/11					3.0					1.0					2.5
2011	2011/12					2.0					1.0					4.5
2012	2012/13					2.0									15	3.0
2013	2013/14															
2014	2014/15															
2015	2015/16					1.2										
2016	2016/17															
2017	2017/18															
2018	2018/19							2							127	
2019	2019/20															
2020	2020/21					3.0										
2021	2021/22														127	
2022	2022/23															
2023	2023/24					4.0	0.5									
2024	2024/25															
2025	2025/26					2.0										
2026	2026/27															
2027	2027/28	1.0				2.0										
2028	2028/29															
2029	2029/30															
2030	2030/31															

10-Year IRP Period (2009–2019)

Extended Planning Period (2020–2030)

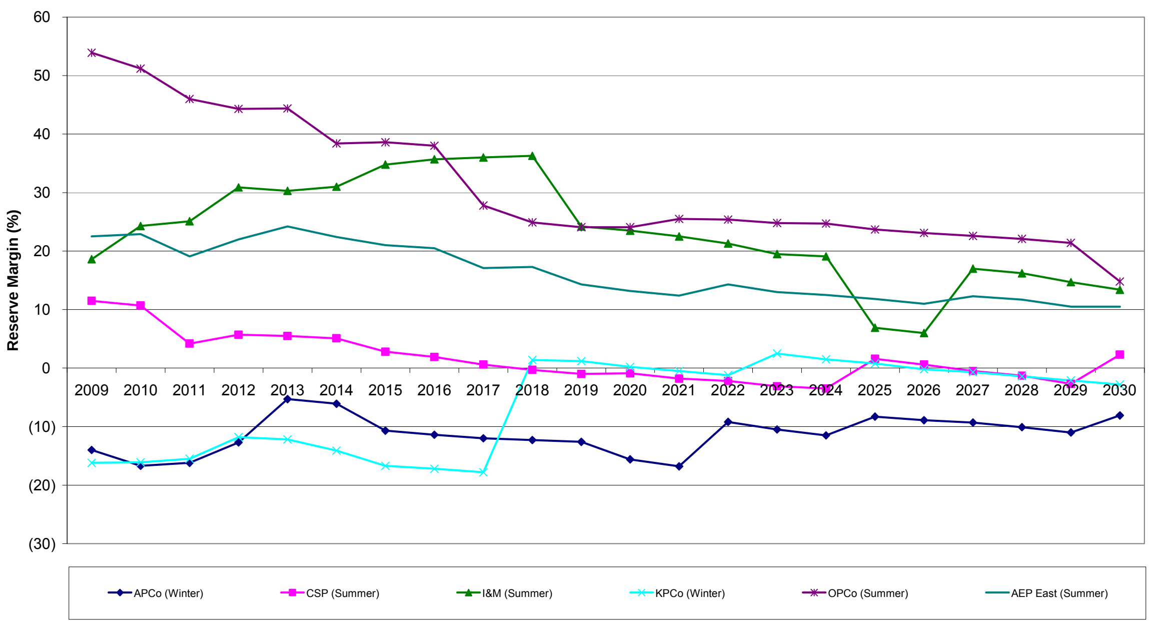
Capacity (MW/Unit)	CC	CT	D CC2	Bio Mass	Wind**
Summer	611	157	540	1	50
Winter	669	171	625	1	50

* To qualify for Summer availability status a resource must be available by June 1st of that year.

** Wind resources must be completed by December 31st of the previous year to qualify for Summer availability status. A unit marked available for the Summer of 2010 must be completed no later than 12/31/2009

Source: AEP Resource Planning

Exhibit 14-2: Projected AEP-East Reserve Margin, By Company and System for IRP Period



Source: AEP Resource Planning

14.2 AEP-East "Pool" Impacts

Under the AEP Pool Agreement, capacity cost sharing is determined by each Member Company assuming its Member Primary Capacity Reservation share of the overall (AEP-East zone) System Primary Capacity (calculated by multiplying each Member Company's respective Member Load Ratio {MLR} by the total System Primary Capacity). Consequently, as new capacity is added or removed, all Member Companies' Capacity Settlement payments or receipts are changed.

Exhibit 14-3 summarizes the projected incremental System Pool/Capacity Settlement impacts to the AEP-East zone Member Companies assumed in this recommended 2009 plan. While the largest portion of the incremental capacity resource ownership obligation for new capacity would be borne by APCo, the incremental annual capacity pool "credits" APCo would be, cumulatively, $803 million by the end of 2019

Exhibit 14-3: Incremental Capacity Settlement Impacts of the IRP

Capacity Settlement Benefits/(Costs) ($in Millions) - IRP Change											
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
APCo	-	-	23	28	56	126	144	95	92	121	116
CSP	-	-	12	11	0	(18)	(4)	(13)	(16)	5	0
I&M	-	-	17	17	39	18	41	86	100	146	163
KPCo	-	-	4	3	10	4	5	8	7	12	81
OPCo	-	-	(56)	(59)	(105)	(130)	(187)	(176)	(183)	(285)	(361)
Total	**-**	**-**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Source: AEP Financial Forecasting

15.0 Implementation

15.1 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
- Natural Gas Combined Cycle units – about 36 months
- Solid Fuel units – about 72 months or more

15.1.1 AEP-East Implementation Status

1) **Wind Contracts** (by 12/31/2009): Contracts have been signed for wind purchases for a total of 625 MW (nameplate) on behalf of APCo (375 MW), CSP (50 MW), OPCo (50 MW) and I&M (150 MW). Regulatory approvals have been received for some of these contracts in four of the five states (Virginia, West Virginia, Indiana, and Michigan). No approval was sought or received in Ohio.

2) **DSM Market Potential** Studies have either been completed or have been commissioned in Ohio, Virginia, West Virginia, Tennessee, Michigan and Indiana; all are expected to be complete by Fall 2009 The following states are preparing to file petitions with their commissions or have plans already filed:

   Indiana:

   I&M's initial proposed DR/EE program portfolio was rejected by the IURC in-March 2009. Subsequently a collaborative was formed, as mandated by the IURC, to redefine the DR/EE portfolio. I&M expects to begin implementation of programs in early 2010.

   Michigan:

   Energy Optimization (energy efficiency) and renewable standards are included as part of a comprehensive energy law enacted in 2008.
   On Dec. 19, 2008, I&M filed with the MPSC intent to use the State Independent Energy Optimization Program Administrator to meet the requirements of the law. I&M expects to have energy optimization programs in place in early 2010.

   Kentucky:

   Currently implementing three new programs in 2009. Will continue to work through the collaborative process towards achievement of internal goals.

   Ohio:

   An initial group of seven quicker starting programs have been developed to share with a utility collaborative and PUCO staff for early implementation upon approval of the Electricity Security Plan. The filing covers the 2009-2011 period.

Virginia:

APCo filed testimony addressing reasonably achievable levels of energy efficiency with the Virginia State Corporation Commission (SCC). The filing was required of the state's largest electric utilities as part of legislation adopted by the 2009 General Assembly seeking how best to develop energy efficiency or demand reduction programs to slow or reverse the growth of energy consumption in Virginia.

3) **Dresden CC Unit** (2013): The partially built, 540MW (summer) unit has been purchased. Completion of construction is scheduled prior to June 1, 2013.

4) **Renewable** (by 1/31/2011): (a) On June 1, 2009 AEP issued a request for proposals (RFP) seeking long-term purchases of up to 1,100 megawatts (MW) of renewable energy resources. Proposals must include commercially proven renewable energy technologies such as wind, certified low-impact hydro, commercial-scale solar, geothermal, biologically derived methane gas and certain biomass and biofuels energy projects. The generation must be interconnected to PJM Interconnection (PJM) or Southwest Power Pool (SPP) and be operational no later than Dec. 31, 2011.

5) **NG Combustion Turbine (**2018): Given the uncertainty surrounding efforts (or ability given the current RPM protocol) to either: 1) purchase PJM market capacity in the future; or 2) identify and acquire additional distressed assets opportunities, steps will ultimately need to be undertaken internally to evaluate Greenfield or Brownfield-site construction of CT capacity in the East Zone.
   - *The New Generation Development siting advisory group* has performed evaluations to establish a short-list, from a list of 40 potential sites–most of which are located in Ohio, Virginia, or West Virginia–originally identified by the group in April 2006. Such siting studies are intended to screen, score and rank potential CT or CC sites based on a multitude of factors and will be updated in the future as necessary.
   - *Generation Asset Purchase Opportunities*: Although some years remain before concrete action would be needed to have a greenfield CT plant on by 2018, AEP continues to monitor the region for potential asset purchase opportunities.

6) **Solar** (2010-2012): AEP-Ohio has a PPA for 10 MW of solar capacity beginning 2010. This will meet the solar benchmarks included in SB 221 through 2011. Solar benchmarks for 2010, 2011 and 2012 are, respectively 1.8 GWh, 4.5 GWh, and 12.0 GWh.

To implement the recommendations included in this plan, significant capital expenditures will be required. These expenditures are outlined in the confidential Appendix I. 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-East Zone

AEP System - East Zone
(Including Buckeye Power Capacity per Operating Agreement)
Existing Generation Capacity as of June 1, 2009

Plant Name	Unit No.	In-Service Date		AEP Own/ Contract	Mode of Operation	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	SCR Installation Year	FGD Installation Year	Super Critical	Age
APCo												
Amos	1	1971		O	Base	800	800	Coal	2005	2013	Y	38
Amos	2	1972		O	Base	800	800	Coal	2004	2012	Y	37
Amos	3	1973		O	Base	433	428	Coal	2004	2009	Y	36
Clinch River	1	1958		O	Base	235	230	Coal	--	--	N	51
Clinch River	2	1958		O	Base	235	230	Coal	--	--	N	51
Clinch River	3	1961		O	Base	235	230	Coal	--	--	N	48
Glen Lyn	5	1944		O	Base	95	90	Coal	--	--	N	65
Glen Lyn	6	1957		O	Base	240	235	Coal	--	--	N	52
Kanawha River	1	1953		O	Base	200	200	Coal	--	--	N	56
Kanawha River	2	1953		O	Base	200	200	Coal	--	--	N	56
Mountaineer	1	1980		O	Base	1,320	1,310	Coal	2004	2007	Y	29
Sporn	1	1950		O	Base	150	145	Coal	--	--	N	59
Sporn	3	1951		O	Base	150	145	Coal	--	--	N	58
APCo Coal						5,093	5,043					41
Ceredo	1-6	2001	(a)	O	Peaking	516	450	Gas (CT)	--	--	N	8
APCo Gas						516	450					8
APCo Hydro		Various		O	Base	142	51	Hydro	--	--		
Summersville	1-2	2001		C	Base	27	7	Hydro	--	--		8
APCo Hydro			(b)			169	59					8
Smith Mountain	1	1965		O	Peaking	66	66	PSH	--	--	--	44
Smith Mountain	2	1965		O	Peaking	174	174	PSH	--	--	--	44
Smith Mountain	3	1980		O	Peaking	105	105	PSH	--	--	--	29
Smith Mountain	4	1966		O	Peaking	174	174	PSH	--	--	--	43
Smith Mountain	5	1966		O	Peaking	66	66	PSH	--	--	--	43
APCo Pumped Storage						585	585					41
APCo Wind		Various	(c)	C	Wind Project	26	26	Wind	--	--	--	
Total APCo						**6,389**	**6,163**					
Cardinal-Buckeye												
Cardinal	2	1967		C	Base	580	580	Coal	2004	2008	Y	42
Cardinal	3	1977		C	Base	630	630	Coal	2004	2012	Y	32
Buckeye Coal						1,210	1,210					37
Robert Mone	1-3	2001	(d)	C	Peaking	145	55	Gas (CT)	--	--	--	8
Buckeye Gas						145	55					8
Total Buckeye						**1,355**	**1,265**					
CSP												
Beckjord	6	1969		O	Base	52	52	Coal	--	--	N	40
Conesville	3	1962		O	Base	165	165	Coal	--	--	N	47
Conesville	4	1973		O	Base	337	337	Coal	2009	2009	Y	36
Conesville	5	1976		O	Base	395	395	Coal	2015	1976	N	33
Conesville	6	1978		O	Base	395	395	Coal	2015	1978	N	31
Picway	5	1955		O	Base	100	95	Coal	--	--	N	54
Stuart	1	1971		O	Base	151	151	Coal	2004	2008	Y	38
Stuart	2	1970		O	Base	151	151	Coal	2004	2008	Y	39
Stuart	3	1972		O	Base	151	151	Coal	2004	2008	Y	37
Stuart	4	1974		O	Base	151	151	Coal	2004	2008	Y	35
Zimmer	1	1991		O	Base	330	330	Coal	2004	1991	Y	18
CSP Coal						2,378	2,373					34
Waterford	1-6	2002	(a)	O	Intermediate/Pkg (CC)	850	810	Gas (CC)	2002	--	N	7
Darby	1-6	2002	(e)	O	Peaking (CT)	507	435	Gas (CT)	2002	--	N	7
Lawrenceburg	1-6	2004	(e)	O	Intermediate/Pkg (CC)	1,186	1,120	Gas (CC)	--	--	N	5
Stuart Diesel	1-4	1969		O	Peaking (Diesel)	3	3	Oil (Diesel)	--	--	N	40
CSP Gas/Oil						2,546	2,368					6
CSP Wind		Various	(c)	C	Wind Project	0	0	Wind	--	--	--	
Total CSP						**4,924**	**4,741**					

(a) Acquired in 2005
(b) Hydro capacity is rated at expected annual average output
(c) The capacity of the Wind Energy Projects are listed at the preliminary PJM credit, 13% of the nameplate capacity
(d) The listed Mone capacity is the net impact of the various contracts with Buckeye Power
(e) Acquired in 2007 by AEP Generating Co, CSP receives capacity and energy via agreement

Appendix A, Figure 2 Existing Generating Capacity, AEP-East Zone (cont'd)

AEP System - East Zone
(Including Buckeye Power Capacity per Operating Agreement)
Existing Generation Capacity as of June 1, 2009

Plant Name	Unit No.	In-Service Date		AEP Own/ Contract	Mode of Operation	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	SCR Installation Year	FGD Installation Year	Super Critical	Age
I&M												
Rockport	1	1984		O	Base	1,122	1,114	Coal	2017	2017	Y	25
Rockport	2	1989		C	Base	1,105	1,105	Coal	2019	2019	Y	20
Tanners Creek	1	1951		O	Base	145	145	Coal	--	--	N	58
Tanners Creek	2	1952		O	Base	145	145	Coal	--	--	N	57
Tanners Creek	3	1954		O	Base	205	195	Coal	--	--	N	55
Tanners Creek	4	1964		O	Base	500	500	Coal	--	--	Y	45
I&M Coal						3,222	3,204					31
I&M Hydro			(b)		Base	15	11	Hydro	--	--	--	
Cook Nuclear	1	1975		O	Base	1,084	1,007	Nuclear	--	--	--	34
Cook Nuclear	2	1978		O	Base	1,107	1,057	Nuclear	--	--	--	31
I&M Nuclear						2,191	2,064					32
I&M Wind		Various	(c)	C	Wind Project	13	13	Wind	--	--	--	
Total I&M						**5,441**	**5,292**					
KPCo												
Big Sandy	1	1963		O	Base	260	260	Coal	--	--	N	46
Big Sandy	2	1969		O	Base	800	800	Coal	2004	2015	Y	40
Rockport	1	1984		O	Base	198	197	Coal	2017	2017	Y	25
Rockport	2	1989		C	Base	195	195	Coal	2019	2019	Y	20
KPCo Coal						1,453	1,452					36
Total KPCo						**1,453**	**1,452**					36
OPCo												
Amos	3	1973		O	Base	867	857	Coal	2004	2009	Y	36
Cardinal	1	1967		O	Base	580	580	Coal	2004	2008	Y	42
Gavin	1	1974		O	Base	1,320	1,315	Coal	2004	1994	Y	35
Gavin	2	1975		O	Base	1,320	1,315	Coal	2004	1994	Y	34
Kammer	1	1958		O	Base	210	200	Coal	--	--	N	51
Kammer	2	1958		O	Base	210	200	Coal	--	--	N	51
Kammer	3	1959		O	Base	210	200	Coal	--	--	N	50
Mitchell	1	1971		O	Base	770	754	Coal	2007	2007	Y	38
Mitchell	2	1971		O	Base	790	790	Coal	2007	2007	Y	38
Muskingum River	1	1953		O	Base	205	190	Coal	--	--	N	56
Muskingum River	2	1954		O	Base	205	190	Coal	--	--	N	55
Muskingum River	3	1957		O	Base	215	205	Coal	--	--	N	52
Muskingum River	4	1958		O	Base	215	205	Coal	--	--	N	51
Muskingum River	5	1968		O	Base	600	600	Coal	2005	2015	Y	41
Sporn	2	1950		O	Base	150	145	Coal	--	--	N	59
Sporn	4	1952		O	Base	150	145	Coal	--	--	N	57
Sporn	5	1960		O	Base	450	440	Coal	--	--	Y	49
OPCo Coal						8,467	8,331					41
OPCo Hydro		1983	(b)	O	Base	26	20	Hydro	--	--	--	26
OPCo Wind		Various	(c)	C	Wind Project	0	0	Wind	--	--	--	
Total OPCo						**8,492**	**8,351**					

(b) Hydro capacity is rated at expected annual average output.
(c) The capacity of the Wind Energy Projects are listed at the preliminary PJM credit, 13% of the nameplate capacity

	Winter	Summer
TOTAL AEP-East (excl. OVEC)	**28,054**	**27,262**
OVEC Purchase Entitlement	980	947
TOTAL AEP-East	**29,034**	**28,209**

Totals by type

	Winter	Summer
Coal	22,803	22,559
Nuclear	2,191	2,064
Hydro	795	675
Gas/Diesel	3,207	2,873
Wind	39	39
Total	**29,034**	**28,209**

Appendix B, Figure 1 Assumed FGD Scrubber Efficiency and Timing

Assumed FGD Scrubber Efficiency and Timings

Units	Current Scrubber Efficiency - %	New - FGD Installs		FGD - Upgraded	
	2009	Month / Year	Scrubber Efficiency - %	Month / Year	Scrubber Efficiency - %
Amos 1	-	Jan-13	95.0	Jan-14	96.5
Amos 2	-	Apr-12	95.0	Jan-13	96.5
Amos 3	-	Mar-09	95.0	Jan-11	96.5
Big Sandy 2	-	Jun-15	98.0	-	-
Cardinal 1	97.0	-	-	Jan-10	96.5
Cardinal 2	93.0	-	-	Jan-10	96.5
Cardinal 3	-	Jan-12	95.0	Jan-14	96.5
Conesville 4	-	Jun-09	95.0	Jan-11	96.5
Conesville 5	97.0	-	-	-	-
Conesville 6	97.0	-	-	-	-
Gavin 1	94.0	-	-	-	-
Gavin 2	95.0	-	-	-	-
Mitchell 1	98.0	-	-	-	-
Mitchell 2	98.0	-	-	-	-
Mountaineer 1	98.5	-	-	-	-
Muskingum 5	-	Dec-15	97.0	-	-
Rockport 1	-	Jun-17	96.0	-	-
Rockport 2	-	Jun-19	96.0	-	-
Stuart 1-4 (a)	96.0	-	-	Jun-09	96.7
Stuart 1-4	-	-	-	Jul-09	97.0
Zimmer 1	93.0	-	-	-	-

Notes:
(a): Stuart 1-4 FGD is nonoperational from 3/1/09 - 5/31/09
Assumed scrubber efficiencies per K. L. Anderson/T. A. March (4/29/09), WSR (5/05/09)

AMERICAN ELECTRIC POWER

Appendix B, Figure 2 Assumed Capacity Changes Incorporated into Long Range Plan

AEP Eastern Fleet

Anticipated Capacity Changes Incorporated into Long-Range Planning

Unit / Amount / Timing

In MW	Capacity Rating NDC	HP/1st RH Turbine ADSP Improvement (10 MW)	In-Service Date	HP/1st RH Turbine ADSP Improvement 800-series (12 MW)	In-Service Date	HP ADSP Turbine Improvement 1300 series (20-MW)	In-Service Date	Main StopValve MSV/CV Changeout (35-MW)	In-Service Date	Carbon Capture Project (Test/Comm.Oper.)	In-Service Date	(Biomass) Separate Injection	In-Service Date	SCR Derate	In-Service Date	FGD Derate	In-Service Date	Net (MW)
Amos 1	800			812	Jan-13											(22)	Jan-13	790
Amos 2	800			812	Apr-12											(22)	Apr-12	790
Amos 3	1300											1259	Jan-19					1259
Big Sandy 1	260	270	Dec-08															270
Big Sandy 2	800											775	Jan-15			(40)	Jun-15	735
Cardinal 3	630															(10)	Jan-12	620
Conesville 4	337															(2)	Jun-09	335
Conesville 5	395													(4)	Nov-15			391
Conesville 6	395													(4)	Nov-15			391
Gavin 1	1320					0	Jun-09											1320
Gavin 2	1320					0	Jun-11											1320
Mountaineer 1	1320									1315	Oct-09							1315
Mountaineer 1	1315									1285	Jun-14							1285
Mountaineer 1	1285									1125	Jun-20							1125
Muskingum 5	600											582	Jan-15			(10)	Dec-15	572
Rockport 1	1320							1355	Jun-17							(35)	Jun-17	1320
Rockport 2	1300							1335	Jun-19							(35)	Jun-19	1300

Sources:
1) Estimate Big Sandy 1 10-MW capability uprate for the turbine upgrade.
2) The 20-MW capacity increase at both Gavin 1+2 have been removed in June 2009 & 2011, however there will be a heat rate improvement and loss of the seasonal derate, once the work is completed per D. L. Untch/D. M. Collins (5/27/09).
3) Revised main stop valve (MSV) ratings of 35-MW per M. A. Gray (8/30/06).
4) Mountaineer 1 includes a seasonal derate in the period Jun-Sep per R. E. Dool (4/23/09).
5) Carbon Capture project begins in October 2009 will reflect a 5-MW derate per J. L. Perry (9/17/08). The 2009 IRP Expansion Plan CLR (5/19/09) assumes the commercial operation of carbon capture at Mountaineer; capacity reduction (30-MW) 6/2014 and (160-MW) 6/2020.
6) No change in unit capacity after the MSV/FGD are installed at Rockport 1+2 per D. L. Untch/D. M. Collins (5/29/09).
7) The forecast reflects the units being derated for (biomass) separate injection at Amos 3, Big Sandy 2 and Muskingum 5.

Appendix C, (Public) Figure 1 Key Supply Side Resource Assumptions

AEP SYSTEM-EAST ZONE
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) Std. ISO	Trans. Cost (e) ($/kW)	Emission Rates SO2 (g) (lb/MMBtu)	NOx (lb/MMBtu)	CO2 (lb/MMBtu)	Capacity Factor (%)	Overall Availability (%)
Base Load							
Pulv. Coal (Subcritical) (h)	618	24	0.06	0.070	205.3	85	90.7
Pulv. Coal (Subcritical) (h)	736	20	0.06	0.070	205.3	85	89.6
Pulv. Coal (Supercritical) (h)	618	24	0.06	0.070	205.3	85	90.7
Pulv. Coal (Supercritical) (h)	736	20	0.06	0.070	205.3	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	618	24	0.06	0.070	205.3	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	736	20	0.06	0.070	205.3	85	89.6
CFB (h)	585	26	0.06	0.070	210.3	80	90.7
IGCC (h)	630	24	0.06	0.057	205.3	85	87.5
Nuclear (MHI ABWR)	1,606	62	0.00	0.000	0.0	85	94.0
Base Load (50% CO2 Capture New Unit)							
Pulv. Coal (Subcritical) (h)	515	29	0.06	0.070	102.7	85	89.6
Pulv. Coal (Supercritical) (h)	515	29	0.06	0.070	102.7	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	515	29	0.06	0.070	102.7	85	89.6
IGCC (h)	578	26	0.06	0.057	102.7	85	87.5
Base Load (90% CO2 Capture New Unit)							
Pulv. Coal (Subcritical) (h)	433	35	0.0577	0.070	20.5	85	89.6
Pulv. Coal (Subcritical) (h)	515	29	0.0577	0.070	20.5	85	89.6
Pulv. Coal (Supercritical) (h)	433	35	0.0577	0.070	20.5	85	89.6
Pulv. Coal (Supercritical) (h)	515	29	0.0577	0.070	20.5	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	433	35	0.0577	0.070	20.5	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	515	29	0.0577	0.070	20.5	85	89.6
CFB (h)	410	37	0.0577	0.070	20.5	80	89.6
IGCC (h)	536	28	0.0585	0.057	20.5	85	87.5
IGCC (w/ CCS) (h)	536	28	0.0585	0.057	20.5	85	87.5
Intermediate							
Combined Cycle (2X1 GE7FA)	507	30	0.0007	0.008	116.0	85	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	619	24	0.0007	0.008	116.0	85	89.1
Combined Cycle (2X1 GE7FB)	538	28	0.0007	0.008	116.0	85	89.1
Combined Cycle (2X1 GE7FB, w/ Duct Firing)	650	23	0.0007	0.008	116.0	85	89.1
Intermediate (70% CO2 Capture New Unit)							
Combined Cycle (2X1 GE7FA)	447	34	0.0007	0.008	34.8	85	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	546	27	0.0007	0.008	34.8	85	89.1
Combined Cycle (2X1 GE7FB)	475	32	0.0007	0.008	34.8	85	89.1
Combined Cycle (2X1 GE7FB, w/ Duct Firing)	574	26	0.0007	0.008	34.8	85	89.1
Peaking							
Combustion Turbine (2X1GE7EA)	165	60	0.0007	0.033	116.0	5	90.1
Combustion Turbine (2X1GE7EA,w/ Inlet Chillers)	165	60	0.0007	0.009	116.0	5	90.1
Combustion Turbine (4X1GE7EA)	329	60	0.0007	0.033	116.0	5	90.1
Combustion Turbine (4X1GE7EA,w/ Inlet Chillers)	329	60	0.0007	0.009	116.0	5	90.1
Combustion Turbine (6X1GE7EA)	494	60	0.0007	0.033	116.0	5	90.1
Combustion Turbine (6X1GE7EA,w/ Inlet Chillers)	494	60	0.0007	0.009	116.0	5	90.1
Combustion Turbine (8X1GE7EA)	658	60	0.0007	0.033	116.0	5	90.1
Combustion Turbine (8X1GE7EA,w/ Inlet Chillers)	658	60	0.0007	0.009	116.0	5	90.1
Combustion Turbine (2X1GE7FA)	328	60	0.0007	0.033	116.0	5	90.1
Combustion Turbine (2X1GE7FA, w/ Inlet Chillers)	328	60	0.0007	0.009	116.0	5	90.1
Combustion Turbine (3X1GE7FA)	492	60	0.0007	0.033	116.0	5	90.1
Combustion Turbine (3X1GE7FA, w/ Inlet Chillers)	492	60	0.0007	0.009	116.0	5	90.1
Combustion Turbine (4X1GE7FA)	657	60	0.0007	0.033	116.0	5	90.1
Combustion Turbine (4X1GE7FA, w/ Inlet Chillers)	657	60	0.0007	0.009	116.0	5	90.1
Aero-Derivative (4X1GE LM6000PC)	181	60	0.0007	0.056	116.0	5	89.1
Aero-Derivative (1X GE LMS100)	96	60	0.0007	0.056	116.0	5	89.1
Aero-Derivative (1X GE LMS100, w/ Inlet Chillers)	96	60	0.0007	0.009	116.0	5	90.1
Aero-Derivative (2X1GE LMS100)	191	60	0.0007	0.056	116.0	5	89.1
Aero-Derivative (2X1GE LMS100, w/ Inlet Chillers)	191	60	0.0007	0.009	116.0	5	90.1

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2008 dollars. Assume 2.0% escalation rate for 2008 and beyond.
(c) $/kW costs are based on Standard ISO capability.
(e) Transmission Cost ($/kW,w/AFUDC).
(g) Based on 4.5 lb. Coal.
(h) Pittsburgh #8 Coal.

Appendix D, 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 E, Figure 1 AEP-East Summer Peak Demands, Capabilities and Margins

AEP SYSTEM - EASTERN ZONE
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (May 2009) Load Forecast
(2007/2008 - 2030/2031)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
				=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)
	Obligation to PJM										Resources								AEP Position (MW)	
Planning Year	Internal Demand (a)	DSM and Solar (b)	Projected DSM and Solar Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Planned Capacity Additions Units	Planned Capacity Additions MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity
2007 /08 (k)	21,087	(1)		21,087	439	0.957	1.079	22,301	1,391	23,692	28,769	2,574				26,195	7.61%	24,202	510	510
2008 /09 (k)	21,326	(1)		21,326	439	0.958	1.080	22,570	1,400	23,970	28,830	1,793				27,037	7.65%	24,969	999	999
2009 /10 (k)	21,642	(59)		21,642	473	0.957	1.080	22,874	1,400	24,274	28,796	1,131	200 MW Wind	26	0	27,691	8.41%	25,362	1,064	1,088
2010 /11 (k)	21,940	(326)	(1)	21,939	473	0.955	1.083	23,277	1,400	24,677	28,342	1,166	350 MW Wind	46	0	27,248	11.18%	24,202	(539)	(475)
2011 /12	21,698	(629)	(1)	21,697	473	0.955	1.083	23,015	1,391	24,406	28,326	1,107	600 MW Wind	78	0	27,369	8.27%	25,106	562	700
2012 /13	21,915	(816)	(1)	21,914	473	0.950	1.087	23,336	1,391	24,727	27,789	26	60 MW Bio Mass & 700 MW Wind	151	0	28,064	7.36%	25,998	993	1,271
2013 /14	22,170	(1,007)	(1)	22,169	473	0.950	1.087	23,614	1,391	25,005	27,789	26	540 MW D CC2 & 500 MW Wind	605	0	28,669	6.88%	26,697	848	1,692
2014 /15	22,375	(1,196)	(59)	22,316	473	0.950	1.087	23,774	1,391	25,165	27,093	26				27,973	7.24%	25,948	(58)	783
2015 /16	22,557	(1,386)	(326)	22,231	473	0.950	1.087	23,680	1,391	25,071	26,783	(4)				27,693	7.09%	25,730	(183)	659
2016 /17	22,700	(1,396)	(629)	22,072	473	0.950	1.087	23,507	1,391	24,898	26,851	(4)	100 MW Wind	13	0	27,774	7.13%	25,794	42	896
2017 /18	22,918	(1,405)	(816)	22,102	473	0.950	1.087	23,540	1,391	24,931	26,329	(4)				27,252	6.99%	25,347	(439)	416
2018 /19	23,103	(1,417)	(1,007)	22,096	473	0.950	1.087	23,534	1,391	24,925	25,776	(4)	628 MW CT & 127 MW Bio Mass	755	0	27,454	6.56%	25,653	(836)	728
2019 /20	23,254	(1,429)	(1,196)	22,058	473	0.950	1.087	23,493	1,391	24,884	25,291	(4)				26,969	5.90%	25,378	(1,081)	494
2020 /21	23,350	(1,440)	(1,386)	21,964	473	0.950	1.087	23,390	1,391	24,781	25,131	(4)	200 MW Wind	26	0	26,835	5.90%	25,252	(1,129)	471
2021 /22	23,591	(1,464)	(1,396)	22,196	473	0.950	1.087	23,642	1,391	25,033	24,441	(4)	611 MW CC & 127 MW Bio Mass & 150 MW Wind	758	0	26,902	5.82%	25,336	(2,011)	303
2022 /23	23,790	(1,500)	(1,405)	22,385	473	0.950	1.087	23,848	1,391	25,239	24,400	(4)	628 MW CT & 100 MW Wind	641	0	27,502	5.85%	25,893	(2,263)	654
2023 /24	23,905	(1,500)	(1,417)	22,488	473	0.950	1.087	23,960	1,391	25,351	23,740	(4)	611 MW CC & 100 MW Wind	624	0	27,466	5.74%	25,889	(2,970)	538
2024 /25	24,178	(1,537)	(1,429)	22,749	473	0.950	1.087	24,244	1,391	25,635	23,740	(4)	200 MW Wind	26	0	27,492	5.74%	25,914	(3,254)	279
2025 /26	24,429	(1,537)	(1,440)	22,989	473	0.950	1.087	24,504	1,391	25,895	23,240	(4)	628 MW CT & 100 MW Wind	641	0	27,633	5.40%	26,141	(3,906)	246
2026 /27	24,620	(1,561)	(1,464)	23,155	473	0.950	1.087	24,686	1,391	26,077	23,199	(4)	100 MW Wind	13	0	27,605	5.40%	26,114	(4,127)	37
2027 /28	24,813	(1,561)	(1,500)	23,313	473	0.950	1.087	24,857	1,391	26,248	23,199	(4)	611 MW CC & 100 MW Wind	624	0	28,229	5.40%	26,705	(4,298)	457
2028 /29	24,967	(1,585)	(1,500)	23,466	473	0.950	1.087	25,024	1,391	26,415	23,199	(4)	200 MW Wind	26	0	28,255	5.40%	26,729	(4,465)	314
2029 /30	25,205	(1,585)	(1,537)	23,668	473	0.950	1.087	25,243	1,391	26,634	23,199	(4)				28,255	5.40%	26,729	(4,684)	95
2030 /31	25,422	(1,615)	(1,537)	23,885	473	0.950	1.087	25,479	1,391	26,870	22,803	(4)	628 MW CT	628	0	28,487	5.46%	26,932	(5,308)	62

Notes:
(a) Based on (May 2009) Load Forecast (with implied PJM diversity factor)
Includes Monongahela Power & NCEMC

(b) Existing plus approved DSM plus projected solar resource impact.

(c) Reflects a 5 year delay for DSM increases and a 2 year delay for DSM decreases

(d) Demand Response approved by PJM in the prior planning year

(e) Installed Reserve Margin (IRM) = 15.0% through 2009/10, 15.5% through 2011/2012, then 16.2%
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes:
FRR view of obligations only.
Buckeye Cardinal and Mone obligations

(g) Reflects the following summer capability assumptions:
OVEC purchase: 951 MW (Summer)
Assumes hydro units, including Summersville, are derated to August average output in 2014/15
WIND FARM (nameplate):
75 MW Total
EFFICIENCY IMPROVEMENTS:
2007/08: Cardinal 2: 0 MW (turbine) (offset to FGD derate)
2008/09: Rockport 1: 20 MW (turbine); Amos 3: 35 MW (valve)
2009/10: Big Sandy 1: 0 MW (turbine); Gavin 1: 0 MW (turbine)
2011/12: Amos 2: 12 MW (turbine); Cook 2: 14 MW (Uprate); Gavin 2: 0 MW (turbine)
2012/13: Amos 1: 12 MW (turbine)
2014/15: Cook 2: 45 MW (Uprate)
2015/16: Cook 1: 100 MW (Uprate); Cook 2: 68 MW (Uprate)
2016/17: Cook 1: 68 MW (Uprate)
2017/18: Cook 2: 68 MW (Uprate); Rockport 1: 35 MW (valve) (offset to FGD derate)
2018/19: Cook 1: 68 MW (Uprate)
2019/20: Rockport 2: 35 MW (valve) (offset to FGD derate)
CCS DERATES:
2010/11: Mountaineer 1: 5 MW
2014/15: Mountaineer 1: 30 MW
2020/21: Mountaineer 1: 160 MW
2030/31: Gavin 1: 198 MW; Gavin 2: 198 MW

(g) continued
SEPARATE INJECTION DERATES:
2014/15: Big Sandy 2: 25 MW; Muskingum R. 5: 18 MW
2018/19: Amos 3: 41 MW
2022/23: Rockport 1: 41 MW
2026/27: Rockport 2: 41 MW
FGD DERATES:
2007/08: Cardinal 1&2: 20 MW each; Stuart 1-4: 1 MW each
2008/09: Amos 3: 35 MW
2009/10: Conesville 4: 2 MW; Kyger Creek 4-5: 3 MW each
2010/11: Kyger Creek 1-3: 3 MW each
2011/12: Amos 2: 22 MW; Cardinal 3: 10 MW; Clifty Creek 1-5: 2 MW each
2012/13: Amos 1: 22 MW; Clifty Creek 6: 2 MW
2015/16: Big Sandy 2: 40 MW; Muskingum R. 5: 10 MW
2017/18: Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
SCR DERATES:
2009/10: Conesville 4: 0 MW
2015/16: Conesville 5-6: 4 MW each
2017/18: Rockport 1: 0 MW
2019/20: Rockport 2: 0 MW
RETIREMENTS:
2010/11: Sporn 5
2012/13: Conesville 3; Muskingum River 2,4
2014/15: Muskingum River 1,3
2015/16: Glen Lyn 5-6; Picway 5
2017/18: Kammer 1-3
2018/19: Sporn 1-4
2019/20: Tanners Ck. 1-3
2021/22: Clinch R. 1-3
2023/24: Big Sandy 1; Kanawha River 1&2
2025/26: Tanners Ck. 4

(h) Includes:
CP&L Rockport sale through 2009/10
East-West transfer of 250 MW in 2007/08
Sale of 50 MW to Wisconsin Public Service in 2007/08
Sale of 100 MW to Wolverine in 2007/08 - 2009/10, netted against a 100 MW purchase from Dynegy in 2007/08
Constellation purchase of 315 MW in 2009/10-2011/12
Purchase to cover CSP's former Monongahela Power load in 2007/08 - 2009/10
Darby and Lawrenceburg are sold in the 2007/08 RPM auction (by AEP and PSEG)
MISO Sale of 348 MW in 2008/09 and 25 MW in 2009/10
Sale of 22 MW from Tanners Ck. 4 in 2010/11-2014/15
RPM Auction Sales 2007/08 - 2011/12 (775 MW, 1408 MW, 1379 MW, 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(i) New wind capacity value is 13% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30/07

(k) Actual PJM forecast

Appendix F, Figure 1 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%	29	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%	118	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%	29	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%	118	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%	384	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 G, DSM by Company

Demand (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
APCO Va	0	45	90	112	140	167	195	195	195	195
APCO WV	0	45	90	112	140	167	195	195	195	195
KngsP	0	9	16	22	27	32	38	38	38	38
I&M - I	3	50	97	125	152	179	205	205	205	205
I&M - M	2	5	9	25	31	36	42	42	42	42
KPCo	0	18	37	49	61	74	86	86	86	86
OPCo	28	76	139	178	217	256	295	295	295	295
CSP	25	68	130	160	191	222	252	252	252	252
WP	0	9	16	22	27	32	38	38	38	38
AEP-East Zone	**58**	**324**	**624**	**806**	**986**	**1,167**	**1,347**	**1,347**	**1,347**	**1,347**
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**